Agenda Date: 11/21/14
Agenda Item: 2E

STATE OF NEW JERSEY

Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

ENERGY

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE (BGS) FOR THE PERIOD BEGINNING JUNE 1, 2015	))))	DECISION AND ORDER DOCKET NO. ER14040370

Parties of Record

Gregory Eisenstark, Esq., Windels Marx Lane & Mittendorf, LLP, on behalf of Jersey Central Power & Light Company
Alexander C. Stern, Esq., Attorney for Public Service Electric and Gas Company
Philip J. Passanante, Esq., Associate General Counsel for Atlantic City Electric Company
Margaret Comes, Esq., Senior Attorney for Rockland Electric Company
Chantale LaCasse, BGS Auction Manager, NERA Economic Consulting
Stefanie A. Brand, Esq., Director, Division of Rate Counsel
Murray E. Bevan, Esq., Bevan, Mosca, Giuditta & Zarillo, P.C., on behalf of the Retail Energy Supply Association
Adam Kaufman, Independent Energy Producers of New Jersey
Aundrea Williams, Director Regulatory Affairs, NextEra Energy Resources LLC
Stuart Ormsbee, Manager Power Marketing, TransCanada Power Marketing Ltd.
James Laskey, Esq., Norris McLaughlin & Marcus, P.A. on behalf of Noble Americas Energy Solutions LLC.
Ira G. Megdal, Esq., Cozen O'Connor, PC on behalf of FirstEnergy Solutions Corp.
Christi L. Nicolay, Division Director, Macquarie Energy LLC
Divesh Gupta, Esq., Managing Counsel - Constellation New Energy, Inc. and Exelon Generation Company, LLC

BY THE BOARD[1]:

This Order memorializes actions taken by the New Jersey Board of Public Utilities ("Board" or "BPU") at its November 21, 2014 agenda meeting pertaining to the provision of basic generation service ("BGS") for retail customers who continue to purchase their electric supply from their electric utility company for the period beginning June 1, 2015.

---

[1] Commissioner Upendra J. Chivukula has recused himself due to a possible conflict of interest and did not participate in the deliberations on this matter. Commissioner Dianne Solomon was not present at the 11/21/14 agenda meeting.

By Order dated May 21, 2014, in the within matter, the Board directed the electric distribution companies ("EDCs") consisting of Atlantic City Electric Company ("ACE"), Jersey Central Power & Light Company ("JCP&L"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO"), and invited all other interested parties, to file proposals by July 1, 2014 to determine how to procure the remaining one-third of the State's BGS fixed price ("FP") and the annual Commercial and Industrial Energy Pricing ("CIEP") requirements for the period beginning June 1, 2015. A procedural schedule to address the proposals was also adopted by the Board at that time, including an opportunity for initial written comments, a legislative-type hearing, and final written comments.

On July 1, 2014, the EDCs filed a Joint Proposal for BGS procurement ("Joint EDC Proposal"), and each EDC also filed a company-specific addendum to the Joint EDC Proposal. A discovery period followed. Initial Comments on the BGS proposals were filed on September 3, 2014. Final Comments were filed on October 1, 2014.

Parties that filed either a proposal, comments, or appeared at the public hearing include the EDCs (ACE, JCP&L, PSE&G, and RECO, jointly), National Economic Research Associates ("NERA"), the New Jersey Division of Rate Counsel ("Rate Counsel"), the Retail Energy Supply Association ("RESA"), Nextera Energy Power Marketing, LLC ("NEPM"), Noble Americas Energy Solutions LLC ("Noble"), TransCanada Power Marketing Ltd. ("TransCanada") and the Independent Energy Producers of New Jersey ("IEPNJ").

Public hearings were held in each EDC's service territory to allow members of the public to present their views on the procurement process proposed by the EDCs, and the potential effect on customers' rates. ACE's public hearing was held on September 22, 2014; PSE&G's public hearing was held on September 19, 2014; RECO's public hearing was held on September 29, 2014, and JCP&L's public hearing was held on September 24, 2014.

The Board also held a legislative-type hearing on September 29, 2014 at its Trenton hearing room, chaired by Commissioner Holden. The purpose of the hearing was to take additional comments on the pending proposals. Because of the pending action by PJM[2] described below, it was determined that allowing additional comments on the proposal after it was expected to be filed was reasonable.

On October 7, 2014 PJM Interconnection, L.L.C. ("PJM") released its Capacity Performance Updated Proposal. As discussed at the legislative-type hearing, Board Staff offered parties the opportunity to comment on the PJM Capacity Performance Proposal Transition Auction Mechanism, Section XIII of the proposal, as Staff had concerns about the possible impact on BGS procurement process and current BGS contractual obligations. Parties submitted supplemental comments by October 22, 1014 and supplemental reply comments by October 29, 2014. Parties that filed comments on the PJM Capacity Proposal included the EDCs, Rate Counsel, NEPM, TransCanada, IEPNJ, Constellation New Energy, Inc. and Exelon Generation Company, LLC ("Constellation"), Macquarie Energy LLC ("Macquarie Energy"), and FirstEnergy Solutions Corp. ("FirstEnergy").

---

[2] PJM, the Pennsylvania-New Jersey-Maryland Interconnection, LLC, is the Federal Energy Regulatory Commission approved regional transmission organization that manages the wholesale competitive energy market, and coordinates the movement of electricity in all or parts of a group of states including most of New Jersey.

POSITIONS OF THE PARTIES: PROPOSALS, INITIAL COMMENTS AND FINAL COMMENTS

The Board has carefully reviewed the record in this proceeding. The parties' filings have largely relied on previous auctions and on the Joint EDC Proposal as the baseline for proposing specific modifications and/or additions. This Order will summarize the main features of the Joint EDC Proposal because it forms the basis of much of the discussion in this Order, and because with the modifications described below, it is the basis for the BGS procurement process that the Board will approve through this Order. The Board will not separately summarize each party's position in similar detail, but has carefully reviewed each party's proposals and/or positions in reviewing the record in this matter and rendering this decision.

JOINT EDC PROPOSAL

As previously stated, on July 1, 2014, the four EDCs filed a Joint EDC Proposal for BGS, consisting of a generic proposal for procurement of BGS for the period beginning on June 1, 2015, including proposed preliminary auction rules for the Auctions, Supplier Master Agreement ("SMA") and EDC-specific addenda.

The EDCs have jointly proposed two simultaneous, multi-round, descending clock auctions for the procurement of services to meet the full electricity requirements (i.e., energy, capacity, ancillary services, transmission, etc.) of retail customers that have not chosen a third party supplier ("TPS").

One Auction would procure service for a one-year period beginning June 1, 2015, for the larger Commercial and Industrial ("C&I") customers on the EDCs' systems through an auction to provide hourly-priced service (the "CIEP Auction"). The customers in this category represent approximately 3,300 Megawatts ("MW") of load to be procured through bidding on 43 full-requirements tranches[3] of approximately 75 MW each.[4] This is the same type of Auction that the Board approved last year in Docket Number ER13050378.

The second auction would procure one-third of the service requirements for all other customers of all four EDCs[5] for a three-year period beginning June 1, 2015, through a fixed-price auction ("BGS-FP Auction") for approximately 5,500 MW of load to be served through 57 full-requirements tranches[6] of approximately 100 MW each. This is the same type of Auction that the Board approved last year in Docket Number ER13050378.

The competitive process by which the EDCs propose to procure their supply requirements for BGS load for the BGS period is detailed in the Joint EDC Proposal and in Appendices A and B thereto (Provisional CIEP and FP Auction Rules, respectively), and is the same type of auction process that the Board has approved for each of the past thirteen years. Under the Joint EDC Proposal, the retail load of each EDC is considered a separate "product" in each Auction. When a participant bids in either BGS Auction, that participant states the number of tranches that it is willing to serve for each EDC at the prices in force at that point in the Auction. In the BGS-FP Auction, a price for an EDC is the amount in cents per Kilowatt-Hour ("kWh") to be paid for each kWh of BGS load

[3] A tranche is a full-requirements product and represents a fixed percentage share of an EDC's load for a specific period.
[4] The 75 MW tranche size is an approximate amount of BGS-CIEP eligible load for ACE, JCP&L and PSE&G tranches. However, RECO only has one tranche with an eligible load of about 38 MW.
[5] As explained below, this does not include procurement for the RECO customers within the company's territory outside of PJM. A separate procurement plan is proposed for those customers.
[6] The EDCs have previously secured two-thirds of their total FP load requirements through May 31, 2017 by means of Board-approved auctions in February 2013 and February 2014.

served. In the BGS-CIEP Auction, a price for an EDC is an amount in dollars per Megawatt-Day ($/MW-day) paid for the capacity obligation associated with the BGS-CIEP customers served. A tranche of one product (i.e. a tranche of the BGS load for one EDC) is a full requirements (capacity, transmission, energy, ancillary services, etc.) tranche. At the end of the Auctions, the final prices for the EDCs' tranches may be different because of differences in the products, due to each EDC's load factor, delivery location and other factors.

The EDCs proposed that rates for BGS-FP customers be designed using a generic methodology implemented as described in the Company-specific addenda. Bidders would be provided with a spreadsheet that converts the Auction price into customer rates for each EDC, to enable bidders to assess migration risk at various Auction price levels. BGS-FP rates would be fixed tariff rates determined by converting the Auction prices to BGS-FP rates in a manner that reflects seasonality and time of use indications, where appropriate and feasible, in order to provide appropriate price signals.

The EDCs proposed that payments to winning BGS-FP bidders for June through September be adjusted to reflect higher summer costs. Payments to bidders for the remainder of the delivery period would be adjusted to reflect lower winter costs. The summer and winter factors are designed so that the overall average payment to the bidder would equal the Auction clearing price.

The EDCs proposed that for BGS-CIEP tranches, rate schedules would be designed to include the transmission and ancillary service costs, and a provision to pass through the hourly PJM real-time energy price. Bidders would indicate how many tranches they want to supply in exchange for a $/MW-day capacity payment and various other payments for energy, ancillary services and transmission which would be known in advance of the Auction. Under the EDCs' proposal, winning bidders would also receive a Standby Charge of $0.00015/kWh. The Standby Charge would essentially act as an "option fee." The capacity payment would be charged to all CIEP customers on BGS service, while the Standby Charge would be charged to all customers in the CIEP service category whether they take BGS service or obtain service through a TPS. Winning bidders would be paid the Auction clearing price for all capacity provided for customers taking BGS-CIEP service plus the Standby Charge rate times the monthly sales to all CIEP customers, whether on BGS-CIEP or not. Under the Joint EDC Proposal, each BGS supplier would be required to assume PJM Load Serving Entity ("LSE") responsibility for the portion of BGS load (whether BGS-CIEP or BGS-FP) served by that supplier. In accordance with the PJM Agreements required of LSEs, BGS suppliers would be physically and financially responsible for the day-to-day provision of electric supply for BGS customers. The detailed commercial terms and conditions, under which the BGS supplier would operate, including credit requirements, are set forth in the CIEP and FP SMAs attached to the Joint EDC Proposal as Appendix C and D, respectively.

The EDCs requested that the Board render a decision on the Auction process, and thereafter render a decision on the results of the Auctions. Specifically, they requested that the Board approve or reject in their entirety the results of the BGS-FP Auction and, separately, the results of the BGS-CIEP Auction, by the end of the second full business day after the calendar day on which the last of the two Auctions closes. The EDCs also recommended that the Board clarify that, at its discretion, it may act on one completed Auction while the second is still ongoing. Upon Board approval, the Auction results would be a binding commitment on the EDCs and winning bidders.

Each of the Company-specific addenda addresses the use of committed supply, contingency plans, accounting and cost recovery, and utility pricing and tariff sheets.

Numerous other Auction details are explained in the Joint EDC Proposal, Company-specific addenda, and attachments, including that:

- BGS suppliers must meet all New Jersey Renewable Portfolio Standards ("RPS") requirements, and any similar standards imposed under any federal, state or local legislation that may be applicable throughout the respective supply periods;

- as conditions of qualification, applicants must meet pre-bidding creditworthiness requirements; agree to comply with all rules of the Auction; and agree that if they become Auction winners, they will execute the BGS SMA within three business days of Board certification of the results, and they will demonstrate compliance with the creditworthiness requirements set forth in that agreement;

- to qualify, applicants must disclose what, if any, bidder associations exist and if so, applicants will provide such additional information as the Auction Manager may require;

- qualified bidders are required to post a per-tranche letter of credit or bid bond; and

- the BGS-CIEP Auction secures supply for a period of 12 months, and the BGS-FP Auction secures one-third of each EDC's total load requirements for three years,[7] with the remaining two-thirds having been secured through previous BGS-FP Auctions.

In addition, RECO is proposing to secure the full service requirements for BGS customers in that portion of the Company's service territory that lies outside of the area served through PJM, its Central and Western Divisions, commencing June 1, 2015. The Board will not be making a decision at this time regarding how RECO should procure the full service requirements for BGS customers in its Central and Western Divisions. Staff still is in discussions with RECO on the procurement process and will bring that issue back to the Board at a future date.

DISCUSSION AND FINDINGS

FP and CIEP AUCTION FORMAT

In reaching our decision regarding the provision of BGS for the period beginning June 1, 2015, the Board is mindful that the current BGS Auction process contains a set of carefully crafted and well defined features, and that it is not always possible to modify one aspect of the process without disrupting the balance of the entire process. In 2001, when the Auction process was a new concept, the Board was presented with and considered many arguments for alternate processes, alternate designs within the Auction framework and varying procurement periods. The Board's decision at that time was developed after considering all of the comments received. In 2002, after a process open to all interested participants, the Board determined to retain the basic Auction design while initiating separate Auctions for both BGS-FP and BGS-CIEP customers.[8] For the 2003 through 2014 BGS Auctions, the Board continued to approve descending-clock Auctions for the procurement of default service while continuing to adjust

[7] While the concept is to divide the EDCs' load requirements into thirds, the actual tranches available for any EDC for any time period may vary by EDC.

[8] Board Order dated December 18, 2002, Docket Nos. EO02070384 and EX01110754.

certain elements of the process including changing the beginning of the supply period from August to June and expanding the size of the CIEP class.[9]

As previously stated, for the period beginning June 1, 2015, by Order dated May 21, 2014, the Board directed the EDCs and invited all other interested parties to file proposals to determine how to procure the remaining one third of the EDCs' BGS-FP and the annual CIEP requirements. Specifically, the Board afforded an opportunity for parties to file alternatives to be considered by the Board on how to procure the BGS requirements for the FP and CIEP customer classes for the period beginning June 1, 2015. At this time, while the Board is again presented with recommendations to modify certain elements of the Auction process, there have been no fully developed, concrete proposals to change the basic descending-clock Auction design. The Board believes that the Auction process that was implemented with the 2002 Auction, and which has since been modified to include a BGS-FP and BGS-CIEP Auction, has worked well and has resulted in the best prices possible at the time.

The Board appreciates the efforts of all involved to provide constructive comments and criticism to improve on a process that is important to all of the EDCs' electric ratepayers. In making its decision, the Board has considered the suggestions that were made. The Board has attempted to reach a balance of competing interests, mindful of its statutory responsibility to ensure continued provision of BGS at just and reasonable rates consistent with market conditions. N.J.S.A. 48:3-57(a)(1). The Board will address the issues raised by the various parties during the proceeding in this Order.

Based on the experience of previous BGS Auctions, and having considered the record that has been developed in this matter, the Board **FINDS** that a BGS-FP and BGS-CIEP Auction, using a descending-clock Auction format, should be used for the procurement period beginning June 1, 2015.

BGS-CIEP AUCTION SUPPLY PERIOD

No party took issue with the continued use of a 12-month period for the BGS-CIEP Auction. The Board **FINDS** that a 12–month procurement period is appropriate and reasonable and **APPROVES** that aspect of the EDCs' proposal.

BGS-FP AUCTION SUPPLY PERIOD

RESA recommends that the Board should encourage a more competitive marketplace by transitioning the BGS procurement process away from the laddered-three-year contracts currently employed in the BGS-FP Auction and towards more frequent procurements held closer to the delivery date. RESA indicates that this transition will result in more market reflective default service pricing because it minimizes the time over which the default price can diverge from actual market prices. RESA believes that making this change would result in customers on default service receiving a product that is comparable to the product offerings of TPS, thus customers would be making choices between similar products. Further, RESA indicates that the current structure serves as a barrier to the further development of retail competition. RESA

[9] Board Orders dated December 2, 2003, Docket No. EO03050394; December 1, 2004, Docket No. EO04040288; December 8, 2005, Docket No. EO05040317; December 22, 2006, Docket No. EO06020119; January 25, 2008, Docket No. ER07060379; January 20, 2009, Docket No. ER08050310; December 10, 2009, Docket No. EO09050351; December 6, 2010, Docket ER10040287; November 11, 2011, Docket No. EO11040250; November 20, 2012, Docket No, ER12060485, and November 22, 2013, Docket No. ER13050378.

proposes that the Board replace the three-year laddered contracts currently employed in the BGS-FP auction with a procurement process that includes quarterly pricing for all commercial and industrial customers and annual pricing for all residential customers starting June 1, 2015. (RESA Initial Comments at 6 - 7).

IEPNJ indicates its support for the current three-year BGS auction structure. IEPNJ feels it is important that the rules of the auction do not result in increased or volatile prices. It is IEPNJ's position that the three-year BGS auction structure strikes the appropriate balance to hedge against price spikes, while minimizing future risk to suppliers' contracts of a longer term. IEPNJ maintains that a three-year term allows the suppliers bidding into the BGS auction to rely on several known variables when preparing their bids. IEPNJ indicates that knowing these values reduces the risk to suppliers, thereby helping to keep bid prices reasonably low. IEPNJ feels that the averaging of the contracts entered over the course of three years provides stability to customer rates. According to IEPNJ, a term of less than three years will result in increased price volatility. It is IEPNJ's position that this increased price volatility will increase the budgetary stress on BGS customers who benefit from stable energy rates. IEPNJ points out that in this economy, at this time, increasing price volatility risk to consumers is harmful for residents and businesses alike. IEPNJ indicates that the current three-year structure addresses the appropriate goal of protecting consumers from price volatility in the energy markets. As a result, based on the success of this structure over the last decade, IEPNJ strongly endorse the continuation of this policy. (IEPNJ Initial Comments, 2 - 3).

The EDCs request that the Board reject RESA's recommendation to alter the current BGS-FP procurement structure. The EDCs point out that RESA again renews its arguments in this proceeding for shorter procurement periods and, thereby, for fundamental change to the BGS-FP procurement structure. The EDCs indicate that RESA recommends that the Board replace the three-year BGS portfolio with quarterly procurements for all commercial BGS-FP customers and annual pricing for residential BGS-FP customers starting June 1, 2015.

The EDCs believe that RESA provides no new support for this position, which has been repeatedly rejected in prior BGS proceedings. Furthermore, the EDCs point out that RESA ignores the benefits of the three-year term structure, which have been affirmed repeatedly by the Board. The EDCs indicate that the Board has found consistently that a rolling three-year term provides the proper balance for BGS-FP customers between the need to reflect market prices and the need to protect these customers from market volatility. The EDCs further indicate that the Board has repeatedly reaffirmed its decision to maintain the three-year term structure for BGS-FP customers. The EDCs believe that unstable energy market conditions, such as those associated with this past winter's polar vortex, could expose both residential-FP and commercial-FP customers to the unnecessary risks associated with energy price fluctuation and increases should the Board adopt RESA's proposal. The EDCs believe that the current BGS procurement structure protects customers who may not have the necessary expertise or inclination to properly manage the additional risk and the volatile energy prices that are the necessary by-product of RESA's proposal. (EDCs' Final Comments, 3 - 4).

