State of New Jersey
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

I		
/M/O The Provision Of Basic	)	ENERGY
Generation Service Pursuant	)	
To The Electric Discount And	)	DECISION AND ORDER
Energy Competition Act,	)	
N.J.S.A. 48:3-49 et seq.	)	Docket No. EX01110754 and EO02070384

(Service List Attached)

BY THE BOARD:

The Electric Discount and Energy Competition Act of 1999 ("EDECA" or "Act"), N.J.S.A. 48:3-49 et seq., provides that for at least three years from the starting date of electric retail choice and until the Board finds it to be no longer necessary and in the public interest, electric public utilities shall provide basic generation service ("BGS"). N.J.S.A. 48:3-57(a).

After an extensive proceeding, the Board, by Order dated December 11, 2001, determined that for Year 4 of the Transition Period (August 1, 2002-July 31, 2003), the electric utilities should continue to provide BGS, with the procurement of supply to meet the full electricity requirements of BGS customers to be achieved via an auction process. The Board further determined that a further review as to whether to make BGS available on a competitive basis for the period beginning August 1, 2003 ("post-Transition Period") would be undertaken pursuant to a separate scheduling order.

By Order dated January 10, 2002, the Board solicited information from interested parties so that it could make a timely decision whether BGS should be provided on a competitive basis for the post-Transition Period, and what should be the appropriate pricing mechanism for BGS after August 1, 2003. The Board issued a list of questions concerning competitive BGS to all interested parties. Responses were received from the following parties: Public Service Electric & Gas Company ("PSE&G"); Conectiv Power Delivery ("Conectiv"); Williams Energy Marketing & Trading Co. ("Williams"); Independent Energy Producers of New Jersey ("IEPNJ"); Division of the Ratepayer Advocate ("RPA"); National Energy Marketers Association ("NEMA"); Jersey Central Power & Light Company ("JCP&L"); AES NewEnergy Inc. ("AES"); Rockland Electric Company ("Rockland"); Reliant Resources, Inc. ("Reliant"); the New Power Co. ("New Power"); and Mid-Atlantic Power Supply Assoc.("MAPSA"). The January 10, 2002 Order also directed Staff to meet with interested parties in a working group-like setting to discuss the major issues, explore possible areas of common ground, determine where differences exist and identify potential solutions.

Upon completion of the two working group meetings and review of the written comments, the Board determined that additional information in the form of formal, detailed proposals was required from the parties. Accordingly, by Order dated June 6, 2002, the Board ordered the electric utilities and other interested parties to file formal proposals by July 1, 2002, on how BGS should be procured for the post-Transition Period. The Board further ordered that the proposals follow a list of guidelines that reflected the areas of concern initially raised by the parties in their written comments and at the working group meetings. The Board also adopted a procedural schedule, which would enable a Board decision on this issue in the fourth quarter of 2002. Among other things, the procedural schedule provided for discovery, public hearings, and the filing by all interested parties of comments and reply comments.

On July 1, 2002, the Board received numerous proposals on how to proceed with the BGS procurement process for the post-Transition Period, from interested parties. A joint proposal and company specific addenda were received from the electric distribution companies ("EDCs"), including PSE&G, JCP&L, Conectiv, and Rockland ("Joint EDC Proposal"). In addition, proposals were filed by the RPA, MAPSA, Williams, Consolidated Edison Solutions, Inc. ("CESI") and Consolidated Edison Energy, Inc. ("CEEI"), Constellation NewEnergy, Inc., formerly AES NewEnergy, Inc. ("Constellation"), Pepco Energy Services, Inc. ("Pepco"), New Jersey Large Energy Users Coalition ("NJLEUC"), IEPNJ, Reliant, Select Energy, Inc. ("Select"), Duke Energy Trading and Marketing, LLC ("Duke"), and the New Jersey Food Council ("NJFC").

JCP&L also submitted a separate filing, dated July 2, 2002, proposing a retail pilot program to be implemented in conjunction with the BGS procurement process proposed in the Joint EDC Proposal.

At the July 12, 2002 Board agenda meeting, the Board authorized the issuance of a Request for Proposals ("RFP") to obtain the services of a consulting firm to provide advice to the Board and its Staff on the BGS procurement process for the post-Transition Period. At the August 29, 2002 Board agenda meeting, the Board determined to engage the consulting firm of Charles River Associates ("CRA") to review the July 1, 2002 proposals, and provide oversight of any auction process approved by the Board.

On September 10, 2002, a legislative-type hearing was held at the Board's Newark office. The hearing was chaired by Commissioner Butler. Commissioner Hughes also participated in the proceeding. 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, Pepco, NJLEUC, and NJFC.

A number of informal settlement conferences were also held on September 11, 17, 18, and 19, in an attempt to find common ground among the participants on as many issues as possible.

On September 23, 2002, pursuant to the procedural schedule that had been established, Board Staff ("Staff") filed its initial position. The EDCs and all other interested participants also filed initial comments, which, in some cases, included modifications to their respective initial positions. Besides Staff and the EDCs, the parties filing initial comments were the RPA, NJLEUC, IEPNJ, MAPSA/Pepco (Joint), TXU Energy Trading Co.("TXU"), Conectiv Energy Supply, Inc., DTE Energy Trading, Inc. ("DTE"), Constellation, Reliant, Sempra Energy Trading Corp. ("Sempra"), and Mieco, Inc. ("Mieco").

At its regularly scheduled public agenda meeting of October 3, 2002, the Board amended the procedural schedule to extend the time for Reply Comments until October 11, 2002.

On October 11, 2002, Reply Comments were filed by Staff, the EDCs, JCP&L (company-specific comments), RPA, Duke, MAPSA/Pepco (Joint), NJLEUC, Constellation, IEPNJ, Reliant, PJM, Natural Resources Defense Council ("NRDC"), Chemistry Council of New Jersey ("CCNJ"), and J. Aron & Company ('Aron").

PARTICIPANT PROPOSALS, 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, 2002 filing. The Board will not, in this Order, separately summarize each party's position in similar detail. The Proposals, Comments and Reply Comments filed by all parties identified above are available on the Board's webpage at www.bpu.state.nj.us, under Energy.

JOINT EDC PROPOSAL

On July 1, 2002, the four EDCs filed a Joint EDC Proposal for BGS, consisting of three parts: (1) a Proposal for Basic Generation Service Beyond July 31, 2003; (2) EDC-specific addenda; and (3) a form of BGS Supplier Master Agreement.

The EDCs have jointly proposed two simultaneous, multi-round, descending clock auctions ("Auctions") for the procurement of supply 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 1750 largest commercial and industrial ("C&I") customers on the utility systems of ACE, JCP&L and PSE&G through an hourly energy price ("HEP") Auction[1]. The EDCs propose to move these largest customers to real-time, hourly pricing, using interval meters. The customers in this category would represent approximately 2460 megawatts ("Mw") of load procured through bidding on approximately 49 full-requirements tranches of 50 Mw each. Rockland did not propose to have an hourly pricing class of customers.

