IN THE MATTER OF PUBLIC SERVIC ELECTRIC AND GAS COMPANY=S RATE UNBUNDLING, STRANDED COSTS AND RESTRUCTURING FILINGS
FINAL DECISION AND ORDER
BPU DOCKET NOS. EO97070461 EO97070462, AND EO97070463

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STATE OF NEW JERSEY
Board of Public Utilities
Two Gateway Center
Newark, NJ 07102

ENERGY

IN THE MATTER OF PUBLIC SERVICE	**)**	**FINAL DECISION AND ORDER**
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(SERVICE LIST ATTACHED)

BY THE BOARD:

This Decision and Order memorializes and provides the reasoning for the action taken by the Board of Public Utilities ("Board" or "BPU") in these matters, by a vote of three Commissioners, at its April 21, 1999 public agenda meeting, which action was summarized in our Summary Order dated April 21, 1999. The structure of this Decision and Order is set forth in the following Table of Contents.

I. BACKGROUND AND PROCEDURAL HISTORY

The New Jersey Energy Master Plan Phase I Report ("Phase I Report"), released in March 1995, presented a vision for the State in which energy markets in New Jersey would be guided by market-based principles and competition. The Phase I Report recognized that increased competition in New Jersey's energy markets could potentially help reduce the high energy prices existing in the State, further the State's economic development goals, and provide an opportunity to streamline the regulatory review process. The Phase I Report provided a policy framework for the transition from energy industry monopolies to competitive markets.

The Phase I Report also made several policy recommendations to be implemented as short term or interim measures to address immediate competitive pressures in the State and to prepare for the transition to competition. These included the adoption of legislation allowing rate flexibility and permitting alternative regulation to enable New Jersey's electric utilities to compete to retain certain "at risk" customers and attract new customers, while stimulating efficiency and innovation. The Phase I Report further recommended the adoption of significant consumer protection standards to ensure that captive ratepayers do not subsidize competitive activities and that all ratepayers benefit from the transition to more competition. In addition to the recommendations for interim action, the Phase I Report also explicitly directed the BPU to investigate possible changes to the structure of the electric power industry in New Jersey as a longer term means of achieving lower costs of electricity in the State.

In response to the identified need for interim measures, the Rate Flex and Alternative Regulation Act, N.J.S.A. 48:2-21.24 et seq. (the "Rate Flex Act"), was enacted in July 1995. In this Act, the Legislature found that during a transitional phase aimed at achieving the long term goal of lower electric and natural gas costs to consumers, it might be necessary for the BPU to implement short-term measures to promote and enhance economic development and employment in the State, and to permit New Jersey utilities to compete for customers with competitive alternatives. The Rate Flex Act specifically allows the State's electric utilities to enter into off-tariff rate agreements with customers for a period of seven years from the Act's passage and permits electric or gas utilities to petition the BPU to be regulated under alternatives to rate base/rate of return regulation.

The Rate Flex Act further declared that it is the policy of the State to foster the production and delivery of electricity and natural gas in a manner that lowers costs and rates while improving the quality and choices of service for all energy consumers; to ensure that New Jersey remains economically competitive on a regional, national and international basis; and to enhance the economic vitality of the State by attracting and retaining business and creating and retaining jobs. The Legislature also found that competitive market forces can produce the stated goals of improved quality and choices of energy services at lower costs, while promoting efficiency, reducing regulatory delay and fostering productivity and innovation.

Consistent with the Phase I Report, and in keeping with the Legislature's stated desire that increased competition in energy markets be explored as a more long-term means to reduce the cost of electricity in New Jersey for all customers, the BPU, by Order dated June 1, 1995, initiated a Phase II proceeding under Docket No. EX94120585. This proceeding was intended to accomplish several goals. By investigating the long term structure of the electric power industry in the State, it was hoped that an electric power industry policy could be developed to facilitate the emergence of a competitive marketplace which would foster the production and delivery of electricity in such a matter as to lower costs and rates and improve the quality and choices of service. In those areas where effective competition developed, ongoing regulation in its present form might be unnecessary. Additionally, there was the goal of facilitating the development of competition in those markets where competitive services did not yet exist, but where increased competition could benefit consumers. Finally, there was a concern about the need to continue to regulate the quality and price of energy supplies and services where competition does not exist and it is determined that consumers are best served by continued regulation.

