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State of New Jersey
Board of Public Utilities
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IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR YEAR TWO OF THE POST-TRANSITION PERIOD	ENERGY DECISION AND ORDER DOCKET NO. EO03050394

(Service List Attached)

BY THE BOARD:

As a result of previous Board Orders dated December 11, 2001 (Docket No. EX01050303), and December 18, 2002 (Docket Nos. EX01110754 and EO02070384) ("Year One Orders") the Board determined that the electricity requirements of Basic Generation Service ("BGS") customers for Year 4 of the Transition Period (August 1, 2002-July 31, 2003) and for varying periods of the post-Transition Period, beginning August 1, 2003, should be obtained by the electric utilities via a descending clock auction process. By Order dated June 20, 2003, the Board directed the electric distribution companies including Public Service Electric & Gas Company ("PSE&G"), Conectiv Power Delivery ("Conectiv"), Jersey Central Power & Light Company ("JCP&L"), and Rockland Electric Company ("Rockland") (collectively the "EDCs") to file proposals addressing how to procure BGS for Year Two of the post-Transition Period and beyond[1], and established a procedural schedule to address the EDCs' proposals including an opportunity for initial written comments and alternative proposals, a legislative-type hearing, and final written comments. On July 1, 2003, a joint proposal and company specific addenda were received from the EDCs.

The following parties provided Initial Comments on the EDCs' proposal on August 8, 2003 and/or Final Comments on September 18, 2003: the EDCs, including PSE&G, JCP&L, Conectiv, and Rockland; Division of the Ratepayer Advocate ("RPA"); Mid-Atlantic Power Supply Association ("MAPSA"); Consolidated Edison Solutions, Inc.; Consolidated Edison Energy, Inc. ("CEE"); Constellation NewEnergy, Inc. and Constellation Power Source (collectively "Constellation"); Pepco Energy Services, Inc.; New Jersey Large Energy Users Coalition ("NJLEUC"); Independent Electric Power Suppliers of NJ ("IEPNJ"); Reliant Resources ("Reliant"); Select Energy, Inc.; Coral Power; WPS Energy Services, Inc; New Jersey Food Council ("NJFC"); J. Aron & Company ("J. Aron"); Strategic Energy; American Association of Retired Persons ("AARP"); and Morgan Stanley Capital Group ("MSCG").

[1] Year Two of the post-Transition Period ("Year Two"), for purposes of this proceeding, begins June 1, 2004.

In addition, on September 10, 2003, a legislative-type hearing was held at the Board's Newark office. Commissioner Carol J. Murphy chaired the hearing. All interested parties were allowed to present their positions for the record. The parties who presented positions were the EDCs, the RPA, Reliant, IEPNJ, Constellation, MAPSA, National Resources Defense Council ("NRDC"), Strategic, J. Aron, NJLEUC and NJFC.

Two informal conferences were also held in an attempt to find common ground among participants on issues associated with the Supplier Master Agreements.

POSITIONS OF THE PARTIES, COMMENTS AND REPLY COMMENTS

The Board has carefully reviewed the record in this proceeding. The parties' filings have largely focused on last year's auction process and on the Joint EDC Proposal as the baseline for proposing specific modifications and/or additions. For this reason, and because it forms the basis of much of the discussion in this Order and because, with the modifications described below, the Joint EDC Proposal contains many elements that will be incorporated into the BGS procurement process which the Board will approve herein, the Board will summarize, in this Order, the main features of the EDCs' July 1, 2003 filing. The Board will not, in this Order, separately summarize each party's position in similar detail.

JOINT EDC PROPOSAL

On July 1, 2003, the four EDCs filed a Joint EDC Proposal for BGS, consisting of a generic proposal for Basic Generation Service, preliminary rules for the BGS-CIEP and BGS-FP[2] Auctions, as described below, proposed CIEP and FP Supplier Master Agreements and EDC-specific addenda.

The EDCs have jointly proposed two simultaneous, multi-round, descending clock auctions ("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 be to procure service for the approximately 1766 larger commercial and industrial ("C&I") customers on the utility systems through an Auction to provide hourly-priced service ("BGS CIEP Auction"). The customers in this category would represent approximately 2359 megawatts ("Mw") of load procured through bidding on 107 full-requirements tranches[3] of approximately 25 Mw each. This is the same type and size auction that the Board approved last year.

The second Auction would be to procure service for all other customers of all four EDCs through a fixed price Auction ("BGS-FP Auction") for approximately 16,630 Mw of load to be served through 155 full-requirements tranches[4] of approximately 100 Mw each.

The competitive process by which the EDCs propose to procure their supply for BGS load for Year Two is detailed in the EDCs' Attachments A and B (Preliminary CIEP and FP Auction Rules, respectively) and is the same type of auction process that the Board approved by Order dated December 18, 2002. Under the Joint EDC Proposal, the retail load of each EDC is considered a

[2] CIEP stands for Commercial and Industrial Energy Pricing and FP means Fixed Price.

[3] A tranche is a full-requirements product and represents a fixed percentage share of an EDC's load for a specific period.

[4] Since the EDCs have secured one-third of their total FP load requirements through May 31, 2006 by means of a Board-approved auction in February 2003, there would be approximately 104 FP tranches actually available at this time.

separate “product” in each Auction. When a participant bids in either BGS Auction, that participant would state 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 an amount in cents per kilowatt-hour (“kwh”) paid for each kwh of BGS load served. In the BGS-CIEP Auction, a price for an EDC is an amount in dollars per megawatt-day ($/Mw-day) paid for capacity for BGS-CIEP load 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 propose that rates for BGS-FP customers be designed using a generic methodology implemented as described in the utility-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 market-influenced seasonality and time of use indications, where appropriate and feasible, in order to provide efficient price signals.

The EDCs propose 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 bid period would be adjusted to reflect lower winter costs. The overall average payment to the bidder would depend upon BGS demand in each season and, consequently, would likely differ somewhat from the auction clearing price.

The EDCs propose that, for BGS-CIEP tranches, rate schedules would be designed to include the transmission obligation and ancillary service costs, and a provision to pass through the hourly PJM[5] real-time energy price. Bidders would indicate how many tranches they want to supply in exchange for a $/Mw-day capacity payment. Under the EDCs’ proposal, winning bidders would also receive a Default Supply Service Availability Charge (“DSSAC”) of $.0003/kwh. The DSSAC charge, and the winning capacity prices, to the extent they are above market, would essentially act as an “option fee”. The capacity payment would be charged to all CIEP customers on BGS service, while the DSSAC would be charged to all customers eligible for BGS-CIEP service. Winning bidders would be paid the auction clearing price for the capacity provided for customers taking BGS-CIEP service plus the DSSAC rate times the monthly sales to all BGS-CIEP eligible 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/or 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 Supplier Master Agreements attached to the Joint EDC Proposal as Attachment C and D, respectively.

