
IN THE MATTER OF THE PROVISION OF :
BASIC GENERATION SERVICE FOR BASIC :
GENERATION SERVICE REQUIREMENTS :
EFFECTIVE JUNE 1, 2010 : Docket No. EO09050351

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PROPOSAL FOR

BASIC GENERATION SERVICE

REQUIREMENTS TO BE PROCURED EFFECTIVE

JUNE 1, 2010

COMPANY SPECIFIC ADDENDUM

July 1, 2009

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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.

PSE&G will credit the pro-rata share of the Interruptible Load for Reliability Credit received from PJM ("ILR Credit") from PSE&G's Residential Air Conditioning Cycling Program as configured June 1, 2008, to parties of the 2008 BGS-FP Supplier Master Agreements (SMAs) based upon each supplier's responsibility share. Any remaining ILR credits (e.g. the ILR credit associated with supplier responsibility shares arising from the 2009 or 2010 BGS-FP SMAs and any PSE&G ILR Credits resulting from programs initiated after June 1, 2008¹, will be credited to the System Control Charge ("SCC") or successor clause, and will not be provided to suppliers for the portion of BGS-FP Supply associated with the 2009 or 2010 SMAs. PSE&G expects to propose additional demand response programs to the Board that may become eligible for ILR Credit. Any such credit received by PSE&G will be credited to the SCC or other clause as designated by the Board through orders authorizing such new demand response programs².

¹ This includes any ILR credits associated with an expansion of PSE&G's Air Conditioner Cycling Program beyond the amount available from the program as configured on June 1, 2008. The equivalent amount of ILR associated with the 6/1/08 configuration of the Air Conditioner Cycling program is 61.5 MW. Parties to the 2008 BGS-FP SMAs will be entitled their pro-rata share of the ILR credit applicable to the 2008 SMA (28/85^{ths}).

² PSE&G has proposed a new demand response program that will subsume the existing residential air conditioner cycling program. In that filing, PSE&G proposed the elimination of the SCC. Until such time as the Board approves that filing, PSE&G will follow the Board's directive in Docket No. EO03050394, and fund the costs associated with the Company's residential Air Conditioner Cycling Program through the SCC. Regardless of the Board's action in that matter, PSE&G proposes to continue to provide the ILR credit to the parties to the 2008 BGS SMA consistent with the process described in this paragraph.

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, 2010;
- (c) A default during the June 1, 2010 – May 31, 2013 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, 2010, and may retain Committed Supply to serve these tranches. After May 31, 2010 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 2010.

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, 2010 through May 31, 2013 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.

System Control Charge (SCC)

The SCC will continue to be applied to all distribution customers' bills to provide recovery for residential air conditioning load-cycling program costs. Although PSE&G is not proposing any changes to the SCC at this time, any change to the SCC rate to be effective June 1, 2010 will be included with the compliance tariff sheets filed with the Board following the BGS Auction. The current SCC tariff sheet is included in Attachment 1 and is labeled as 2nd Revised Sheet Number 64. PSE&G has also filed a separate proceeding with the Board that would subsume the existing residential air conditioning load-cycling program, and eliminates the SCC. In the event that that occurs, PSE&G will reflect those changes in our final compliance filing.

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;
3. BGS-FP and BGS-CIEP Retail Margin revenues and Board-approved expenses will be tracked using established accounting procedures and will be subject to deferred accounting. These revenues will be recorded separately as Retail Margin revenue and shall not be included in the calculation of BGS-FP or BGS-CIEP reconciliation charges.

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 cents 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 1000 kW. 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, HEP, and LPL-Primary and for LPL-Secondary customers with a peak load share (PLS) of 1000 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 1000 kW).

The following sections describe the tariff sheets that would implement Public Service’s BGS service effective June 1, 2010.

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. 67, 67A, and 68. 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 1000 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. Customers served under delivery Rate Schedule LPL-Secondary having a peak load share of 750 kW or greater as of November 1 of a given year, will have a retail margin charge of \$0.005 per kilowatt hour added to the BGS-FP Energy Charge for all metered kWh use effective for the annual period beginning on June 1st of the following year.

In order to more accurately reflect the costs of providing energy and other electric services when relying on the day-ahead PJM versus 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 2009 to May 2010 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, 2010 to May 31, 2011. For example, for Public Service, for the period beginning June 1, 2010, the weighting will be based on the load (i.e. successfully bid tranches) at the 36-month prices from the 2008, 2009, and 2010 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 1000 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 2010/2011, 2011/2012 and 2012/2013 Base Residual Auction for RPM (Reliability Pricing Model) results applicable to load 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 1000 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, 2010. The winning bid prices will be adjusted for any changes in the BPU-approved BGS Transmission Charges as they occur subsequent to January 1, 2010 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 2010 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 0.015 cents 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. 65, 70 and 70A.

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 1.166164%) 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). A retail margin of \$0.005 per kilowatt hour, as determined by the Board, will then be added to this total for all metered kWh use for all BGS-CIEP customers.

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 0.015 cents 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 Revised Sheet No. 65, 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 1000 kW or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage, HEP, and all customers on Rate Schedules HS, GLP, and LPL-Secondary (less than 1000 kW) that have elected the BGS-CIEP default supply option. PSE&G proposes to update the language in Sheet No. 65 to clarify the intent and applicability of the CIEP Standby Fee.

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 2010/2011 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 2006, 2007 and 2008, 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 2006, 2007, and 2008. As was done with Table #1, the three-year average was used to reduce the effects of weather in a particular year.

Table #3 (Class Usage @ customer) contains the calendar month sales forecasted for the calendar year 2009. For Rate LPL-Secondary, these values have been reduced for the percentage of customers having a Peak Load Share of 1000 kW or greater, and thus having BGS-CIEP as their default service. These monthly percentages were based on the 2008 monthly percentages of total actual sales for customers meeting this Peak Load Share threshold.

Table #4 (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 2010 to May 2011 and the historical ratio of actual off-peak to on-peak PJM LMPs for the 2006, 2007 and 2008 energy years.