The second Auction would be to procure service for all other customers of all four EDCs through a fixed price ("FP") Auction ("BGS-FP Auction") for approximately 15,460 Mw of load to be procured through approximately 154 full-requirements tranches of 100 Mw each. These customers would be priced at fixed tariff rates determined by converting the auction prices to BGS-FP rates in a manner that reflects rate class and seasonal load characteristics and market prices.

[1] The Board will hereinafter refer to the HEP class of customers as the Commercial and Industrial Energy Pricing ("CIEP") class and customers in this category and receiving BGS service will be on BGS-CIEP. The Auction will continue to be referred to as the BGS-HEP Auction or the BGS-HEP Auction for the CIEP customer class.

The competitive process by which the EDCs propose to procure their supply for BGS load for the post-Transition Period is the same type of auction that the Board approved by Order dated December 11, 2001, which was used to procure supply for the period from August 1, 2002 through July 31, 2003. 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 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. A price for an EDC is an amount in cents per kilowatt-hour (“kwh”) paid for each kwh of BGS load served. A tranche of one product (i.e., a tranche of the BGS load for one EDC) is a full requirements (capacity, transmission, electric, 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 reflect 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 August and 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-HEP tranches, rate schedules would be designed to include a monthly rate for the capacity obligation, a monthly rate for the transmission obligation and ancillary service costs, and a provision to pass through the hourly PJM[2] real-time energy price. Bidders would indicate how many tranches they want to supply in exchange for a ¢/kwh payment called the Default Supply Service Availability Charge (“DSSAC”). The DSSAC is intended to essentially act as an “option fee.”

Under the EDCs’ proposal, the DSSAC would be charged to all customers eligible for BGS-CIEP service and represents the value of the BGS-CIEP option. Winning bidders would be paid the auction clearing price for the option fee 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 electricity to BGS customers. The detailed commercial terms and conditions under which the BGS supplier would operate, including credit requirements, are set forth in the BGS Supplier Master Agreement attached to the Joint EDC Proposal as Attachment A.

The EDCs propose that the Board render a decision on the Auction process and render a decision

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

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-HEP Auction, by the end of the second full calendar 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.

Numerous other Auction details are explained in the Joint EDC Proposal, EDC-specific Addenda, Attachment A and Supplier Master Agreement including that:

- all customers will be free of all switching restrictions save for the Board's 20-day, anti-slamming enrollment process which the EDCs propose be extended to a 50-day process;

- BGS suppliers must meet all New Jersey Renewable Portfolio Standards ("RPS") requirements, including the reporting standards as prescribed by Board Order dated June 12, 2001, Docket No. EX99030182, in addition to all requirements of N.J.A.C. 14:4-8.1 et seq.;

- bidders do not need to obtain a BPU retail supplier license in order to participate in the BGS-HEP or BGS-FP Auction;

- 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 two 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 if 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 Auction should be for a supply period of 10 months[3].

The Joint EDC Proposal included the Supplier Master Agreement from last year's Auction. On September 12, 2002, the EDCs replaced this Agreement with a BGS Supplier Master Agreement that the EDCs proposed be used for the current BGS Auction process. In the BGS Supplier Master Agreement proposed for this Auction, the EDCs indicate that they have attempted to be more responsive to concerns that were raised by bidders last year, but were not able to be addressed at that time.

EDC-SPECIFIC ADDENDA

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, they each address

[3] In the alternative, PSE&G proposed that a term-averaged procurement period be considered in which one-third of each EDC's load would be secured for 10 months, one-third for 22 months and one-third for 34 months. The 10 month, 22 month and 34 month time periods are meant to synchronize the BGS procurement process with the PJM planning year, which runs from June 1 through May 31.

the issue of a retail adder. PSE&G, Conectiv and Rockland oppose any such adder. JCP&L has sponsored a 1.6 cents/kwh adder for BGS-FP customers, and indicates that it is doing so as part of a side agreement with certain TPSs which was entered into around the time of the FirstEnergy merger.

Included in JCP&L's addendum is a proposal that 300Mw of its FP load be available for a wholesale "green" procurement process. The green power would be procured through either an auction or sealed bid process. All JCP&L BGS-FP customers, including those that are part of this green proposal, would pay the same blended price, within rate classes.

Included in PSE&G's addendum is a proposal that a term-averaged procurement period be considered, in which one-third of each EDC's load would be secured for 10 months, one-third for 22 months and one-third for 34 months.

Included in Rockland's addendum is an RFP to secure a fixed price supply for its Western and Central Divisions, which are served through the New York Independent System Operator ("NYISO"). As the Western and Central Divisions are not part of PJM, they cannot participate in the regular BGS-FP Auction process.

In a separate filing, JCP&L proposed that 500Mw of its FP load be made available for licensed suppliers to serve at retail. Customers would be randomly assigned. Assigned customers would have the opportunity to opt-out and would be permitted to switch to other licensed suppliers. Customers that opt-out would be replaced by other randomly selected customers. All JCP&L customers on BGS–FP, including those served through this retail proposal, would pay the same blended price, within rate classes.

<u>ISSUES RAISED BY OTHER PARTICIPANTS</u>

Throughout this proceeding, there have been issues raised by the wide range of participants, which touch upon both technical and policy matters, as well as auction mechanics. While the participants agree on bringing the BGS procurement period in line with the PJM planning year, a number of different lengths for the procurement period have been proposed. 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 are also differing opinions about whether additional incentives are needed to produce a competitive retail market and whether such incentives are warranted. JCP&L's proposals that part of its load be served through two pilot programs were criticized by some participants for varying reasons. In addition, various participants raised issues with respect to customer switching, 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.

<u>DISCUSSION AND FINDINGS</u>

By way of introduction, there are a number of policy issues that the Board will address in this Order. In some cases, the Board will only be making decisions for a 10-month timeframe. The Board will revisit these policy issues once data from the Auction and initial switching information for Year One of the post-Transition Period (August 1, 2003 through May 31, 2004, "Year One") starts to become available. In other cases, as specifically noted herein, the Board's decision will apply to other more extended periods.

PROCUREMENT STRUCTURE

In contrast to last year, when an auction process was a new and untried concept and its merits were challenged by some participants, all participants this year either openly support continuation of the descending clock auction process proposed by the EDCs or, by only providing comments that propose refinements to the auction process, implicitly do not object to it. Most parties also support the separation of customers into a BGS-FP Auction and a BGS-HEP Auction for larger customers.

The Board believes that the auction process which was implemented last year consistent with the Board's December 12, 2001 Order, appeared to work well and 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 supports providing real-time pricing signals to customers who are prepared and able to take advantage of this type of rate design. Thus, with the modifications and enhancements described herein, the Board believes that a dual auction process as proposed by the EDCs should be adopted for the next procurement period.