The EDCs propose that the Board render a decision on the Auction process and render a decision on the Auction results. They further propose 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. Upon Board approval, the Auction results would be a binding commitment on the EDCs and winning bidders.

[5] PJM is the Pennsylvania-New Jersey-Maryland Interconnection.

Each of the utility-specific addenda addresses the use of committed supply, contingency plans, accounting and cost recovery, and utility pricing and tariff sheets. In addition, included in Rockland's addendum is an RFP to secure a fixed price supply for its 55 Mw of Western and Central Division load, which is served through the New York Independent System Operator ("NYISO"). As Rockland's Western and Central Divisions are not part of PJM, they cannot participate in the regular BGS-FP and BGS-CIEP Auctions.

Numerous other Auction details are explained in the Joint EDC Proposal, EDC-specific Addenda, and Attachments including that:

- all customers will be free of all switching restrictions, save for the Board's 20-day, anti-slamming enrollment process;
- BGS suppliers must meet all New Jersey Renewable Portfolio Standards ("RPS") requirements 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 Supplier Master Agreement 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 bid bond; and
- the BGS-CIEP Auction should be for a supply period of 12 months and the BGS-FP Auction should secure one-third of each EDC's total load requirements for one year and one-third for three years,[6] with the remaining one-third having been secured through last year's BGS-FP Auction.

DISCUSSION AND FINDINGS

Throughout this proceeding, there have been issues raised by the wide range of participants, which touch upon policy matters as well as the auction design and mechanics. A number of parties proposed different lengths for the procurement period under consideration. While most parties agree that larger customers should be priced closer to market than smaller customers, there is a difference of opinion about where the dividing line should be drawn. There were also suggestions for differing designs of the auction products and for modifying the auction rules. In addition, various participants raised issues with respect to committed supply, rate design, confidentiality and supplier contract issues. There was also a proposal that the BGS procurement process include load management alternatives. The Board will address each of these areas in its Order.

[6] 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.

AUCTION RULES, DESIGN, PRODUCT AND PROCUREMENT PERIOD

The Board believes that the auction process that was implemented with the 2002 Auction and which was modified in 2003 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 continues to believe that, with certain refinements and enhancements as will be discussed herein, a similar auction process should be approved for the next procurement period.

The Board is aware that the current 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 heard 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. Today the Board is again faced with recommendations for modifications to the basic auction design for the upcoming procurement period.

The Board appreciates the efforts of all involved to provide constructive criticism in order to improve upon a process so important to all of the State's ratepayers. In making its decision, the Board has considered the suggestions that were made, and has attempted to reach a balance of competing interests, mindful of its statutory responsibility to ensure continued provision of basic generation service at just and reasonable rates. Since the descending clock auction process, as it is used here, is relatively new, the ability to make direct comparisons with other procurement processes is limited. Therefore, many of the arguments made by participants in this process are necessarily theoretical. Nonetheless, the Board, its Staff and the Auction Manager have developed some expertise in these areas, having conducted two successful auctions under basically the current auction structure and rules. In light of that successful experience to date, the Board is reluctant to make major changes to the basic structure of the auction process absent compelling arguments.

The RPA, citing experience in other states, has proposed that the Board consider a number of other ways to structure the bid products other than the current "slice of system." These could include defining products by type of load, e.g. base load, peaking, etc. (RPA Initial Comments at 2) and/or segregating load by rate class. (Id. at 6). As the EDCs point out in response, in reviewing default service for some EDCs in Massachusetts, a comparison of prices between states often is not straightforward. (EDC Final Comments at 26). The Board is not convinced that ratepayers would benefit by redefining the bid products by load type and/or rate class. To the contrary, the Board believes that significant segmentation of the bid products will more likely cause bidders to either focus on particular products to the detriment of others and/or to back away from the entire process while the products are being redefined.

AARP and the RPA have proposed that the product be a mix of shorter and longer-term periods with the longer periods extending to 10 years and perhaps beyond in order to assure customers with stable, predictable and affordable service. (RPA Initial Comments at 4, AARP Final Comments at 3). Shorter contract periods are proposed by third-party suppliers with the underlying reason that a retail BGS model, as proposed by MAPSA and others, cannot be implemented unless all BGS supply contracts expire at the same time. (MAPSA Initial Comments at 4). J. Aron supports a 36-month supply period for the remaining two-thirds of the EDC load available, in order to stabilize rates while electricity markets continue to develop and to amortize transactional costs over a longer time period. (J. Aron Initial Comments at 9).

For the post-Transition Year One FP Auction, the Board elected to adopt a term-averaged approach, as it would hedge the risk of unfavorable market conditions that might be present at any one point in time. This logic still appears valid, especially since the only support for a one-year procurement process comes from suppliers who have not adequately addressed the short-term risk issues. As for going beyond a three-year term, the Board's experience with the still developing energy markets is that electric prices become more uncertain as one goes out in time. As one attempts to project prices beyond 36 months, the information that is available becomes much less reliable. While stable, predictable and affordable prices are a laudable goal, there is no evidence that entering into long-term contracts at this time would achieve the desired result. In fact, the Board's experience, obtained from the many long-term non-utility generation ("NUG") contracts still in existence has been just the opposite. More likely, beyond 36 months the added risk of volatile fuel markets, global and national affairs and regulatory change would simply be passed on to ratepayers in the form of higher prices. Furthermore, at a time when industry basics are under review at the Federal Energy Regulatory Commission ("FERC") and in Congress and when our experience with the CIEP customer class is just beginning and the Board has had only two years of experience with this type of auction process, it would not be prudent for the Board to authorize longer-term supply contracts, at this time, as suggested by the RPA and AARP.

Therefore, in an effort to balance the risks to ratepayers, the Board DIRECTS the EDCs to procure approximately one-third of the EDCs' current BGS-FP load for a 12-month period and one-third for a 36-month period, and continue to use a "slice of the system" as the bid product. The tranche-weighted average of the winning bids from both the 12 and 36-month periods, as well as the 34-month supply secured previously will be used to determine the price for BGS-FP rate design for Year Two. The Board will review its decision and the results of the procurement process prior to the procurement for Year Three (beginning June 1, 2005) to determine at that time how best to proceed with future procurements.

Without exception, the comments support a 12-month period for the BGS-CIEP Auction and, thus, the Board FINDS that a 12-month procurement period is appropriate and reasonable.