Based on the experience of the previous BGS Auctions, and having considered the record which has been developed in this matter, the Board continues to believe that the staggered three-year rolling procurement process currently in use for the BGS-FP Auction provides a hedge to customers in a time of extreme weather events that impact prices as we have seen recently, volatile energy prices and the potential of increasing capacity prices even though it may make it more difficult for retail suppliers to compete for FP customers in times of rising prices. By way of contrast, as market prices started to come down in wholesale electric markets over the last four years, retail suppliers have been able to be more competitive than the rolling three-year average FP Auction price, and competition appears to have increased. The Board is not convinced that RESA's proposals for pricing based on more frequent auctions for procurement of electricity for shorter periods than the current format would increase retail competition significantly.

The Board believes that the goal of the BGS procurement process should be to enable smaller commercial and residential customers to benefit from both a stable yet market-based rate for BGS-FP supply over the term of the procurement plan for this service while still allowing these customers the ability to choose alternative providers. The Board further believes that the use of the staggered three-year rolling procurement process, ensuring price stability, is a policy decision that has value for those customers who continue to receive BGS service from the EDCs. Therefore, the Board **DIRECTS** the EDCs to procure the approximate one-third of the EDCs' current BGS-FP load not under contract for a 36-month period. The tranche-weighted average of the winning bids from the upcoming 36-month period blended with the tranche-weighted average of the 36-month supply contracts secured previously, will be used to determine the price for BGS-FP rates for the June 1, 2015 to May 31, 2018 period.

CIEP THRESHOLD

RESA recommends that the Board reduce the BGS-CIEP threshold to require all customers using 400 kw and above to be on BGS-CIEP pricing beginning in June 1, 2015, and to require all customers using 100 kw and above to be on BGS-CIEP pricing by June 1, 2017. RESA asserts that customers utilizing between 100 kw and 400 kw have the necessary ability to understand hourly pricing. (RESA Initial Comments at 5).

Rate Counsel continues to have concerns about the wisdom of forcing mid-sized customers into the BGS-CIEP class to bolster competition, especially when these mid-sized customers already have the option to shop or to be served under BGS-CIEP. Rate Counsel submits that further lowering the CIEP threshold only serves to force customers onto an hourly price structure, even if these customers are unable to deal effectively with hourly prices and have therefore chosen to remain as BGS-FP customers. Rate Counsel believes that business owners are in the best position to determine for themselves whether it makes economic sense to switch to a TPS, and certainly many have chosen to do so. Rate Counsel maintains that the Board should not force these customers to change their minds when they have determined that switching is not economically reasonable for their businesses.

Rate Counsel further points out that since June 4, 2013, customers with a Peak Load contribution of 500 kW or more have been required to take service under a BGS-CIEP tariff. In previous comments, Rate Counsel recommended that the Board investigate the impact of this decision to lower the CIEP threshold prior to further lowering the CIEP threshold in this proceeding or in the future. Rae Counsel recommends that this information be gathered not only from retail suppliers but also from the customers affected by the lower CIEP threshold. Rate Counsel asserts that with one year of experience, the EDCs should be able to determine how smaller business owners are reacting to the new challenge of managing energy usage and markets. Prior to making any further changes, Rate Counsel recommends that the Board direct the EDCs to solicit specific information from customers about the impact of the lower CIEP threshold on customers' bills and customer reaction to the change. (Rate Counsel Initial Comments at 4 - 5).

The EDCs agree with Rate Counsel in opposing RESA's proposal to further lower the CIEP threshold. The EDCs indicate that RESA suggests that the Board lower the CIEP threshold to 400 kW beginning in June 1, 2015, and then to 100 kW beginning in June 1, 2017. The EDCs believe that RESA's suggestions ignore a fundamental reason for the division of the products to occur at a higher kW threshold, reflecting customers' relative ability to understand and manage price risk. They point out that as addressed in their July 1 filing, some customer classes are able to understand the risks of price movements in competitive markets and will be able to absorb risks or contract for management of those risks. They further point out that, on the other hand, other customer classes may neither understand nor be able to manage these price risks. They believe that the three-year term and fixed-price nature of the BGS-FP product provides stability to those smaller commercial and industrial customers unable to engage in, or uninterested in, risk management.

The EDCs further indicate that no party has presented evidence that the FP commercial and industrial customers with peak demands between 100 kW and 499 kW would be well served by being forced to manage the volatility of the hourly-priced BGS-CIEP product. Further, the EDCs believe that RESA's proposal would limit customers' choice, again ignoring the fact that all commercial and industrial customers already have the option to select BGS-CIEP on an optional basis if they would like an hourly-priced service. The EDCs indicate that simply charging customers on an hourly basis would not provide them with the necessary skills to make informed decisions with regard to their electricity purchases. The EDCs see no benefit in forcing customers of this size to be served under BGS-CIEP, given that they may not be able to hire a facilities manager, may not have systems in place to manage load in response to volatile hourly prices in an automatic fashion, and may not be able to afford the distractions from their business that would come with managing such risks themselves. (EDCs' Final Comments at 7).

By Order dated June 18, 2012, In the Matter of the Review of the Basic Generation Service Procurement Process, Docket No. ER12020150 ("BGS Review Order"), the Board concluded that a gradual expansion of the number of customers on hourly pricing, given the record presented in that proceeding, was reasonable, prudent and warranted at that time, and approved RESA's request to lower the CIEP threshold for customers with a peak load share of 500 kW and above. As part of the decision, the Board saw a value in limiting the reduction to those customers with a peak load share of 500 kW and not immediately moving to the 300 kW range as proposed by RESA. Therefore, the Board rejected RESA's request to expand the BGS-CIEP threshold to 300 kW effective for the next BGS procurement. However, the Board, as proposed by RESA, encouraged feedback on the BGS-CIEP threshold during future BGS procurement proceedings each year in order to receive stakeholder input through comments and legislative-type hearings. The Board stated that through these BGS proceedings, it can garner information, inclusive of up-to-date market data, to make an informed decision on a future lowering of the BGS-CIEP threshold that is gradual, orderly, and structured to enable a greater number of customers to respond to real-time pricing, possibly using additional conservation and energy efficiency products and services available in the marketplace.

Based on the record in this matter, the Board agrees with the EDCs that there has been no evidence presented in this proceeding by RESA or any of the stakeholders that would at this time indicate that further lowering the BGS-CIEP threshold to 400 kw beginning in June 1, 2015 and to 100 kw by June 1, 2017, is either desired by the relevant customers or will bring net benefits to those customers. Based on the record presented, the Board agrees with Rate Counsel and the EDCs that smaller, commercial customers continue to be better served by a fixed-price, three-year product and that further lowering the BGS-CIEP threshold only serves to force customers onto an hourly price structure, even if these customers are unable to deal effectively with hourly prices and have therefore chosen to remain as BGS-FP customers. Further the Board believes that these customers in the BGS-FP class are in the best position to determine for themselves whether it makes economic sense to switch to a TPS and certainly many have chosen to do so. For those customers who have not switched to a TPS and continue to want to receive the BGS-FP product, the Board believes that these customers have determined that switching is not economically reasonable for their businesses, and by lowering the BGS CIEP threshold the Board would be making a decision for these customers that they may have chosen not to make. Therefore, the Board continues to believe that a cautious, gradual approach to any expansion of the BGS-CIEP class remains the appropriate policy, and that the appropriate cutoff for mandatory inclusion in the CIEP is a peak load share of 500 kW. Therefore, the Board **REJECTS** RESA's request to expand the BGS-CIEP threshold to 400 kw beginning in June 1, 2014 and to require all customers using 100 kw and above to be on BGS-CIEP pricing by June 1, 2016.

Rate Counsel has requested that prior to any further lowering of the BGS-CIEP threshold, the Board direct the EDCs to solicit specific information from customers about the impact of the lower CIEP threshold on customers' bills and customer reaction to the change. The Board, based on the record in this proceeding, has rejected RESA's request to lower the BGS-CIEP threshold to 400 kW and above beginning in June 1, 2015. Therefore, there is no need to perform the requested review process suggested by Rate Counsel at this time.

Further, for the 2004 through 2014 Auctions, certain C&I FP customers, to the extent they could be identified and metered without a material impact on the BGS Auction process, were permitted to join the CIEP class on a voluntary basis. Staff recommends that voluntary enrollment in the CIEP class should again be permitted for the 2015 Auction with similar constraints. Specifically, the choice must be made in a timely manner and, once made, must be irrevocable for the one-year term of the CIEP contract. Therefore, Staff recommends that the Board direct the EDCs to work with Staff to develop a process and schedule for identifying and converting non-residential customers that choose to be included in the BGS-CIEP category. The process developed should be based on the foregoing parameters. It should require a customer commitment for participation by no later than the second business day in January 2015. Similarly, those customers that are currently part of the CIEP class on a voluntary basis should have until the second business day in January 2015 to reconsider their decision for the upcoming 2015 Auction.

The Board has reviewed the submissions and Staff's recommendations, and **FINDS** the Staff recommendations to be reasonable. Therefore, the Board **DIRECTS** the EDCs to work with Staff to develop and implement a process similar to that used in the past to notify customers of this "window of opportunity" to voluntarily transfer into the BGS-CIEP class. Further, the Board also **DIRECTS** the EDCs to post the conditions of the voluntary CIEP process in a conspicuous location on their web pages.

ISSUES RELATED TO INTERVAL METERS

RESA, in conjunction with lowering the BGS-CIEP threshold to 400 kw beginning in June 1, 2015, argues that the Board must require the EDCs to install interval meters for all customers above this threshold who do not currently have them. RESA indicates that without interval meters, customers have no means to gauge their energy use or respond to the price signals associated with it. RESA maintains that requiring the applicable EDC to install interval meters for customers using more than 400 kw will provide customers with the opportunity to actively monitor and respond to the cost of electricity on a real-time or hourly basis, and will enable New Jersey customers to better manage their energy consumption and costs. (RESA Initial Comments at 6).

The EDCs argue that the Board should reject RESA's proposal to require the EDCs to install interval meters by June 1, 2015. They indicate that interval meters have a cost (including capital and operation and maintenance costs) and RESA provides no analysis to demonstrate that the cost would be justified; furthermore, RESA has not proposed a mechanism to ensure EDC recovery of those costs. (EDCs' Final Comments at 10).

RESA requests that in conjunction with lowering the BGS-CIEP threshold to 400 kw beginning in June 1, 2015, the Board require the EDCs to install interval meters for all customers above this threshold who do not currently have them. Since the Board has rejected RESA's request to expand the BGS-CIEP threshold to 400 kW and above beginning on June 1, 2015, the Board believes that this issue need not be resolved at this time.

CHANGES TO THE BGS-FP CLASSIFICATION

RESA indicates that given the recent changes to the Energy Competition rules and the current allowance for some BGS provider costs to be passed on to customers, the BGS-FP product is not properly classified, as the product does not meet the same requirements that TPS must meet when offering a product as "fixed-price." RESA asserts that competitive fairness should allow TPSs to pass through certain costs on fixed price products, ensuring identical treatment between TPS and BGS providers of "fixed price" offerings. RESA points out that in absence of such a change, the Board should rename the BGS-FP product to bring it in line with the requirements imposed upon TPSs. (RESA Initial Comments at 3).

The EDCs argue that RESA ignores a fundamental aspect of the Electric Discount and Energy Competition Act ("EDECA") and of the Board's regulatory oversight. They indicate that the aspect is that the EDCs do not "market" or promote BGS. They point out that they have no financial interest in the level of BGS vs. TPS sales, have no reason to promote BGS to customers, and are prohibited by law from marketing or promoting BGS. They point out that the term BGS-FP is primarily used by the EDCs to describe the BGS supply opportunity to bidders and suppliers. It is not used to market BGS-FP and retail customers' bills reflect that fact that BGS-FP rates fluctuate by time of day and season and are subject to various changes such as the reconciliation charge. The EDCs feel that changing the name of BGS-FP would be confusing to suppliers, expensive to the EDCs and ultimately ratepayers as billing and customer information systems would need to be modified. The EDCs maintain that such a change is unnecessary as the EDCs do not in any way market or promote BGS-FP to retail customers. (EDCs' Final Comments at 16).

The Board agrees with the EDCs that RESA ignores a fundamental aspect of EDECA and of the Board's regulatory oversight of BGS. EDECA says the charges assessed to customers for BGS shall be fully regulated by the Board and shall be based on the reasonable and prudent costs to the utility of providing such service. N.J.S.A. 48:3-57 (a)(1). Nowhere does EDECA say that the pricing of BGS needs to meet the same requirements as TPS pricing. The Board further agrees with the EDCs that they have no financial interest in the level of BGS vs. TPS sales, have no reason to promote BGS to customers, and are prohibited by law from marketing or promoting BGS. The EDCs are only permitted to recover in their BGS charges reasonable and prudently incurred costs incurred in the provision of BGS which makes BGS service essentially a pass through of those costs which have been deemed to be reasonable and prudent.

However, over the years the Board has modified the BGS-FP product and has made the decision to lower the CIEP threshold. The CIEP by the nature of its name - Commercial Industrial Energy Pricing - reflects the actual type of customer that the BGS product is intended to serve. As the CIEP threshold has been lowered, the customers remaining within the BGS-FP class of customers are primarily residential and small commercial in nature. It is the Board's position that to align the name of the BGS-FP product with the type of customer it is intended to serve, the Board believes that the name of the BGS-FP class should be changed to the Residential & Small Commercial Pricing ("RSCP") class. The Board feels changing this name in no way changes the its authority to regulate the price for this product,

Further, the Board believes that changing the name of the BGS-FP product to the BGS-RSCP in no way changes a BGS supplier's obligations with respect to contracts currently in place from the 2013 and 2014 BGS Auctions. However, the Board agrees with the EDCs that immediately changing the name "BGS-FP" to "BGS-RSCP" will have an impact on auction documents, bidding software used by NERA and bidders, billing and customer information systems, and in some instances it may take some time to implement this change. Therefore, for the purposes of conducting the 2015 BGS Auction the Board **DIRECTS** the EDCs to continue to use the term BGS-FP in any documents and bidding software used by NERA for the purposes of conducting the Auction, with the exception of the 2015 SMA which should reflect the name change. Further, the Board **DIRECTS** Staff to work with the EDCs to transition the change of the name of the BGS-FP product in any BGS documents, billing and in customer information systems to BGS-RSCP so the product offered to customers is termed BGS-RSCP by June 1, 2015.

CIEP LOAD CAPS

Rate Counsel indicates that in addressing the competitiveness of the BGS-CIEP auction, the Board's consultant, Boston Pacific, noted in its 2014 Final Report[10] that the BGS-CIEP auction was "adequately competitive" but "somewhat less competitive" than the BGS-FP auction. Rate Counsel points out that Boston Pacific noted the excess quantity offered was low but adequate, and that there were five winners in the CIEP auction, one less winner than last year. In addition, Rate Counsel points out that Boston Pacific noted of particular concern is "the fact that some bidders who previously participated in the CIEP auction may no longer be participating.

Rate Counsel further indicates that to address the issue of low excess supply, Boston Pacific recommended increasing the statewide load cap in future BGS-CIEP auctions from the current load cap of approximately one-third of the CIEP tranche target to a load cap of about 45 percent of the CIEP tranche target. Rate Counsel urges the Board not to adopt this recommendation at this time. Rate Counsel submits that there is no way for it to determine whether raising the load cap will increase the number of bidders in the CIEP auction. Rate Counsel comments that any analysis done by Boston Pacific to support its recommendation is not presented in the redacted copy of the Boston Pacific Annual Final Report. Rate Counsel further indicates that the redacted report notes that bidders who do offer in the CIEP Auctions tend to offer at the load cap, and reasons that higher load caps would result in increased offers, thereby increasing the ratio of offers to need and potentially driving down prices. Rate Counsel acknowledges while it may be true that an increase in the number of tranches a bidder can win may increase the amount of supply offered into the CIEP auction, it does not necessarily follow that this increase in supply produces a more competitive auction or increased bidder participation in the auction. Rate Counsel recommends that the Board remain cautious about implementing untested changes in the CIEP auction at this time. Accordingly, Rate Counsel recommends that the

[10] Boston Pacific, Inc. ("Boston Pacific") was retained in July 2012 on behalf of the Board, to oversee and monitor the process proposed by the four EDCs in New Jersey to procure supplies for BGS, for three years, starting with the 2013 BGS procurement process. As part of its contract, Boston Pacific provides a Final Report to the Board on the BGS procurement process, and also provides recommendations to improve future BGS procurement processes. At its June 18, 2014 Agenda meeting, the Board accepted for filing Boston Pacific's Annual Final Report on the 2014 BGS FP AND CIEP Auctions and the 2014 RECO Swap RFP, dated June 3, 2014.

Board further examine the causes of decreased bidder participation and explore alternate mechanisms to ensure competition in the CIEP auction. (Rate Counsel Initial Comments, 2 - 3).

The EDCs indicate that in Boston Pacific's post-auction Final Report, the Board's consultant recommended increasing the statewide load cap to 45% of the statewide CIEP volume. The EDCs point out that Boston Pacific reasoned that Bidders would likely respond to higher load caps by increasing their offers, thereby increasing the ratio of offers to need and potentially driving down prices. The EDCs indicate that such lower prices would benefit BGS-CIEP customers.

The EDCs stated that they are not taking a position on whether a 45% load cap is appropriate or not for this upcoming BGS-CIEP Auction; however, the EDCs do note that in the past four BGS-CIEP Auctions, three different suppliers have won tranches at the statewide load cap. The EDCs believe this data supports Boston Pacific's contention that the likely consequence of a higher load cap would be for these suppliers, and perhaps others as well, to increase their offers at the start of the Auction, thereby increasing the competitive pressure on prices. Thus, the EDCs recommend that the Board reject Rate Counsel's suggestion that the Board explore alternate ways of increasing competition in the BGS-CIEP Auction. The EDCs request that the Board approve the Auction Rules as filed and thereby affirm the ability of the EDCs, Board Staff, and Boston Pacific to set the load caps as conditions dictate. (EDCs' Final Comments at 17).

Boston Pacific in its Final Report regarding the 2014 CIEP Auction indicated that the fact that some bidders who previously participated in the CIEP Auction may no longer be participating is of particular concern. As a solution to low excess supply, Boston Pacific suggests that the BPU and EDCs consider a small increase in the load cap for the CIEP Auction from its current level of about one-third of the CIEP tranche target to 45 percent of the CIEP tranche target. Boston Pacific indicated it made this suggestion for two reasons: at least some of the reduced participation seen last year is likely to carry over to future Auctions, and bidders who do offer in the CIEP Auctions tend to offer at the load cap. For these reasons Boston Pacific believes that bidders would likely respond to higher load caps by increasing their offers, thereby increasing the ratio of offers to need and potentially driving down prices.

The Board agrees with the EDCs' and Boston Pacific's contention that the likely consequence of a higher load cap would be for these CIEP suppliers and perhaps others as well, to increase their offers at the start of the Auction, thereby increasing the competitive pressure and potentially driving down prices. Therefore, the Board **DIRECTS** the EDCs to increase the statewide load cap in the upcoming BGS-CIEP auction from the current load cap of approximately one-third of the CIEP tranche target to a load cap of about 45 percent of the CIEP tranche target.