PROCUREMENT PERIOD

Without exception, the comments support a 10-month period for the BGS-HEP Auction. A number of different procurement periods have been proposed for the BGS-FP Auction. Some participants, including Staff and the RPA, have proposed a 10-month period followed by a second Auction for the subsequent 12-month period. J. Aron proposed a 34-month procurement period. The EDCs, while initially proposing a 10-month period, in their Reply Comments support a term-averaged procurement process in which equal portions of an EDC's load is procured through the Auction process for either a two or three year term. The one common factor in all proposals is that the procurement periods conclude on May 31, in order to bring the procurement process in line with PJM scheduling timeframes.

Staff proposed a 10-month procurement period for BGS-FP because of the uncertainty inherent in a longer procurement period, and because the electric market is not as established and transparent as its natural gas counterpart, and also because there are certain policy decisions before the Board which, if not decided at this time, could add uncertainty to the process and therefore potentially increase the end prices for longer term supply. (Staff Comments at 2).

The proponents of a term-averaged procurement process cite the economic benefits of spreading the risk of weather, market conditions, economic activity and political uncertainty over staggered periods of time. They also assert that having a two or three year product may be more attractive to some bidders and could potentially increase the competitiveness of the process. (IEPNJ Reply Comments at 2-3). Duke asserts that a term-averaged approach would help avoid "rate shock" and would provide bidders with longer-term supply opportunities and with lower administrative costs. (Duke Reply Comments at 11). Other considerations in determining whether to adopt a fixed or multi-year procurement period include the transparency of the electric market and the effect of the proposals on retail competition. The Board believes that a term-averaged approach has merit as it would hedge the risk of unfavorable market conditions that might be present at any one point in time. Economic and political uncertainties are part of normal business risk, which arguably would mitigate for, rather than against, a multi-year hedged approach. The Board recognizes that if it approves a multi-year process, it should strive to provide as much certainty as possible for each year of that process. The Board believes that, to a large extent, it can provide guidance on a number of key issues for a 34-month period in order to minimize bidder uncertainty.

The Board believes that the J. Aron proposal for a 34-month procurement period for the entire supply would place undue risk on customers, with limited offsetting benefits. Given the lack of extensive empirical experience with longer term procurements in the marketplace, a 34-month procurement period for 100% of the BGS-FP load is not acceptable to the Board at this time.

Therefore, in an effort to balance the risks to ratepayers, the Board will approve a term-averaged procurement process in which two-thirds of the EDCs' BGS-FP load is auctioned for a 10-month period and one-third for a 34-month period. The tranche-weighted average of the winning bids from both the 10 and 34-month periods will be used to determine the price for BGS-FP rate design for Year One. The Board will review its decision and the results of the procurement process prior to the procurement for Year Two (June 1, 2004 through May 31, 2005) to determine how best to proceed at that time with future procurements.

CUSTOMER SWITCHING

The Board currently has a 20-day enrollment process for customer switching. In addition, the Board's December 12, 2001 Order imposed a restriction on non-residential customer switching from August 1, 2002 through July 31, 2003, in order to reduce risks to BGS bidders during that supply period. It was the Board's intention at the time that this issue would be reviewed again in this present proceeding. The EDCs have proposed to remove that restriction on non-residential customers and, in their Reply Comments, recommend that the Board maintain its current 20-day enrollment process. The Joint EDC Proposal on customer switching would also remove any seasonal switching restrictions in individual EDC tariffs. A number of other parties support this proposal. The Board believes that unrestricted switching (except for the 20-day enrollment process), although it may impute some additional risk to winning bidders, is consistent with the goals of EDECA.

BGS-FP AUCTION

Rate Design

Beginning with the post-Transition Period, the prices resulting from the procurement process approved by the Board will be reflected fully and directly in customer rates. Since the filing of the initial proposals to accomplish this inclusion of bid prices into rates, Staff has taken issue with some aspects of the EDCs' proposed rate design. Staff has discussed the disputed rate design issues with the EDCs and addressed specific issues in its Comments and Reply Comments. In their Reply Comments, the EDCs have proposed to modify certain aspects of their rate design proposal. In order to resolve disputed rate design issues, the EDCs have proposed to change the rate design methodologies filed with each EDC's individual Company-specific Addendum to:

1. modify the methodology to convert the forwards market prices into the on and off peak periods of each EDC's specific on and off peak tariff periods; and

2. shift a much larger proportion of the capacity obligation costs into the summer period rates.

The EDCs have not agreed to Staff's proposal to lower BGS-FP prices for the first block of the EDCs' residential rates and to raise prices for the second block. Staff has argued that its proposal would provide consumers with appropriate energy conservation signals, and that the EDCs' rate design proposal would likely lead to increased summer load growth, contribute to higher BGS bid prices and generally higher market energy prices for all customers.

The EDCs argue that this aspect of Staff's rate design proposal: 1) would distort market pricing contrary to the intent of EDECA; 2) makes the "price to compare" confusing to larger use customers since it will change on each bill depending on the level of usage; 3) discriminates against smaller use customers whose "price to compare" will be artificially below market; and 4) subverts the "conservation signal" intent for the majority of customers whose usage falls entirely in the first residential block.

A further rate design issue raised by Staff concerns the reasonableness of the assumed \$30/Mw/day average market capacity cost used in the BGS-FP rate design, which Staff asserts is unsubstantiated, as it is based solely upon undocumented quotes purportedly sought by the EDCs from capacity brokers.

The Board disagrees with the EDCs' arguments on rate design. First, 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. EDECA only requires that pricing be "based" on market prices. <u>N.J.S.A.</u> 48:3-57(d). As for the EDCs' other arguments, the Board recognizes that rate design is not a precise science. While the EDCs oppose the concept of inverted rate blocks for residential customers, the Board views such a model as an important regulatory tool. Inverted rate blocks send a conservation message to larger volume residential consumers, namely, that not every kilowatt-hour costs the same to produce and that reducing consumption will save you money. While this rate design is not perfect, the Board finds the Staff proposal to be preferable to the EDC proposal, at this time.

As for the \$30/Mw/day capacity cost, the Board has been advised that Staff and the EDCs have agreed that \$20/Mw/day is a more reasonable estimate for the purposes of this proceeding. The Board accepts this compromise position and emphasizes that this is simply a negotiated value for purposes of rate design and only for use in this proceeding, with no precedential value for future proceedings.

BGS-FP Retail Margin

A number of parties have proposed that a retail adder, which the Board will hereinafter refer to as the Retail Margin, be included in the price that BGS-FP customers pay. Only those customers taking BGS service would pay the Retail Margin. Some parties argue that it is necessary for BGS service to reflect the cost of providing electric service at retail, including marketing costs, risk and portfolio management costs, working capital, administrative expenses and profit margin. JCP&L has proposed a Retail Margin of 1.6 cents per kwh for all utility BGS-FP customers. (JCP&L Company Specific Addendum at 1). Staff has proposed a Retail Margin of 5 mils per kwh for all BGS-FP customers. (Staff Reply Comments at 3). The RPA opposes the imposition of a Retail Margin on BGS-FP customers, arguing that such a charge could be counter-productive. The RPA asserts that most smaller customers are not yet ready for retail competition and, therefore, a Retail Margin would increase costs to these customers without spurring retail competition. (RPA Reply Comments at 3).