The RPA has proposed two changes to the auction rules. The first proposal is that prices should "tick down on ties." (RPA Final Comments at 6). Under current rules, the prices for a product tick down when the amount of supply bid exceeds the amount required. If the amounts bid and required are identical the price does not change. The RPA believes that, in such circumstances, some or all parties might be willing to continue to bid at the next price decrement, thereby reducing the final cost to ratepayers. Somewhat connected to this proposal is the RPA's second proposed modification that bidders be paid the last price that they bid ("pay-as-bid"), rather than the higher clearing price which is the current and the proposed practice.

In the Board's view, the same basic flaw exists in both of these proposals. For either proposal to result in lower costs to ratepayers as the RPA suggests, one has to assume that the auction would proceed exactly the same under the RPA's revised rules as under the current rules, i.e., the auction would be at the same bid price with the same number of bidders and tranches bid when the RPA revisions are implemented. However, the Board does not find this to be a plausible assumption. The RPA's proposals ignore the likelihood that under differing sets of rules, bidders will respond differently, which could adversely affect prices to BGS customers.

In the first proposal, in particular, the current rules tell bidders that if the price decreases then there is still an overabundance of supply and a bidder is not assured of being a winning bidder unless it continues to bid as the price decreases[7]. Under the RPA's proposal, an announced price decrease does not have the same meaning to bidders. At some point, as price decreases continue to be announced, bidders have to begin to consider if they need to continue to bid to remain competitive, or if a tie might not have been reached and they are bidding against themselves. Rather than encouraging bidders to stay in the auction until the lowest possible price, the RPA's first proposal may encourage bidders to question their continued participation in the auction at an earlier stage.

The RPA's pay-as-bid proposal is opposed by the EDCs as unfounded in theory (EDCs' Final Comments at 23) and as possibly detracting from the current auction process. (Id at 24). The Board has reviewed the position of the parties in this highly theoretical debate. From the authorities cited in the comments, it appears as though the best that could be hoped for from the RPA's proposed modification is no net change in the resulting prices, if bidders act according to the theory. If they do not, auction prices could actually rise. (Id at 23.) Additionally, the Board is concerned that the RPA's position would undermine certain basic auction principles. In particular, a pay-as–bid rule would result in bidders being paid different prices for delivering the same product and may distort the perceived difference between products in the auctions. The value to bidders of these two features of the current process is similarly difficult to quantify. What is clear to the Board is that the first two auctions, following basically similar rules to those currently proposed by the EDCs, have worked well and produced results acceptable to the Board. Based on the submissions, the Board is not persuaded that the RPA's modifications would enhance this process. Therefore, the Board APPROVES the auction rules as proposed by the EDCs.

Board Staff had made two proposals based upon its comparison of the zonal average load-weighted PJM Locational Marginal Price ("LMP"), adjusted for capacity, transmission and ancillary services, for the past two years with the winning bids in the BGS Auction. Based upon calculations, which appear to indicate that the zonal LMP has been lower than the BGS auction results, Staff solicited comments on a proposal that 5% of the EDCs' one-year FP tranches be procured through the spot market[8]. For similar reasons, Staff also solicited comments on a proposal that the EDCs' existing NUGs be used to serve FP load rather than be sold into the spot market as is currently the practice and as is proposed by the EDCs for Year Two.

While Staff clearly understands the difference between a spot market product and the Auction-supplied "slice of system" product, it based its two proposals on the actual spot market results since January 2001, and what appears to be a trend for the spot prices to be below the auction prices on any annual basis. However, as several parties indicate, historical spot market prices are not necessarily an accurate indicator of future prices. (Id at 9).

Some parties (e.g. Select Energy) oppose reintroducing the EDCs into the supply management function. The Board is sensitive to this concern, but notes that this issue has been revisited each year since the first auction and that the EDCs had, in the past, proposed to allocate their NUG energy to winning auction bidders, apparently in an attempt to maximize the value of the NUG contracts to ratepayers.

The Board is seeking to find the best way to use the output from the existing NUG contracts in order to reach the goal of maximum value to ratepayers. To this end, the Board will adopt a limited modification to the current practice of selling NUG output into the spot market. As JCP&L has the largest quantity of NUG commitments and also has personnel that are experienced in supply and

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[7] A bidder may in fact be successful without bidding at the next decrement. If the next decrement results in less than all of the tranches being filled, then the procedures for exit bids would apply.

[8] Staff's review, and the Board's discussion of the Staff proposals, includes an understanding that an adjustment of spot prices is necessary to account for capacity, transmission & ancillary charges

generation scheduling, the Board will approve a pilot program for three tranches of BGS load that would otherwise have been included in JCP&L's one-year FP auction (covering the period from June 1, 2004 to May 31, 2005) to be withheld from that auction to be served by JCP&L, in effect, from its available must-run NUG commitments. These three tranches ("JCP&L retained tranches") will be priced at the winning bid price for JCP&L's one-year FP tranches. To accomplish this objective, JCP&L will schedule on the PJM day-ahead market its forecasted load for the JCP&L retained tranches for each hour of the following day and shall offer its must-run NUG output at a zero price on the same PJM day-ahead market. JCP&L will balance any difference between: (i) the load for the JCP&L retained tranches that was scheduled on the day-ahead market; and (ii) the actual amount of such load, with either purchases or sales on the PJM real-time market, as necessary. The Board has determined that it is appropriate to rely on the PJM spot market for purposes of this pilot program. Therefore, JCP&L will not engage in any other forward purchases or hedging activities with respect to the JCP&L retained tranches. JCP&L also will continue to sell the output from its dispatchable NUG commitments on the PJM market. JCP&L will retain sufficient capacity and ancillary services from its overall committed supply to meet its obligations as a Load Serving Entity for the three JCP&L retained tranches, and will continue to sell the remainder of such capacity and ancillary services into PJM markets. For the purposes of this pilot program, the cost of procuring the power in this manner to meet the load for the JCP&L retained tranches, including costs that may be incurred to meet its LSE obligations for capacity and ancillary services that are not met from JCP&L's committed supply, are determined to be prudent and therefore will be recoverable as BGS costs through JCP&L's deferred balance and MTC. In addition, all costs incurred under the NUG contracts will continue to be recoverable through JCP&L's deferred balance and MTC, with all proceeds from the sale of the NUG output to be credited to the deferred balance. For purposes of this pilot program, JCP&L will be deemed to have retained enough renewable energy attributes from its overall committed supply to meet, in total, the minimum Renewable Portfolio Standards for the JCP&L retained tranches. To the extent permitted by applicable regulatory and contractual provisions, JCP&L will provide the remainder of these renewable energy attributes, if any, on a pro rata basis to winning bidders in the BGS-FP and BGS-CIEP auctions. In the event that there is a change in PJM markets or rules, JCP&L shall consult with Board Staff as to any modifications to the foregoing procedures that would be appropriate.