Thus, a proceeding was initiated by the Board to investigate the appropriateness and feasibility of electricity wheeling or electric power competition at the retail level; the actions necessary to establish a fully efficient, competitive wholesale marketplace for electric generation; whether divestiture of electric utility generation assets is necessary; the need for retail wheeling if an efficient, competitive wholesale electric power market is achieved; the need for divestiture of electric utility generation assets or alternatively, the unbundling and corporate separation of electric services; and the definition and equitable treatment of stranded investments. Consistent with State policy goals expressed in the Rate Flex Act, the Board specifically directed that the proceeding investigate the appropriate manner of continuing existing consumer and environmental protections in a restructured market; ensuring universal, non-discriminatory access to service; guaranteeing the provision of a safe and adequate power supply and system reliability; and achieving the State=s environmental and energy efficiency goals.

The Board sought to obtain guidance and input on the many issues raised from the widest possible array of interests. The BPU solicited and received several rounds of written comments as well as written testimony, conducted public and legislative-type hearings and, through its Staff, formed and facilitated informal working groups and a negotiating team to explore issues in more depth and to attempt to develop a consensus, where possible.

On January 16, 1997, the BPU released its Proposed Findings and Recommendations in the Phase II Proceeding ("Draft Report"). The Board held a public hearing to receive oral comments on the recommendations contained in the Draft Report at the Board's Newark offices on February 4, 1997. Additional public hearings were held in Blackwood, New Jersey on February 5, 1997 and in Trenton on February 11, 1997. The Board received written comments from 39 parties and heard testimony from 42 parties relative to the Draft Report.

On April 30, 1997, after careful consideration of the input received regarding its Draft Report, the Board issued an Order Adopting and Releasing Final Report. The Final Report, entitled ARestructuring the Electric Power Industry in New Jersey: Findings and Recommendations@ ("Final Report"), was submitted to the Governor and the Legislature for their consideration and contained the BPU's findings and recommendations concerning the future structure of the electric power industry in New Jersey, including the recommendation to offer electric consumers a choice of electric power suppliers, beginning in October 1998, to effectuate substantial economic benefit, in the form of lower electric bills and more service options to the State's residents and businesses. In the introductory letter presenting the Final Report to the Legislature, Governor and residents and business owners of the State, the Board expressly stated that it looked forward to working with the Legislature and the public over the coming months to develop legislation necessary to adopt appropriate consumer protection measures and to implement these policy findings and recommendations.

Recognizing that there were a number of substantial procedural steps necessary to implement the recommended policies, and in order to prepare for the commencement of retail competition, the Board, in its April 30, 1997 Order, directed each of the State's four investor owned electric utilities, Atlantic Electric Company ("ACE"), Jersey Central Power and Light Company, d/b/a GPU Energy ("GPU"), Public Service Electric and Gas Company ("PSE&G" or "Company") and Rockland Electric Company ("RECO") to make three filings by July 15, 1997. These included a rate unbundling petition, a stranded cost petition, and a restructuring plan. The Board also recognized that there were a number of issues which needed to be addressed generically for all four electric utilities, including standards for fair competition, affiliate relationship standards, analysis of market power, and the mechanics for the phase-in of customer choice. The Board anticipated that these issues would be pulled out of the individual utility proceedings and reviewed generically.

By Order dated June 25, 1997, the Board directed its Division in Audits, in cooperation with the Division of Energy, to initiate management audits on ACE, GPU, PSE&G and RECO in accordance with N.J.S.A. 48:2-16.4 , and to solicit the assistance of qualified consulting firms to perform said audits under the supervision of Board Staff. Said audits were to include, but not be limited to, focused reviews of the individual electric utilities' unbundling, stranded costs and restructuring filings. A Request for Proposals was issued on June 27, 1997, and after receipt and review of numerous proposals, Vantage/ICF Consulting ("ICF" or "the Auditors") was selected by the Board to perform the audit of PSE&G, under BPU Docket No. EA7060397.