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.

Table #5 (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, for the 2006, 2007, and 2008 energy years.

Table #6 (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-rating factors based on July 2007 to February 2009 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 1000 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 2009. 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 1000 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 zone³. 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

³ This transmission service cost (\$18,054 per MW-yr) does not include RMR or other PJM Schedule 12 Transmission Enhancement Charges

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 \$87.00 per MWh and the GLP multiplier for summer is 1.078 and the constant is \$(19.571), the summer BGS rate charged customers would equal $(\$87.00 * 1.078) - \19.571 , or \$74.22 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 2010 to May 2011 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, 2010 to May 31, 2013.
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” SCC, BGS-FP, BGS-CIEP and CIEP Standby Fee tariff sheets.

SYSTEM CONTROL CHARGE

	Charge (cents per kilowatthour)
SYSTEM CONTROL CHARGE	
Charge	0.0115
Charge including New Jersey Sales and Use Tax (SUT)	0.0123

SYSTEM CONTROL CHARGE

This mechanism is designed to provide recovery of costs associated with the operation of certain programs as approved by the BPU. Actual costs incurred by the Company will be subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances. This interest rate shall change each August 1.

Date of Issue: July 14, 2006

Effective: July 15, 2006

Issued by FRANCIS E. DELANY, Jr., Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102

Filed pursuant to Order of Board of Public Utilities dated February 11, 2004
in Docket No. EO03050394 and also Docket No. AT06070502

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

The CIEP Standby Fee is a Delivery Charge that is applicable to all customers having BGS-CIEP as their default supply service option. This includes all customers served on Default electric supply service for Rate Schedules LPL-Secondary (1,000 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage and HEP, and to any customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 1,000 kilowatts) who have has elected BGS-CIEP as their default supply service.

**Charge
(cents per kilowatthour)**

Commercial and Industrial Energy Pricing (CIEP) Standby Fee 0.0150

Charge including New Jersey Sales and Use Tax (SUT)..... 0.0161

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:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Effective:

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

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,000 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 <u>October through May</u>		For usage in each of the months of <u>June through September</u>	
	Charges		Charges	
	<u>Charges</u>	<u>Including SUT</u>	<u>Charges</u>	<u>Including SUT</u>
RS – first 600 kWh	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
RS – in excess of 600 kWh	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
RHS – first 600 kWh	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
RHS – in excess of 600 kWh	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
RLM On-Peak	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
RLM Off-Peak	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
WH	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
WHS	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
HS	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
BPL	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
BPL-POF	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
PSAL	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢

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.

Date of Issue:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Effective:

**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:

Rate Schedule	For usage in each of the months of <u>October through May</u>		For usage in each of the months of <u>June through September</u>	
	<u>Charges</u>	<u>Charges Including SUT</u>	<u>Charges</u>	<u>Charges Including SUT</u>
	GLP	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
GLP Night Use	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
LPL-Sec. under 750 kW				
On-Peak	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
Off-Peak	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
LPL-Sec. equal to or greater than 750 kW but less than 1,000 kW				
On-Peak	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢
Off-Peak	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢	x.xxxx ¢

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.

Date of Issue:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Effective:

**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 stated in the FERC Electric Tariff of the PJM Interconnection, LLC	\$ 18,054.72 per MW per year
PJM Seams Elimination Cost Assignment Charges	\$ xx.xx per MW per month
PJM Reliability Must Run Charge.....	\$ xx.xx per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company Projects.....	\$ xx.xx per MW per month
Virginia Electric and Power Company Projects	\$ xx.xx per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	\$ 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).

Date of Issue:

Effective:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

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

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (1,000 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage and HEP and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 1,000 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, PJM Ancillary Services and a Retail Margin. 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 4.07251.166164%), 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 4.07251.166164%), and adjusted for SUT, plus
- A Retail Margin at the rate of \$0.005000 (\$0.005350 including SUT) per kilowatthour.

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.

Date of Issue:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Effective:

**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 stated in the FERC Electric Tariff of the PJM Interconnection, LLC	\$ 18,054.72 per MW per year
PJM Seams Elimination Cost Assignment Charges	\$ xx.xx per MW per month
PJM Reliability Must Run Charge.....	\$ xx.xx per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company Projects	\$ xx.xx per MW per month
Virginia Electric and Power Company Projects	\$ xx.xx per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	\$ 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.

Date of Issue:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Effective:

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

(Pages 1 through 7)

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

**Development of BGS-FP Cost and Bid Factors for 2010/11 BGS Filing
Adjusted to Billing Time Periods**

Table #1 % Usage During PJM On-Peak Period

*Based on average of year 2006, 2007 & 2008 Load Profile Information
On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays*

(data rounded to nearest .01%)	Profile Meter	Profile Meter	Profile Meter	Profile Meter	Profile	Profile	--- Other Analysis ---		Profile Meter	Profile Meter
	Data RS	Data RHS	Data RLM	Data WH	Meter Data WHS	Meter Data HS	PSAL	BPL	Data GLP	Data LPL-S
January	49.78%	49.06%	50.55%	44.36%	45.10%	49.23%	23.78%	23.78%	59.15%	56.12%
February	50.70%	49.06%	51.13%	44.83%	42.25%	48.52%	28.66%	28.66%	59.43%	56.26%
March	50.11%	49.10%	49.99%	44.22%	42.61%	48.41%	23.79%	23.79%	58.61%	56.27%
April	49.70%	50.55%	50.17%	42.64%	41.95%	52.60%	26.59%	26.59%	59.49%	57.02%
May	49.55%	52.33%	50.47%	43.44%	42.70%	60.05%	25.34%	25.34%	60.46%	58.05%
June	52.44%	53.75%	53.61%	43.64%	44.14%	67.65%	22.33%	22.33%	62.12%	58.50%
July	50.72%	51.49%	51.62%	41.95%	43.61%	64.18%	17.85%	17.85%	60.03%	55.51%
August	53.62%	54.83%	54.17%	45.07%	46.07%	67.29%	21.48%	21.48%	62.63%	58.36%
September	46.43%	49.28%	47.63%	41.23%	42.06%	63.34%	20.27%	20.27%	58.48%	55.63%
October	52.01%	53.04%	53.79%	45.84%	44.51%	62.05%	27.47%	27.47%	62.46%	60.19%
November	48.05%	47.16%	49.21%	42.41%	42.24%	47.40%	29.87%	29.87%	57.60%	55.27%
December	47.56%	46.19%	48.12%	41.34%	39.19%	45.88%	30.47%	30.47%	55.94%	53.27%