RETAIL BGS

Retail suppliers have proposed that the Board establish a framework to promote retail competition in a manner that is equitable to all stakeholders and consistent with the goals articulated in N.J.S.A. 48:3-50(c). As proposed, both retail BGS providers and competitive retail marketers would have individual customer accounts and thus each would be positioned to offer demand response, conservation services, renewables and reduced emission products. (Strategic Final Comments at 5).

MAPSA's Initial Comments outline the retail BGS framework supported by most retail suppliers. In general, it recommends that customers be segmented according to demand and that suppliers would bid to serve tranches or blocks of these customer groups. A winning supplier would provide full requirements generation services for end-user load (load following, energy, capacity, ancillaries, transmission service, transmission and distribution losses, and all other services required by PJM or individual TPS Agreements for load serving entities), provide back-up supply in the event another BGS supplier defaults, provide a customer call center operation to address generation commodity inquiries, and provide for customer billing, credit and collection, revenue accounting and disbursement. (MAPSA Initial Comments at 7).

The Board has considered the retail suppliers' comments, but concludes that the retail market does not appear to be sufficiently mature and the proposal has not been developed enough for the Board to be in a position to endorse it at this time and certainly not for implementation in June, 2005 as Strategic suggests. In particular, there is an absence of information as to what customer rates would look like under this proposal. The proponents of retail BGS appear to imply that since all aspects of the service would be obtained through competitive bid that it would, by definition, be competitive and perhaps even produce rates comparable to those derived through the auction process. However, with fewer than 2000 residential customers currently receiving service from TPSs, the Board is skeptical that interest exists among current TPSs to competitively bid for the opportunity to serve these customers. Since activity in the retail area has only recently begun to increase, apparently as the result of the creation of the BGS-CIEP customer class, the same concerns exist for small and medium-sized commercial customers. Moreover, many of the services identified in the retail BGS proposal to be provided by TPSs are services directly involving residential customers, in which the Board often has specific regulations. In particular, areas such as customer call center operation, customer billing, and credit and collection need to be investigated to insure that current requirements would continue to be met and/or to modify current requirements, where appropriate, to reflect a retail BGS structure. If TPSs were to provide the aforementioned functions, it is likely that an appropriate credit would be expected from the EDCs to reflect this change in responsibilities and to avoid duplicate charges to customers. This is an area that the Board attempted to investigate, but did not resolve, through its Customer Account Services proceeding.[9] It became clear from that experience that calculating the decremental cost of service for these activities is complicated and time consuming. For the foregoing reasons, the Board does not endorse the retail BGS concept, as put forth by the TPSs, at this time.

BGS-FP AUCTION

Rate Design

Beginning with the post-Transition Period (August 1, 2003), the prices resulting from the BGS procurement process approved by the Board are being reflected fully and directly in customer rates. For Year One, the Board modified some aspects of the EDCs' proposed rate design having to do with blocking of residential summer rates and the capacity cost used in the FP rate design. In their filing for Year Two, the EDCs except for JCP&L, have proposed to eliminate the blocking structure for residential customers that was approved last year. AARP noted that the EDCs' return to earlier rate design philosophies will have a particularly adverse impact on seniors and low-income customers who generally exhibit a low-usage profile. (AARP Final Comments at 5).

For reasons similar to those expressed last year, the Board disagrees with the summer residential rate design proposals of Conectiv, PSE&G and Rockland[10] and DIRECTS those EDCs to continue the summer residential blocking that currently exists.

[9] Docket No. EX99090676

[10] In its previous Order, the Board indicated that, except for customers on hourly pricing, electric rate design is by definition not actual market pricing but, rather, a regulatory determination made for legitimate, reasonable and generally accepted reasons. The Electric Discount and Energy Competition Act of 1999 ("EDECA") only requires that pricing be "based" on market prices. N.J.S.A. 48:3-57(d). The Board also recognized that rate design is not a precise science. The Board viewed the concept of inverted rate blocks for residential customers as an important regulatory tool. Inverted rate blocks send a conservation message to larger volume residential consumers, namely that every kilowatt-hour does not cost the same to produce. While this rate design is not perfect, the Board found it preferable to the EDC proposal. (Order dated December 18, 2002, pg 9)

Furthermore, Conectiv has worked with the Board Staff to be able to reinstate a residential time-of-use rate class. The Board believes that time-of-use rates should be available for interested residential customers and DIRECTS Conectiv to include final tariff pages for this rate class in its compliance filing required below.

BGS-CIEP AUCTION

Default Supply Service Availability Charge (“DSSAC”)

The DSSAC charge, which acts as an “option fee” for having BGS available as a default service, is currently assessed to all CIEP customers on a per kwh basis and paid to winning BGS-CIEP bidders. In its final, modified proposal for last year’s BGS-CIEP Auction, the EDCs proposed that the DSSAC be set at three one-hundredths of a cent per kwh. The Board determined that, for Year One, a DSSAC fee of fifteen one-thousandths of a cent ($.00015) per kwh should produce revenues adequate to attract bidders interested in providing BGS-CIEP service. The EDCs have proposed for Year Two that the DSSAC be raised to three one-hundredths of a cent ($.0003) per kwh and continue to be charged to all CIEP customers.

NJLEUC and others have argued for elimination or a reduction of the DSSAC, noting that, at a DSSAC level of $.00015/kwh, the first BGS-CIEP Auction was fully subscribed and resulted in eight winning bidders. (NJLEUC Initial Comments at 5). The EDCs argue that the higher the DSSAC, the lower the price for capacity in the BGS-CIEP Auction. The EDCs further argue that a higher DSSAC is likely to attract more bidders to the Auction. (EDC Final Comments at 5).

The Board agrees that the DSSAC provides winning bidders with a steady revenue stream for the service provided and gives all BGS-CIEP customers the option to switch with assurance that there will be a ready provider for the customer to fall back on. The Board continues to find that CIEP customers as a whole benefit from the availability of this option and that all CIEP customers should pay the DSSAC.