PJM CAPACITY PROPOSAL TRANSITION MECHANISM

On October 7, 2014, PJM issued its Staff Updated Proposal entitled PJM Capacity Performance ("CP") Updated Proposal. The CP Updated Proposal calls for the creation of a new capacity product designed to provide what PJM believes is the proper level of revenues to supply side resources to ensure operational certainty during times of extreme stress on the bulk electric system. On October 8, 2014, Board Staff offered parties the opportunity to comment on the CP Updated Proposal's Transition Auction Mechanism, Section XIII, as Staff was concerned about the possible impact on the BGS procurement process and current BGS contractual obligations.

The EDCs pointed out that PJM, in the CP Updated Proposal, confirmed its intention to pursue changes to the RPM construct that the EDCs believe could lead to BGS Suppliers facing materially higher capacity costs than could have been reasonably anticipated based on the Reliability Pricing Model ("RPM") structure and Base Residual Auction ("BRA") results that prevailed at the time of BGS Suppliers' bids in the 2013 or 2014 BGS Auctions. The EDCs point out this potential increase applies as well to bidders who win in the 2015 BGS Auctions, as it is unlikely that the Federal Energy Regulatory Commission's ("FERC") decision on PJM's proposed changes to the capacity market and the impacts of those changes will be known by the time of the 2015 BGS Auctions in February, 2015. The EDCs assert that PJM's CP Updated Proposal could therefore detrimentally impact the BGS Auction process, absent appropriate preventative action by the Board.

The EDCs have previously indicated they believe the BGS process has served customers well. They recommend that to maintain the viability of the BGS process, the Board should direct them to implement a supplement to the BGS Supplier Master Agreements ("SMAs") that would provide compensation to BGS Suppliers for the incremental costs they face as a result of changes to the RPM construct that arise from PJM's proposed CP Updated Proposal. They believe such a supplement should be incorporated into the standard SMAs for the 2015 BGS Auctions, and made available on a voluntary basis with the standard SMAs for the 2013 and 2014 BGS Auctions, so the winning bidders from those auctions would also not be unfairly harmed. They further point out that supplementing the BGS SMAs to provide a payment for these incremental costs is likely to be in the best long-term interests of customers. The EDCs fully agree that BGS Suppliers have and must continue to accept the risks associated with customer migration and economy driven energy and capacity market volatility. However, the EDCs believe it is unlikely that in the future there will be entities that are willing to commit to serve BGS load if they do not have confidence that the Board will continue its practice of providing a mechanism for compensating BGS Suppliers when structural changes to the rules that govern the energy or capacity markets result in major identifiable but unknown and unknowable changes to the costs of serving the BGS load.

The EDCs believe that the structural changes to RPM being proposed by PJM are unprecedented, and if approved, will impose potentially material costs upon BGS Suppliers that could not have been reasonably anticipated. The EDCs recommend, in order to preserve the viability of the BGS process, the Board direct that the EDCs incorporate Attachment 1 to their Supplemental Comments ("Attachment 1") into the 2015 BGS-FP SMA, and make Attachment 1 available to suppliers who won tranches in the 2013 and 2014 BGS-FP Auctions. The EDCs further recommend the Board direct the EDCs to incorporate Attachment 2 to their Supplemental Comments ("Attachment 2") into the 2015 BGS-CIEP-SMA.

The EDCs indicate the Auction results are translated into BGS-FP tariffs using a rate design spreadsheet and incorporated directly into the capacity rate in the BGS-CIEP Tariff. They indicate there is no need to modify the calculations in the BGS-FP spreadsheets that have been filed in this proceeding. The EDCs indicate the final spreadsheets will need to adjust the Auction Prices used for rate design purposes to reflect the estimated additional supplier payments to be made as result of the BGS-FP SMA Supplements and to modify the RPM capacity price inputs so they reflect the revised PJM Zonal Net Load Price. The EDCs indicate that as part of the EDCs Compliance Filing in this proceeding, the EDCs will provide a worksheet that demonstrates the methodology for adjusting the Auction prices to reflect the estimated additional supplier payments made as result of the BGS-FP SMA Supplements. As soon as the revised PJM Net Zonal Load Prices are available to the EDCs and the Board, the EDCs will file revised BGS BGS-FP tariff sheets for the change in prices resulting from incorporating the difference between the revised PJM Zonal Net Load Price for 2015/2016 and the pre-existing PJM Zonal Net Load Price for 2015/2016 (Incremental PJM Net Zonal Load Price) into the BGS-FP spreadsheet.

The EDCs state the BGS-CIEP tariffs for each of the EDCs charge the BGS-CIEP Auction clearing price directly in the Capacity Charge. The EDCs realize the effect of the changes to PJM's RPM construct may not be known until after the 2015 BGS Auction results have been approved by the Board. The EDCs request the Board direct them to file tariff sheets with the June 1, 2015 BGS-CIEP rates in March 2015, while also recognizing those rates may need to be revised as soon as the revised PJM Net Zonal Load Prices are available to the EDCs and the Board. When the revised PJM Net Zonal Load Prices are available to the EDCs and the Board, the EDCs will file revised BGS-CIEP tariff sheets for the price changes resulting from the Incremental PJM Net Zonal Load Price being added to the capacity charge in the BGS-CIEP tariffs. (EDC Supplemental Comments at 1 – 7).

NEPM indicates that it is opposing PJM's Updated Capacity Proposal given its disregard for the existing commercial arrangements of wholesale suppliers that in good faith relied on clearing prices for capacity established in prior PJM RPM Auctions. NEPM feels that this disruption to BGS, especially in the transition, introduces high levels of market uncertainty that will inevitably lead to higher wholesale supplier risk premiums as the proposal injects fear and doubt into the otherwise stable and successful BGS process.

NEPM further indicates that, in addition to potential billions of unnecessary costs being paid by customers, the PJM Updated Capacity Proposal could undermine and jeopardize the entire foundation of success that the BGS process in New Jersey has thrived and flourished on for over a decade. NEPM believes that this may cause market participants to flee, and that this mid-stream change will inevitably cast lingering shadows of doubt related to capacity pricing. NEPM believes the Board must act swiftly to amend the BGS procurement SMA to prevent disruption to BGS service in New Jersey.

NEPM indicated that in light of the proposed transition mechanism in PJM's Updated Capacity Proposal beginning as early as the BGS year 2015/2016, the SMA should be revised to fix the PJM capacity price and volume[11] suppliers should use in preparing their bids for each year of the SMA term to the values published at the time of the BGS Auction in the in the most current RPM BRA and Incremental Auction. NEPM recommends that any change in PJM Capacity price/volume due to subsequent incremental RPM auctions, or costs associated with PJM proposed imposition of a CP (or similar obligation), should become a pass-through for a BGS Supplier. In addition, following the same logic, NEPM believes that the Board should authorize amendment of existing SMAs. NEPM feels this is necessary to ensure a well-functioning BGS Auction that draws the maximum participation from potential suppliers at the lowest reasonable price and that complies with the requirements of EDECA section 9 that BGS Suppliers be given the opportunity to recover all costs incurred in providing BGS Supply. NEPM proposes that, in order to permit such recovery, the Board promptly issue an order authorizing all existing SMAs to be amended to permit recovery of any increased Capacity or CP obligation ultimately imposed on BGS-FP suppliers. (NEPM Supplemental Comments at 1 – 7).

Constellation states that to the extent that a CP product for these interim years in the Transition Period is approved, it recommends the Board order each EDC to propose and submit for approval a new non- bypassable rider under which an EDC will recover these new, unhedgeable charges only for an Interim CP Product from all consumers, whether shopping for supply from a TPS or taking BGS supply service from the EDC. (Constellation Supplemental Comments at 3 - 4).

[11] Capacity process referred to is identified by PJM as the Final Zonal Load price ($/MW-day); Capacity volume referred to as the Final Zonal Unforced Capacity ("UCAP") Obligation (MW).

TransCanada agrees with NEPM that there will be considerable uncertainty regarding the year-over-year cost impact on BGS suppliers of PJM's proposed capacity market reforms that will persists for future BGS procurements that, at the very least, include delivery year 2015/2016. TransCanada indicates, to the extent that the impact of unforeseen risks can be minimized with limited regulatory cost pass though mechanisms, greater certainty is achieved and risk premiums will be reduced. TransCanada believes the purpose of the performance capacity product is to improve the level of reliability to end-use customers. Consequently, TransCanada believes it is reasonable for end-use customers to pay their fair share of costs by way of a direct pass through. With respect to NEPM's proposal to amend the BGS-FP SMA, TransCanada generally agrees with NEPM"s proposal. TransCanada requests the Board modify the BGS-FP SMA to adapt the mechanism used to fix transmission charges to also fix BGS-FP SMA rates for capacity for the forward years of supply contracts entered into in the 2013 and 2014 BGS Auctions, and SMA to be entered in for the 2015 BGS Auction. (TransCanada Supplemental Comments at 3 - 4)

FirstEnergy indicates that BGS Suppliers' bids in the 2013 and 2014 BGS Auctions and their resulting capacity obligations under the BGS SMAs were based on known capacity costs that were established largely based on the PJM BRA that preceded each BGS Auction. FirstEnergy believes that the proposed PJM CP Transition Auction Mechanism could result in BGS suppliers subsequently incurring capacity costs they could not have foreseen when they bid to serve BGS Load. In addition, FirstEnergy also points out that BGS suppliers will likely bid in the upcoming 2015 BGS Auction before FERC has issued a decision on the PJM CP Updated Proposal. FirstEnergy believes that suppliers participating in the upcoming 2015 BGS Auction will also face the possibility of subsequently incurring costs they did not factor into their bids.

FirstEnergy believes to address this uncertainty the BGS SMA must be amended or supplemented to ensure that current and future winning BGS suppliers will be made whole for any subsequent increase in capacity costs as a result of the PJM CP Updated Proposal. FirstEnergy believes this recommendation is consistent with the SMA treatment of increases in Firm Transmission Service during the term of the SMA, and that such an amendment or supplement to the SMA will provide BGS suppliers with valuable certainty regarding their contractual obligations resulting from recent BGS Auctions as well as the upcoming 2015 BGS Auction. (FirstEnergy Supplemental Comments at 1 – 2).

IEPNJ asserts that now that the PJM CP process has evolved through two proposals (an initial proposal filed on August 20 and an Amended Proposal filed on October 7), it is becoming clearer that there are significant issues that the Board should address in its BGS Order so that the uncertainty of the CP process is squarely addressed and bidders will be able to a) participate in the BGS auction and b) bid prices that do not contain significant risk premiums embedded in their prices, which would be harmful to ratepayers. IEPNJ believes that as this PJM process has evolved, it has become clearer the BPU should take preemptive action to preserve the positive effects of its tested BGS auction process. IEPNJ indicates without BPU action, the State's BGS process will be infused with uncertainly that will impact supplier behavior for not only the 2015 auction, but for future auctions as well. In addition, IEPNJ believes robust participation in the BGS will be threatened with suppliers electing to opt out, rather than take the risks imposed by PJM under the CP Updated Proposal.

IEPNJ therefore recommends an adjustment to the SMA in the currently effective BGS contracts resulting from the 2013 and 2014 BGS Auctions and in the SMA to be used in the upcoming 2015 BGS auction can effectively address the impact of any PJM action, and thereby maintain the integrity of New Jersey's BGS process. IEPNJ indicates this should be done with a formula approach, allowing these costs, when and if they materialize, to be recovered by BGS Suppliers. IEPNJ believes this adjustment can be written in a manner that is a) flexible so it can adjust to reflect the CP structure the FERC ultimately accepts (and if the proposal does not move forward at FERC, then the SMA adjustment is not activated), and b) is formulaic and based on numbers that are available and transparent based on PJM and EDC data. IEPNJ indicates without this modification of the SMA, Suppliers participating in the BGS auction will price the "worst-case- scenario-uncertainty" into their BGS prices with resulting higher prices for New Jersey's ratepayers. Further, prices in future BGS auctions will reflect the uncertainty on the part of suppliers that the BPU has not maintained a BGS process that instills confidence in the BGS structure such that unanticipated changes by PJM will be recoverable. (IEPNJ Supplemental Comments at 2 – 5).

Noble indicates it is important that any cost recovery mechanism regarding PJM's CP proposal recognize existing retail contractual commitments and the existing retail electric market. Noble recommends any cost recovery mechanism that is entertained by the Board be completely bypassable by any customer which is not on the default service, and the costs be handled timely and in a way that accurately reflects current market conditions and does not allow for deferrals or other mechanisms that would distort the true costs and market price signals. (Noble Supplemental Comments at 2-3).

RESA maintains unless the Board acts to provide an explicit recovery mechanism for the increased cost resulting from the CP Updated Proposal, both TPSs and BGS suppliers will be financially harmed as they incur these unanticipated costs without the ability to recover them from their customers with existing Fixed Price contracts. RESA indicates that as a result, New Jersey customers would face dramatic price increases as BGS suppliers and TPSs build significant risk premiums into their price offerings (to protect themselves from future unknowable events) and/or exit the New Jersey market altogether.

RESA recommends to avoid further damage to the retail market in New Jersey, the Board create an EDC administered cost recovery mechanism for the incremental costs created during the PJM CP Transitional Years. RESA recommends the Board direct the New Jersey EDCs to create a reconcilable and nonbypassable charge to assess these incremental costs to all delivery system customers. RESA maintains that under this approach, the EDCs would collect the identifiable CP costs from both BGS customers and TPS customers through a BPU-approved surcharge on customer bills. RESA asserts universally imposing these costs as a wires charge would be the fairest way to asses these charges to TPS and BGS customers, while promoting confidence among TPSs and BGS suppliers and stability in New Jersey's energy marketplace.

TransCanada, in response to the EDCs' proposal, indicates it appears to capture only a change in the capacity price. Because the PJM CP Transition Mechanism calls for the acquisition of additional capacity, it is highly likely Final Zonal UCAP obligations will increase, and with it the UCAP obligation of BGS Suppliers. TransCanada indicates the incremental costs associated with such an increase in capacity obligations would be material to BGS suppliers, and therefore, should also be part of any mechanism to recover the costs.

In addition, TransCanada notes the same concern it and other competitive suppliers have articulated in comments filled in this docket; that regulatory uncertainty about the PJM capacity market could reduce participation by suppliers in the BGS solicitations. This same concern was cited by consultants who reviewed the results of the most recent standard offer service solicitation in Maryland.[12] TransCanada indicates that in explaining the decrease in bidders, the consultant, Boston Pacific, stated at page seven of the testimony the primary cause was uncertainty surrounding PJM's capacity market. TransCanada pointed out the consultant indicated that PJM is currently considering several changes that will have an effect not only on prospective capacity prices, but also on established prices. For this reason, TransCanada urges the Board to implement a mechanism to allow suppliers to recover these costs. (TransCanada Supplemental Comments at 3 – 4).

NEPM, in reply to the EDCs' proposal, believes the formula used in the supplements as proposed by the EDCs should be refined to calculate both the price and volume of capacity in the pass through formula. NEPM indicates PJM has two options at its disposal with respect to how it may actually implement CP. The first is to somehow improve the quality of the capacity PJM has already purchased, which in NEPM's opinion will translate into higher pricing for that product, and second, by purchasing additional capacity above and beyond the current planning parameters of RPM. NEPM agrees that the EDCs' proposal correctly adjusts EDC payments made to BGS suppliers to account for their additional capacity costs. NEPM believes in the latter case the EDC proposal would not adequately account for a BGS Suppliers' additional capacity costs as with this type of solution, the volume of capacity obligation BGS Suppliers will bear is raised while the price of that capacity may or may not be increased. NEPM indicates that the fail-safe solution is that regardless of the mechanism used by PJM to transition CP, the Board should adopt a mechanism that would be able to address changes in both price and volume.

Further NEPM echoes TransCanada's comments that without definitive action by the BPU, New Jersey's BGS Auction scheduled for February will face similar challenges as Maryland's standard offer service ("SOS") procurement. NEPM stresses that these challenges will place customers in the precarious position of potentially having to pay excessive prices based on risk premiums or, equally troubling, unnecessarily high prices due to lack of participation and competition. (NEPM Supplemental Reply Comments at 3 – 5).

Rate Counsel protests, as expressed in its supplemental comments, that allowing the pass through of increased capacity costs to New Jersey ratepayers sends the wrong message. Rate Counsel believes if the Board allows the BGS providers and TPS to pass through increased capacity costs imposed on them by PJM and/or FERC, there is absolutely no incentive for these suppliers to participate at PJM and FERC to advocate for reasonable capacity prices. Rate Counsel believes the persistent changes to RPM will continue and costs for all New Jersey customers will increase. Rate Counsel urges the Board not to modify the SMA or establish a non-bypassable charge to cover any increase in capacity costs for existing contracts.

Rate Counsel strenuously objects to NEPM's proposed changes to the SMA. Rate Counsel believes the proposed changes would completely insulate BGS Suppliers from any and all PJM capacity market changes. Rate Counsel also believes BGS is supposed to be a full requirements product, and the proposed changes would fundamentally alter that structure and threaten the stability and purpose of the BGS auction. Rate Counsel argues PJM capacity market rules change frequently, and the proposal to add each change into the BGS-FP auction price is a radical change that is neither warranted nor fair. Rate Counsel believes BGS providers are in a far better position to anticipate and influence capacity market changes than BGS customers.

---

[12] The testimony is available at:
http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOoenFile.cfm?filepath=C:/Casenum/9000-9099/9056/Item_510//MossburgandGottshallTestimony102314.pdf

Rate Counsel does recognize the Board's concern regarding existing BGS Suppliers who could not have reasonably foreseen PJM's proposed CP changes to the capacity market at the time they bid into the prior BGS auctions. Rate Counsel proposes that if the Board is inclined to do anything, the pass through should be limited to allow current BGS providers to pass through incremental costs they can demonstrate are the result of CP changes. Rate Counsel does not believe bidders in the upcoming 2015 BGS auction should be protected from the proposed changes as by February 2015, bidders in the BGS auction should be able to reasonably project future capacity costs, at least for the next three years.

Further, Rate Counsel strongly advocates this kind of mechanism should not apply to TPS. Rate Counsel indicates that BGS is a regulated product, there are no individually negotiated contracts, all winners in the auction are required to sign the same SMA. On the other hand, as noted in comments filed in this proceeding, TPSs have the freedom to determine what products and services to offer into the New Jersey Retail Electric Marketplace. Rate Counsel believes a TPS provider is in the business of managing risk and has the ability to address future changes of law or unanticipated price increases due to regulatory action in a negotiated contract. (Rate Counsel Supplemental Reply Comments 2 -5).

The Board is faced with making a decision on what action to take within the BGS procurement proceeding, if any, in light of the PJM proposed changes to the capacity market based primarily on comments made by stakeholders in the current BGS proceeding regarding the PJM Capacity CP Transition Auction Mechanism, Section XIII of the proposal. The Board believes the proposed changes may introduce uncertainty into the BGS procurement process and current BGS contractual obligations, and therefore, the Board should take preemptive action. It should be noted, however, that any actions the Board may take in this proceeding to protect the integrity of the BGS procurement process should in no way be seen as changing its position regarding the merits of the PJM CP Updated Proposal.