Table #2 % Usage During PSE&G On-Peak Billing Period

*Based on average of year 2006, 2007 & 2008 Load Profile Information
On-Peak periods as defined in specified rate schedule (average of %s for 2006, 2007 & 2008)*

(data rounded to nearest .01%)	N/A	N/A	Profile Meter	N/A	N/A	N/A	N/A	N/A	N/A	Profile Meter
	RS	RHS	Data RLM	WH	WHS	HS	PSAL	BPL	GLP	Data LPL-S
January	---	---	43.18%	---	---	---	---	---	---	48.84%
February	---	---	42.89%	---	---	---	---	---	---	49.49%
March	---	---	45.40%	---	---	---	---	---	---	49.21%
April	---	---	42.70%	---	---	---	---	---	---	50.12%
May	---	---	44.44%	---	---	---	---	---	---	51.13%
June	---	---	46.12%	---	---	---	---	---	---	51.80%
July	---	---	47.72%	---	---	---	---	---	---	51.27%
August	---	---	48.46%	---	---	---	---	---	---	51.19%
September	---	---	46.49%	---	---	---	---	---	---	51.28%
October	---	---	45.09%	---	---	---	---	---	---	51.39%
November	---	---	44.08%	---	---	---	---	---	---	51.06%
December	---	---	43.45%	---	---	---	---	---	---	49.35%

Table #3 Class Usage @ customer

calendar month sales forecasted for 2009, less % for LPL-Sec >1000 kW Peak Load Share in MWh

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	> 1000 kW LPL-S	
January	1,186,684	25,153	24,482	273	3	3,711	23,399	35,006	690,010	830,640	83.3%
February	935,789	21,162	19,455	274	3	3,754	12,818	29,289	659,897	790,814	
March	955,437	18,518	19,306	288	4	2,380	17,675	29,133	671,573	816,602	
April	820,449	11,580	16,645	237	3	1,491	6,774	24,826	620,921	770,811	
May	911,049	8,450	19,316	272	4	795	11,612	22,868	643,753	791,959	
June	1,302,947	10,008	28,707	233	2	1,233	9,549	20,597	740,114	838,059	

**Public Service Electric and Gas Company Specific Addendum
Attachment 2**

July	1,696,537	11,476	35,734	216	3	1,399	11,516	22,006	837,554	977,403
August	1,565,442	10,682	32,333	171	3	1,397	13,563	24,434	829,808	988,548
September	1,141,988	8,463	24,309	177	1	371	14,586	26,862	701,716	876,050
October	864,749	9,564	18,177	201	2	1,211	18,290	31,091	639,475	813,737
November	893,827	13,964	17,298	226	4	1,701	17,911	32,970	597,304	733,043
December	1,032,307	20,092	20,927	234	3	3,325	18,041	35,711	632,817	737,163
Total	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793	8,264,942	9,964,829

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	71.00	0.7174	50.935
February	71.00	0.7174	50.935
March	61.75	0.7174	44.299
April	61.75	0.7174	44.299
May	57.25	0.7174	41.071
June	61.38	0.6284	38.571
July	75.44	0.6284	47.406
August	75.44	0.6284	47.406
September	58.85	0.6284	36.981
October	56.88	0.7174	40.806
November	56.88	0.7174	40.806
December	56.88	0.7174	40.806

Table #5 Zone to Western Hub Basis Differential

	On-Peak	Off-Peak	
January	116%	111%	NYMEX Forwards (June 9, 2009) from NERA 6/2006 through 5/2009 average for Zone/Hub differentials
February	116%	111%	
March	116%	111%	
April	116%	111%	
May	116%	111%	
June	111%	110%	
July	111%	110%	
August	111%	110%	
September	111%	110%	
October	116%	111%	
November	116%	111%	
December	116%	111%	

Table #6 Losses

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
<i>from meter to bulk system (includes Delivery & PJM EHV losses)</i>										
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
<i>from meter to transmission node (includes Delivery less mean hourly PJM marginal losses)</i>										
Loss Factors =	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%
Expansion Factor =	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909
1 / Expansion Factor =	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533

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	\$ 67.87	\$ 67.91	\$ 68.02	\$ 64.10	\$ 67.24	\$ 73.78	\$ 57.25	\$ 57.10	\$ 70.35	\$ 69.06
PJM on pk	\$ 83.44	\$ 82.86	\$ 83.23	\$ 81.76	\$ 85.21	\$ 84.58	\$ 81.58	\$ 81.33	\$ 82.60	\$ 82.44
PJM off pk	\$ 51.63	\$ 51.40	\$ 51.56	\$ 50.80	\$ 52.91	\$ 52.75	\$ 51.00	\$ 50.87	\$ 51.29	\$ 51.33
Winter - all hrs	\$ 65.88	\$ 66.93	\$ 66.10	\$ 64.47	\$ 63.61	\$ 67.65	\$ 60.16	\$ 60.10	\$ 68.03	\$ 67.35
PJM on pk	\$ 78.28	\$ 79.67	\$ 78.29	\$ 78.39	\$ 77.70	\$ 80.19	\$ 77.71	\$ 77.63	\$ 78.02	\$ 77.93
PJM off pk	\$ 53.65	\$ 54.66	\$ 53.70	\$ 53.69	\$ 53.21	\$ 55.21	\$ 53.70	\$ 53.57	\$ 53.55	\$ 53.55
Annual	\$ 66.73	\$ 67.16	\$ 66.94	\$ 64.36	\$ 64.55	\$ 68.83	\$ 59.35	\$ 59.26	\$ 68.90	\$ 67.98