While an active competitive retail market has been slow to develop, the Board believes that it needs to move cautiously in this area, especially when it concerns smaller customers. As noted above, the BGS-FP Auction being approved by this Order will result in bids that translate directly into customer rates beginning August 1, 2003. In addition, for non-residential FP customers, switching restrictions, which the Board found to be necessary for the last auction period, will be eliminated along with seasonal switching restrictions peculiar to each EDC. These changes should help make the retail market for FP customers more attractive to licensed suppliers. It is not clear whether these changes, by themselves, will be enough to either encourage customers to shop or to encourage electric suppliers to market. It is likely that, initially, more of this activity will occur for larger FP customers than for residential and small commercial customers. If the Board were to impose a Retail Margin on all FP customers and the amount of competitive activity in Year One was still minimal or limited to larger FP customers, the Retail Margin would just increase the cost of electricity to most of the customers in the State with minimal resulting benefits. In the alternative, if a Retail Margin were imposed on FP customers and switching activity increased above some minimum level, the Board would not be sure how much of this activity was a result of the Retail Margin and how much was a result of market-based rates and unrestricted switching. Accordingly, the Board does not believe it appropriate to approve a Retail Margin on FP customers for Year One.

Looking ahead to post-Transition Period Years Two and Three, the Board believes that larger FP customers should be encouraged to shop for retail electric suppliers. As discussed below, the Board will consider expansion of the hourly pricing customer class though inclusion of additional customers from the current FP category. If larger FP customers are transferred to hourly pricing for Years Two and Three, the Retail Margin in effect for hourly pricing customers, as discussed below, would also apply to these customers. If, for whatever reason, the Board does not find it appropriate to transfer these customers to hourly pricing in Years Two and Three, the Board believes that the imposition of a Retail Margin on those customers with a load above 750Kw would be appropriate at that time, as these customers will likely be the first group targeted by marketers after the hourly pricing customers. Over the next 16 months, through the CIEP Education Task Force described below, it is anticipated that these customers will become more familiar with the changes occurring in the electric marketplace in New Jersey and the options available to them. The Board intends to gradually expand the number of customers on hourly pricing and believes that these larger customers should be given appropriate price signals to encourage the development of retail competition. For these reasons, the Board FINDS that for Years Two and Three, a Retail Margin of 5 mils per kwh is appropriate and should be included in the rates of BGS-FP customers with an annual generation capacity obligation (“annual load”) equal to or greater than 750Kw.

At this time, the Board is not comfortable with imposing a Retail Margin on customers with an annual load of less than 750 Kw. However, the Board will reconsider this issue prior to Year Two. In order to provide BGS-FP bidders with some degree of certainty on this issue, the Board is prepared to state at this time that, in the event that a Retail Margin is imposed on some or all BGS-FP customers with an annual load less than 750Kw in Years Two or Three, the Retail Margin imposed will not be greater than 5 mils per kwh.

In considering the issue of a Retail Margin for BGS-FP customers, the Board looked at whether it might be appropriate to differentiate, within the BGS-FP class, between residential, small commercial and industrial customers and larger BGS-FP customers. The RPA has also suggested that the Board make a distinction between smaller and larger C&I customers within the BGS-FP category. (RPA Reply Comments at 1). One of the difficulties with making this type of decision is that there is no consistent definition of what constitutes a “small commercial and industrial customer” among the various EDCs. This issue has come up before in a number of different contexts. Since, in terms of consumption and demand, a small commercial or industrial customer may be substantially similar to a residential customer, the Board finds that this lack of a generic definition restricts the Board’s decision-making flexibility. Therefore, the Board DIRECTS the EDCs to propose, by December 31, 2002, a generic definition of small commercial and industrial customers for rate-making purposes. In this same proposal, the EDCs should comment on any problems they see with the creation of uniform EDC rate classes for all customer classes. The Board thereafter will determine whether the proposed definition of small commercial and industrial customer is acceptable and whether it should be used in the current and future EDC rate proceedings. The Board also will determine whether further uniformity among EDC rate classes is appropriate.

BGS-HEP AUCTION

HEP Bid Product and DSSAC

The EDCs, in their Reply Comments, modified their proposal to accommodate concerns that if the capacity charge is set too low to cover the cost or risks of agreeing to provide BGS-CIEP at a fixed capacity rate, the DSSAC, which, as originally proposed, would be paid by all customers, may be excessively high and could inefficiently discourage shopping. The EDCs now propose that the DSSAC be set at three one-hundredths of a cent per kwh. The EDCs argue that the DSSAC is a necessary component to make BGS-CIEP an attractive product to bidders, who will be bidding for the right to wait to serve BGS-CIEP-eligible customers who may never take BGS-CIEP service. Staff agrees with the concept of having capacity as the bid product and the DSSAC charged to all CIEP customers, but proposed a fixed DSSAC of one one-hundredth of a cent per kwh. (Staff Reply Comments at 3). NJLEUC, MAPSA, and Reliant argue that the DSSAC is not necessary or should only apply to BGS-CIEP customers and not to CIEP customers that have switched to TPSs.

The Board agrees with the change to capacity as the bid product. The Board also 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. Therefore, the Board FINDS that CIEP customers as a whole benefit from the availability of this option and all CIEP customers should pay the DSSAC.

The level of the DSSAC is somewhat subjective, given the lack of actual experience in this area. Staff suggests that a DSSAC of one one-hundredth of a cent per kwh would produce approximately $1.5 million annually, which should be sufficient for providing this service. On a 10-month basis, which is the term of the initial BGS-HEP supply period, the DSSAC would produce approximately $1.2 million if Staff's proposal were accepted. Having reviewed the position of the parties on this issue, the Board will set the DSSAC for Year One, for all CIEP customers at fifteen one-thousandths of a cent ($.00015) per kwh, which should produce revenues of approximately $1.8 million, which should be adequate to attract bidder interest in providing this service. The Board believes that structuring the BGS-HEP Auction to attract more bidders should result in lower bids for capacity, which, in turn, would potentially benefit all BGS-CIEP customers and offset the relatively minor DSSAC.

BGS-CIEP Retail Margin

As described above under the section <u>BGS-FP Retail Margin</u>, the Board recognizes that there are additional costs involved in providing retail service compared to default service. For the reasons explained in that discussion, and for the same reasons that the Board will impose a Retail Margin on customers with an annual load equal to or greater than 750Kw starting in Year Two, the Board similarly FINDS that a 5 mil per kwh Retail Margin is appropriate for BGS-CIEP customers beginning with Year One.