Specifically, the Board is on the record with the Organization of PJM States ("OPSI") in expressing to PJM that the solutions proposed in the PJM CP proposal are quite complex and could have substantial adverse pricing effects upon end-users and PJM has not provided sufficient data to permit OPSI members and other stakeholders to evaluate the need, benefits to load or effectiveness in protecting reliability of its proposals. OPSI has argued that the PJM CP proposals require further examination and discussion among stakeholders once PJM has provided adequate analyses of the expected effects of the CP proposals before any implementation. Accordingly, OPSI urged that PJM continue a robust stakeholder process at least through the next winter season. Also, OPSI believes that many of PJM's more aggressive market redesign proposals should not be considered for adoption until after the implementation of several near-term programs this winter and an evaluation of the effectiveness of those programs. If PJM decides to file the CP Updated Proposal with FERC, the Board along with OPSI and other PJM stakeholders with the same interests, will continue to argue against the proposal. While the Board is taking actions in its 2015 BGS proceeding to address the PJM CP Proposal Transition Mechanism as it relates to BGS, it is doing so solely to protect the structural integrity of the BGS procurement process that has led to a competitive BGS Auction process for the last thirteen years. As such, adoption of any mechanism to accommodate the possible approval of some form of the CP Updated Proposal in no way diminishes the right of the Board to argue its objections regarding the merits of the PJM CP proposal at PJM and at the FERC.

On October 7, 2014 PJM Interconnection, L.L.C. ("PJM") released its CP Updated Proposal. Board Staff offered parties the opportunity to comment on the PJM Capacity Performance Proposal Transition Auction Mechanism, Section XIII of the proposal, as Staff believed it might introduce uncertainty into the BGS procurement process and current BGS contractual obligations. Parties submitted supplemental comments by October 22, 1014 and supplemental reply comments by October 29, 2014. In response, as indicated above, the Board received a variety of proposals from market participants. These included an EDC proposal that would make BGS suppliers whole for increases in capacity prices as a result of possible FERC approval of the PJM CP proposal for those who signed the BGS-FP SMA for the 2013 and 2014 BGS Auctions, and for BGS winners who sign the 2015 SMAs. In addition, the EDCs' proposal also includes a methodology for collection in rates to allow winning bidders to recover the increase in capacity costs, using the same methodology currently used to recover other BGS costs from ratepayers. Of importance, the EDCs indicated their proposal would not have any impact on ratepayers should for whatever reason the PJM CP proposal not to be implemented. NEPM filed a proposal similar to the EDCs' making BGS Suppliers who signed the 2013, 2104 SMAs and who will sign the upcoming 2015 SMAs whole for any increase in price and volume resulting from FERC approval of a CP Proposal. IEPNJ also recommended that an adjustment be made to the SMAs that are currently effective for BGS contracts resulting from the 2013 and 2014 BGS Auctions, and in the SMA that will be used in the upcoming 2015 BGS auction to address the potential impact of the PJM CP proposal and thereby maintain the integrity of New Jersey's BGS process. Several parties, including RESA, proposed the use of a variety of methodologies for creating a non-bypassable charge to recover the expected increase in capacity costs from ratepayers. Rate Counsel protested allowing the pass through of increased capacity costs to New Jersey ratepayers sends the wrong message. However, Rate Counsel indicated it does recognize the Board's concern regarding existing BGS suppliers who could not have reasonably foreseen PJM's proposed CP changes to the capacity market at the time they bid into the BGS auction. Therefore, Rate Counsel proposes, if the Board is inclined to do anything, the pass through should be limited to allow current BGS providers to pass through incremental costs they can demonstrate are the result of PJM CP changes. Rate Counsel does not believe bidders in the upcoming 2015 BGS auction should be protected from the proposed changes. Rate Counsel feels that by February 2015, bidders in the BGS auction should be able to reasonably project future capacity costs, at least for the next three years. Further, Rate Counsel strongly advocates any adjustment mechanism should not apply to TPS.

The Board agrees with the comments in this matter that point to a common theme among all stakeholders - the PJM CP proposal is an unforeseen and unhedgeable event that proposes structural changes to the rules governing capacity markets, having the potential to result in unknowable changes to the costs of serving BGS load. Many stakeholders indicated to maintain the viability of the BGS process, the Board should provide compensation to BGS Suppliers for the incremental costs they face as a result of proposed changes to the RPM construct that arise from PJM's CP proposal. There were points made by some stakeholders that especially in the transition period, the PJM CP proposal introduces high levels of market uncertainty and will inevitably lead to higher wholesale supplier risk premiums as it injects fear and doubt into the otherwise stable and previously successful BGS procurement process. Further, stakeholders have articulated in comments filled in this docket, regulatory uncertainty concerning the PJM capacity market could reduce participation by suppliers in the BGS solicitations as was cited by the consultants who reviewed the results of the most recent standard offer service solicitation in Maryland. In explaining the decrease in bidder participation in the recent Maryland procurement for default load, the consultant, the same consultant the Board relies on in this proceeding, concluded the primary cause for the decreased participation was uncertainty surrounding PJM's capacity market.

For these reasons, the Board believes it should take preemptive action to preserve the positive effects of its tested BGS auction process. The Board feels that without action, the BGS process will be infused with uncertainly, likely to impact supplier behavior for not only the 2015 procurement process, but for future procurements as well. In addition, the Board is concerned the robust participation in the BGS procurement process that has been the hallmark of previous successful BGS procurements will be threatened with suppliers electing to opt out, rather than taking the risks imposed by the CP Proposal. The Board's BGS consultant, Boston Pacific, has repeatedly indicated in its Final Report that a large number of bidders is helpful because it increases the total supply bid offered in the Auction, resulting in pushing prices down. The Board believes a reduction in the number of bidders in the BGS procurement process could undermine the structural integrity of the Auction process and increase BGS costs to ratepayers. The Board is further concerned, especially during the transition phase, the PJM CP proposal introduces high levels of market uncertainty that could lead to higher wholesale supplier risk premiums as it injects an additional element of risk into the otherwise stable and successful BGS process.

N.J.S.A. 48:3-57(e) provides that BGS suppliers shall be permitted to recover through BGS charges on a full and timely basis all reasonable and prudently incurred costs in the provision of BGS. Although EDECA does not specify how such recovery is to be implemented, the Board has long recognized that the BGS procurement process works best and leads to the lowest reasonable prices when potential suppliers are not exposed to future costs (such as PJM Network Integration Transmission Services ("NITS"), PJM Transmission Enhancement Charges ("TECs") and PJM Deactivation Charges or Reliability Must Run ("RMR") charges or costs due to changes by regulatory agencies) that are not reasonably quantifiable or hedgeable at the time that bids are submitted during the BGS procurement process. Otherwise, suppliers would likely include an enhanced risk premium in their BGS bids to reflect the potential imposition of unforeseeable or unhedgeable costs that may or may not be imposed during the period of the proposed contract.

Based on the comments in the record, to preserve the viability of the BGS process, the Board **DIRECTS** the EDCs to incorporate Attachment 1 to their Supplemental Comments into the 2015 BGS-RSCP (formerly, BGS-FP) SMA, and make Attachment 1 available to suppliers who won tranches in the 2013 and 2014 BGS-FP Auctions. Further the Board **DIRECTS** the EDCs to incorporate Attachment 2 to their Supplemental Comments into the 2015 BGS-CIEP SMA. Both of these Attachments are included in Attachment D to this Order. In addition, the Board **DIRECTS** the EDCs to incorporate the mechanism to allow recovery of increased capacity prices resulting from potential FERC approval of the PJM CP proposal in the BGS-RSCP (formerly, BGS-FP) and BGS-CIEP tariffs as proposed in their Supplemental comments. Further, the Board **DIRECTS** the EDCs to make a compliance filing to incorporate the increased capacity price resulting from FERC approval of the PJM CP proposal in the BGS-RSCP and BGS-CIEP tariffs as proposed in their Supplemental comments, within 14 days of the time the new capacity prices are available to the EDCs and the Board. Finally, the Board **DIRECTS** each EDC to conduct a public hearing in its service territory indicating for the period beginning June 1, 2015 that FERC approval of the PJM CP proposal may lead to an increase in BGS rates.

After reviewing the various proposals submitted by parties, the Board believes the NEPM proposal to make price and volume adjustments as a result of any FERC approval of the PJM CP proposal has some merit. The PJM CP Updated Proposal in its current form could have PJM procure up to 10,000 MW of additional capacity somewhere in the PJM footprint for the 2015/2016 delivery year. This increase in capacity could increase a BGS Supplier's volume, thus increasing its capacity obligation and the cost of that obligation even if the cost of capacity itself is not increased. The EDCs' proposal is not structured to compensate suppliers for this increase in their capacity obligations and for the additional costs that could result from this aspect of PJM's CP proposal.

For the remaining two years of the PJM CP Updated Proposal, there is no mention of procuring new capacity; rather, the focus is on improving the quality of the capacity that PJM has already purchased for which NEPM agrees that the EDCs' proposal correctly adjusts EDC payments to be made to BGS suppliers to account for their additional capacity costs. Therefore, for the 2015/2016 delivery year, the Board **DIRECTS** the EDCs to modify their proposal to take into account both price and volume adjustments for capacity additions resulting from the PJM CP proposal, if ultimately approved by FERC. Further, the Board **DIRECTS** the EDCs to submit a compliance filing 14 days from the date of this Order including a mechanism to allow recovery of increased capacity costs, modifying Attachment 1 and 2 to allow BGS Suppliers to be compensated for both price and volume adjustments for only the 2015/2016 delivery year of PJM CP proposal.

RESA has stated that as a result of the PJM CP proposal unless the Board acts to provide the TPS with an explicit recovery mechanism for the increased costs resulting from this proposal, they will be financially harmed as they incur these unanticipated costs without the ability to recover from their existing Fixed Price contracts. RESA indicates as a result, New Jersey customers would face dramatic price increases as BGS suppliers and TPSs build significant risk premiums into their price offerings (to protect themselves from future unknowable events) and/or exit the New Jersey Market altogether. In the instant proceeding, the Board is focused on implementing a successful BGS procurement process. The Board needs to better understand the financial harm that would impact the TPS community as a result of the implementation of the PJM CP proposal before it can make any determination on the merits of RESA's proposal. Therefore, the Board invites TPSs to make a filing with the Board explaining how they would be financially harmed, recognizing that TPSs have the freedom to determine what products and services to offer into the New Jersey retail electric marketplace through a negotiated contract. This filing should also include several options that TPSs feel would resolve what they perceive as financial harms, as well as a verification mechanism to determine the actual costs a TPSs is exposed to as a result of PJM CP proposal.

BGS COLLATERAL REQUIREMENT

NEPM requests that the Board make specific changes to the BGS structure to ensure the credit terms appropriately reflect changing market conditions. NEPM does not propose to do away with the independent collateral requirement ("IRC") but rather to improve upon that existing use of certain collateral instruments and ultimately reduce what NEPM sees as unnecessary costs for customers. NEPM believes the current collateral requirements in the BGS-FP auctions leads to over- collateralization in Below Contract Price Environments, an inefficiency that they believe is not without cost, a cost ultimately borne by customers. (NEPM Final Comments at 9).

The EDCs recommend that the Board reject NEPM's proposal to alter the BGS-FP collateral requirements. The EDCs indicate that NEPM argues in its comments that the current BGS-FP collateral requirements lead to supplier over-collateralization, in turn resulting in higher supplier underwriting costs and in premiums in BGS-FP bid prices. The EDCs believe that there is no evidence that the current BGS-FP collateral requirements have in fact led to these outcomes. Further, the EDCs feel that the determination of what BGS-FP collateral requirements are appropriate must start with the question of what BGS-FP collateral requirements are needed to ensure that customers are protected and receive the benefit of the bargain struck at the BGS-FP Auction in the event of supplier default. They indicate that under the SMA, a supplier may be granted an unsecured credit line and will post security in excess of that unsecured line of credit. They further indicate that in the event that a BGS-FP Supplier encounters financial difficulties, or market prices rise suddenly and a BGS-FP Supplier elects to default and deploy its supply sources elsewhere, the EDC has access to sufficient funds to replace the defaulted supply and protect BGS customers. Thus, the EDCs believe that monetary security provides critical protection to BGS customers in the event of a default.

The EDCs feel that NEPM's proposed changes to the credit requirements should be rejected for the following reasons. 1) The ICR is necessary so that customers receive the benefit of the bargain obtained at the Auction. Netting of negative MTM values results in inadequate protection to cover liquidation risk, as they feel this past winter's experience shows. 2) Very few BGS-FP Suppliers are required to post liquid security for purposes of the ICR; and 3) The BGS-FP SMA credit requirements are the result of a long-standing compromise that includes the ICR as currently constituted, two unsecured credit lines offered by each EDC, and MTM marking only when monthly, bi-monthly or annual quotes are available. If NEPM's proposal were accepted, these items would need to be re-examined and changes to the SMAs could be complicated and extensive, and would be significant. (EDCs' Final comments at 11 - 14).

After carefully considering this request by NEPM, the Board concludes that customers should be protected from any default by suppliers providing BGS, and the ICR and the MTM multiplier provide adequate protection. Since BGS suppliers are Load Serving Entities ("LSEs") in PJM, the EDCs have transferred the PJM market credit requirements to BGS suppliers. As a result, the primary collateral underlying the SMA is the posting of security in excess of the unsecured credit line. Such monetary security is necessary in the event that a BGS supplier encounters financial difficulties, market prices increase suddenly or if, for whatever reason, a BGS supplier defaults on its obligations. In such an event, customers would be protected by the ICR and MTM because the EDCs would have sufficient access to funds to replace the missing supply. The monetary protection currently required by the SMA provides critical protection to the EDCs and their customers in the event of a default. Additionally, given that 1) participation in the BGS-FP Auction has been robust, 2) there is no evidence that the current BGS-FP collateral requirements have in fact led to the outcomes as presented by NEPM in their comments, 3) there is a lack of support for the proposed change, and 4) the Board in previous BGS proceedings rejected similar proposed changes and has not been presented with any new evidence to support it, the Board **DENIES** the request made by NEPM to modify the BGS collateral requirement.

SEASONAL BILLING FACTOR PROCESS REQUIREMENT

NEPM indicates that historically, the BGS Auction has employed two Seasonal Billing Factors. NEPM indicates one called "Summer" (June through September) and the other "Non-Summer" (October through May). NEPM indicates that as a result pf the "polar vortex" and to help appropriately refine the current design for wholesale supplier pricing, NEPM believes Seasonal Billing Factors should now include three distinct periods: Summer, Non-Summer and "Winter". NEPM indicates the Summer period would remain the same, and Non-Summer would be changed to the months of October through December, and March through May. Winter would be defined as January through February. NEPM believes that these periods provide better alignment of BGS-FP Supplier's revenues with their costs, reduce required working capital and risk premiums, and ensure New Jersey consumers that remain on default supply don't have a default price that is increased for unnecessary risk premiums from wholesale suppliers. (NEPM Initial Comments at 5 to 6).

The EDCs assert that the seasonal billing factor changes advocated by NEPM are unnecessary. The EDCs indicate that the BGS-FP Auction has historically applied a summer Seasonal Billing Factor (June through September) and a winter Seasonal Billing Factor (October through May) to final BGS-FP Auction prices by aligning prices paid to BGS-FP Suppliers with suppliers' seasonal costs. The EDCs point out that NEPM argues that two Seasonal Billing Factors are no longer sufficient due to the price volatility experienced during the polar vortex. The EDCs believe that retail BGS-FP rates are based on two seasons. They indicate that Seasonal Billing Factors are derived in the same manner as the retail rates. They further indicate that implementing three Seasonal Billing Factors, while maintaining the existing retail rate structure, would increase the volume of the reconciliation charges. (EDCs Final Comments at 23).

The Board agrees with the EDCs that changes to the seasonal billing factor advocated by NEPM are unnecessary for several reasons: 1) Seasonal Billing Factors are derived in the same manner as the retail rates which are based on two seasons, 2) implementing three Seasonal Billing Factors, while maintaining the existing retail rate structure, would have the potential to increase the volume of the reconciliation charges; and 3) there is a lack of support for the proposed change. Therefore, the Board **DENIES** the request made by NEPM to modify the BGS Seasonal Billing Factors used by the EDCs.

NON-BYPASSABLE CHARGES AND TRANSMISSION RELATED CHARGES

RESA urges the Board to ensure that the cost components in BGS service are set equitably between BGS and TPS supply. RESA asserts that charges related to PJM NITS, TECs and RMR agreements lack price transparency, and RESA believes these cost components, which are regularly reconciled for BGS customers, are best suited for the utilities to handle as part of a nonbypassable charge. Therefore RESA requests that responsibility for NITs, TECs and RMR charges should be transferred to the EDCs and be accounted for through a reconcilable and nonbypassable charge. (RESA Initial Comments at 3 - 4).

Rate Counsel urges that RESA's proposal for the creation of a nonbypassable charge for changes to transmission-related costs should be rejected by the Board. Rate Counsel indicated that since 2006, hundreds of millions of dollars in transmission-related increases have been passed through to BGS-FP customers pursuant to Section 15.9 of the SMA. Rate Counsel argues, as it has argued in the past, that BGS providers are better equipped and have the resources necessary to intervene in FERC and PJM proceedings setting transmission rates. With a nonbypassable charge directly passing any increases in transmission related charges to ratepayers, the generators and marketers of supply in New Jersey will have no incentive to fight for reasonable transmission rates. Rate Counsel therefore encourages the Board to discontinue the pass through of changes to transmission related costs to BGS customers as is currently the practice. Thus, rather than burdening ratepayers with additional nonbypassable charges, Rate Counsel believes that none of these costs should be directly passed through to ratepayers but should be integrated into the cost of supply as part of a full requirements fixed price product. (Rate Counsel BGS Legislative Hearing Comments at 2 - 4).

The EDCs have two responses to RESA's proposal that the Board should ensure "that the cost components in BGS service be set equitably between BGS and TPS supply." First, the EDCs maintain that the transparency issue is a "red herring." Second, the suggestion that transmission responsibility be shifted to the EDCs has been examined and rejected many times in the past and there is no reason to reconsider this issue.

The EDCs believe that individual TPS representatives may initially be unfamiliar with New Jersey BGS Tariffs and require assistance in understanding the derivation of rate components. They indicate that answers to any questions that TPS representatives may have are already available from the individual EDC itself through the EDC's TPS liaisons, or from the EDCs' tariffs, or from responses posted to the BGS Auction web site FAQs. The EDCs believe that when RESA asserts that charges related to NITS, TECs, and RMR agreements lack price transparency, RESA fails to acknowledge that there are tools already in place and at the TPSs' disposal to understand these charges.

The EDCs believe that with respect to the effective shift of all transmission responsibility to the EDCs that is a step backward not forward. They believe BGS was founded on the simple principle that the BGS provider was to the Load Serving Entity ("LSE") and responsible for all PJM-mandated functions. This provides full parity and competitive neutrality with TPSs. The ECDS indicate that in the past arguments have been made that certain functions that in the EDCs' view are appropriately handled by the LSEs should be placed back on the EDCs. This is a view that has been and should continue to be rejected, whether it originates from BGS Suppliers or TPSs.