On July 11, 1997, the Board issued an Order Establishing Procedures, wherein it determined to transmit each utility=s rate unbundling and stranded cost filing to the Office of Administrative Law ("OAL") for hearings and Initial Decision, and to retain the restructuring plan filings for its review and, as necessary, hearings, with the intention of issuing a Final Decision and Order in these matters before the anticipated start date of competition.

On July 15, 1997, Public Service Electric & Gas Company filed its Proposal in Response to the Final Report.[1] The Company's proposal was supported by the prefiled direct testimony of Lawrence R. Codey, Frederick W. Lark, Robert C. Murray, Gerald W. Schirra, Robert C. Krueger, Dr Colin J. Loxley, and Paul I. Joskow.

The unbundling and stranded costs portions of PSE&G's filing were transmitted to the OAL, and assigned to Administrative Law Judge ("ALJ") Louis G. McAfoos t/a. The restructuring portion of the filing was retained by the Board.

On September 15, 1997, the Board issued an Order on Motions to Intervene/Participate and for Pro Hoc Vice Admission, wherein it considered and ruled upon numerous motions for intervention and /or participation and pro hac vice admission in the restructuring proceedings retained by the Board. Motions to intervene in the PSE&G unbundling and stranded cost proceedings were ruled upon by ALJ McAfoos.[2]

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[1] Unlike the other three utilities, and contrary to the Board's directive in its April 30, 1997 Order, PSE&G did not make three separate filings, but made a single filing containing its unbundling, stranded costs and restructuring proposals. The filing was assigned three separate BPU Docket Nos. EO97070461, EO97070462, and EO97070463, for the respective unbundling, stranded costs and restructuring issues.

[2] In addition to PSE&G, Staff and the Division of the Ratepayer Advocate, the following parties were granted intervenor status by ALJ McAfoos: Atlantic City Electric Company; Co-Steel Raritan ("Co-Steel"); Coalition For Fair Competition ("CFC"); Cogen Technologies Energy Group ("Cogen"); County of Passaic; Duke Energy Trading and

On September 19, 1997, the Board issued an Order in response to a letter motion filed by the Division of the Ratepayer Advocate ("RPA"), wherein, among other things, the Board provided certain clarifications and guidance as to the scope of the proceedings before the OAL, offered further guidance on the issues of securitization, the level of rate reductions and divestiture, and extended, by one month, the date by which Initial Decisions were to be rendered by the OAL.

By Order dated September 25, 1997, the Board established procedures for the restructuring proceedings retained by the Board, and identified issues that would be specifically considered. The Board Order identified certain issues which it anticipated were likely to be contested, as well as issues with generic implications which might lend themselves to a collaborative review. For the generic issues, the Board created three working groups on customer processes, reliability and competitive issues, to discuss specific details, narrow issues in contention and attempt to develop a consensus position, if possible. The working groups were directed to provide status reports to the Board by January 10, 1998, identifying areas of consensus, as well as areas where consensus was unlikely. The Board recognized that where consensus was unlikely, a further procedural schedule would need to be established.

Additional Orders in the above-captioned dockets were issued by the Board between October 1997 and March 1999, addressing additional motions by various parties, including motions for intervention, pro hac vice admission, schedule modifications, clarification and reconsideration of earlier rulings, and interlocutory review of certain ALJ rulings. Additionally, by Order dated January 28, 1998, the Board established a procedural schedule for review of the following generic restructuring issues: the potential for exercise of market power by the State=s electric utilities regarding their generation assets; functional separation plans; divestiture of generation assets; basic generation plans, including the cost to provide service to low-income and bad-debt customers; mechanics of the phase-in of retail competition; the customer enrollment process; load balancing and a settlement system requirements for alternative supplier deliveries; and Demand Side Management (ADSM@) and renewables issues. The Board noted that PSE&G's proposal to introduce retail choice initially on an energy-only basis, an issue specific to PSE&G, could also be the subject of testimony. The Board also noted that there might be a need for hearings in the proceedings before it on any individual issues left unresolved in the unbundling and stranded cost proceedings.