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System Total \$ 67.55

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	\$	387,335	\$ 2,759	\$ 8,236	\$ 51	\$ 1	\$ 325	\$ 2,818	\$ 5,362	\$ 218,726	\$ 254,139
	PJM on pk	\$ 243,093	\$ 1,766	\$ 5,238	\$ 28	\$ 0	\$ 246	\$ 821	\$ 1,563	\$ 156,331	\$ 172,892
	PJM off pk	\$ 144,242	\$ 993	\$ 2,998	\$ 23	\$ 0	\$ 79	\$ 1,997	\$ 3,799	\$ 62,395	\$ 81,247
Winter - all hrs	\$	500,717	\$ 8,599	\$ 10,285	\$ 129	\$ 2	\$ 1,243	\$ 7,612	\$ 14,477	\$ 350,734	\$ 423,266
	PJM on pk	\$ 295,384	\$ 5,021	\$ 6,141	\$ 69	\$ 1	\$ 733	\$ 2,647	\$ 5,070	\$ 237,974	\$ 277,228
	PJM off pk	\$ 205,333	\$ 3,578	\$ 4,144	\$ 61	\$ 1	\$ 509	\$ 4,965	\$ 9,406	\$ 112,760	\$ 146,038
Annual	\$	888,052	\$ 11,358	\$ 18,521	\$ 180	\$ 2	\$ 1,567	\$ 10,429	\$ 19,839	\$ 569,461	\$ 677,404
System Total	\$	2,196,813									

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	\$	67.87	\$ 67.91	\$ 68.02	\$ 64.10	\$ 67.24	\$ 73.78	\$ 57.25	\$ 57.10	\$ 70.35	\$ 69.06
	PSE&G On pk			\$ 84.80							\$ 84.14
	PSE&G Off pk			\$ 52.97							\$ 53.12
Winter - all hrs	\$	65.88	\$ 66.93	\$ 66.10	\$ 64.47	\$ 63.61	\$ 67.65	\$ 60.16	\$ 60.10	\$ 68.03	\$ 67.35
	PSE&G On pk			\$ 80.12							\$ 79.52
	PSE&G Off pk			\$ 55.13							\$ 55.14
Annual Average	\$	66.73	\$ 67.16	\$ 66.94	\$ 64.36	\$ 64.55	\$ 68.83	\$ 59.35	\$ 59.26	\$ 68.90	\$ 67.98
System Average	\$	67.55									

Table #10 Generation & Transmission Obligations and Costs and Other Adjustments
*obligations - Peak Load shares eff 6/1/09, scaling factors eff 6/1/09, Transmission Loads eff 1/1/09; costs are market estimates
in MW*

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	Adj for PLS > 1000 kW LPL-S
Gen Obl - MW	4,859.2	37.3	94.2	0.6	0.0	6.8	0.0	0.0	2,580.3	2,360.0
Trans Obl - MW	4,286.8	32.8	82.8	0.5	0.0	5.9	0.0	0.0	2,313.6	2,120.1
# 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 = \$	18,054.72	per MW-yr							
Generation Capacity cost	summer = \$	149.07	\$/MWh/day							

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winter = \$ 149.07 \$/MWh/day

	RS	RHS	
<u>% usage in Summer Blocks</u>			
Block 1 (0-600 kWh/m)	60.8%	47.2%	(based on W/N actuals for 2002, rounded to .1%)
Block 2 (>600 kWh/m)	39.2%	52.8%	
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 \$	5.82	\$ 3.50	\$ 5.40	\$ 3.22	\$ -	\$ 4.68	\$ -	\$ -
Generation Obl -								
per annual MWh \$	19.87	\$ 12.00	\$ 40.82	\$ 11.65	\$ -	\$ 16.25	\$ -	\$ -
recovery per summer MWh \$	15.49	\$ 16.70	\$ 29.92	\$ 13.69	\$ -	\$ 28.11	\$ -	\$ -
recovery per winter MWh \$	23.16	\$ 10.52	\$ 49.97	\$ 10.84	\$ -	\$ 13.41	\$ -	\$ -
			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 \$	92.43	\$ 91.37	\$	\$ 84.27	\$ 70.50	\$ 109.83	\$ 60.52	\$ 60.37
PSE&G On pk			\$ 123.38					
PSE&G Off pk			\$ 61.63					
Block 1 (0-600 kWh/m) \$	89.04	\$ 85.26						
Block 2 (>600 kWh/m) \$	97.70	\$ 96.83						
Winter - all hrs \$	98.12	\$ 84.21	\$	\$ 81.79	\$ 66.88	\$ 89.00	\$ 63.42	\$ 63.36
PSE&G On pk			\$ 138.76					
PSE&G Off pk			\$ 63.80					
Annual -all hrs \$	95.68	\$ 85.93	\$ 94.13	\$ 82.50	\$ 67.81	\$ 93.02	\$ 62.61	\$ 62.52

DEMAND RATES

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

	GLP	LPL-S	PLUS:	GLP	LPL-S
Summer - all hrs \$	73.61	\$ 72.32	<u>Gen Cost</u>		
PSE&G On pk		\$ 87.41	summer \$	4.5466	\$ 4.5466 per kW of G obl /month

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	PSE&G Off pk	\$	56.38		winter \$	4.5280	\$	4.5280	per kW of G obl /month
Winter - all hrs		\$	71.29	\$	70.61				
	PSE&G On pk			\$	82.78				
	PSE&G Off pk			\$	58.41				
						<u>Trans cost</u>			
						all months \$	1.5046	\$	1.5046 per kW of T obl /month
Annual - all hrs per MWh only		\$	72.16	\$	71.24				
<u>Including T&G Obligation \$</u>									
Summer - all hrs		\$	93.18	\$	87.45				Note: Obligation \$ included in On pk costs
	PSE&G On pk			\$	116.86				
	PSE&G Off pk			\$	56.38				
Winter - all hrs		\$	94.82	\$	88.27				
	PSE&G On pk			\$	118.06				
	PSE&G Off pk			\$	58.41				
Annual - including T&G Obl \$		\$	94.20	\$	87.97				