The EDCs further note that Rate Counsel opposes RESA's request, but went further at the Legislative Hearing to recommend that the "pass-through" in Section 15.9 of the SMAs be eliminated so that all transmission cost risks be placed upon the BGS Suppliers. The EDCs agree with Rate Counsel that the responsibility for transmission for TPS customers should not be shifted to the EDCs but disagree with Rate Counsel's recommendation to eliminate Section 15.9 and take issue with the facts offered in support. First the EDCs point out that increases through Section 15.9 are not simply pass-throughs. The EDCs indicate that they file such increases with the Board and these increases are only reflected in retail rates after the Board has approved them. Second, the EDCs point out that hundreds of million dollars that have been reflected in rates under Section 15.9 are not additional or incremental charges. They feel absent Section 15.9, these same amounts would be in rates and, in addition, risk premiums associated with taking the transmission cost risk would be in rates. The EDCs indicate that BGS Suppliers must pay transmission costs and, without Section 15.9, anticipated increases in transmission rate would be reflected in bids, albeit based on estimates and with an allowance for uncertainty. They believe that the funds collected under Section 15.9 are payments that would have been made even if Section 15.9 did not exist. (EDCs' Final Comments at 20 - 22).

RESA indicates several reasons to support its claim that the Board should ensure that the cost components in BGS service are set equitably between BGS and TPS supply, and that responsibility for NITs, TECs and RMR charges should be transferred to the EDCs and be accounted for through a reconcilable and nonbypassable charge. First, RESA claims that NITS, TECs, and RMR agreements lack price transparency. In response, the EDCs believe that RESA fails to acknowledge that there are tools already in place and at the TPSs' disposal to understand these charges. The EDCs point out that individual TPS representative may initially be unfamiliar with New Jersey BGS Tariffs and require assistance in understanding the derivation of rate components. They indicate that answers to any questions that TPS representatives may have about these charges are already available from the individual EDC itself through the EDC's TPS liaisons, or from the EDCs' tariffs, or from responses posted to the BGS Auction web site FAQs. Second, RESA requests that responsibility for NITs, TECs and RMR charges should be transferred to the EDCs and be accounted for through a reconcilable and nonbypassable charge. In response, the EDCs believe BGS was founded on the simple principle that the BGS provider was to the Load Serving Entity ("LSE") and responsible for all PJM-mandated functions. They believe this provides full parity and competitive neutrality with TPSs. Based on the record in this matter, the Board believes that the appropriate mechanisms for a TPS to better understand and/or to obtain answers to questions about various BGS-FP pricing components should be through the EDCs' TPS liaisons, or from the EDCs' tariffs, or from responses to BGS Auction web site FAQs. Further the Board agrees with the EDCs that BGS was founded on the simple principle that the BGS provider was to be the LSE and responsible for all PJM-mandated functions. The Board further believes that BGS Suppliers are best positioned to assess and manage all risks, and that the BGS price should reflect such risks.

However, the Board believes that transmission related costs are an exception. They are regulated costs that cannot be managed or hedged and to which all suppliers are exposed. Often they are reflected in rates charged by PJM to wholesales suppliers while not final and are subject to refund. Therefore, the Board **DENIES** RESA's request that responsibility for NITs, TECs and RMR charges should be transferred to the EDCs and be accounted for through a reconcilable and nonbypassable charge.

Rate Counsel's opposition to RESA's proposal went further and recommended that the "pass-through" in Section 15.9 of the SMAs be eliminated so that all transmission cost risk be placed upon the BGS Supplier. The EDCs indicate that while they agree with Rate Counsel that the responsibility for transmission related costs for TPS customers should not be shifted to the EDCs, the EDCs disagree with Rate Counsel's recommendation to eliminate Section 15.9 and take issue with the facts offered in support. First the EDCs point out that increases through Section 15.9 are not pass-throughs. The EDCs indicate that they file such increases with the Board and these increases are only reflected in retail rates after the Board has approved them. Second, the EDCS point out that hundreds of million dollars that have been reflected in rates under Section 15.9 are not additional or incremental charges. They feel, absent Section 15.9, these same amounts would be in rates, and in addition, risk premiums associated with taking the transmission cost risk would be in rates.

The Board agrees with the EDCs that BGS Suppliers must pay transmission costs and, without Section 15.9, anticipated increases in transmission rates would be reflected in bids, albeit based on estimates and with an additional allowance for uncertainty. The Board believes that Section 15.9 of the SMA was developed as a practical middle ground. The purpose of Section 15.9 was that BGS Suppliers receive protection against increases in NITS, RTEP and RMR changes that, while perhaps not 100% perfect, is reasonable as any reductions in those charges must also be reflected in rates. While there may well be premiums for residual risk, the Board believes that competition limits those premiums. Further, while it is true that Section 15.9 can be complex at times and does result in administrative costs, it represents a well-crafted balance that preserves in large part the fixed-price nature of BGS and provides for a reasonable means of compensating BGS suppliers for unhedgeable costs approved in advance by the Board. The Board feels that Rate Counsel provides no factual basis that the "pass-through" in Section 15.9 of the SMAs be eliminated so that all transmission cost risk be placed upon the BGS Supplier would provide any benefit to ratepayers, and would only add higher risk premiums and uncertainty to the BGS process. At this time, the existing process for the "pass-through" of increases and decreases in these costs, as defined in Section 15.9 of the SMA, is the most efficient mechanism for minimizing the uncertainty of collection of these costs while maintaining the full requirements nature of the BGS product. For these reasons, the Board **REJECTS** the proposal of Rate Counsel to eliminate Section 15.9 of the SMA.

ADMINISTRATIVE EXPENSES

Rate Counsel indicates that every year in the EDCs' Joint Proposal, the EDCs notify the Board that the EDCs will retain NERA as the Auction Manager to administer the Auctions and advise the Board that, as in years past, the cost of the Auction Manager will be recovered through tranche fees paid by winning bidders. Rate Counsel asserts that these fees are ultimately paid by New Jersey ratepayers, whether through tranche fees or through the BGS reconciliation charge, and therefore, the Board has an obligation to ensure that these amounts paid by ratepayers are just and reasonable.

Rate Counsel also indicates that in previous BGS proceeding comments it raised the issue of legal fees resulting from the BGS patent defense claim being collected from ratepayers through the BGS administrative fees. Rate Counsel points out that in response, the Board directed the EDCs to submit a report to Staff and Rate Counsel detailing the total amount of BGS auction patent legal fees paid to date and the recovery of these fees from ratepayers. Rate Counsel further points out that the Board directed that after receipt and review of this information by Staff, Staff will inform Rate Counsel and the EDCs how it plans to proceed before making any recommendation to the Board. Rate Counsel indicates that on April 30, 2014, PSE&G, on behalf of the EDCs, provided to the Board a table of the annual fees billed to the EDCs in connection with the BGS "patent issues." Legal fees through February 2014 total $2,383,359.83. Rate Counsel asserts that while it has not yet received Staff's proposal, it questions whether ratepayers should pay these fees.

Further Rate Counsel indicates that in addition, all the amounts paid through the BGS administrative charge may be due for further review. Rate Counsel accordingly recommends that the Board continue and expand the Staff action taken in the previous BGS proceeding and initiate a review of all BGS administrative amounts. (Rate Counsel Initial Comments at 5 to 6).

The EDCs believe the BGS proceeding is an inappropriate forum for the review of administrative expenses. The EDCs continue to believe this proceeding is not the appropriate forum to review these patent claim issues, which may be the subject of litigation. They believe that the BGS process is by necessity a streamlined process and must be resolved in a four to five month period. The EDCs indicate that administrative cost reviews are akin to typical base rate case expense level reviews that allow for a longer schedule. The Board is already in the process of reviewing the BGS Auction patent issues in a separate review proceeding and should continue with that process. (EDCs' Final Comments at 15).

The Board agrees with Rate Counsel that it should initiate a review of all BGS administrative costs that are collected through the tranche fees. Therefore, the Board **DIRECTS** Staff to initiate a review of BGS Administrative fees collected through the BGS tranche fees in a separate proceeding to ensure that the amounts being paid by ratepayers are just and reasonable. However, with regards to litigation fees, the Board believes that with the ongoing litigation of patent claims issues associated with the BGS Auction process, specifically the costs associated with the litigation itself should continue to be subject to confidentiality until the conclusion of the patent claims issues involving the BGS Auction process. Therefore, at this time, the litigation costs of patent claims issues associated with the BGS Auction process shall remain confidential until the conclusion of the litigation. Upon conclusion of the litigation, the Board **DIRECTS** Staff to initiate a review of the litigation costs of patent defense involving the BGS Auction process.

RECONCILIATION CHARGE

RESA has recommended that the EDCs be required to utilize the same reconciliation charge period. RESA asserts that a quarterly, forward looking reconciliation charge should be implemented across all of the EDCs. RESA indicates that a uniform reconciliation charge will better facilitate a transparent and forward looking price to compare ("PTC") which RESA believes will assist customers in understanding their energy costs, and, if they choose to do so, effectively shop for energy from a competitive supplier. RESA further points out that the lack of a standardized, forward-looking reconciliation mechanism precludes the price transparency needed for the successful implementation and utilization of a shopping comparison website. RESA urges the Board to take action on this matter in this BGS proceeding, and direct the EDCs to utilize a quarterly, forward looking reconciliation charge. (RESA Initial Comments, 3 - 4).

Rate Counsel notes that the EDCs have proposed changes in this proceeding to more accurately calculate the BGS reconciliation charge. Accordingly, Rate Counsel recommends that the Board not introduce further changes in the reconciliation charge calculation until the EDCs' proposed changes have been implemented and evaluated. (Rate Counsel BGS Legislative Hearing Comments at 4).

The EDCs indicate that they categorically disagree with RESA's claims. The EDCs indicate that in their July 1, 2014 filing for the upcoming BGS Auctions they have updated the rate design to reflect current migration levels, which should lower deviations between costs and revenue, and ultimately reduce reconciliation charges. In addition the EDCs point out that the difference in time periods is a function of each EDC's billing system, and mandating changes that would require billing system modifications is not justified. The EDCs also believe that the concept of a "forward looking reconciliation charge" is inherently contradictory. A reconciliation charge is necessary because revenues collected for BGS and payments to BGS suppliers differ. Further, the EDCs indicate that they have been working with Board Staff and believe that data improvements made in this year's BGS filing will move toward reducing the amount of the reconciliation charge. Finally, the EDCs point out that Rate Counsel in its comments in this proceeding has noted these efforts and concurred that the changes sought by RESA are ill advised given this effort. The EDCS believe that the RESA proposal is neither practical nor necessary, and as such should be rejected by the Board. (EDCs' Final Comments at 19).

The Board agrees with Rate Counsel and the EDCs that the current BGS filing does include changes that have the potential to more accurately calculate the BGS reconciliation charge. Further, the Board agrees with Rate Counsel that the Board should not introduce further changes in the reconciliation charge calculation until the EDCs' proposed changes have been implemented and evaluated. Accordingly, the Board **DIRECTS** the EDCs to provide data to Staff and Rate Counsel in July 2016 on the implementation of the proposed changes to the reconciliation charge over the Energy Year 2015 period. Until Staff and Rate Counsel have had a chance to review the data provided by the EDCs, the Board **DENIES** RESA's request for the Board to direct the EDCs to utilize a quarterly, forward looking reconciliation charge.

CONFIDENTIALITY

The EDCs have requested that the Board approve a confidentiality order as in prior years. The integrity of the Auction process depends on a fair set of rules that promotes dissemination of information in a non-discriminatory manner, and results in no bidder or bidders having an advantage over any other. From the Board's experience with prior BGS Auctions, it appears that certain information pertaining to the Auction design methodologies, including, but not limited to, the starting price and volume adjustment guidelines, if made public, could have the potential to distort the Auction results. Furthermore, information provided in the bidder application forms and specific bidder activity during the Auction may be information that, if disclosed, could place bidders at a competitive disadvantage, and/or potentially distort the Auction results. The Board considered and ruled upon Auction confidentiality issues in its December 1, 2004 Order (Docket No. EO04040288). The Board found that certain financial and competitive information should be protected, not only as a matter of fairness to potential bidders, but also to ensure that these and any future BGS Auctions are competitive. These provisions were adopted and applied in subsequent Auctions. The Board **FINDS** that the confidentiality provisions of its December 1, 2004 Order in Docket No. EO04040288 remain necessary and appropriate for the continued success of the BGS Auctions, and **HEREBY APPROVES** the same confidentiality provisions for the 2015 BGS Auctions, and incorporates the reasoning and relevant provisions of its December 1, 2004 Order as if set forth at length herein. A copy of that Order is attached hereto as Attachment C.

AUCTION PROMOTION/DEVELOPMENT

The Board concludes that a successful BGS procurement can be achieved with a well-designed simultaneous descending clock Auction, provided that the rules and details are specified and implemented correctly, and provided that the Auction process provides sufficient awareness among qualified potential bidders so that a competitive procurement takes place. To maximize participation and competition, the Auction process requires a marketing and promotion plan aimed at ensuring exposure and awareness among qualified potential bidders. This year, as in past years, the EDCs and the Auction Manager will attempt to facilitate the process and increase the number of prospective bidders by publicizing the Auctions and by educating potential bidders about the proposed Auctions. Among the steps to be undertaken are the following:[13]

- Bidder Information Session in Philadelphia;
- An Auction Web Site at www.bgs-auction.com which publicizes new developments, allows interested parties to download documents related to the Auctions, has FAQs (Frequently Asked Questions with answers) so all bidders are similarly informed, provides potential bidders with data relevant to the bidding process, and has links to PJM and other useful sites;
- Press releases to newspapers and trade publications; and
- Direct e-mails to interested parties to inform them of any new developments or any new documents posted to the web site.

The Board **FINDS** that the foregoing marketing efforts by the EDCs and the Auction Manager should increase the chances that a successful BGS procurement will be achieved. Accordingly, the Board **APPROVES** continuation of the above-referenced Auction promotion initiatives.

BOARD APPROVAL PROCESS

As noted above, the Board believes that a successful BGS procurement can be achieved with a well-designed simultaneous descending clock Auction process, provided that the rules and details are specified and implemented correctly. Therefore, barring some unforeseen emergency, the timing of the Auction process approved with this Order, including certification of the Auction results, needs to take place according to a pre-approved schedule. As indicated in Attachment A, *Tentative Approvals and Process,*[14] there are a number of decisions/actions that need to be made after Board approval of the Auction process. Each of these decisions/actions needs to take place according to such a schedule so that the bidders are prepared for and comfortable with participating in the Auctions,, and the Auctions result in competitive market-based BGS prices.

Based on the Board's experience with the previous BGS Auctions, uncertainty or delay in the period between the submission of bids and the approval of bid results by the Board is of

[13] These actions have occurred for past Auctions and in anticipation of a favorable Board ruling herein, some of these actions may have already been undertaken for the 2015 Auction.

[14] Attachment A is labelled "Tentative" to indicate that the Auction Manager, in consultation with Staff, has discretion to make minor adjustments to these dates in order to provide for an orderly implementation process, not to indicate that the Board anticipates any significant changes to this schedule.

substantial concern to bidders. Paramount among the actions that need to be taken by the Board is prompt certification of the Auctions' results. Because of the volatility of the electric markets, bids cannot remain viable for any prolonged period of time. If bidders perceive that there may be a delay in certifying the results, any additional risk could be reflected through higher bid prices. Furthermore, the Auctions have been designed to secure supply for all four EDCs at the same time. The structure of the Auctions that permits and encourages bidder movement among EDC products implies to the bidders that, while being different products, tranches will be viewed on equal terms by the Board. It is important to the efficiency and economy of the process that bidders do not impute unwarranted uncertainty into the Auction results of any EDC. Therefore, as with past Auctions, the Board will consider the results of the BGS-FP Auction in their entirety and consider the results of the BGS-CIEP Auction in their entirety, and certify the results of each Auction for all of the EDCs or for none of them. The Board will also commit to addressing the results of the BGS-FP Auction and the BGS-CIEP Auction no later than the second business day[15] after the last Auction closes. At its discretion and depending on circumstances, the Board may address the results of one Auction that has closed while the second Auction continues. However, under all circumstances, the Board intends to have considered the outcome of both Auctions by no later than the second business day after the last Auction closes.

Another decision that requires Board approval is acceptance of the EDCs' Compliance Filings. Because of the significance of this proceeding, the Board **DIRECTS** the EDCs to make a Compliance Filing by November 26, 2014. Further, the Board gives Staff the authority in reviewing the EDCs' compliance filings, to request that the Board Secretary issue compliance letters approving the filings should Staff upon review find them in compliance with this Order.

Either the EDCs or the Auction Manager, in consultation with Staff and the Board's consultant, may make other Auction decisions as identified in Attachment A to this Order. These decisions include establishing minimum and maximum starting prices, establishing specific starting prices, the resolution of association issues, specific bidder application and credit issues, load cap and volume adjustment decisions, Auction price decrements, and other decisions which might be required throughout the implementation process. Some of the aforementioned areas, such as bidder application and credit issues, are subject to rules spelled out in the Joint EDC Proposal. Other areas, such as load caps and volume adjustment decisions, establishing minimum and maximum starting prices, establishing specific starting prices, the resolution of association issues, and Auction price decrements are either Company-specific concerns, are determined directly from algorithms included in and approved as part of the Joint EDC Proposal, or are areas that need to be addressed by the Auction Manager based on its experience in this field. In the event that these other areas need to be addressed by the Auction Manger, the Board **DIRECTS** that the Auction Manager include in its Final Report a description of any such actions. Should any unforeseen circumstances occur during the Auction decision-making process, the Board **DIRECTS** Staff to immediately bring the matter to the Board's attention.

When the Auctions are complete, the Board will review and consider the results within the time frame set forth above. Prior to Board certification of the results, the Auction Manager will provide a Final Report to the Board on the results of the Auctions and how the Auctions were conducted, including the post-Auction evaluation forms in Attachment B. The Auction Manager will also provide a redacted version of the Final Report, consistent with the confidentiality provisions of this Order, to the EDCs and Rate Counsel. The Board's Auction consultant shall provide a Pre-

---

[15] As used in this Order, a "business day" is a day when the Board is open for business. Should weather or other conditions make the Board's offices inaccessible, the period will run until the end of the next day that is not a Saturday, Sunday or legal holiday.

certification Report to the Board, including completed post-Auction evaluation forms in the form of Attachment B to this Order, prior to Board certification of the results.

FINDINGS AND CONCLUSIONS

Based on the foregoing and after carefully reviewing the record in this proceeding, the Board **FINDS** that:

This has been an open proceeding, with all parties desiring to present written or oral comments on the record having been afforded the opportunity to do so;

The Joint EDC Proposal, as modified herein, is consistent with the Electric Discount and Energy Competition Act, N.J.S.A.48:3-49 to -107, and the EDCs' Final Restructuring Orders;

The Joint EDC Proposal, as modified herein, can and should be implemented in a timely fashion so as to secure BGS service for BGS customers beginning June 1, 2014;

The Joint EDC Proposal, as modified herein, appears to be the best means to secure BGS service for the 2015 BGS period for BGS-CIEP customers, and for the remaining one-third of the needs of BGS-FP customers, as well as for a portion of the BGS-FP service required for the 2016 and 2017 BGS periods;

The name BGS-FP will be changed to the BGS-RSCP for the BGS period beginning June 1, 2015.