Marketing, L.L.C. ("Duke"); Electric Clearinghouse, Inc. Additionally, participant status, pursuant to N.J.A.C.1:1-16.5, was granted to Citizens Against Rate Escalation ("C.A.R.E."); New Jersey Citizen Action ("NJCA"); Allen Goldberg; New Jersey Natural Gas Company ("NJNG"); and South Jersey Gas Company ("SJG"). MidCon/mc2 withdrew from these cases in June 1998.

ALJ McAfoos issued a Procedural Order Setting Schedule for the proceedings at the OAL on October 8, 1997, which was modified on November 10, 1997 to allow additional time for parties to submit prefiled testimony.

On or about November 26, 1997, testimony was filed in the unbundling and stranded cost proceedings by the following witnesses on behalf of the intervenors: Raymond E. Makul on behalf of the CFC; Jeffrey A. Brown, Harry J. Kingerski and Theodore F. Kuhn on behalf of Enron; Steven Gabel on behalf of IEPNJ; Steven Gabel on behalf of MAPSA; David Magnus Boonin and Nancy I. Day on behalf of NEV; Dr. Alan Rosenberg on behalf of NJBUS and NJICG; John L. Parodi, Henry Riewerts and James B. Rouse on behalf of NJBUS; Dr. Dennis W. Goins on behalf of NJCU; William B. Marcus and Edward A. Smeloff on behalf of NJPII[3]; Cheryl Beach on behalf of NJT; Charles Wolfe on behalf of IBEW Local 94; Peter A. Bradford, Michael D. Dirmeier, Robert J. Henkes, Dr. Richard A. Rosen, Douglas C. Smith and John K. Stutz on behalf of the Ratepayer Advocate; and Elliot M. Loyless and Herman L. Seedorf on behalf of Tosco. [4]

The Company filed rebuttal testimony by: Lawrence R. Codey, Dr. Paul L. Joskow, Robert C. Krueger, Frederick W. Lark, Dr. Colin J. Loxley, Robert W. Metcalfe, Robert C. Murray, David R. Powell, Gerald W. Schirra and Albert N. Stellwag.

ALJ McAfoos conducted a status conference on January 16, 1998 and issued a hearing schedule for the unbundling and stranded costs proceedings on January 24, 1998.

On or about January 26, 1998, surrebuttal testimony was filed by the following witnesses on behalf of the intervenors: Vincent C. Dimiceli and Scott Norwood on behalf of Co-Steel Raritan; Harry J. Kingerski and Theodore F. Kuhn on behalf of Enron; Dr. Alan Rosenberg on behalf of NJBUS and NJICG; Peter A. Bradford, Michael D. Dirmeier, Robert I. Henkes, Dr. Richard A. Rosen, James A. Rothschild, Douglas C. Smith and John K. Stutz on behalf of the Ratepayer Advocate; William B. Marcus on behalf of NJPII; Dr. Dennis A. Goins on behalf of NJCU; Steven Gabel on behalf of MAPSA; and Raymond E. Makul on behalf of the CFC. Tosco also filed and served revised prefiled testimony of witnesses

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3 The Natural Resources Defense Council (ANRDC@), a member of the NJPII coalition, did not join in the submission by NJPII of testimony, briefs and/or exceptions in the stranded costs, unbundling and restructuring proceedings.

4 As outlined in the Procedural History attached to the Initial Decision, a number of motions to strike portions of the various testimonies were filed by the Company and ruled upon by the ALJ. Some of these rulings were followed by motions to the Board for interlocutory review, which were in turn, considered by the Board.

Loyless and Seedorf to conform with a December 23, 1997 ruling by the ALJ concerning the striking of certain portions of their prefiled testimony.

On January 29, 1998, the Board accepted as received and released to all parties in the unbundling and stranded cost proceedings, copies of the Management Audit Report entitled AAudit of Public Service Electric and Gas Unbundling and Stranded Cost Filings of its Electric Restructuring Docket No. EX97060397" which was prepared for the Board by Vantage/ICF Consulting. On March 5, 1998, the Board accepted as received and released to all parties in the restructuring proceeding, copies of the Management Audit Report regarding PSE&G's restructuring filing prepared by ICF.