At this time it is not possible to estimate the level of revenues that will be collected from customers in the form of a Retail Margin. Although the revenues could conceivably approach $60 million for Year One if all CIEP customers stay with BGS service, it is unlikely that this will be the case. However, there is no way of reasonably estimating the number of customers that might switch to TPSs given the number of new factors being introduced to these customers, including hourly pricing, unrestricted switching and a Retail Margin. The Board strongly believes that the revenues which the EDCs receive from the Retail Margin are customer supplied funds that must be returned to customers. This could be done in a number of ways, including as an offset to deferred balances, which were authorized pursuant to and incurred subsequent to the enactment of EDECA in 1999.[4] The Board will make a determination as to how these funds should be returned to customers at a future date. Therefore, the Board DIRECTS that the EDCs maintain the revenues collected from the BGS-CIEP Retail Margin in a deferred account with interest, until the Board makes a determination as to how the BGS-CIEP Retail Margin should be returned to customers.

Expansion of the CIEP Class

A number of parties have suggested that the CIEP category be expanded to include additional large commercial and industrial customers. Reliant comments that if the CIEP class is limited in

[4] Among other things, EDECA allowed the EDCs to defer certain costs during the Transition Period, and provided for future recovery from customers.

size, licensed suppliers may choose not to participate in the retail market. They suggest that a structured expansion of this class is acceptable, but if a working group is created to address the expansion of the CIEP class it should be open to TPSs. (Reliant Reply Comments at 1-2). NJLEU agrees that the CIEP class must be sufficiently broad to provide a strong foundation for competition. (NJLEU Reply Comments at 6). Duke asserts that implementing hourly pricing for all customers with a peak load above 1 Mw per month would alleviate the risk associated with C&I customer switching. (Duke Reply Comments at 7). Staff proposed that, at a minimum, Rockland create a CIEP class for its largest customers. (Staff Reply Comments at 3).

In response to the proposals for expansion of the CIEP class, the EDCs have presented a proposal to identify appropriate customers and include those customers in the CIEP class for Year Three. They argue that load profile data must be gathered to redefine the CIEP and FP class of customers, and that without such data there would be increased bidder uncertainty for both customer class groupings, with a resulting increase in bidder risk and prices for BGS customers. The EDCs maintain that the CIEP class should not be expanded without empirical evidence derived during Year One to determine whether these generally “smaller” customers are going to have viable shopping alternatives. They also suggest that the Board complete the consideration of future metering options that was initiated by its July 22, 2002 Order before undertaking expansion of the use of advanced metering beyond the rate classes currently proposed to be included under CIEP. (EDC Joint Reply Comments at 21-23).

The Board believes that the number of FP customers with an annual load above 750Kw is about 650 statewide. While the Board has some idea of the types of businesses included in this group of 650, it is not sure of their individual ability to respond to hourly pricing. Below the 750Kw annual load level the Board has little information of any kind that would be useful in determining this issue. The Board is concerned that expansion of the CIEP class at this time is premature and could result in the inclusion of customers who would be unable to adapt their operations so as to shift load and readily adapt to hourly pricing, thus leaving these customers without viable alternatives in the competitive market. The Board does not have adequate information on the largest FP customers that would be the next logical candidates for inclusion in the CIEP category to make such a decision at this time. The Board also recognizes that reasonable load profile information for auction participants has the potential to benefit all consumers. For these reasons, even though the Board supports the concept of hourly pricing for larger customers, it is reluctant to move too rapidly. As the EDCs indicated, the Board recently initiated a review of EDC metering practices to be conducted by Staff in conjunction with the RPA. This would be an appropriate forum in which to further explore this issue. Accordingly, the Board DIRECTS that this review process be expanded to a Metering Working Group (“Working Group”) to consider how and when the CIEP class should be expanded and whether inclusion in the CIEP category should be voluntary or mandatory. Furthermore, the review process initiated earlier by the Board was limited to Staff and the RPA, as it was anticipated to have a limited scope and was basically intended to provide reference material for the Board. With an expanded scope, the Working Group just ordered should be open to all interested participants.

Because the remainder of BGS supply for Years Two and Three will likely continue to be procured through a competitive process, the Board will need accurate load profile information in a timely manner. The Board will therefore need to decide on the size of the CIEP class, at least for Year Two, in the near future. In order to do so, the Metering Working Group needs to begin consideration of the issues early in 2003. In order that this Working Group has adequate information to begin the process with meaningful discussions, the Board DIRECTS the EDCs to provide to the Board and interested stakeholders, by no later than December 31, 2002, information regarding the EDC's FP rate class containing, in general, the largest commercial and industrial customers that are not included in the BGS-HEP Auction for the current year. These classes are: for ACE-AGS Primary; for JCP&L-GST; for PSEG-LPL Secondary; and for Rockland-SC-2 Primary and SC-7.

This information should fully describe the customers in each such rate class by number of customers, by usage level increments set forth in 100kw monthly peak demand (e.g. number of customers 100-199kw, 200-299kw etc.), number of advanced meters (interval, time of use, pulse) currently installed, and any other relevant identifying factors that would assist the Working Group in achieving its goals.

Based on the information to be provided to the Board by the EDCs, the Board DIRECTS the Metering Working Group created by this Order, to develop, by no later than April 30, 2003, recommendations and an implementation plan for the transition of the customers in these rate classes to the CIEP class. The plan shall ensure that all customers in these rate classes will be provided with necessary interval metering capabilities and that the EDCs shall implement any data management improvements necessary to enable these customers to be transitioned to the CIEP class by no later than May 31, 2004, whether or not the Board decides to do so in that timeframe. Costs associated with interval meter installation required by this Order, including capital, operation and maintenance costs and the cost of billing system enhancements, should be determined in the context of the current rate proceedings for JCP&L, PSE&G and Rockland and in the upcoming rate proceeding for Conectiv. Those costs, whether or not incurred during the relevant test year, should be reflected, on a pro forma basis if necessary, in the revenue requirements on which rates will be set in those proceedings.

While Rockland has not proposed to create a CIEP category at this time, even though it has 18 customers that are appropriate for this category, the Board sees no reason why Rockland's largest customers should be treated differently than other similarly situated customers in other EDCs' territories. Therefore, the Board DIRECTS Rockland to create a CIEP category and to include these 18 customers in that category for Year One, to participate in the BGS-HEP Auction and to participate in the Metering Working Group. Since Rockland's resulting aggregate CIEP load may be less than the 50Mw currently proposed as a tranche size in the BGS-HEP Auction, the appropriate adjustment should be made in the compliance filing which will be required later in this Order.