As for the DSSAC level, the Board has reviewed the arguments from both sides. However, the arguments remain largely theoretical. There is no reasonable basis for the Board to conclude, at this time, that an increase in the DSSAC would result in lower capacity prices or vice versa. Even if the Board were to assume the theories to be accurate, the Board has no way to accurately measure whether a change is DSSAC is equally, more or less accounted for in the capacity bids. On a 12-month basis, which is the term of the BGS-CIEP supply period, a DSSAC of $.00015/kwh would produce approximately $2.1 million. With the experience of only one BGS-CIEP Auction with which to gauge, the level of the DSSAC remains somewhat subjective. Experience with the next BGS-CIEP Auction may shed additional light on this subject. Until then, the Board DIRECTS that the DSSAC should remain at its current level.

ROCKLAND RFP

Rockland has proposed to issue an RFP for two separate financial swaps to secure a fixed price for the capacity and energy needed for customers in its non-PJM areas. The RFP would be issued in early December 2003 with responses due at a January 2004 date to be determined. If approved by the Board, the Rockland RFP price would be averaged with the Rockland BGS-FP price to determine customer rates. There has been no opposition to the Rockland RFP proposal for its non-PJM load.

Rockland issued a similar RFP last year for non-PJM load for the current supply period that produced results acceptable to the Board.[11] This year Rockland is proposing to solicit one and three-year bids for each swap. The results of each bid will be presented to the Board with a recommendation from Rockland and a recommendation from Board Staff to accept one or more of the bids or to reject all of them. Staff from the Division of Energy and from the Economist's Office will monitor the RFP process for the Board. Similar to last year, the Board will certify the results of the Rockland RFP within two business days of those bids having been submitted to the Board for its consideration.

Based on the foregoing, the Board APPROVES the Rockland RFP process for its non-PJM load and DIRECTS Rockland to work with Staff to develop an RFP schedule that complies with the foregoing and results in a Board decision on the RFP results prior to February 2, 2004.

BGS SUPPLIER MASTER AGREEMENT

During the course of this proceeding, the proposed CIEP and FP Supplier Master Agreements drew comments from a number of parties including potential bidders. Staff convened two meetings with interested parties to discuss the outstanding issues and attempt to resolve differences, where possible. In addition, the EDCs hosted other meetings and conference calls to address these issues. As a result of those meetings, a number of changes were proposed and agreed to by most, if not all, of the participants. These changes are detailed in Attachment C to this Order. The Board FINDS these changes to be reasonable and appropriate. Three other issues remain unresolved.

The first is the issue of reciprocal credit requirements. Potential bidders including MSCG, Constellation, Con Ed, J. Aron and Reliant urge the Board to adopt credit protections that apply equally to the EDCs and to winning BGS suppliers. They suggest that failure to do so will have a negative impact on BGS suppliers' participation in the auction process. (MSCG Final Contract Comments at 3). This issue was raised and addressed by the Board during previous auction proceedings.[12] In the current Supplier Master Agreements, the Board did not require reciprocal credit provisions, but adopted expedited procedures that would apply in the event a utility's credit rating were reduced below investment grade. The Board is sensitive to the concerns of potential bidders and strives to maintain rules and processes that will enhance the competitive nature of the Auctions. The Board is well aware of the importance of this issue to bidders. Bidders, however, have to recognize that EDCs, as regulated entities, do not fall in the same category as all other counterparties with which suppliers do business. The Board certainly cannot control the risk analysis performed by potential bidders including the assessment of the credit risk of a particular EDC in a contractual relationship. However, the Board, with the financial stability of its regulated entities as its centerpiece, has the statutory responsibility to ensure that EDCs continue to provide the ratepayers of this State with safe and reliable service at just and reasonable rates. The Board's commitment to and understanding of the auction process, its continued oversight of the EDCs' financial situation and the rules developed for the Year One Auction, including a process for an expedited Board decision in the event of an EDC being placed on a negative credit watch, should provide sufficient assurance to bidders that their interests are being protected. For the foregoing reasons, the Board does not find it appropriate to make changes to this area of the Supplier Master Agreements at this time.

The second issue has to do with the termination payment structure. In the supplier agreements currently in effect and approved last year by the Board, in the event of a default, the defaulting and non-defaulting parties were to true up their positions based on current market conditions. Under this

[11] Board Order dated January 13, 2003, Docket No. EX01110754.
[12] Board Orders dated December 4, 2002.

process, if the non-defaulting party would realize a gain as a result of a favorable change in the price of power, the non-defaulting party would make a payment to the defaulting party to return both parties to the pricing terms of the original agreement. Similarly, if the non-defaulting party were to realize additional costs, the defaulting party would compensate the non-defaulting party for the actual costs incurred. In the proposed Supplier Master Agreements, the EDCs have eliminated two-way termination payments. As proposed by the EDCs, payments would only go from the defaulting to the non-defaulting party.

The Board accepts the suppliers' position that two-way termination payments are standard in these types of contracts and that they do not favor either party, but merely place both parties in a position of living up to the "agreed-to bargain." The intent of the termination payment is to keep the parties whole and for each party to receive the benefits of the original bargain. (CEE Final Contract Comments at 1). The EDCs have attempted to argue that two-way termination payments act as an incentive for a supplier to default when "in the money," however the suppliers argue that such an incentive does not exist. (Constellation Final Comments at 9). The Board agrees with the suppliers that, faced with a default situation, a supplier should prefer to assign the contract to another party, in which case the EDC should be neutral. Two-way termination payments are in effect under the current Board-approved BGS Agreements. The Board finds that the EDCs have not made a convincing case for a change is these terms. Accordingly, the Board DIRECTS the EDCs to reinstate two-way termination payments in the BGS Supplier Master Agreements.

The third issue has to do with the EDCs' proposed mark-to-market multiplier of 1.15. In order to protect the EDCs from market increases from the time a margin call is made until it is posted, the EDCs propose to multiply the mark-to-market requirement by 1.15. While recognizing that the market could fluctuate to this extent, the suppliers argue that this occurs less than half the time and that the EDCs have interpreted the data in their favor. They recommend that the multiplier be eliminated. (MSCG Final Contract Comments at 13). This is a case where the data can be interpreted in several ways and the Board is not convinced that the data being considered leads conclusively to a 1.15 multiplier. However, the Board is aware that markets do fluctuate and to the extent they are moving higher while a margin call is outstanding, the EDCs and consequently ratepayers are at risk. Therefore, for purposes of these Agreements, the Board DIRECTS the EDCs to reduce the mark-to-market multiplier to 1.10.