Twenty days of evidentiary hearings were conducted at the OAL between February 9, 1998 and March 18, 1998 on the unbundling and stranded costs proceedings. During that time period, witnesses were cross-examined on their prefiled direct testimony, as well as on any filed rebuttal or surrebuttal testimony. At the close of hearings, a briefing schedule and issues outline were adopted by ALJ McAfoos. After requesting and receiving extensions of time from the Board, Initial Briefs were filed on or about April 13, 1998. Reply Briefs were filed on or about April 20, 1998.

After the PSE&G unbundling and stranded cost hearings and briefing were completed at the OAL, approximately twenty additional days of evidentiary hearings were held before Commissioner Carmen J. Armenti between April 27, 1998 and May 28, 1998, for testimony and cross-examination by the parties on certain identified restructuring issues affecting all four electric utilities which had been retained by the Board.

Direct and/or rebuttal or surrebuttal testimony was filed by Atlantic Electric Company (Joseph R. Bartalone, Jr., Tsion M. Messick, Thomas S. Shaw, Jerrold L. Jacobs, Henry K. Levary, Eileen Unger, Ashley C. Brown, Rodney Frame, Paul L. Joskow); the CFC (Raymond E. Makul); GPU (Dennis Baldissari, Douglas J. Howe, Charles A. Mascari, William Hogan, Almarin Phillips); IBEW Local 94 (Charles Wolfe); IEPNJ (Steven Gabel); MAPSA (Steven Gabel, Dr. Craig Roach); NEV (Barbara Kates Garnick); NJBUS (Henry Riewerts, John Parodi); NJICG (Fred Mazurski); NJPII (not including the NRDC) (Nathaniel Greene, Bruce Biewald, Edward Smeloff, Thomas Bourgeois); NorAm (Keith Sappenfield); PSE&G (Gerald W. Schirra, Frederick W. Lark, Colin Loxley, Lawrence R. Codey, Alfred E. Kahn, Rodney Frame, Paul Jaskow); the Ratepayer Advocate (Barbara Alexander, Peter Lanzalotta, Andrea Crane, Peter A. Bradford, Roger Colton, James D. Cotton, Dr. David A. Nichols); RECO (Terry L. Dittrich, Frank P. Marino, John C. Dalton, John Lombardi); and SESCO (Richard Esteves). In addition, representatives of the four consulting firms (ICF, Stone and Webster, Barrington-Wellsley and Hagler Bailley) which submitted Management Audit Reports to the Board on the four electric utilities' restructuring filings also testified and were cross-examined.

During the hearings, various motions, including motions to strike certain portions of the prefiled testimony were ruled upon by Commissioner Armenti, whose rulings are **HEREBY AFFIRMED** by the entire Board, essentially for the reasons set forth by Commissioner Armenti in the transcripts.

After the close of hearings before Commissioner Armenti, briefs and reply briefs on the restructuring issues were filed on June 26 and July 17, 1998, respectively. This Order also incorporates, as they apply to PSE&G, four of the issues considered in the restructuring proceeding before the Board: market power, basic generation, divestiture and the proposal of PSE&G to initially introduce retail choice on an Aenergy-only@ basis.

After requesting and receiving an extension of time from the Board, ALJ McAfoos issued an Initial Decision and Report on PSE&G's unbundling and stranded cost filings on August 14, 1998. The parties filed Exceptions and Replies to Exceptions to the Initial Decision with the Board on October 2 and October 30, 1998, respectively.

On February 9, 1999, Governor Whitman signed into law the Electric Deregulation and Energy Competition Act ("the Act"), N.J.S.A. 48:3-49 et seq. The Act authorizes the Board to permit competition in the electric generation and natural gas supply marketplace and such other traditional utility areas as the Board determines. In addition, all four electric utilities were mandated to implement specific rate reductions over the course of the next four years.[5] Among other things, the Act requires that the Board, by Order, shall provide that by no later than August 1, 1999, each electric public utility shall provide retail choice of electric power suppliers for its customers, reduce its aggregate level of rates for each customer class by no less than five percent, unbundle its rate schedules and establish so-called "shopping credits" applicable to the bills of retail customers who choose alternative electric power suppliers.