EDC-SPECIFIC PROPOSALS

Rockland RFP

Rockland has proposed to issue an RFP to secure a fixed price for its supply needs for approximately 40Mw of load in its non-PJM areas. The bids would be opened the day after the BGS-FP Auction closes and the successful bid(s) presented to the Board for approval. If approved, the Rockland RFP price would be averaged with the Rockland BGS-FP price to determine customer rates. While the Board agrees with the RFP process proposed by Rockland to secure electricity for its non-PJM load, it also agrees with Staff's recommendation that the Rockland RFP process be completed prior to the BGS-FP Auction. The Board believes this is necessary to prevent the possibility that exists under Rockland's proposed timeline, that bidders in the Rockland RFP process who also bid in the BGS-FP Auction might have information, which would provide them with an advantage over other RFP bidders who did not also participate in the BGS-FP Auction. Therefore, the Board DIRECTS Rockland to work with Staff to revise its RFP process and timeline for non-PJM load, consistent with this Order.

JCP&L - Retail Pilot

JCP&L proposed a Retail Pilot Program ("Retail Pilot") that would make 500Mw of its BGS-FP load available for licensed suppliers to serve at retail. Customers would be randomly assigned and all customers on BGS–FP, including those served through this Retail Pilot would pay the same price, within rate classes. Staff is opposed to this program as providing little benefit to customers or the Board. The RPA is also opposed to the Retail Pilot because it proposes both customer assignment and averaging of bids to come up with a uniform BGS-FP rate. (RPA Reply Comments at 2). The Board would be willing to consider a pilot program if such a program were to advance customer awareness of a changing marketplace, provide the Board with some indication of customer preferences, attempt new methods to transition to a competitive market, and/or attempt to advance other Board policies. The JCP&L Retail Pilot as filed does none of these. While the Board could modify the proposal to include voluntary customer enrollment, this would probably be meaningless, since to the customer, the product proposed by JCP&L is indistinguishable from BGS-FP service. At this time, the Board sees no meaningful benefit to consumers or to the market in approving this proposal. Therefore, the Board DENIES JCP&L's petition for a Retail Pilot program.

JCP&L - Green Pilot Proposal

Included in JCP&L's addendum is a proposal that 300Mw of its BGS-FP load be procured via a wholesale green auction, similar to the BGS-FP Auction. Staff has proposed several modifications to the JCP&L proposal, including reducing the size to 200Mw and changing the program from wholesale to retail. Staff also endorsed the sealed bid format that JCP&L had identified as an option. (Staff Comments at 5-6).

Although the JCP&L Green Pilot proposal would likely foster demand for renewable energy in New Jersey, the Board would prefer a pilot program that more closely replicates market conditions and that has the potential to improve the competitive marketplace. Staff's proposed modifications move the Green Pilot in these directions, but in the Board's view do not go far enough.

The Board believes that voluntary customer choice would advance customer awareness of renewable energy and the changing retail electric marketplace. Similarly, by focusing on residential customers, there is a better chance that customers enrolled may choose to stay with "green" providers after the program's conclusion and therefore the Green Pilot program could lead to a permanent change in some customer's behavior. Both of these modifications are possible. The Board would like to help jump start the green marketplace in New Jersey and to see customer choice based on clear pricing signals, which this proposal, even after Staff's proposed modifications, does not have. However, the majority of the Board believes that with the above-described modifications, the Green Pilot program can potentially provide meaningful benefits, including improved air quality, to consumers and to the market.

Therefore, with the foregoing modifications and for the foregoing reasons, the Board DIRECTS JCP&L to implement a Green Pilot program for Year One[5]. The Green Pilot will be for 200Mw of residential load or 150,000 customers, whichever is greater, supplied through a sealed bid process for licensed electric power suppliers. The Board will have the opportunity to review the final winning bids and accept or reject them in whole or in part. JCP&L customers will be informed of their ability to opt-in to the Pilot and of the nature of the green power to be supplied (see below). To the extent 200Mw of load is only partially enrolled on a voluntary basis, JCP&L shall provide for random customer assignment to provide sufficient residential load for a 200Mw RFP. Bidders in the pilot program will be required to have, or be capable of obtaining by June 1, 2003, an electric power supplier license. Since the modifications made herein to the JCP&L Green Pilot requires JCP&L to significantly adjust the processes and the documents related thereto, the Board DIRECTS JCP&L to work with Staff to develop a Green Pilot RFP and other related and necessary documents, based upon the above requirements, so that a Green Pilot RFP can be issued consistent with the timeframe identified in Attachment A.

OTHER ISSUES

Retail Green Marketing Program

In addition to the Green Pilot proposal, Staff proposed that the Board encourage renewable energy by providing green retailers throughout the State with a margin of 5 mils for each kilowatt-hour of green power supplied. As initially proposed by Staff, the 5 mils would have come from the collection of a 5 mil Retail Margin, which Staff had proposed be levied on BGS-FP customers. Under Staff's proposal, green retailers would effectively receive a 10 mil differential between itself and the effective BGS-FP rate as a marketing incentive. (Staff Reply Comments at 4).

For the reasons explained above, the Board has determined that it is not appropriate to assess a Retail Margin on BGS-FP customers for Year One. This makes much of the Staff proposal unworkable, at least for Year One. However, as indicated above, the Board is interested in promoting renewable energy and is particularly interested in doing so through customer choice rather than customer assignment. The Board recognizes that various forms of green energy typically cost more than other forms of retail power. The Board believes that a 5 mil per kwh incentive, while less than the 10 mil differential to BGS-FP service proposed by Staff, would help develop the fledgling green retail market in New Jersey. It would also do so through a process that has customers affirmatively choosing green power based on price, albeit with some price support, and other factors in a true retail setting. The Board believes that such a program should be available on a statewide basis.

As noted above, there is no BGS-FP Retail Margin for Year One to use as a possible funding source for the Staff proposal, and even though the Board has approved a Retail Margin for the BGS-CIEP class for Year One, it has decided to delay determination on the use of those funds to a later date. Therefore, the Board cannot approve the Staff's Retail Green Marketing Program proposal for Year One. However, since the Board supports the concept and is comfortable that it will be able to identify a source of price support for this program in the future, the majority of the Board will approve Staff's Retail Green Marketing Program for implementation as a pilot

[5] The Board approved the JCP&L Green Pilot Program by a vote of 4 to 1, with Commissioner Connie O. Hughes dissenting. See Dissenting Opinion at the end of this Order.

program in Year Two[6]. Since this will be a pilot program, the Board will limit the number of customers that can be enrolled in this program to 200,000 residential customers statewide.

For the foregoing reasons, the Board DIRECTS each EDC to implement a Retail Green Marketing Program described above for Year Two and to work with Staff to develop the necessary parameters and procedures for this program in a timely manner. The Board will review and approve the necessary parameters and procedures prior to Year Two. At a later date, the Board will review the Green Retail Marketing Program and determine its applicability to Year Three.