This is the third year in which the Board has addressed issues concerning the Supplier Master Agreement. Many of the issues raised this year by potential bidders were also raised in previous years. At this point, the Board believes that all contentious areas of the Supplier Master Agreements have been resolved among the parties and/or have been fairly, properly and publicly considered by this Board. Accordingly, the Board is of the view that it is not necessary or appropriate for the parties to continue to raise the same issues that the Board has already addressed concerning the Supplier Master Agreements absent a material change in the facts related to the specific issue. Therefore, the Board HEREBY APPROVES the FP Supplier Master Agreement and the CIEP Supplier Master Agreement, as modified herein, for use in connection with the Year Two Auction specifically and will require that, for future auctions of this nature, parties show new or changed facts or a real or perceived change in industry structure affecting the way industry participants conduct business before it will consider revisions to these Agreements.

OUTSTANDING ISSUES FROM POST-TRANSITION YEAR ONE ORDER

Several items from the Board's December 18, 2002, post-Transition Year One BGS procurement Order need to be addressed to bring closure or to provide clarity or guidance with respect to these issues.

JCP&L Green Pilot Program

The JCP&L Green Pilot Program, approved by Order dated December 18, 2002, is scheduled to expire on May 31, 2004. The voluntary response to this program (5,700 customers) and the number of customers that were assigned and chose to opt-out of the program (24,100 customers) were disappointing to the Board. At this time, the Board does not believe this program should be extended. However, since customers in this program may have an interest in cleaner energy, the Board would like to see these customers made aware of alternative programs that may be available to them when the JCP&L Green Pilot Program ends. Therefore, the Board DIRECTS JCP&L to work with the Office of Clean Energy ("OCE") and to notify existing Green Pilot Program participants of alternative clean energy options that exist or may soon be available to them when the Pilot Program terminates.

Retail Green Marketing Program

In addition to the JCP&L Green Pilot Program, the Board had also approved a second program to encourage renewable energy by providing green retailers throughout the State with a margin of 5 mils for each kilowatt-hour of greener power supplied. This Retail Green Marketing Program was to commence on June 1, 2004. The Board recognized that various forms of green energy typically cost more than other forms of retail power and believed that a 5 mil per kwh incentive would help develop the fledgling green retail market in New Jersey through a process that had customers affirmatively choosing green power based on price, and other factors in a true retail setting.

After considering the state of the retail green market, the price differential between renewable energy and BGS, and being aware of other programs under development by the OCE, the Board believes that there will be more effective ways of promoting green energy in the near future. In order to ensure that the limited funding available for such programs is put to the most effective use, the Board ORDERS that the Retail Green Marketing Program, previously approved to begin on June 1, 2004, not be implemented. The Board wishes to emphasize, however, that it remains committed to encouraging renewable energy and will continue to explore creative ways to raise consumer awareness in the future.

Expansion of the CIEP Class

In its Year One Order, the Board indicated that it expected to render a decision by the middle of 2003 on whether and how far to expand the CIEP rate class on a mandatory basis. However, in order to include customer reaction including actual customer switching data in that evaluation, the Board delayed a decision on this issue. It expects to address this issue shortly.

At this time, the Board believes that non-residential customers that want to be included in the CIEP category for Year Two should be allowed to do so on a voluntary basis. Certain commercial and industrial customers may find hourly pricing attractive and, to the extent they can be identified and metered without a material impact on the BGS Auction process, their preferences should be accommodated. Since significant switching from the FP to the CIEP class would impact both the

BGS-FP and BGS-CIEP Auctions, the choice must be made in a timely manner and, once made, must be irrevocable for the term of the CIEP contract. Furthermore, certain unmetered and other specific small commercial accounts are by their nature such that hourly pricing would not encourage load management. For this reason, and because there is the possibility that, if permitted to switch to CIEP at this time these accounts would create an administrative burden such that other commercial accounts would be precluded from enrolling in this program in a timely manner, the C&I customers eligible to enroll in BGS-CIEP may need to be limited, at least for Year Two. Therefore, the Board DIRECTS 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 and also require a customer commitment for Year Two participation, by no later than January 5, 2004.

The EDCs had previously been instructed to include the costs for the enhanced metering and communications necessary to effectuate hourly pricing in their base rate proceedings. Since the Board believes that hourly pricing could be a benefit to all customers through lower supply costs as a result of possible peak load reductions, and since customers currently in the CIEP class were not individually charged for the enhanced meter installations, the Board DIRECTS the EDCs to make the necessary metering and communications installations for voluntary CIEP participation at no cost to the individual customer. The EDCs can request to recover any such enhanced metering and communication costs once the number of customers and costs associated therewith have been identified for Year Two.

The foregoing does not presume the direction that the Board may take as to expansion of the BGS-CIEP class on a mandatory basis.

Customers above 750kw

The Board's Year One Order approved a retail margin of 5 mils/kwh to be paid by all BGS-CIEP customers beginning August 1, 2003. The Board's Year One Order also approved a retail margin of 5 mils/kwh to be paid, beginning June 1, 2004 (start of Year Two), by non-residential BGS-FP customers with a peak load share ("PLS") of 750 kw or greater. In light of the Board's decision to permit voluntary enrollment in BGS-CIEP for Year Two, certain C&I customers with a PLS of 750kw or greater may find BGS-CIEP preferable to BGS-FP. Because of the relatively short time in which to enroll in BGS-CIEP for Year Two, the Board DIRECTS the EDCs to directly notify all customers that will become subject to the 5 mil retail margin of the nature, terms and conditions of BGS-CIEP voluntary enrollment.

The Board is aware that retail marketing to larger customers has dramatically increased since the creation of BGS-CIEP. Nonetheless, it appears that many of those CIEP customers that have remained on BGS have done so less as a conscious choice, than of a scarcity of competing offers. It appears that not all CIEP customers can be readily identified by retail marketers. Since the current CIEP category is generally comprised of larger C&I customers, the ability for retail marketers to identify BGS-FP customers with a PLS of 750kw or greater may be even more difficult. Therefore, the Board DIRECTS the EDCs to work with Staff to develop a means whereby customers becoming subject to the retail margin in 2004 would have the ability to voluntarily make their name and contact information available to licensed electric power suppliers, registered energy agents and registered private aggregators.

Use of Retail Margin

In its December 18, 2002 Order, the Board indicated that the retail margins would be returned to customers and that it would address the manner in which this would be accomplished at a later date. At this time, the Board is not ready to make that determination.

Load Management.