An Auction process for one-third of the EDCs' BGS-RSCP load for a 36-month period balances risks and provides a reasonable opportunity for price stability under current conditions;

An Auction process for procurement of the entire non-shopping BGS-CIEP load for a 12-month period is appropriate;

The EDCs' BGS-RCSP rate design is an appropriate methodology to translate final BGS-RCSP bids into customer rates for the purpose of this Auction;

The application of seasonal payment factors to the tranche-weighted Auction prices, determined in the manner prescribed herein is appropriate, and may be updated by the EDCs in January to reflect the most recent data;

Recovery of increases or decreases in rates for Firm Transmission Service from both RCSP and CIEP customers, and payment of such increases or downward adjustments to rates paid to BGS Suppliers, as provided in Section 15.9 of the SMAs is appropriate, subject to review and verification of those charges by the EDCs prior to submission to the Board;

Consistent with the Board's policy that all CIEP customers benefit and should pay the costs of having BGS-CIEP service available, capacity is the bid product in the CIEP Auction and the CIEP Standby Fee will be assessed to all CIEP customers;

The EDCs are the parties responsible to the Board for compliance with the RPS requirements;

The EDCs will prepare the RPS reports required by the Board on behalf of the BGS suppliers, and will contractually require the BGS suppliers to comply with the Board's RPS requirements;

The EDCs have designated NERA to continue to act as the Auction Manager for the 2015 Auctions;

Fulfillment of their Auction obligations will not cause successful bidders in the BGS Auction to be "Electric Power Suppliers" as defined in N.J.S.A. 48:3-51 and N.J.A.C. 14:4-1.2, and thus, successful bidders do not need to obtain a New Jersey electric power supplier license to fulfill their Auction obligations;

All Auction rules, algorithms and procedures that were unchanged in this proceeding, and were approved in prior Board Orders, as well as the Auction rules, algorithms and procedures that were modified in this proceeding, including changes in the decrement formulas, are deemed reasonable for the purpose of these Auctions;

Certain information and processes associated with the Auctions may be competitively sensitive by nature, and the Board has incorporated herein a Protective Order addressing treatment of this competitive information as Attachment C;

The accounting and cost recovery processes identified in the EDC-specific Addenda to the Joint EDC Proposal, as modified herein, are reasonable and consistent with the Board's Final Unbundling Orders;

The EDC-specific Contingency Plans are reasonable;

The Tentative Approvals and Decision Process Schedule in Attachment A reasonably balance process efficiency with Board oversight;

Boston Pacific will be the Board's Auction Advisor for the 2015 Auctions, and will oversee the Auctions on behalf of the Board consistent with the terms of its contract;

Two designees from the Board's Energy Division, the Office of the Economist and its consultant, Boston Pacific, shall observe the Auctions for the Board;

The Auction Advisor will provide the post-Auction evaluation forms in Attachment B to the Board, and a redacted version to the EDCs and Rate Counsel, on the results of the Auctions and how the Auctions were conducted, prior to Board certification of the results;

Boston Pacific shall also provide a completed post-Auction evaluation form in the form of Attachment B to the Board, prior to Board certification of the results;

The Board will consider the results of the BGS-RCSP Auction and the BGS-CIEP Auction each in its entirety and certify the results of each for all of the EDCs or for none of them no later than the second business day after the last Auction closes. At its discretion and depending on circumstances, the Board may address one Auction that has closed while the second continues;

Nothing herein is in any way intended to relieve the EDCs and/or the Auction Manager of their responsibilities to conduct the Auction in a lawful manner, including obtaining any appropriate licenses that may be required by law; and

For RPS compliance purposes, winning bidders in the 2015 BGS Auction, through the EDCs, will be credited with an equivalent level of non-utility generation ("NUG") RECs as would be available to them through the EDCs.

Accordingly, for the foregoing reasons, the Board **APPROVES** the Joint EDC Proposal, including the BGS-FP and BGS-CIEP Auction Rules, the EDC-specific addenda and the Supplier Master Agreements, with the modifications described herein. The Board reserves the right, at the certification meeting, to reject the BGS-FP Auction results and/or the BGS-CIEP Auction results.

Furthermore, the Board **DIRECTS** that the Joint EDC Proposal be modified consistent with the foregoing, and that the EDCs make compliance filings consistent with this decision by November 26, 2014. In addition, as indicated above, the EDCs shall file a compliance filing within 14 days from the date of the Final Order including a mechanism to allow recovery of increased capacity costs, modifying Attachments 1 and 2 to allow BGS Suppliers to be compensated for both price and volume adjustments for only the 2015/2016 delivery year of PJM CP proposal, and an additional compliance filing, if needed, to incorporate the increased capacity prices resulting from FERC approval of the PJM CP proposal in the BGS-RSCP and BGS-CIEP tariffs as proposed in their Supplemental comments, within 14 days of the time the new capacity prices are available to the EDCs and the Board, if FERC approves the PJM CP Proposal. The Board **AUTHORIZES** Staff, after reviewing each of the EDCs' above described compliance filings, to request that the Board Secretary issue a compliance letter of approval if Staff upon review finds the filings in compliance with this Order.

The Board **FURTHER DIRECTS** the EDCs to work with Staff and Boston Pacific to ensure that any supplemental documents are fair and consistent with this decision, and that the review procedures for bidder applications are applied in a consistent and non-discriminatory manner.

DATED: 11/24/14

BOARD OF PUBLIC UTILITIES
BY:

RICHARD S. MROZ
PRESIDENT

JOSEPH L. FIORDALISO
COMMISSIONER

MARY-ANNA HOLDEN
COMMISSIONER

ATTEST:

KRISTI IZZO
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities

In the Matter of the Provision of Basic Generation Service
For the Period Beginning June 1, 2015
Docket No. ER14040370
Service List

BPU

Kristi Izzo, Secretary
New Jersey Board of Public Utilities
Post Office Box 350
44 South Clinton Ave., 9th Floor
Trenton, NJ 08625-0350
kristi.izzo@bpu.state.nj.us

Frank Perrotti
New Jersey Board of Public Utilities
Post Office Box 350
44 South Clinton Ave., 9th Floor
Trenton, NJ 08625-0350
frank.perrotti@bpu.state.nj.us

Jerome May, Director
New Jersey Board of Public Utilities
Post Office Box 350
44 South Clinton Ave., 9th Floor
Trenton, NJ 08625-0350
Jerome.may@bpu.state.nj.us

Mark Beyer, Chief Economist
New Jersey Board of Public Utilities
Post Office Box 350
44 South Clinton Ave., 9th Floor
Trenton, NJ 08625-0350
mark.beyer@bpu.state.nj.us

Stacy Peterson
New Jersey Board of Public Utilities
Post Office Box 350
44 South Clinton Ave., 9th Floor
Trenton, NJ 08625-0350
stacy.peterson@bpu.state.nj.us

Donna Sebest
New Jersey Board of Public Utilities
Post Office Box 350
44 South Clinton Ave., 9th Floor
Trenton, NJ 08625-0350
donna.sebest@bpu.state.nj.us

DAG

Babette Tenzer
Deputy Attorney General
Division of Law
Board of Public Utilities Section
124 Halsey Street
P.O. Box 45029
Newark, New Jersey 07101
babette.tenzer@dol.lps.state.nj.us

Jennifer Hsia
Deputy Attorney General
Division of Law
Board of Public Utilities Section
124 Halsey Street
P.O. Box 45029
Newark, New Jersey 07101
Jennifer.Hsia@dol.lps.state.nj.us

BPU's BGS CONSULTANTS

Craig R. Roach
Boston Pacific Company, Inc.
1100 New York Avenue, NW
Suite 490 east
Washington, DC 2005
croach@bostonpacific.com

Frank Mossburg
Boston Pacific Company, Inc.
1100 New York Avenue, NW
Suite 490 east
Washington, DC 2005
fmossburg@bostonpacific.com

DIVISION OF RATE COUNSEL

Stefanie A. Brand, Esq., Director
Division of Rate Counsel
140 East Front Street, 4th Floor
Post Office Box 003
Trenton, New Jersey 08625
sbrand@rpa.state.nj.us

Ami Morita
Division of Rate Counsel
140 East Front Street, 4th Floor
Post Office Box 003
Trenton, New Jersey 08625
amorita@rpa.state.nj.us

Diane Schulze
Division of Rate Counsel
140 East Front Street, 4th Floor
Post Office Box 003
Trenton, New Jersey 08625
dschulze@rpa.state.nj.us

PSE&G

Alexander C. Stern, Esq.
Assistant General Regulatory Counsel
Law Department
80 Park Plaza, T-05
Newark, New Jersey 07102-4194
Alexander.Stern@pseg.com

Tony Robinson
Public Service Electric & Gas Co.
80 Park Plaza, T-8
Newark, NJ 07101
Anthony.Robinson@pseg.com

ATLANTIC CITY ELECTRIC CO.

Joseph F. Janocha, Manager,
Regulatory Affairs
Atlantic City Electric Co. – 63ML38
5100 Harding Highway
Atlantic Regional Office
Mays Landing, NJ 08330
joseph.janocha@pepcoholdings.com

Gregory R. Marquis
Pepco Holdings, Inc.
701 Ninth Street NW
Washington, DC 20068-0001
grmarquis@pepco.com

Philip J. Passanante,
Assistant General Counsel
Atlantic City Electric Co. - 89KS42
800 King Street, 5th Floor
PO Box 231
Wilmington, DE 19899-0231
philip.passanante@pepcoholdings.com

JCP&L

Kevin Connelly
First Energy
300 Madison Avenue
Morristown, NJ 07960
kconnelly@firstenergycorp.com

Greg Eisenstark
Windels Marx &Mittendorf, LLP
120 Albany Street, 6th Floor
New Brunswick, NJ 08901
geisenstark@windelsmarx.com

Sally J Cheong
First Energy
300 Madison Avenue
P. O. Box 1911
Morristown, NJ 07962-1911
scheong@firstenergycorp.com

ROCKLAND

John L. Carley, Esq.
Consolidated Edison Co. of NY
Law Dept., Room 1815-S
4 Irving Place
New York, NY 10003
carleyj@coned.com

James C. Meyer, Esq.
Riker, Danzig, Scherer, Hyland & Perretti
Headquarters Plaza
One Speedwell Avenue
Morristown, NJ 07962
jmeyer@riker.com

William A. Atzl, Jr.
Rockland Electric Company
4 Irving Place - 2nd Floor SE
New York, NY 10003
atzlw@coned.com

Margaret Comes, Esq.,
Consolidated Edison Co. of NY
Law Department, Room 1815-S
4 Irving Place
New York, NY 10003
comesm@coned.com

In the Matter of the Provision of Basic Generation Service For the Period Beginning June 1, 2015 Docket No. ER14040370 Service List

NERA

Gene Meehan
NERA Economic Consulting
1255 23rd St. NW
Washington, DC 20037
Gene.Meehan@NERA.com

Chantale LaCasse
NERA Economic Consulting
1255 23rd St. NW
Washington, DC 20037
Chantale.LaCasse@NERA.com

Third Party Suppliers

Murray E. Bevin, Esq.
Bevan, Mosca, Giuditta & Zarillo, P.C.
776 Mountain Blvd.
Suite 202
Watchung, NJ 07069
mbevan@bmgzlaw.com

SueAnne I. Harrel
Pepco Energy Services
39 Crestview Drive
Asset Mgmt Group
Clinton, NJ 08809
sharrel@pepcoenergy.com

Dana Swieson
EPEX
717 Constitution Drive
Suite 110
Exton, PA 19341
Dana.swieson@epex.cc

Marc A. Hanks
Senior Manager, Government & Regulatory Affairs
Direct Energy Services, LLC
Marc.Hanks@directenergy.com

Mark S. Kumm
Pepco Energy Services, Inc.
1300 N. 17th, Suite 1600
Arlington, VA 22209
mkumm@pepcoenergy.com

Stacey Rantala
National Energy Marketers Association
3333 K Street, N.W., Suite 110
Washington, D.C. 20007
srantala@energymarketers.com

David B. Applebaum
Director, Regulatory Affairs
NextEra Energy Resources, LLC
21 Pardee Place
Ewing, New Jersey 08628
david.applebaum@nexteraenergy.com

David Gil
Manager, Regulatory Affairs
NextEra Energy Resources, LLC
700 Universe Boulevard
Juno Beach, Florida 33408
david.gil@nexteraenergy.com

Kathleen Maher
Constellation NewEnergy
810 Seventh Avenue, Suite 400
New York, NY 10019-5818
kathleen.maher@constellation.com

Bob Blake
VP Elec. Operations & Regulatory Affairs
MXenergy
10010 Junction Dr, Suite 104S
Annapolis Junction, MD 20701
rblake@mxenergy.com

NJLEUC

Paul F. Forshay, Partner
SUTHERLAND
1275 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2415
paul.forshay@sutherland.com

Steven S. Goldenberg, NJLEUC, Esq.
Fox Rothschild LLP
Princeton Corporate Center
997 Lenox Drive, BLDG. 3
Lawrenceville, NJ 08648-2311
SGoldenberg@foxrothschild.com

BGS SUPPLIERS

Steven Gabel - IEPNJ
Gabel Associates
417 Denison Street
Highland Park, NJ 08904
steven@gabelassociates.com

James Laskey, Esq. - IEPNJ
Norris McLaughlin & Marcus
721 Route 202-206
Bridgewater, NJ 08807
jlaskey@nmmlaw.com

Mark Baird, Director, Regulatory Affairs
RRI Energy, Inc.
7642 West 450 North
Sharpsville, IN 46068
mbaird@rrienergy.com

Raymond Depillo
PSEG Energy Resources & Trade
80 Park Plaza, T-19
P.O. Box 570
Newark, NJ 07101
raymond.depillo@pseg.com

Shawn P. Leyden, Esq.
PSEG Energy Resources & Trade
80 Park Plaza, T-19
P. O. Box 570
Newark, NJ 07101
shawn.leyden@pseg.com

David K Richter, Esq.
PSEG
Regulatory Department
80 Park Plaza, T-5C
P. O. Box 570
Newark, NJ 07101
david.richter@pseg.com

Ken Gfroerer
RRI Energy
RR1 Box 246
Stahlstown, PA 15687
kgfroerer@rrienergy.com

Craig S. Blume
Director, Power Marketing
UGI Energy Services / UGI Development Company
One Meridian Boulevard, Suite 2C01
Wyomissing, PA 19610
cblume@ugies.com

Robert O'Connell,
VP & Compliance Manager
J.P. Morgan Ventures Energy Corp.
1033 Squires Drive
West Chester, PA, 19382
robert.oconnell@jpmorgan.com

Deborah Hart, Vice President
Morgan Stanley Capital Group
2000 Westchester Avenue
Trading Floor
Purchase, NY 10577
deborah.hart@morganstanley.com

Marcia Hissong, Director, Contract Administration/Counsel
DTE EnergyTrading, Inc.
414 South Main Street
Suite 200
Ann Arbor, MI 48104
hissongm@dteenergy.com

Don Hubschman
American Electric Power
155 W. Nationwide Blvd.
Columbus, OH 43215
dmhubschman@aepes.com

Christine McGarvey
AEP Energy Partners, Inc.
Energy Trader
155 W Nationwide Blvd
Suite 500
Columbus, OH 43215
clmcgarvey@aepes.com

Glenn Riepl
AEP Energy Services
1 Riverside Plaza
14th Floor
Columbus, OH 43215-2373
gfriepl@aep.com

In the Matter of the Provision of Basic Generation Service For the Period Beginning June 1, 2015 Docket No. ER14040370 Service List

Jean-Paul St. Germain
Sempra Energy Trading
58 Commerce Road
Stamford, CT 06902
jean-paul.st.germain@rbssempra

Howard O. Thompson - BGS
Russo Tumulty Nester Thompson
Kelly, LLP
240 Cedar Knolls Road
Suite 306
Cedar Knolls, NJ 07927
hthompson@russotumulty.com

Sharon Weber
PPL Energy Plus
2 North 9th Street TW 20
Allentown, PA 18101
sjweber@pplweb.com

Stephen Wemple
Con Edison Energy
701 Westchester Avenue
Suite 201 West
White Plains, NY 10604
wemples@conedenergy.com

Glen Thomas
The P[3] Group
GT Power Group LLC
1060 First Avenue
Suite 400
King of Prussia, PA 19406
Gthomas@gtpowergroup.com

Divesh Gupta
Senior Counsel
Constellation Energy
100 Constellation Way, Suite 500C
Baltimore, Maryland 21202
divesh.gupta@constellation.com

Tom Hoatson
LS Power Development, LLC
2 Tower Center
East Brunswick, NJ 08816
thoatson@lspower.com

John Citrolo
Conectiv Energy Supply, Inc.
PO Box 6066, MS 92DC69
Newark, DE 19714
john.citrolo@conectiv.com

Adam Kaufman
Executive Director
Independent Energy Producers of NJ
Five Vaughn Drive, Suite 101
Princeton, NJ 08540
akaufman@kzgrp.com

Stuart Ormsbee
TransCanada Power Marketing Ltd.
110 Turnpike Road, Suite 300
Westborough, MA 01581
Stuart_ormsbee@transcanada.com

Gregory K. Lawrence
Cadwalader, Wickersham & Taft LLP
One World Financial Center
New York, NY 10281
greg.lawrence@cwt.com

Victoria M. Lauterbach
Cadwalader, Wickersham & Taft LLP
700 Sixth Street, N.W.
Washington, DC 20001
tory.lauterbach@cwt.com

Anthony Pietranico
ConEdison Solutions Inc.
Electricity Supply Specialist
Tel: 732-741-5822 x204
pietranicoa@conedsolutions.com

Aundrea Williams
Director Regulatory Affairs
NextEra Power Marketing LLC
700 Universe Boulevard
Juno Beach, Fl. 33408
aundrea.williams@nexteraenergyservices.com

Ira G. Megdal
Cozen O'Connor
457 Haddonfield Road
Suite 300 P.O. Box 5459
Cherry Hill, NJ 08002
imegdal@cozen.com

Christi L. Nicolay
Division Director
Macquarie Energy LLC
500 Dallas St., Level 31
Houston, TX 77002
Christi.Nicolay@macquarie.com

OTHER PARTIES

Sara Bluhm
NJBIA
102 West State Street
Trenton, NJ 08608-1199
sbluhm@njbia.org

John Holub
NJ Retail Merchants Assoc.
332 West State Street
Trenton, NJ 08618
John@njrma.org

Judy Misoyianis, Administrator
New Jersey Retail Merchants Assoc.
332 West State Street
Trenton, NJ 08618
judy.njrma@verizon.net

Holly Minogue
Gabel Associates
Energy, Environmental, and Public
Utility Consulting
417 Denison Street
Highland Park, NJ 08904
holly.minogue@gabelassociates.com

Larry Spielvogel, PE
L. G. Spielvogel, Inc.
190 Presidential Blvd # 310
Bala Cynwyd, PA 19004-1151
spielvogel@comcast.net

Robert Macksoud, Jr, CEP
Director Energy Procurement
EnergySolve
One Executive Dr, Suite 401
Somerset, NJ 08873
rmacksoud@energysolve.com

Lyle Rawlings
Mid-Atlantic Solar Energy Industries
Association
Rutgers EcoComplex, Suite 208-B
1200 Florence-Columbus Road,
Bordentown, NJ 08505
lrawlings@mseia.net

Katie Bolcar
Mid-Atlantic Director
Solar Energy Industries Association
575 7th Street, NW, Suite 400,
Washington DC 20005
kbolcar@seia.org

Bruce H. Burcat, Esq.
Executive Director
Mid-Atlantic Renewable Energy Coalition
208 Stonegate Way
Camden, DE 19934
bburcat@marec.us

ATTACHMENT A

Tentative 2015 Auction Approvals and Decision Process

This document sets forth a high level view of the proposed approval and interaction process. For purposes of the decision making schedule, the following abbreviations apply:

1. EDCs – These are decisions for which the EDCs are solely responsible. The EDCs may draw upon the Auction Manager (AM) or consultants as they desire.