ALL RATES

Grand Total Cost in \$1000 = \$ 3,003,309
 All-In Average cost @ customer = \$ 92.36 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 86.40 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				0.975	0.816	1.271	0.700	0.699	
	PSE&G On pk		1.428				Use weighted average		
	PSE&G Off pk		0.713				for all streetlighting =		0.699
	All usage Multiplier	1.070	1.058						
	Constant (in \$/MWh) \$	(3.392)	(6.108)	for Block 1 (0-600 kWh/m) usage					
	Constant (in \$/MWh) \$	5.260	5.461	for Block 2 (>600 kWh/m) usage					
Winter - all hrs	1.136	0.975		0.947	0.774	1.030	0.734	0.733	
	PSE&G On pk		1.606				Use weighted average		
	PSE&G Off pk		0.738				for all streetlighting =		0.733
Annual - all hrs	1.107	0.995	1.089	0.955	0.785	1.077	0.725	0.724	

DEMAND RATES

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

GLP GLP LPL-S LPL-S PLUS:

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	Multiplier	Constant (in \$/MWh)	Multiplier	Constant (in \$/MWh)						
Summer - all hrs	1.078	(19.571)								
PSE&G On pk			1.353	(29.452)	<u>Gen Cost</u>	summer \$	4.5466	\$	4.5466	per kW of G obl /month
PSE&G Off pk			0.653	-		winter \$	4.5280	\$	4.5280	per kW of G obl /month
Winter - all hrs	1.097	(23.530)								
PSE&G On pk			1.366	(35.280)	<u>Trans cost</u>	all months \$	1.5046	\$	1.5046	per kW of T obl /month
PSE&G Off pk			0.676	-						
Annual - including T&G Obl \$	1.090		1.018							

Assumptions:

Gen Cost = \$ 149.07 /MW day summer
 \$ 149.07 /MW day winter

Trans cost = \$ 18,054.72 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 2009 energy use by class, PJM and PSE&G on/off % from 2006, 2007 & 2008 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	\$ 527,518	\$ 3,712	\$ 10,998	\$ 67	\$ 1	\$ 483	\$ 2,978	\$ 5,668	\$ 289,721	\$ 321,824
Winter	\$ 745,737	\$ 10,819	\$ 15,046	\$ 164	\$ 2	\$ 1,635	\$ 8,024	\$ 15,263	\$ 488,871	\$ 554,777
Total	\$ 1,273,256	\$ 14,532	\$ 26,044	\$ 231	\$ 2	\$ 2,118	\$ 11,003	\$ 20,931	\$ 778,592	\$ 876,601
% of Annual Total \$ by Rate										
Summer	41%	26%	42%	29%	27%	23%	27%	27%	37%	37%
Winter	59%	74%	58%	71%	73%	77%	73%	73%	63%	63%
Total Costs - in \$1000										
Summer	\$ 1,162,972									
Winter	\$ 1,840,338									
Total	\$ 3,003,309									
% of Annual Total \$										
Summer	39%									
Winter	61%									

rounded to 4 decimal places

			If total \$ were split on a per MWh basis (on transmission node MWhs):			
Summer	39%	\$ 84.96	per MWh @ trans nodes	Ratio to All-In Cost >>>	Summer	0.9833
Winter	61%	\$ 87.34	per MWh @ trans nodes		Winter	1.0109

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

Assumed Winning Bid Price = \$ **87.00** (bid includes payments for all losses)
 Payment Ratio - Summer = 0.9833
 Payment Ratio - Winter = 1.0109

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in \$1000										
Summer	\$ 531,254	\$ 3,740	\$ 11,073	\$ 68	\$ 1	\$ 487	\$ 2,993	\$ 5,710	\$ 291,599	\$ 324,200
Winter	\$ 751,152	\$ 10,899	\$ 15,148	\$ 165	\$ 2	\$ 1,646	\$ 8,068	\$ 15,362	\$ 492,062	\$ 558,502
Total	\$ 1,282,406	\$ 14,638	\$ 26,220	\$ 233	\$ 2	\$ 2,132	\$ 11,061	\$ 21,072	\$ 783,661	\$ 882,702
Total Summer	\$ 1,171,124									
Total Winter	\$ 1,853,005									
Grand Total	\$ 3,024,129									
	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Supplier Payment - in \$1000										
Summer	\$ 521,852	\$ 3,715	\$ 11,072	\$ 73	\$ 1	\$ 402	\$ 4,500	\$ 8,586	\$ 284,311	\$ 336,512
Winter	\$ 714,494	\$ 12,079	\$ 14,628	\$ 188	\$ 2	\$ 1,727	\$ 11,894	\$ 22,646	\$ 484,686	\$ 590,823
Total	\$ 1,236,346	\$ 15,794	\$ 25,700	\$ 261	\$ 3	\$ 2,129	\$ 16,394	\$ 31,232	\$ 768,996	\$ 927,335
Total Summer	\$ 1,171,025									
Total Winter	\$ 1,853,167									
Grand Total	\$ 3,024,192									

Difference (in \$1000) = \$ (63)

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 13,688,659
 Winter 21,071,096
 Total 34,759,755

**VII. ATTACHMENT 3 – SPREADSHEETS FOR THE CALCULATION OF
BGS RATES**

(Pages 1 through 6)

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**Development of BGS-FP Cost and Bid Factors for 2010/11 BGS Filing
Adjusted to Billing Time Periods**

Table #1 % Usage During PJM On-Peak Period

*Based on average of year 2006, 2007 & 2008 Load Profile Information
On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays*