The connection between load management and BGS costs was raised in the last auction proceeding, but was not specifically addressed therein. Since that time Division of Energy staff, in consultation with the Office of Clean Energy, has been considering how best to incorporate effective load management techniques into the BGS procurement process. Currently, the major existing load management programs in the State are the appliance cycling programs of Conectiv, JCP&L and PSE&G. These programs were developed and funded from the Clean Energy Program component of the Societal Benefits Charge ("SBC"). Since there is a direct connection between the effectiveness of these programs and the cost of BGS supply, Staff proposed that the funding responsibility for the appliance cycling programs fall under the umbrella of BGS procurement and for the period beginning June 1, 2004 be funded through the auction process as a per kwh charge, rather than from SBC funds through a new non-bypassable charge. Since the program theoretically benefits all customers, the per kwh charge would apply to all EDC customers. Staff circulated this proposal prior to the deadline for final comments. Staff addressed questions and concerns that were raised through subsequent modifications and clarifications to the initial proposal.

The Board concurs with this Staff proposal. Additionally, because the cycling programs are currently in "maintenance mode", the Board believes that the existing programs may be under-utilized and could potentially deliver substantially greater savings if the level of customer participation were expanded and if the programs were reviewed and, where necessary, modified to reflect current market structure and practices. The advantages of peak load management ("PLM") exist not only for those customers that are able to participate directly in these programs but, more importantly, for the general customer base through a reduction in the need for suppliers to purchase more costly peak generation. In the current auction format, the ability to manage peak demand, to the extent it is quantifiable and reliable, should be recognized by the participants and reflected in their bids. For the purposes of this proceeding and the February 2004 Auction, the ability to deliver measurable peak load reductions must be defined in a timeframe that permits these benefits to be quantified by bidders. Therefore, the immediate priorities are to reopen the existing programs to new customers without significant design changes, for customers to be informed of the availability of these cycling programs, for a realistic estimate of the benefits available to BGS suppliers beginning in June 2004 to be determined prior to February 2004, for appliance cycling program costs to be removed from the SBC starting June 1, 2004, and for the funding of appliance cycling to become the responsibility of the BGS procurement process on June 1, 2004 via a charge which, for Year Two, would be assessed on each kwh of electricity delivered by the EDC. Until June 1, 2004, costs incurred associated with the appliance cycling program shall continue to be funded from the Clean Energy Program component of the SBC. Beginning June 1, 2004, appliance cycling costs shall be subject to deferred accounting, to reflect the likely mismatch between cost incurrence and revenue recovery.

Consistent with the foregoing, the Board DIRECTS the EDCs to work with Staff to effectuate the foregoing including the development and implementation, on a "best efforts" basis, of a plan that would expand the current appliance cycling programs in a cost-effective manner and define the operating parameters of the programs such that the total peak load reduction that will be effective as a result of this expanded program can be quantified prior to February 2004. The Board FURTHER

DIRECTS the EDCs to continue to provide quarterly status reports on the appliance cycling programs to the OCE and to the Division of Energy, and to provide such additional data, including cost recovery, as staff may require. Although Rockland does not currently have an appliance cycling program, it should be included in these discussions as they will likely be the basis for further peak load management initiatives, as detailed below, that will include Rockland. Although funding of appliance cycling is to become the responsibility of the BGS procurement process, and the BGS procurement process, including the integration of PLM into that process is the responsibility of the Division of Energy, design of the appliance cycling program should remain the responsibility of the OCE, subject to Board approval.

The foregoing addresses PLM and specifically appliance cycling as it affects the 2004 Auction. For the longer term, the ability to understand the impact of and to develop a cost-effective plan for PLM vis-a-vis BGS is important to the Board and the ratepayers of this State. For this reason, the Board DIRECTS the Division of Energy and the OCE together to review, consider and make recommendations to the Board for PLM on a going forward basis. Areas that should be addressed include:

1. whether the foregoing appliance cycling programs are designed and implemented in a manner that provides maximum benefits to the State. Because each PLM initiative provides a benefit to the region as well as to the State as a whole, serious consideration should be given to requiring Rockland to develop an appliance cycling program;

2. a plan for systematically considering additional PLM initiatives, including how commercial and industrial customers can best be included in PLM activities and whether some or all PLM programs could deliver greater benefits if transferred to suppliers or other market players.

OTHER ISSUES

Confidentiality

The integrity of the Auction process depends on a fair set of rules that promote 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 the BGS auctions conducted in February 2002 and 2003, it appears that certain information pertaining to the Auction design methodologies, including 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 this issue at its October 22, 2003 meeting, as memorialized by written Order dated October 23, 2003. The Board found that this 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.

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. In past years, the EDCs and the Auction

Manager have attempted 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 that have[13] and will be undertaken are:

?? Bidder Information Sessions in Philadelphia and Washington, D.C.;

?? An Auction web site at www.bgs-auction.com which publicizes new developments, allows interested parties to download documents related to the auction, has FAQs (Frequently Asked Questions with answers) so all bidders are similarly informed; and has links to PJM and other useful sites;

?? A virtual data room for potential bidders with data relevant to the bid and answers to questions posed by bidders about the data in the virtual data room;

?? Bidder information packets including the background information and information about the auction process;

?? 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 website.

The Board believes that the foregoing marketing effort by the EDCs and the Auction Manager will increase the chances that a successful BGS procurement can be achieved.

Board Approval Process

As with previous auctions, the Board believes that a successful BGS procurement can be achieved with a well-designed simultaneous descending clock auction process, as described above, provided that the rules and details are specified and implemented correctly. Therefore, barring some national or industry emergency, the timing of the auction process being 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, there are a number of decisions/actions that would 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 in order that the bidders are prepared and comfortable with participating and the Auctions result in competitive market-based BGS prices. 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.

Based on the Board's experience with the previous two auctions, a fundamental concern driving the approval process is that uncertainty or delay concerning the period between the submission of bids and the approval of the bid results by the Board is of substantial concern to bidders. Paramount among the actions that need to be taken by the Board is prompt certification of the Auction results. Because of the volatility of the electric markets, bids cannot remain valid for any prolonged period of time. If bidders perceive that there may be a delay in certifying the results, the additional risk to bidders could show itself through higher prices. Therefore, the Board will commit to addressing the

[13] These actions have occurred for past auctions and in anticipation of a favorable Board opinion, some of these actions may have already been undertaken for the 2004 auction.

results of the BGS-FP 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.

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, 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.

Another decision that requires Board approval is acceptance of the EDCs' Compliance Filing. Because of the significance of this proceeding, the Board DIRECTS the EDCs to make a Compliance Filing by November 7, 2003. The Board will consider approval of the Compliance Filing at its next scheduled Board meeting thereafter.[13]

Either the EDCs or the Auction Manager, in consultation with Staff and the Board's consultant, Charles River Associates ("CRA"), may make other Auction decisions identified in Attachment A. These decisions include determination of Contingency Plan levels, 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 unknown lesser 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, determination of Contingency Plan levels, establishing minimum and maximum starting prices, establishing specific starting prices, the resolution of association issues, and auction price decrements are either utility-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. Should any unforeseen circumstances occur during the Auction decision-making process, Staff will immediately bring the matter to the Board's attention.