2. EDCs/BA – These are decisions for which the EDCs are solely responsible, where the Board Advisor (Staff and/or Boston Pacific) will have an opportunity to observe the decision process, but for which consensus or approval is not requested.

3. EDCs/AM/BA – These are decisions for which the EDCs are responsible, but where the Auction Manager may advise, and the Board Advisor (Staff and/or Boston Pacific) will have an opportunity to observe.

4. AM/BA – These are actions for which the Auction Manager is responsible, and on which the BA will have the opportunity to observe and advise.

5. BPU – These are actions to be taken by the Board.

6. AM/EDCs – These are actions for which the Auction Manager is responsible and for which the Auction Manager acts in concert with the EDCs.

Decision point	**Decision process**	**Timing**
Joint EDC Filing	EDCs	July 1, 2014
Decision on 2014 Process	BPU	November 21, 2014
Compliance Filing	EDCs	November 26, 2014
Approval of Compliance filing	BPU	Early December 2014
Final Auction Rules and Supplier Agreements available	AM/EDCs	Early December 2014
Announce minimum and maximum starting prices	AM/BA	December 2, 2014
Announce Tranche Targets	AM	December 2, 2014
Announce Load Caps	AM/BA	December 2, 2014
Information session for potential bidders	AM/EDCs	December 5, 2014
Review Part I applications	AM/BA	December 16-19, 2014

ATTACHMENT A

Tentative 2013 Auction Approvals and Decision Process

Review Part 2 applications	AM/BA	January 14-22, 2014
Setting of target limit exposure to contingency plan	EDCs/BA	Mid-January 2015
Information Session for registered bidders	AM/EDCs	January 27, 2015
Trial Auction	AM	January 29, 2015
Establish EDC-specific starting prices	EDCs/AM/BA	Announced to bidders for CIEP Auction on February 3, 2015, for FP Auction on February 4, 2015
BGS-CIEP Auction starts		February 6, 2015
BGS-FP Auction starts		February 9, 2015
Provide full factual report to Board	AM/BA	Upon competition of FP Auction
Board decision on Auction results	BPU	No later than by end of 2^{nd} business day following the calendar day on which the last auction closes.

ATTACHMENT B
Docket No. ER14040370

POST-AUCTION CHECKLIST
FOR THE NEW JERSEY 2015 BGS-FP AUCTION

Prepared by: [Company]

[Introductory comments, if any.]

Auction began with the opening of Round 1 at [x:xx am] on Friday, February 9, 2015

Auction finished with the close of Round ## at [xxx] on [xxx]

	Start of Round 1	Start of Round 2 * (after volume reduction in Round 1, if applicable)	Start of Round n * (after post-Round 1 volume reduction, if applicable)
# Bidders			
Tranche target	## tranches	## tranches	## tranches
Eligibility ratio			
PSE&G load cap	## tranches	## tranches	## tranches
JCP&L load cap	## tranches	## tranches	## tranches
ACE load cap	## tranches	## tranches	## tranches
RECO load cap	## tranches	## tranches	## tranches
Statewide load cap	## tranches	## tranches	## tranches

* Note: [No volume adjustment was made during the FP auction, so the pre-auction tranche target and EDC-specific load caps were unchanged for the auction. / Or alternatively, note details of volume adjustments if they occurred.]

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-FP Auction

Table 1 below shows pertinent indicators and measures for the auction.

Table 1. Summary of BGS-FP Auction

	PSE&G	JCP&L	ACE	RECO	Total
BGS-FP peak load share (MW)					
Total tranches needed					
Starting tranche target in auction					
Final tranche target in auction					
Tranche size (%)					
Tranche size (approximate MW)					
Starting EDC load caps (# tranches)					
Starting statewide load cap (#tranches)					
Final EDC load caps (# tranches)					
Final statewide load cap (#tranches)					
Quantity procured (# tranches)					
Quantity procured (% BGS–FP load)					
# Winning bidders					
Maximum # of tranches procured from any one bidder					
Minimum and maximum starting prices prior to indicative bids (cents/kWh)					
Starting price at start of auction (cents/kWh) *					
Final auction price (cents/kWh) **					

* Price shown in "Total" column is an average across the EDCs weighted by each EDC's "Starting tranche target in auction".
** Price shown in "Total" column is an average across the EDCs weighted by each EDC's "Final tranche target in auction".

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-FP Auction

Table 2. Overview of Findings on BGS-FP Auction

	Question	Comments
1	BP's/NERA's recommendation as to whether the Board should certify the FP auction results?	
2	Did bidders have sufficient information to prepare for the FP auction?	
3	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	
4	Were there any issues and questions left unresolved prior to the FP auction that created material uncertainty for bidders?	
5	From what BP/NERA could observe, were there any procedural problems or errors with the FP auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the Auction Manager?	
6	From what BP/NERA could observe, were protocols for communication between bidders and the Auction Manager adhered to?	
7	From what BP/NERA could observe, were there any hardware or software problems or errors, either with the FP auction system or with its associated communications systems?	
8	Were there any unanticipated delays during the FP auction?	
9	Did unanticipated delays appear to adversely affect bidding in the FP auction? What adverse effects did BP/NERA directly observe and how did they relate to the unanticipated delays?	
12	Were appropriate data back-up procedures planned and carried out?	
11	Were any security breaches observed with the FP auction process?	

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-FP Auction

	Question	Comments
12	From what BP/NERA could observe, were protocols followed for communications among the EDCs, NERA, BPU staff, the Board (if necessary), and BP/NERA during the FP auction?	
13	From what BP/NERA could observe, were the protocols followed for decisions regarding changes in FP auction parameters (e.g., volume, load caps, bid decrements)?	
14	Were the calculations (e.g., for bid decrements or bidder eligibility) produced by the FP auction software double-checked or reproduced off-line by the Auction Manager?	
15	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	
16	From what BP/NERA could observe, were the communications between the Auction Manager and bidders timely and effective?	
17	Was there evidence that bidders felt unduly rushed during the process? Should the auction have been conducted more expeditiously?	
18	Were there any complaints from bidders about the process that BP/NERA believed were legitimate?	
19	Was the FP auction carried out in an acceptably fair and transparent manner?	
20	Was there evidence of non-productive "gaming" on the part of bidders?	
21	Was there any evidence of collusion or improper coordination among bidders?	
22	Was there any evidence of a breakdown in competition in the FP auction?	
23	Was information made public appropriately? From what BP/NERA could observe, was sensitive information treated appropriately?	

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-FP Auction

	Question	Comments
24	Does the FP auction appear to have generated a result that is consistent with competitive bidding, market-determined prices, and efficient allocation of the BGS-FP load?	
25	Were there factors exogenous to the FP auction (e.g., changes in market environment) that materially affected the FP auction in unanticipated ways?	
26	Are there any concerns with the FP auction's outcome with regard to any specific EDC(s)?	

ATTACHMENT B
Docket No. ER14040370

POST-AUCTION CHECKLIST FOR THE NEW JERSEY 2015 BGS-CIEP AUCTION

Prepared by: [Company].

[Introductory comments, if any]

Auction began with the opening of Round 1 at [x:xx am] on Thursday, February 6, 2015

Auction finished with the close of Round ## at [xxx] on [xxx]

	Start of Round 1	Start of Round 2 * (after volume reduction in Round 1, if applicable)	Start of Round n * (after post-Round 1 volume reduction, if applicable)
# Bidders			
Tranche target	## tranches	## tranches	## tranches
Eligibility ratio			
Statewide load cap	## tranches	## tranches	## tranches

* Note: [No volume adjustment was made during the CIEP auction, so the pre-auction tranche target and the statewide load cap were unchanged for the auction. / Or alternatively, note details of volume adjustments if they occurred.]

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-CIEP Auction

Table 1 below shows pertinent indicators and measures for the auction.

Table 1. Summary of BGS-CIEP Auction

	PSE&G	JCP&L	ACE	RECO	Total
BGS-CIEP peak load share (MW)					
Total tranches needed					
Starting tranche target in auction					
Final tranche target in auction					
Tranche size (%)					
Tranche size (approximate MW)					
Starting load cap (# tranches)					
Final load cap (# tranches)					
Quantity procured (# tranches)					
Quantity procured (% BGS-CIEP load)					
# Winning bidders					
Maximum # of tranches procured from any one bidder					
Minimum and maximum starting prices prior to indicative bids ($/MW-day)					
Starting price at start of auction ($/MW-day)*					
Final auction price ($/MW-day)**					

* Price shown in "Total" column is an average across the EDCs weighted by each EDC's "Starting tranche target in auction".
** Price shown in "Total" column is an average across the EDCs weighted by each EDC's "Final tranche target in auction".

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-CIEP Auction

Table 2. Overview of Findings on BGS-CIEP Auction

	Question	Comments
1	BP's/NERA's recommendation as to whether the Board should certify the CIEP auction results?	
2	Did bidders have sufficient information to prepare for the CIEP auction?	
3	Was the information generally provided to bidders in accordance with the published timetable? Was the timetable updated appropriately as needed?	
4	Were there any issues and questions left unresolved prior to the CIEP auction that created material uncertainty for bidders?	
5	From what BP/NERA could observe, were there any procedural problems or errors with the CIEP auction, including the electronic bidding process, the back-up bidding process, and communications between bidders and the Auction Manager?	
6	From what BP/NERA could observe, were protocols for communication between bidders and the Auction Manager adhered to?	
7	From what BP/NERA could observe, were there any hardware or software problems or errors, either with the CIEP auction system or with its associated communications systems?	
8	Were there any unanticipated delays during the CIEP auction?	
9	Did unanticipated delays appear to adversely affect bidding in the CIEP auction? What adverse effects did BP/NERA directly observe and how did they relate to the unanticipated delay?	
10	Were appropriate data back-up procedures planned and carried out?	
11	Were any security breaches observed with the CIEP auction process?	

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-CIEP Auction

	Question	Comments
12	From what BP/NERA could observe, were protocols followed for communications among the EDCs, NERA, BPU staff, the Board (if necessary), and BP/NERA during the CIEP auction?	
13	From what BP/NERA could observe, were the protocols followed for decisions regarding changes in CIEP auction parameters (e.g., volume, load cap, bid decrements)?	
14	Were the calculations (e.g., for bid decrements or bidder eligibility) produced by the CIEP auction software double-checked or reproduced off-line by the Auction Manager?	
15	Was there evidence of confusion or misunderstanding on the part of bidders that delayed or impaired the auction?	
16	From what BP/NERA could observe, were the communications between the Auction Manager and bidders timely and effective?	
17	Was there evidence that bidders felt unduly rushed during the process? Should the auction have been conducted more expeditiously?	
18	Were there any complaints from bidders about the process that BP/NERA believed were legitimate?	
19	Was the CIEP auction carried out in an acceptably fair and transparent manner?	
20	Was there evidence of non-productive "gaming" on the part of bidders?	
21	Was there any evidence of collusion or improper coordination among bidders?	
22	Was there any evidence of a breakdown in competition in the CIEP auction?	
23	Was information made public appropriately? From what BP/NERA could observe, was sensitive information treated appropriately?	

ATTACHMENT B
Docket No. ER14040370

Post-Auction Checklist for the New Jersey 2015 BGS-CIEP Auction

	Question	Comments
24	Does the CIEP auction appear to have generated a result that is consistent with competitive bidding, market-determined prices, and efficient allocation of the BGS-CIEP load?	
25	Were there factors exogenous to the CIEP auction (e.g., changes in market environment) that materially affected the CIEP auction in unanticipated ways?	
26	Are there any concerns with the CIEP auction's outcome with regard to any specific EDC(s)?	

Attachment C

Agenda Date: 10/22/04
Agenda Item: 2A

STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

ENERGY

IN THE MATTER OF THE PROVISION OF)
BASIC GENERATION SERVICE FOR)
YEAR THREE OF THE POST-TRANSITION)
PERIOD – CONFIDENTIALITY ISSUES)

DECISION AND ORDER

DOCKET No. EO04040288

(SERVICE LIST ATTACHED)

BY THE BOARD:

This matter concerns the confidentiality of certain information to be utilized during the upcoming Basic Generation Service ("BGS") Auction.

At its October 22, 2004, public agenda meeting the Board approved an auction process for the procurement of BGS supplies for the period beginning June 1, 2005 ("Year Three of the post-Transition Period" or "Year Three"), which process is substantially similar to the process which was utilized for the past three years. In each of those auctions, the Board directed that certain sensitive information and processes would be afforded confidential treatment. At this time, in response to a request by the electric distribution companies ("EDCs") (EDC's Initial Proposal at 10-11), the Board is reaffirming the proprietary and confidential nature of the same procurement information and processes for Year Three bidding as it did in its previous Orders. The following areas are covered by this Order.

(1) **The Logic Processes and Algorithms**: The auction manager, National Economic Research Associates ("NERA"), uses logic processes and algorithms to foster a competitive auction.

(2) **Starting Prices**: EDC - specific minimum and maximum starting prices and final starting prices in effect during the bidding phase of the first round of the auction. Each EDC, in consultation with Staff, NERA and the Board's consultant, Charles River Associates ("CRA") sets its own starting prices. The EDC-specific final starting prices are announced to approved bidders only, shortly before the start of the auction.

(3) **Indicative Offers**: The number of tranches that a qualified bidder is willing to supply at the maximum starting price and the number of tranches a qualified bidder is willing to supply at the minimum starting price. Indicative offers are used to determine

eligibility for participation in the auction and are considered in determining final starting prices.

(4) **Round Prices and Individual Bids**: The price set by NERA for each round of the auction, the number of tranches bid by each qualified bidder during each round of the auction, and any other information submitted by the bidder in each round to fully specify its bid, such as exit prices and switching priorities.

(5) **Bidder Information**: The bidder identities and information supplied to NERA on the application forms to become a bidder in the New Jersey BGS Auction.

DISCUSSION

The Open Public Records Act ("OPRA"), N.J.S.A. 47 1A-1 et seq., which amended the former Right to Know Law concerning the public's access to government records, became effective on July 8, 2002. One of the modifications includes an expansion of the definition of a government record from only those documents required to be made, maintained or kept on file by law, to information received, made, maintained or kept on file by a public agency in the course of its official business, except for advisory, consultative or deliberative material. N.J.S.A. 47:1A-1.1. The statute goes on to list information which shall not be included in the definition of a government record and shall be deemed confidential, including trade secrets, proprietary commercial or financial information, and information which, if disclosed, would give an advantage to competitors or bidders. Id.

OPRA also changed procedures regarding government records by setting forth new format and timing requirements for making and responding to requests for access. As a result, many public agencies proposed new rules and regulations to redesign their record request operations in compliance with OPRA. The proposed new rules of the Board of Public Utilities appeared in the July 1, 2002, New Jersey Register, and were adopted in the July 21, 2003 publication of the New Jersey Register.

As part of the new procedures established concerning the public's access to its records and for claimants asserting confidentiality claims, the Board authorized its custodian of records to determine whether information requested by the public is a government record within the meaning of OPRA or is confidential. N.J.A.C.14:1-12.6. Additionally, the Board reserved its authority to make a confidentiality determination when appropriate:

> Nothing herein shall limit the Board's authority to make a confidentiality determination within the context of a hearing or other proceeding or with regard to any other matter, as the Board may deem appropriate.
>
> [N.J.A.C. 14:1-12.6(d).]

Accordingly, the Board may make confidentiality determinations regarding information gathered in proceedings such as the within matter. In ruling on the Year Three procurement processes, the Board has determined that an auction process similar to the ones approved for the past three years are the most appropriate means for obtaining energy prices consistent with those achieved by a competitive market, as required by N.J.S.A. 48:3-57(d).

Simulating market conditions, however, requires that the auction participants know that their competitive positions will not be compromised. Based on the experience and expertise gained in the previous auctions, as well as the advice of its consultant, the Board recognizes the need to alleviate any doubts about its treatment of competitively sensitive information.

The Board has approved the use of a descending clock auction process for Year Three. The auction process, at its most basic level, includes three groups of contributors. The first group is made up of the four electric distribution companies the purchasers of the BGS supply, who rely on maximum participation by qualified bidders in order to ensure a competitive procurement for its BGS customers. The second group consists of the qualified bidders or BGS suppliers, which proffer the competitive bids to supply tranches[1] of power to the EDCs. In order to become a qualified bidder, BGS suppliers must meet certain general. financial and credit requirements. Qualified bidders are made up of two groups: (a) those that provide direct supply and (b) those that provide supply through market purchases. The third contributor is the Auction Manager, National Economic Research Associates, who administers the auction in consultation with the EDCs, the Board Staff and the Board's consultant, Charles River Associates.

During the course of the auction, the auction manager solicits bids through a series of auct on rounds. The first round begins as the BGS suppliers bid the number of tranches they are willing to supply at each EDCs-specific starting prices. Assuming the number of tranches bid are greater than those needed by an EDC, the next auction round proceeds at a lower price. With each new price in the rounds, BGS suppliers may change their bids by modifying the number of tranches they are willing to supply. Rounds in the auction continue until the total number of tranches bid equals the total demand from the EDCs.

The auction process is expected to simulate a competitive market. The object is to allow prices to tick down round by round until the final price is one that approximates a price that could be achieved on an open market. To ensure that the EDCs get a competitive price, the BGS suppliers must bid based on their individual assessments of a fair market value or at least their assessment of individual ability to provide BGS supply at a particular rate. If the bidders knew each other's "market" positions or bid positions, the process would fail to create competition. Similarly, if bidders knew all of the details of the auction process they might also be able to determine their exact position in relation to other bidders and also circumvent the competitive intent of the process.

The Board is charged with overseeing the EDCs acquisition of BGS supply at market value. In order to achieve this goal, the Board FINDS and CONCLUDES that it must provide a certain amount of protection to the information supplied by the participants and to the formulas, algorithms and logic used to develop critical auction particulars. The Board's analysis of the need to treat certain information as competitively sensitive and confidential is set forth below.

I. THE LOGIC PROCESSES AND ALGORITHMS THE AUCTION MANAGER USES TO FOSTER A COMPETITIVE AUCTION

The auction manager will set the parameters for the auction, including the minimum and maximum starting prices. The EDCs must use this price range, as well as their own calculations to set their EDC-specific starting prices. Likewise, the qualified bidders must submit indicative offers using the minimum and maximum starting prices. Though the minimum and maximum starting prices are released publicly prior to the auction, the method used to determine these

[1] A tranche of one product (i.e. a tranche of the BGS load for one EDC) is a full requirements tranche. A tranche for an EDC is a fixed percentage share of the BGS load of that EDC for Year Three of the post-Transition Period beginning June 1, 2004.

prices is confidential information. Revealing this thought process could prejudice the independent evaluation of market prices that qualified bidders would perform. Furthermore, it would impede the competitive nature of the auction. So long as the bidders do not know the rationale behind the auction prices, they must bid based on independent methodologies. As a result, the bidders are more likely to make bids of varying degrees because their valuations will be based on diverse variables.