(data rounded to nearest .01%)	Profile Meter	Profile Meter	Profile Meter	Profile Meter	Profile	Profile	--- Other Analysis ---		Profile Meter	Profile Meter
	Data RS	Data RHS	Data RLM	Data WH	Meter Data WHS	Meter Data HS	PSAL	BPL	Data GLP	Data LPL-S
January	49.78%	49.06%	50.55%	44.36%	45.10%	49.23%	23.78%	23.78%	59.15%	56.12%
February	50.70%	49.06%	51.13%	44.83%	42.25%	48.52%	28.66%	28.66%	59.43%	56.26%
March	50.11%	49.10%	49.99%	44.22%	42.61%	48.41%	23.79%	23.79%	58.61%	56.27%
April	49.70%	50.55%	50.17%	42.64%	41.95%	52.60%	26.59%	26.59%	59.49%	57.02%
May	49.55%	52.33%	50.47%	43.44%	42.70%	60.05%	25.34%	25.34%	60.46%	58.05%
June	52.44%	53.75%	53.61%	43.64%	44.14%	67.65%	22.33%	22.33%	62.12%	58.50%
July	50.72%	51.49%	51.62%	41.95%	43.61%	64.18%	17.85%	17.85%	60.03%	55.51%
August	53.62%	54.83%	54.17%	45.07%	46.07%	67.29%	21.48%	21.48%	62.63%	58.36%
September	46.43%	49.28%	47.63%	41.23%	42.06%	63.34%	20.27%	20.27%	58.48%	55.63%
October	52.01%	53.04%	53.79%	45.84%	44.51%	62.05%	27.47%	27.47%	62.46%	60.19%
November	48.05%	47.16%	49.21%	42.41%	42.24%	47.40%	29.87%	29.87%	57.60%	55.27%
December	47.56%	46.19%	48.12%	41.34%	39.19%	45.88%	30.47%	30.47%	55.94%	53.27%

Table #2 % Usage During PSE&G On-Peak Billing Period

*Based on average of year 2006, 2007 & 2008 Load Profile Information
On-Peak periods as defined in specified rate schedule (average of %s for 2006, 2007 & 2008)*

(data rounded to nearest .01%)	N/A	N/A	Profile Meter	N/A	N/A	N/A	N/A	N/A	N/A	Profile Meter
	RS	RHS	Data RLM	WH	WHS	HS	PSAL	BPL	GLP	Data LPL-S
January	---	---	43.18%	---	---	---	---	---	---	48.84%
February	---	---	42.89%	---	---	---	---	---	---	49.49%
March	---	---	45.40%	---	---	---	---	---	---	49.21%
April	---	---	42.70%	---	---	---	---	---	---	50.12%
May	---	---	44.44%	---	---	---	---	---	---	51.13%
June	---	---	46.12%	---	---	---	---	---	---	51.80%
July	---	---	47.72%	---	---	---	---	---	---	51.27%
August	---	---	48.46%	---	---	---	---	---	---	51.19%
September	---	---	46.49%	---	---	---	---	---	---	51.28%
October	---	---	45.09%	---	---	---	---	---	---	51.39%
November	---	---	44.08%	---	---	---	---	---	---	51.06%
December	---	---	43.45%	---	---	---	---	---	---	49.35%

Table #3 Class Usage @ customer

calendar month sales forecasted for 2009, less % for LPL-Sec >1000 kW Peak Load Share in MWh

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	> 1000 kW LPL-S	
January	1,186,684	25,153	24,482	273	3	3,711	23,399	35,006	690,010	830,640	83.3%
February	935,789	21,162	19,455	274	3	3,754	12,818	29,289	659,897	790,814	
March	955,437	18,518	19,306	288	4	2,380	17,675	29,133	671,573	816,602	
April	820,449	11,580	16,645	237	3	1,491	6,774	24,826	620,921	770,811	
May	911,049	8,450	19,316	272	4	795	11,612	22,868	643,753	791,959	
June	1,302,947	10,008	28,707	233	2	1,233	9,549	20,597	740,114	838,059	

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July	1,696,537	11,476	35,734	216	3	1,399	11,516	22,006	837,554	977,403
August	1,565,442	10,682	32,333	171	3	1,397	13,563	24,434	829,808	988,548
September	1,141,988	8,463	24,309	177	1	371	14,586	26,862	701,716	876,050
October	864,749	9,564	18,177	201	2	1,211	18,290	31,091	639,475	813,737
November	893,827	13,964	17,298	226	4	1,701	17,911	32,970	597,304	733,043
December	1,032,307	20,092	20,927	234	3	3,325	18,041	35,711	632,817	737,163
Total	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793	8,264,942	9,964,829

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	71.00	0.7174	50.935
February	71.00	0.7174	50.935
March	61.75	0.7174	44.299
April	61.75	0.7174	44.299
May	57.25	0.7174	41.071
June	61.38	0.6284	38.571
July	75.44	0.6284	47.406
August	75.44	0.6284	47.406
September	58.85	0.6284	36.981
October	56.88	0.7174	40.806
November	56.88	0.7174	40.806
December	56.88	0.7174	40.806

Table #5 Zone to Western Hub Basis Differential

	On-Peak	Off-Peak	
January	116%	111%	<i>NYMEX Forwards (June 9, 2009) from NERA 6/2006 through 5/2009 average for Zone/Hub differentials</i>
February	116%	111%	
March	116%	111%	
April	116%	111%	
May	116%	111%	
June	111%	110%	
July	111%	110%	
August	111%	110%	
September	111%	110%	
October	116%	111%	
November	116%	111%	
December	116%	111%	

Table #6 Losses

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
<i>from meter to bulk system (includes Delivery & PJM EHV losses)</i>										
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
<i>from meter to transmission node (includes Delivery less mean hourly PJM marginal losses)</i>										
Loss Factors =	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%	6.4467%
Expansion Factor =	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909	1.068909
1 / Expansion Factor =	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533	0.935533