Definition of “Green”

Staff further proposed that, for the purposes of the JCP&L Green Pilot Program and the Retail Green Marketing Program, “green power” be defined as three times the current Renewable Portfolio Standard’s requirements for class I and class II renewables. For 2003, this requirement is currently for all electric power delivered at retail to include .75% Class I plus 2.5% for Class I or II renewables. In its green proposal, JCP&L had proposed that “green” mean that 15% of the electricity delivered would come from either class I or class II renewables. The Board supports the Staff proposal, since it provides a proportion of class I and class II renewables more consistent with that established by the Legislature in EDECA. Furthermore, in order to provide some certainty to bidders in the JCP&L Green Pilot, the Board will define “green power” in that program only, as three times the RPS requirements in effect on the date of this Order, for the RFP supply time period. For the Retail Green Marketing Program, “green power” will be defined as three times the RPS requirements in effect at the time electricity is delivered.

BGS Supplier Master Agreement

At this time, there appear to be outstanding issues involving the BGS Supplier Master Agreement (“Agreement”) as proposed by the EDCs. The Board believes that with some additional discussion among the participants and with the direct involvement of Staff in these discussions, some, if not all, of these issues could be resolved. The Board believes that the Tentative Approvals and Process Schedule, in Attachment A to this Order, incorporates enough flexibility to allow the parties an additional two weeks to continue to attempt to resolve these outstanding Agreement issues. Therefore, the Board DIRECTS Staff to meet with the parties, attempt to resolve outstanding Agreement issues, and report back to the Board with recommendations on the Agreement at its November 20, 2002 agenda meeting.[7]

Consumer Education

Since hourly pricing for CIEP customers is a significant rate design change, the Board is determined that the customers in this category for Year One, and those that may be included in an expanded CIEP class in Year Two and beyond have a thorough understanding of how their electric consumption will be priced and their options for reducing their electric bills. Therefore, the Board ORDERS the creation of a CIEP Education Task Force, open to representatives of all interested parties, to work in conjunction with the Board’s existing customer education program,

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[6] The Board approved the Retail Green Marketing Program by a vote of 4 to 1, with Commissioner Carol J. Murphy dissenting. See Dissenting Opinion at the end of this Order.
[7] This matter was, in fact, considered and addressed by the Board at its November 20, 2002 Agenda meeting.

to develop recommendations for the Board on educating CIEP customers on hourly pricing, the mechanics thereof and their possible alternatives. The Board DIRECTS Staff to schedule a procedural conference with all interested parties as soon as practicable in order to establish procedures and a timeframe for the Task Force to develop its recommendations for final Board approval.

As a practical matter, the EDCs need to begin almost immediately to communicate with those customers on CIEP for Year One about the change to hourly pricing, the mechanics thereof and their possible alternatives. Since it is conceivable that the CIEP Education Task Force may not have formulated comprehensive recommendations in time to properly inform CIEP customers for Year One, the Board DIRECTS the EDCs to work with Staff to begin this education process until such time as CIEP Education Task Force recommendations are available and approved by the Board.

Confidentiality

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 the BGS auction conducted in February 2002, it may be the case 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. It, therefore, appears that this competitive information may need to 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.

The Board DIRECTS its Secretary to prepare a letter describing in further detail the information for which the Board is considering issuing a Protective Order. The Board will permit interested parties to provide comments until Wednesday, November 13, 2002 with reply comments due on Monday, November 18, 2002. The Board will then make a final determination on the status of this information at its next public agenda meeting thereafter.[8]

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 anticipation of Board approval of an auction process, the EDCs have attempted to facilitate the process and increase the number of prospective bidders by educating potential bidders about the proposed Auctions. Among the steps that have and will be undertaken by the EDCs are:

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[8] The Board, in fact considered and ruled on this issue at its November 20, 2002 Agenda meeting.

- 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;
- Direct e-mails to interested parties to inform them of any new developments or any new documents posted to the website; and
- Comments solicited on the draft Auction Rules, the draft BGS Supplier Master Agreements and the draft credit instruments.

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 last year's auction, 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 last year's auction, an overriding fundamental premise of 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 will show itself through higher prices. Therefore, the Board will commit to addressing the results of the BGS-FP Auction and the BGS-HEP 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 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 its entirety and consider the results of the BGS-HEP Auction in its entirety and certify the results of each Auction for all of the EDCs or for none of them.

Another decision that requires full 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 15, 2002. The Board will consider approval of the Compliance Filing at its next scheduled Board meeting thereafter.[9]

Either the EDCs or the Auction Manager, in consultation with Staff and 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 JCP&L Green Pilot RFP and the Rockland RFP within two calendar 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 JCP&L, Rockland and Board Staff on the results of the RFP process, including the post-Auction evaluation form in Attachment B, prior to Board certification of the

[9] The Board considered and approved the Compliance Filing at its November 20, 2002 Agenda meeting

results. In the case of the JCP&L RFP and the Rockland RFP, the Board may approve the entire set of winning bids, just those lowest bids that the Board finds reasonable, or none of them. If some or all of the winning bids from the JCP&L Green Pilot are not acceptable to the Board, that portion of the 200MW of load proposed for this pilot program not secured through the RFP process will then be included as a part of JCP&L's load requirement in its BGS-FP Auction.

Finally, the Board is aware that the dispute between the EDCs and the Geophonics, Inc. regarding an 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 be implemented in a timely fashion so as to provide BGS service for the post-Transition Period;

The Joint EDC Proposal, as modified herein, continues the smooth and orderly transition of the State's electric industry from a regulated monopoly to a competitive power marketplace begun with the Board's December 11, 2001 Order;

The Joint EDC Proposal, as modified herein, will diversify the supply for BGS service by seeking multiple competitive suppliers to serve "tranches" of BGS load;

The EDCs' proposal to obtain any supply not secured in the Auctions through PJM-administered markets will ensure the maximum participation in the auction process;

It is necessary and in the public interest for the electric public utilities to provide BGS-FP service, as approved herein, in Years One, Two and Three of the post-Transition Period;

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

An Auction process for two-thirds of the EDCs' BGS-FP load for 10 months and for one-third of such load for 34 months balances risks and provides a reasonable possibility for price stability under current conditions;

The BGS-FP and BGS-HEP Auction rules provide for financial guarantees from winning bidders that will protect ratepayers from a bidder default;

Switching restrictions for BGS-FP and BGS-CIEP customers are not necessary for Years One, Two or Three;

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

A Retail Margin is not appropriate for BGS-FP customers for the first 10 months of the post-Transition Period;

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

The Board will, at a later date, determine how the Retail Margin collected should be returned to customers, including possibly as an offset to deferred balances;

The Board will make a later determination on whether a Retail Margin is appropriate for Year Two and Year Three for BGS-FP customers with a load of less than 750 Kw. However, if in the future a Retail Margin is determined to be appropriate, in no case will it exceed 5 mils for BGS-FP customers;

Capacity should be the bid product in the BGS-HEP Auction, with a fixed DSSAC charged to all eligible CIEP customers for administration and risk management;