Just as minimum and maximum starting prices are used to promote competition, volume adjustments during the auction rounds must be used to ensure that the EDCs receive the most competitive bids. The auction manager is given the authority to make two volume adjustments to ensure that the prices not only continue to decrease, but that bidding remains competitive. The auction manager may reduce the auction volume (reduce the number of tranches that the EDCs will purchase) after review of the first round bids. Again, simple market theories app.y - if demand is larger than supply, the price remains high. Therefore, the auction rules allow for a volume adjustment after the first round, and once more in a later round. If the guidelines/ algorithms used to make these adjustments were disclosed, the bidders might be able to manipulate the system.

In short, the methodologies used to determine the starting prices, as well as volume adjustments, are integral to the competitive bidding process. Both categories of information fall under an OPRA exception to the definition of a government record because they would provide an advantage to competitors or bidders. As stated above, the Legislature has required the Board to procure energy prices consistent with market conditions. N.J.S.A. 48:3-57(d). The Board is therefore simulating a market scenario through the use of supply and demand theory. Releasing these auction parameters would result in an advantage to all of the bidders, at the expense of higher energy prices for the EDC's customers. Thus, as long as the Board continues to rely on a similar auction process to procure BGS supply, this information continues to require confidential treatment.

The Board HEREBY FINDS and CONCLUDES that this information, if disclosed would provide an advantage to competitors or bidders to the detriment of BGS customers, and shall be deemed confidential and not included as a government record pursuant to OPRA.

Therefore, should a request for this information be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that any requests for access be denied.

II. EDC-SPECIFIC STARTING PRICES

There are two types of starting prices used in the auction. First, there are the minimum and maximum starting prices, which are released to potential bidders shortly before the application process to provide a basis for the EDC-specific starting prices and the BGS suppliers' indicative offers. The second type consists of the EDC-specific starting prices that will be in effect for the first round of the auction. These prices must fall somewhere between the minimum and maximum starting prices, and are released to the qualified bidders shortly before the auction. The EDC-specific starting prices are derived from the indicative offers and the value judgments of the EDCs, Board Staff, CRA and Auction Manager regarding the future price of energy.

Both types of starting prices are intended to attract qualified bidders to the auction. The financial community and/or the general public could misinterpret the EDC-specific starting prices if they were to be made public prior to the release of the final auction results.

Rather than having qualified bidders making independent business judgments on the value assigned to a product, their bids could be influenced by outside perception. For example, should the starting prices create lofty expectations regarding energy prices on the part of shareholders or financial analysts, BGS suppliers might not bid as aggressively as necessary to create market conditions. In short, releasing this information prior to the public announcement of the final auction results could put the entire auction process at a competitive disadvantage. While some individual bidders in the auction might not suffer, distorted financial perceptions could lead to a less competitive auction, ultimately disadvantaging the ratepayers through inflated prices.

The Board HEREBY FINDS and CONCLUDES that this information would provide an advantage to competitors or bidders, and shall be deemed confidential and not included as a government record pursuant to OPRA.

Therefore, should a request for this information be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that any requests for access be denied until the Board has released the auction results.

III. INDICATIVE OFFERS

Indicative offers are the number of tranches that a qualified bidder is willing to supply at the maximum starting price and at the minimum starting price. The number of tranches the bidder offers to supply at the maximum starting price determines the bidder's initial eligibility for the auction. The indicative offer creates two limitations for the bidder. First, the total number of tranches the BGS supplier can bid in any round of the auction is now capped at its initial eligibility. As such, bidders are encouraged to make an indicative offer for the maximum number of tranches they would be willing to serve. Second, the bidder is now required to post a financial guarantee proportional to its initial eligibility.

Clearly, the indicative offer contains proprietary commercial and financial information. N.J.S.A. 47:1A-1.1. The BGS supplier is making a business judgment regarding the amount of load it is willing to supply. These judgments could be based on many factors. For instance, a direct supplier might indicate a willingness to supply a high number of tranches because it has a limited number of supply contracts compared to its available plant capacity. On the other hand a supplier who buys its energy from the market may only be willing to supply a low number of tranches because it has already entered into a number of contracts at the time of the auction. As stated, the indicative offers also reveal information concerning the amount of credit a BGS supplier may or may not have at hand.

Not only do the indicative offers constitute proprietary commercial and financial information, but their release would provide an advantage to competitors, including those not participating as bidders in the auction. N.J.S.A. 47:1A-1.1. BGS suppliers compete in a market place outside of the auction. If such information were to become public, the BGS suppliers' competitors would be given otherwise confidential information, providing an opportunity to speculate on the individual supplier's market position. If the Board does not keep sensitive market data confidential, it will not be able to simulate an arms-length negotiation. Moreover, release of this proprietary commercial and financial information would have a chilling effect on the BGS suppliers' willingness to participate in this or any future auctions.

Accordingly, the Board HEREBY FINDS and CONCLUDES that this information is proprietary commercial and financial information that would provide an advantage to competitors or bidders, and shall be deemed confidential and not included as a government record pursuant to OPRA.

Therefore, should a request for this information be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that any such requests for access be denied for a period of three years from the close of the auction. Three years after the conclusion of the auction, the Board will consider the indicative bids public information, unless prior to the expiration of the three years a party formally requests that this information remain confidential. If a request for continuing confidentiality is made, the information shall remain confidential pending a further decision by the Board.

IV. ROUND PRICES AND INDIVIDUAL BIDS

Each round of the auction produces two sets of information: (a) the price for each round as determined by the auction manager and (b) the individual bids.

For similar reasons to those set forth above in Indicative Offers, the individual bids contain proprietary commercial and financial information. N.J.S.A. 47:1A-1.1. Furthermore, release of either the round-by-round price or the number of tranches individually bid in a round would allow the bidders to mathematically work backwards and determine the incremental algorithm used by the auction manager to make volume adjustments during the course of the auction. As explained in Section I, supra, revealing this methodology could impede the current and any future competitive process to the detriment of customers.

Accordingly, the Board FINDS and CONCLUDES that this information could provide an anti-competitive advantage to competitors or bidders, and shall be deemed confidential and not considered a government record pursuant to OPRA.

Therefore, should a request for the round-by-round prices be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that any requests for access be denied.

Should a request for the individual bids be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that any such requests be denied for a period of three years from the close of the auction. Three years after the conclusion of the auction, the Board will consider the individual bids public information, unless prior to the expiration of the three years a party has formally requested that this information remain confidential. If a request for continuing confidentiality is made, the information shall remain confidential pending a further decision by the Board.

V. BIDDER INFORMATION

While the upcoming auction will be held in February 2005, the period of power supply being procured will not begin to flow until June 1, 2005. For all past auctions, the list of bidders obtaining contracts was announced with the Board Order approving the auction results. Approximately one month before the load was to be served, when suppliers had presumably locked up their contracts, the list of bidders with BGS contracts along with the volumes and prices for each contract were released. The reason for the delayed release of this information was to ensure that the bidders were not placed at a competitive disadvantage. As stated above, there are two types of BGS suppliers - those who supply directly from their own plants and those that purchase power from the market for resale. Power marketers must go to the market and fulfill the BGS requirements they have won by negotiating contracts. If their competitors knew the volumes that the bidder had already contracted to supply as a result of the auction, the successful bidder might be at a competitive disadvantage. The same can be said for direct suppliers who must market their product. If buyers knew the amount of their plant supply already locked up due to the BGS auction, it could put them at a competitive disadvantage for negotiation of other contracts.

The Board also believes that if it were to release the names of all of the auction participants, those suppliers that participated in the auction but failed to obtain a contract could be prejudiced in the private sector energy market. Specifically, the financial community might interpret loss of the contracts as a sign of weakened financial position. Furthermore, releasing the names of everyone who participated but failed to leave the auction with a contract, could lead to speculation by the financial community that might have a chilling effect on the BGS suppliers' willingness to participate in this or any future auctions. As such, the Board could be damaging the competitive nature of its own auction by making the financial risk of participation unpalatable to participants. The ultimate result would be higher energy prices passed on to consumers.

Based on its experience with the past three BGS auctions and the expert recommendations of the Board's consultant, CRA, the Board believes that releasing the winning bidders' volume and price information before contracts for the supply period are locked up, could put those suppliers participating in the auction at a disadvantage in the greater energy market, making such information an exemption to the definition of a government record. N.J.S.A. 47:1A-1.1. Additionally, releasing the list of unsuccessful participants could impair the competitive nature of the auction by making the financial risk of participation unpalatable to participants and resulting in higher energy prices for consumers therefore making such information an exemption to the definition of a government record. N.J.S.A. 47:1A-1.1.

The Board HEREBY FINDS and CONCLUDES that this information is proprietary commercial and financial information that could provide an advantage to competitors or bidders, and that such information shall be deemed confidential and not included as a government record pursuant to OPRA.

Therefore, should a request for the names of winning bidders be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and all requests for access be denied, until May 1, 2005.

Should a request for the names of unsuccessful participants be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that all requests for access be denied.

Once the Board has determined that the winning auction suppliers have had sufficient time to lock in their BGS supply for the designated period of time, information such as volume and the identities of the successful participants may be released. In the past, this information has been released approximately a month before the beginning of the supply period. Identification information would also include all of the public information supplied to NERA on the application forms to become a qualified bidder in the New Jersey Basic Generation Service Auction. For example, information such as name, authorized representative, authorized legal representative, name of the entities' directors are of a public nature and must be disclosed as a government record. On the other hand, both the Part 1 and Part 2 Application Forms contain confidential business information of bidders that is not available publicly. The following information from the applications is non-public proprietary commercial or financial information, which is not considered a government record pursuant to OPRA. N.J.S.A. 47:1A-1.1.

Part 1 Application Form:

Bidding Agreements

Financial and Credit Requirements, except for the supplemental data which includes the following public information:
(i) Two most recent annual Reports
(ii) Most recent SEC From 10-K;
(iii) Applicant's senior unsecured debt rating from Moody's, Standard & Poor's, and Fitch, if unavailable, the issuer rating may be provided instead.

Guarantor's Information

Justification for Omissions

Part 2 Application Form:

Qualified Bidder's Indicative Offer and Calculation of Required Bid Bond

Qualified Bidder's Preliminary Maximum Interest in Each EDC

Additional Financial and Credit Requirements

Bidder Certifications Concerning Associations and Confidential Information

Justification for Omissions

If the information above were to become public as a result of participation in the BGS Auction, some bidders might elect not to participate in order to maintain the confidentiality of their proprietary commercial and financial information. This could impair the ability of the Auction to obtain a market price and could be detrimental to the interests of the EDCs' customers.

The Board HEREBY FINDS and CONCLUDES that the information listed above is proprietary commercial and financial information, and shall be deemed confidential and not included as a government record pursuant to OPRA.

Therefore, should a request for the public bidder information provided to NERA concerning successful bidders be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that all requests for access be denied, until such time as the Board releases the final names and volumes for successful bidders.

Should a request for the public bidder information provided to NERA concerning non-successful bidders be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential and that all requests for access be denied, since such information would identify the non-successful bidders.

Should a request for the non-public bidder information provided to NERA be made to the Board's custodian, the Board DIRECTS that such information be treated as confidential ano that all requests for access be denied.

Attachment C

At its October 22, 2004, public agenda meeting the Board approved a descending clock Auction to procure needed BGS supplies for Year Three as well as for Year Four (supply period beginning June 1, 2006). It is anticipated that, should a request for confidentiality be made, similar reasoning to that described above would apply.

DATED: 12/1/04

BOARD OF PUBLIC UTILITIES
BY:

Jeanne M. Fox
JEANNE M. FOX
PRESIDENT

Frederick F. Butler
FREDERICK F. BUTLER
COMMISSIONER

Connie O. Hughes
CONNIE O. HUGHES
COMMISSIONER

JACK ALTER
COMMISSIONER

ATTEST:

Kristi Izzo
KRISTI IZZO
SECRETARY

ATTACHMENT D

Attachment 1
Supplement to the BGS-FP Supplier Master Agreement
(the "Supplement")

This Supplement to the BGS-FP Supplier Master Agreement ("SMA") entered into as of February __, 2015, by and between ____________________ (the "Company") and ________________ (the "BGS-FP Supplier") (together, the "Parties") is effective as of the final signature date set forth below. Except as specifically modified in and by this Supplement, all terms and conditions of the SMA shall remain in full force and effect and shall apply to this Supplement.

For and in consideration of the promises and mutual covenants contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

Section 9.1 (a) of the SMA is replaced with the following:

Each Billing Month, the Company will prepare a Statement of amounts due to the BGS-FP Supplier. A line item on this Statement will show amounts due equal to the Auction Price multiplied by the applicable Seasonal Billing Factor multiplied by PMEA for the Billing Month in question and an additional line item showing the difference between the PJM RPM Zonal Net Load Price established in the PJM RPM Auction applicable to the Billing Month (the Second Incremental Auction for 2015/2016, the First Incremental Auction for 2016/2017, or the Base Residual Auction for 2017/2018) for the Company's PJM zone and the PJM RPM Zonal Net Load Price actually charged for load served on the day for Company's PJM zone multiplied by the BGS-FP Supplier Responsibility Share of the BGS-FP Capacity obligation (expressed in MW) for each day of the Billing Month in question.

Section 9.1 (d) of the SMA is replaced with the following:

In the event that the Company's minimum senior unsecured debt rating (or, if unavailable, corporate issuer rating discounted one notch) falls below the Required Rating, and until the Company's minimum senior unsecured debt rating (or, if unavailable, corporate issuer rating discounted one notch) becomes equal or higher than the Required Rating, (i) the Company shall make an initial payment on the first business day after the 5th day of the calendar month for approximately 50% of the amount due to the BGS-FP Supplier for the previous calendar month (the "Initial Payment"), and (ii) the Company shall make a second payment on the first business day after the 19th day of the calendar month for any remaining amounts associated with the previous calendar month, which will include the difference between the Initial Payment and any amounts due equal to the Auction Price multiplied by the applicable Seasonal Billing Factor multiplied by PMEA for the Billing Month in question and will also include the difference between the PJM RPM Zonal Net Load Price established in the PJM RPM Auction applicable to the Billing Month (the Second Incremental Auction for 2015/2016, the First Incremental Auction for 2016/2017, or the Base Residual Auction for 2017/2018) for the Company's PJM zone and the PJM RPM Zonal Net Load Price actually charged for load served on the day for Company's PJM zone multiplied by the BGS-FP Supplier Responsibility Share of the BGS-FP Capacity obligation (expressed in MW) for each day of the Billing Month in question.

Section 9.1 (e) is added:

To the extent that the FMEA differs from the PMEA the Company will pay or charge the BGS-FP Supplier for the PMEA/FMEA Adjustment Amount within the PJM deadline for conducting the final settlement. To the extent that the daily Capacity Obligation used in the calculations detailed in Section

9.1(a) and 9.1(d) are adjusted after the PJM deadline for conducting final settlement, the Company will pay or charge the BGS-FP Suppliers any net difference between the payments calculated and made within the PJM deadline for conducting final settlement, and the payments calculated using the adjusted values.

Company	BGS-FP Supplier
By:______________________	By:______________________
Name:____________________	Name:____________________
Title:_____________________	Title:_____________________
Date:_____________________	Date:_____________________

ATTACHMENT D

Attachment 2
Supplement to the BGS-CIEP Supplier Master Agreement
(the "Supplement")

This Supplement to the BGS-CIEP Supplier Master Agreement ("SMA") entered into as of February __, 2015, by and between ____________________ (the "Company") and ______________ (the "BGS-CIEP Supplier") (together, the "Parties") is effective as of the final signature date set forth below. Except as specifically modified in and by this Supplement, all terms and conditions of the SMA shall remain in full force and effect and shall apply to this Supplement.

For and in consideration of the promises and mutual covenants contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

Section 9.1 (a) of the SMA is replaced with the following:

Each Billing Month, the Company will prepare a Statement of amounts due to the BGS-CIEP Supplier. Line items on this Statement will show amounts due equal to the (i) CIEP Standby Fee multiplied by the sum of the BGS-CIEP Supplier Responsibility Share of all BGS-CIEP-Eligible Customers' preliminary Energy usage as measured at the BGS-CIEP-Eligible Customers' meters; plus (ii) Energy Charges equal to the sum of the products of the hourly real-time PJM load weighted average Locational Marginal Prices for the Company's Transmission Zone multiplied by the PHEA in each hour of the Billing Month; plus (iii) Ancillary Service Charge equal to the product of $6.00 per MWh times the PMEA for the Billing Month; plus (iv)BGS-CIEP Price equal to the product of $_____ per MW-day multiplied by the BGS-CIEP Supplier Responsibility Share of the BGS-CIEP Capacity obligation (expressed in MW) for each day of the Billing Month in question; plus (v) the Transmission Charge multiplied by the BGS-CIEP Supplier Responsibility Share of the BGS-CIEP Firm Transmission Service obligation for each day of the Billing Month; plus (vi) the difference between the PJM RPM Net Zonal Load Price established in the PJM RPM second Incremental Auction for the Company's PJM zone applicable to the day and the PJM RPM Net Zonal Load Price actually charged for load served on the day for Company's PJM zone multiplied by the BGS-CIEP Supplier Responsibility Share of the BGS-CIEP Capacity obligation (expressed in MW) for each day of the Billing Month in question.

Section 9.1 (d) of the SMA is replaced with the following:

In the event that the Company's minimum senior unsecured debt rating (or, if unavailable, corporate issuer rating discounted one notch) falls below the Required Rating, and until the Company's minimum senior unsecured debt rating (or, if unavailable, corporate issuer rating discounted one notch) becomes equal or higher than the Required Rating, (i) the Company shall make an initial payment on the first Business Day after the 5th day of the calendar month for approximately 50% of the amount due to the BGS-CIEP Supplier for the previous calendar month (the "Initial Payment"), and (ii) the Company shall make a second payment on the first Business Day after the 19th day of the calendar month for any remaining amounts associated with the previous calendar month, which will include the difference between the Initial Payment and any amounts due equal to the (A) CIEP Standby Fee multiplied by the sum of the BGS-CIEP Supplier Responsibility Share of all BGS-CIEP-Eligible Customers' preliminary Energy usage as measured at the BGS-CIEP-Eligible Customers' meters; plus (B) Energy Charges equal to the sum of the products of the hourly real-time PJM load weighted average Locational Marginal Prices for the Company's Transmission Zone multiplied by the PHEA in each hour of the Billing Month; plus (C) Ancillary Service Charges equal to the product of $6.00 per MWh times the PMEA for the Billing Month; plus (D) the BGS-CIEP Price equal to the product of $_____ per MW-day multiplied by the BGS-CIEP Supplier Responsibility Share of the BGS-CIEP Capacity obligation (expressed in MW) for each day of the Billing Month in question; plus (E) Transmission Charges equal to the PJM OATT daily rate for the Company Transmission Zone multiplied by the BGS-CIEP Supplier Responsibility Share of the BGS-CIEP Firm Transmission Service obligation for each day of the Billing Month; plus (F) the difference between the PJM RPM Net Zonal Load Price established in the PJM RPM second Incremental Auction for the Company's PJM zone applicable to the day and the PJM RPM Net Zonal Load Price actually charged for load served on the day for Company's PJM zone multiplied by the BGS-CIEP Supplier Responsibility Share of the BGS-CIEP Capacity obligation (expressed in MW) for each day of the Billing Month in question.

Company	BGS-CIEP Supplier
By:______________________	By:______________________
Name:____________________	Name:____________________
Title:_____________________	Title:_____________________
Date:_____________________	Date:_____________________