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	\$ 67.87	\$ 67.91	\$ 68.02	\$ 64.10	\$ 67.24	\$ 73.78	\$ 57.25	\$ 57.10	\$ 70.35	\$ 69.06
PJM on pk	\$ 83.44	\$ 82.86	\$ 83.23	\$ 81.76	\$ 85.21	\$ 84.58	\$ 81.58	\$ 81.33	\$ 82.60	\$ 82.44
PJM off pk	\$ 51.63	\$ 51.40	\$ 51.56	\$ 50.80	\$ 52.91	\$ 52.75	\$ 51.00	\$ 50.87	\$ 51.29	\$ 51.33
Winter - all hrs	\$ 65.88	\$ 66.93	\$ 66.10	\$ 64.47	\$ 63.61	\$ 67.65	\$ 60.16	\$ 60.10	\$ 68.03	\$ 67.35
PJM on pk	\$ 78.28	\$ 79.67	\$ 78.29	\$ 78.39	\$ 77.70	\$ 80.19	\$ 77.71	\$ 77.63	\$ 78.02	\$ 77.93
PJM off pk	\$ 53.65	\$ 54.66	\$ 53.70	\$ 53.69	\$ 53.21	\$ 55.21	\$ 53.70	\$ 53.57	\$ 53.55	\$ 53.55
Annual	\$ 66.73	\$ 67.16	\$ 66.94	\$ 64.36	\$ 64.55	\$ 68.83	\$ 59.35	\$ 59.26	\$ 68.90	\$ 67.98

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System Total \$ 67.55

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	\$	387,335	\$ 2,759	\$ 8,236	\$ 51	\$ 1	\$ 325	\$ 2,818	\$ 5,362	\$ 218,726	\$ 254,139
	PJM on pk	\$ 243,093	\$ 1,766	\$ 5,238	\$ 28	\$ 0	\$ 246	\$ 821	\$ 1,563	\$ 156,331	\$ 172,892
	PJM off pk	\$ 144,242	\$ 993	\$ 2,998	\$ 23	\$ 0	\$ 79	\$ 1,997	\$ 3,799	\$ 62,395	\$ 81,247
Winter - all hrs	\$	500,717	\$ 8,599	\$ 10,285	\$ 129	\$ 2	\$ 1,243	\$ 7,612	\$ 14,477	\$ 350,734	\$ 423,266
	PJM on pk	\$ 295,384	\$ 5,021	\$ 6,141	\$ 69	\$ 1	\$ 733	\$ 2,647	\$ 5,070	\$ 237,974	\$ 277,228
	PJM off pk	\$ 205,333	\$ 3,578	\$ 4,144	\$ 61	\$ 1	\$ 509	\$ 4,965	\$ 9,406	\$ 112,760	\$ 146,038
Annual	\$	888,052	\$ 11,358	\$ 18,521	\$ 180	\$ 2	\$ 1,567	\$ 10,429	\$ 19,839	\$ 569,461	\$ 677,404
System Total	\$	2,196,813									

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	\$	67.87	\$ 67.91	\$ 68.02	\$ 64.10	\$ 67.24	\$ 73.78	\$ 57.25	\$ 57.10	\$ 70.35	\$ 69.06
	PSE&G On pk			\$ 84.80							\$ 84.14
	PSE&G Off pk			\$ 52.97							\$ 53.12
Winter - all hrs	\$	65.88	\$ 66.93	\$ 66.10	\$ 64.47	\$ 63.61	\$ 67.65	\$ 60.16	\$ 60.10	\$ 68.03	\$ 67.35
	PSE&G On pk			\$ 80.12							\$ 79.52
	PSE&G Off pk			\$ 55.13							\$ 55.14
Annual Average	\$	66.73	\$ 67.16	\$ 66.94	\$ 64.36	\$ 64.55	\$ 68.83	\$ 59.35	\$ 59.26	\$ 68.90	\$ 67.98
System Average	\$	67.55									

Table #10 Generation & Transmission Obligations and Costs and Other Adjustments
*obligations - Peak Load shares eff 6/1/09, scaling factors eff 6/1/09, Transmission Loads eff 1/1/09; costs are market estimates
in MW*

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	Adj for PLS > 1000 kW LPL-S
Gen Obl - MW	4,859.2	37.3	94.2	0.6	0.0	6.8	0.0	0.0	2,580.3	2,360.0
Trans Obl - MW	4,286.8	32.8	82.8	0.5	0.0	5.9	0.0	0.0	2,313.6	2,120.1
# 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 = \$	18,054.72	per MW-yr							
Generation Capacity cost	summer = \$	149.07	\$/MWh/day							

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winter = \$ 149.07 \$/MW/day

	RS	RHS	
<u>% usage in Summer Blocks</u>			
Block 1 (0-600 kWh/m)	60.8%	47.2%	(based on W/N actuals for 2002, rounded to .1%)
Block 2 (>600 kWh/m)	39.2%	52.8%	
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 \$	5.82	\$ 3.50	\$ 5.40	\$ 3.22	\$ -	\$ 4.68	\$ -	\$ -
Generation Obl -								
per annual MWh \$	19.87	\$ 12.00	\$ 40.82	\$ 11.65	\$ -	\$ 16.25	\$ -	\$ -
recovery per summer MWh \$	15.49	\$ 16.70	\$ 29.92	\$ 13.69	\$ -	\$ 28.11	\$ -	\$ -
recovery per winter MWh \$	23.16	\$ 10.52	\$ 49.97	\$ 10.84	\$ -	\$ 13.41	\$ -	\$ -
			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 \$	92.43	\$ 91.37	\$	\$ 84.27	\$ 70.50	\$ 109.83	\$ 60.52	\$ 60.37
PSE&G On pk			\$ 123.38					
PSE&G Off pk			\$ 61.63					
Block 1 (0-600 kWh/m) \$	89.04	\$ 85.26						
Block 2 (>600 kWh/m) \$	97.70	\$ 96.83						
Winter - all hrs \$	98.12	\$ 84.21	\$	\$ 81.79	\$ 66.88	\$ 89.00	\$ 63.42	\$ 63.36
PSE&G On pk			\$ 138.76					
PSE&G Off pk			\$ 63.80					
Annual -all hrs \$	95.68	\$ 85.93	\$ 94.13	\$ 82.50	\$ 67.81	\$ 93.02	\$ 62.61	\$ 62.52