For the final certification of the Auctions' results, the Board will schedule a special agenda meeting for the first day of the Auctions, as a forum to consider unforeseen circumstance, should any develop. When the Auctions are complete, the Board will review and consider the results. The Auction Manager will provide a Final Report to the Board and to the RPA on the results of the Auctions and how the Auctions were conducted, including the post-Auction evaluation forms in Attachment B, prior to Board certification of the results. CRA shall provide a Pre-certification Report to the Board, including completed post-Auction evaluation forms in Attachment B, prior to Board certification of the results.

In addition to the Auction certifications, the Board will also certify the results of the Rockland RFP within two business days of those bids having been submitted to the Board for its consideration. The Board will review and consider the RFP results, including information provided by Rockland and Board Staff on the results of the RFP process, as well as the post-Auction evaluation form in Attachment B, prior to Board certification of the results. In the case of the Rockland RFP, the Board, in its discretion, may approve the entire set of winning bids, just those lowest bids that the Board finds reasonable, or none of them.

Finally, the Board is aware that the dispute between the EDCs and Geophonics, Inc. regarding an

[13] The Board considered and approved the Compliance Filing at its November 13, 2003 Agenda meeting.

alleged patent infringement remains unresolved. 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 matter, including obtaining any appropriate licenses that may be required by law.

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 EDECA, 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 the BGS customers beginning June 1, 2004;

The Joint EDC Proposal, as modified herein, is the best means to secure BGS service for Year Two, as well as a portion of the BGS service required for Years Three and Four of the post-Transition Period;

The Rockland RFP proposal provides a reasonable means of securing BGS service for its non-PJM load;

The Rockland RFP proposal should be conducted prior to the BGS-FP Auction consistent with the schedule in Attachment A;

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, reporting activity in the Auctions, and the default bid rules are deemed reasonable for the purpose of these Auctions;

An Auction process for one-third of the EDCs' BGS-FP load for 12 months and for one-third of such load for 36 months balances risks and provides a reasonable opportunity for price stability under current conditions;

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

Voluntary enrollment in the BGS-CIEP class from non-residential customers currently in the BGS-FP class should be permitted with the strict timing and switching restrictions described herein;

The Board will make a decision on mandatory expansion of the CIEP class at its next agenda meeting;

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

The application of seasonal payment factors to the tranche-weighted auction prices is appropriate;

The “pass through” of any changes in the network integration transmission charge, and other charges associated with the FERC-approved Open Access Transmission Tariff is appropriate;

A Retail Margin of 5 mils/kwh is appropriate for BGS-FP customers with a load of 750 Kw or greater for Year Two of the post-Transition period;

A Retail Margin of 5 mils/kwh continues to be appropriate for BGS-CIEP customers for Year Two of the post-Transition Period;

The Board will, at a later date, determine how the Retail Margin collected should be returned to customers;

A DSSAC of .15 mils/kwh ($.00015) continues to be reasonable for CIEP customers for Year Two to encourage competition in the BGS-CIEP Auction;

The JCP&L Green Pilot Program should not be continued past May 31, 2004;

The Retail Green Marketing Program is not likely to encourage renewable activity in the region, and should be cancelled;

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

The EDCs should prepare the RPS reports required by the Board on behalf of the BGS suppliers and should contractually require the BGS suppliers to provide supplies that comply with the RPS requirements and the information on such supplies necessary to prepare the RPS reports;

The appliance cycling programs of the EDCs should actively accept additional customer participation, be reviewed to provide maximum benefit to ratepayers and, beginning June 1, 2004, be funded through the BGS procurement process;

The cost of the EDCs’ appliance cycling programs should be subject to deferred accounting and recovered from all EDC customers on a per kwh basis;

It is appropriate that National Economics Research Associates (“NERA”) continue to act as the Auction Manager for these Auctions;

The Staff pilot proposal to serve 3 tranches of JCP&L one-year, FP load from its NUG supply and administered in the fashion described herein is reasonable for Year Two;

The Committed Supply methodology proposed by the EDCs, as modified herein, is the most reasonable means of dealing with the existing utility Committed Supply obligations for Year Two;

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. 14:4-2.2 and, thus, successful bidders do not need to obtain a New Jersey electric power supplier license;

Certain information and processes associated with the auction and/or Rockland RFP processes may be competitive by nature and the Board has issued a Protective Order addressing this competitive information;

The accounting and cost recovery processes identified in the utility-specific addenda to the Joint EDC Proposal are reasonable and consistent with the Board's Final Unbundling Orders;

The utility-specific Contingency Plans, adjusted where necessary to reflect the decisions in this Order, are reasonable;

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

A designee from the Board's Energy Division, from the Board's Office of the Chief Economist and CRA shall observe the Auctions for the Board;

The Auction Manager will provide the post-Auction evaluation forms in Attachment B to the Board and to the RPA on the results of the Auctions and how the Auctions were conducted, prior to Board certification of the results;

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

The Board will consider the results of the BGS-FP 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; and

The Auction Manager will provide an unredacted Final Report to the Board Staff and a redacted Final Report, consistent with the Board's Protective Order in this matter, to the RPA Staff on the results of the Auctions and how the Auctions were conducted.

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, the Rockland RFP process and the Supplier Master Agreement, with the modifications described herein. The Board DIRECTS the EDCs to update the Tentative Approvals and Decision Process Schedule included as Attachment A, consistent with this Order. 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 reserves the right, to reject, in whole or in part the Rockland RFP results.

Furthermore, the Board DIRECTS that the Joint EDC Proposal be modified consistent with the foregoing and that the EDCs make compliance filings, including an updated Attachment A and any other changes consistent with this decision, by Friday, November 7, 2003.[14] The Board FURTHER DIRECTS the EDCs to work with Staff and CRA to ensure that any supplemental documents, such as application forms, are fair and developed consistent with this decision and that the review procedures for bidder applications are applied in a consistent and non-discriminatory manner.

DATED: December 2, 2003

BOARD OF PUBLIC UTILITIES
BY:

(SIGNED)

JEANNE M. FOX
PRESIDENT

(SIGNED)

FREDERICK F. BUTLER
COMMISSIONER

(SIGNED)

CAROL J. MURPHY
COMMISSIONER

(SIGNED)

CONNIE O. HUGHES
COMMISSIONER

(SIGNED)

JACK ALTER
COMMISSIONER

ATTEST:

(SIGNED)

KRISTI IZZO
SECRETARY

[14] Ibid