Rockland should create a BGS-CIEP category and include its 18 largest customers in this category for Year One;

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

A Retail Margin of 5 mils/kwh is appropriate for BGS-CIEP customers for the first 34 months of the post-Transition Period;

For each EDC, customers in the largest BGS-FP rate class of commercial and industrial customers, not currently part of the BGS-CIEP category, as constituted on the date of this Order, should have interval meters installed for Year Two;

The metering review initiated by Board Order dated July 22, 2002 should be expanded to include all interested parties and consider which BGS-FP customers, if any, in the largest BGS-FP rate class of commercial and industrial customers should be included as CIEP customers for Year Two;

Costs associated with interval meter installation required by this Order, including operation, maintenance costs and billing system enhancements, should be subject to recovery by the EDCs in a forum consistent with this Order;

The JCP&L retail pilot proposal as filed would provide limited benefit to customers or the State;

The JCP&L Green Pilot proposal, as modified herein, has the potential to provide meaningful benefits to consumers, green retail suppliers and the State;

An RFP process for the JCP&L Green Pilot proposal, as modified, should be conducted consistent with the schedule in Attachment A;

The Retail Green Marketing Program proposed by Staff, as described and modified above, will allow more consumers to become familiar with and choose green energy under actual retail conditions, will encourage renewable activity in the region, and should be implemented for Year Two;

For the Retail Green Marketing Program, "green power" will be defined as three times the RPS requirement in effect at the time electricity is delivered;

For the JCP&L Green Pilot, as modified above, "green power" will be defined as three times the RPS requirement in effect on the date of this Order, for the RFP supply time period;

The Rockland RFP proposal, as modified herein, provides a reasonable means of securing supplies 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;

A working-group should be created to consider the potential for market-based approaches for delivering cost-effective load management as part of the BGS process;

A program should be developed within the existing customer education program to educate the CIEP customer class about hourly pricing;

It is appropriate that National Economics Research Associates ("NERA") act as Auction Manager for these Auctions;

The Committed Supply methodology proposed by the EDCs is the most reasonable means of dealing with the existing utility Committed Supply obligations;

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;

Successful bidders in the JCP&L Green Pilot need to obtain a New Jersey electric power supplier license;

Certain information and processes, as identified herein, may be competitive by nature and the Board will consider whether a Protective Order should be issued for 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 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 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 a completed post-Auction evaluation form in Attachment B, prior to Board certification of the results;

The Board will consider the results of the BGS-FP Auction and the BGS-HEP 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 day after the last Auction closes; and

It is appropriate for the Board to develop a statewide definition and tariff class for "small" commercial and industrial customers and to consider a more generic approach to all non-residential customer classes.

Accordingly, for the foregoing reasons, the Board APPROVES the Joint EDC Proposal, including the BGS-FP and BGS-HEP Auction Rules, the EDC-specific addenda, the Rockland RFP and the JCP&L Green Pilot Program, with the modifications described herein. The Board DIRECTS the EDCs to update the tentative decision schedule included as Attachment A, consistent with this Order. The updated schedule should include Board certification of the Auction results by the end of the second calendar day following the calendar day on which the last Auction closes and certification of the JCP&L Green Pilot RFP and the Rockland RFP by the end of the second calendar day following the calendar day on which the RFP bids are filed with the Board. The Board reserves the right, at the certification meeting, to reject the BGS-FP Auction results and/or the BGS-HEP Auction results. Furthermore, the Board reserves the right, to reject, in whole or in part, the JCP&L Green Pilot RFP results and/or 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 15, 2002.[10] The Board FURTHER DIRECTS the EDCs to work with Staff and CRA to ensure that any supplemental documents, such as application forms and tariffs, 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. The JCP&L RFP should be developed with Staff and CRA and issued consistent with our foregoing directions.

DATED: 12/18/02

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

[10] See footnote 9

DISSENTING OPINION OF COMMISSIONER CONNIE O. HUGHES AS TO THE JCP&L GREEN PILOT PROGRAM

I respectfully dissent from the majority ruling regarding the Green Pilot Program proposed for implementation by JCP&L.

As discussed at the Board meeting, I am a major proponent of clean energy, renewable energy, energy efficiency and energy conservation. This pilot however is misnamed a "green" pilot. The pilot program's green component is defined "as three times the current Renewable Portfolio Standard's requirement for Class I and Class II renewables." This total reflects 9.25% - 2.25% for Class 1 plus 7.5% for Class I or II renewable energy sources. For 2003, the RPS requirement for all electric power delivered at retail is currently a total of 3.25% (0.75% Class 1 and 2.5% Class I or II) In each case; the percentage of "actual" green energy sources is a minimum component (less than 10%) of the total electric power being provided to retail consumers by JCP&L. Defining this program to the basic retail consumer as "green" is misleading without further explanation.

My dissent is based upon the fact that all JCP&L consumers – low income, senior citizens, moderate and high income – will pay more whether or not they participate in this pilot. In addition, while I support an "opt in" program I do not support the JCP&L proposal that customer would be "switched" into the green program if not enough consumers opt in, initially.

Further, no factual evidence or information was provided either in staff briefings, party comment, or at the public Board meeting, that such a pilot would begin or result in the market transformation the Board is looking for, i.e., consumers having choice in relationship to "cleaner/greener" energy must be based on full information, including how (what proportions) of the pilot program will be cleaner/greener versus the other program options; what are the incentive(s) being used for the consumers choice to transform the market, including that a customers choice may yield a higher cost but provide a cleaner/greener energy product.

For the aforementioned reasons, I cannot support the proposed program implementation of the JCP&L Green Pilot.

(SIGNED)
CONNIE O. HUGHES
COMMISSIONER

DISSENTING OPINION OF COMMISSIONER CAROL J. MURPHY AS TO THE RETAIL GREEN MARKETING PROGRAM

I respectfully dissent from the majority ruling regarding the Retail Green Marketing Program proposed for implementation beginning in Year Two.

Discussed at this Board meeting was the concept of a retail margin to be imposed on customers. The Board did not determine the disposition of the monies garnered from this retail margin during the meeting. Previously, Governor James E. McGreevey expressed such concern about the impact of deferred balances on ratepayers that he convened a Task Force, whose charge was to review these deferred balances and make recommendations on how to pay for them. It is my strong feeling that any retail margins considered by this Board must be dedicated to the repayment of these deferred balances. This Board must retire deferred balance debt before considering, much less funding, new programs.

While I am interested in promoting renewable energy, this Retail Green Marketing Program, as presented, is vague and lacks any documented information as to the financial impact on New Jersey ratepayers. Furthermore, I do not believe that the proposal presents either a true retail setting or meaningful choice for customers.

For all the foregoing reasons, I cannot support that portion of the ruling relating to the Retail Green Marketing Program.

(SIGNED)

CAROL J. MURPHY
COMMISSIONER

ATTEST:

KRISTI IZZO
BOARD SECRETARY