DEMAND RATES

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

	GLP	LPL-S	PLUS:	GLP	LPL-S
Summer - all hrs \$	73.61	\$ 72.32	<u>Gen Cost</u>		
PSE&G On pk		\$ 87.41	summer \$	4.5466	\$ 4.5466 per kW of G obl /month

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	PSE&G Off pk	\$	56.38		winter \$	4.5280	\$	4.5280	per kW of G obl /month
Winter - all hrs		\$	71.29	\$	70.61				
	PSE&G On pk			\$	82.78				
	PSE&G Off pk			\$	58.41				
						<u>Trans cost</u>			
						all months \$	1.5046	\$	1.5046 per kW of T obl /month
Annual - all hrs per MWh only		\$	72.16	\$	71.24				
<u>Including T&G Obligation \$</u>									
Summer - all hrs		\$	93.18	\$	87.45				Note: Obligation \$ included in On pk costs
	PSE&G On pk			\$	116.86				
	PSE&G Off pk			\$	56.38				
Winter - all hrs		\$	94.82	\$	88.27				
	PSE&G On pk			\$	118.06				
	PSE&G Off pk			\$	58.41				
Annual - including T&G Obl \$		\$	94.20	\$	87.97				

ALL RATES

Grand Total Cost in \$1000 = \$ 3,003,309
 All-In Average cost @ customer = \$ 92.36 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 86.40 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				0.975	0.816	1.271	0.700	0.699	
			1.428				Use weighted average		
			0.713				for all streetlighting =		0.699
	All usage Multiplier	1.070	1.058						
	Constant (in \$/MWh) \$	(3.392)	(6.108)						
	Constant (in \$/MWh) \$	5.260	5.461						
Winter - all hrs	1.136	0.975		0.947	0.774	1.030	0.734	0.733	
			1.606				Use weighted average		
			0.738				for all streetlighting =		0.733
Annual - all hrs	1.107	0.995	1.089	0.955	0.785	1.077	0.725	0.724	

DEMAND RATES

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

GLP GLP LPL-S LPL-S PLUS:

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	Multiplier	Constant (in \$/MWh)	Multiplier	Constant (in \$/MWh)						
Summer - all hrs	1.078	(19.571)								
PSE&G On pk			1.353	(29.452)	<u>Gen Cost</u>	summer \$	4.5466	\$	4.5466	per kW of G obl /month
PSE&G Off pk			0.653	-		winter \$	4.5280	\$	4.5280	per kW of G obl /month
Winter - all hrs	1.097	(23.530)								
PSE&G On pk			1.366	(35.280)	<u>Trans cost</u>	all months \$	1.5046	\$	1.5046	per kW of T obl /month
PSE&G Off pk			0.676	-						
Annual - including T&G Obl \$	1.090		1.018							

Assumptions:

Gen Cost = \$ 149.07 /MW day summer
 \$ 149.07 /MW day winter

Trans cost = \$ 18,054.72 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 2009 energy use by class, PJM and PSE&G on/off % from 2006, 2007 & 2008 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	\$ 527,518	\$ 3,712	\$ 10,998	\$ 67	\$ 1	\$ 483	\$ 2,978	\$ 5,668	\$ 289,721	\$ 321,824
Winter	\$ 745,737	\$ 10,819	\$ 15,046	\$ 164	\$ 2	\$ 1,635	\$ 8,024	\$ 15,263	\$ 488,871	\$ 554,777
Total	\$ 1,273,256	\$ 14,532	\$ 26,044	\$ 231	\$ 2	\$ 2,118	\$ 11,003	\$ 20,931	\$ 778,592	\$ 876,601
% of Annual Total \$ by Rate										
Summer	41%	26%	42%	29%	27%	23%	27%	27%	37%	37%
Winter	59%	74%	58%	71%	73%	77%	73%	73%	63%	63%
Total Costs - in \$1000										
Summer	\$ 1,162,972									
Winter	\$ 1,840,338									
Total	\$ 3,003,309									
% of Annual Total \$										
Summer	39%									
Winter	61%									

rounded to 4 decimal places

			If total \$ were split on a per MWh basis (on transmission node MWhs):			
Summer	39%	\$ 84.96	per MWh @ trans nodes	Ratio to All-In Cost >>>	Summer	0.9833
Winter	61%	\$ 87.34	per MWh @ trans nodes		Winter	1.0109

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

Assumed Winning Bid Price = \$ **87.00** (bid includes payments for all losses)
 Payment Ratio - Summer = 0.9833
 Payment Ratio - Winter = 1.0109

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in \$1000										
Summer	\$ 531,254	\$ 3,740	\$ 11,073	\$ 68	\$ 1	\$ 487	\$ 2,993	\$ 5,710	\$ 291,599	\$ 324,200
Winter	\$ 751,152	\$ 10,899	\$ 15,148	\$ 165	\$ 2	\$ 1,646	\$ 8,068	\$ 15,362	\$ 492,062	\$ 558,502
Total	\$ 1,282,406	\$ 14,638	\$ 26,220	\$ 233	\$ 2	\$ 2,132	\$ 11,061	\$ 21,072	\$ 783,661	\$ 882,702
Total Summer	\$ 1,171,124									
Total Winter	\$ 1,853,005									
Grand Total	\$ 3,024,129									
	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Supplier Payment - in \$1000										
Summer	\$ 521,852	\$ 3,715	\$ 11,072	\$ 73	\$ 1	\$ 402	\$ 4,500	\$ 8,586	\$ 284,311	\$ 336,512
Winter	\$ 714,494	\$ 12,079	\$ 14,628	\$ 188	\$ 2	\$ 1,727	\$ 11,894	\$ 22,646	\$ 484,686	\$ 590,823
Total	\$ 1,236,346	\$ 15,794	\$ 25,700	\$ 261	\$ 3	\$ 2,129	\$ 16,394	\$ 31,232	\$ 768,996	\$ 927,335
Total Summer	\$ 1,171,025									
Total Winter	\$ 1,853,167									
Grand Total	\$ 3,024,192									

Difference (in \$1000) = \$ (63)

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	13,688,659
Winter	<u>21,071,096</u>
Total	34,759,755