By letter dated March 8, 1999, MAPSA moved to reopen and supplement the record in the PSE&G unbundling and stranded cost proceedings to update the record on stranded costs and to consider the appropriate level of the shopping credit which the Board is required to establish under the Act. By Order dated March 25, 1999, the Board denied MAPSA's motion.

By Order dated February 11, 1999, the Board established guidelines and a schedule for the commencement of settlement negotiations among the parties in the PSE&G stranded costs, unbundling and restructuring proceedings. The Board set a

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[5] Although the natural gas market will be opened to competition, as will the provision of other energy related services, no specific statewide rate reductions were mandated for the four natural gas utilities.

deadline of March 3, 1999, for the submission to the Board of a negotiated settlement, which deadline was later extended to March 5, 1999. No comprehensive settlement was reached among all the parties; however, on March 17, 1999, a proposed stipulation of settlement ("Stipulation") was filed by PSE&G, NRDC, NJCU, IBEW Local 94, NJT, Enron, Tosco and IEPNJ. A proposed alternative stipulation of settlement ("Stipulation II") was submitted to the Board on March 29, 1999, by the Division of the Ratepayer Advocate, MAPSA, NJBUS, NJICG, NJPII (with the exception of NRDC), and NEV. Parties were provided the opportunity to submit comments to the Board on the Stipulation by April 5, 1999 and on Stipulation II by April 7, 1999.

By Order dated July 13, 1998, the Board ruled on various motions or objections, including a motion dated April 22, 1998 by the CFC for the Board to disclose any <u>ex parte</u> communications in accordance with <u>N.J.A.C</u>. 1:1-14.5(a). <u>N.J.A.C.</u> 1:1-14.5(a) is a part of the Uniform Administrative Procedure Rules, which were adopted by the Office of Administrative Law and pertain to contested case proceedings. This regulation provides:

> Except as specifically permitted by law or this chapter, a judge may not initiate or consider <u>ex</u> <u>parte</u> any evidence or communications concerning issues of fact or law in a pending or impending proceeding. Where <u>ex</u> <u>parte</u> communications are unavoidable, the judge shall advise all parties of the communications as soon as possible thereafter.

In response to the CFC=s April 1998 motion, the Board ruled that Ato the extent there are communications on issues of fact or law being adjudicated in the unbundled rates and stranded cost filings, as opposed to policy and legal issues being considered in the generic, legislative type proceeding, the Board would be required to comply with <u>N.J.A.C</u>. 1:1-14.5(a). Therefore, the Board does not grant or deny the CFC=s motion itself because the Board is required, in any event, to comply with applicable law.@

By a subsequent motion dated February 22, 1999, the CFC again moved pursuant to <u>N.J.A.C.</u> 1:1-14.5(a), for disclosure of <u>ex</u> <u>parte</u> communications. No responses or other filings were made with regard to the CFC's motion. At its agenda meeting of April 21, 1999, the Board confirmed that there had not been <u>ex</u> <u>parte</u> communications on issues of fact or law to be adjudicated by the Board in PSE&G's unbundled rates and stranded cost proceedings. Accordingly, there are no disclosures to be made pursuant to <u>N.J.A.C.</u>1:1-14.5(a) and the Board=s ruling on the CFC=s prior motion, and the Board determined to dismiss the CFC's motion as it pertained to the PSE&G proceedings.

On April 20, 1999, on the eve of the Board's scheduled consideration of this matter at its April 21, 1999 public agenda meeting, the CFC requested oral argument with respect to the pending proposed stipulations, arguing that there has been no opportunity for public dialogue between the Board and the parties on the issues raised by the the stipulations. PSE&G opposed the request for oral argument. At our April 21, 1999 public agenda meeting, we determined to deny the motion for oral argument. We note that oral argument is discretionary with the Board and we are satisfied that the CFC and all parties have had extensive opportunities to raise their concerns through evidentiary hearings, briefing, the stipulation process and in written comments with respect to the pending stipulations.

II. INITIAL DECISION

On August 14, 1998, ALJ McAfoos filed his Initial Decision with the Board. The I.D. contains a procedural history and a summary of PSE&G=s July 15, 1997 filing, a summary and analysis of the record, and provides the ALJ's findings with respect to the numerous litigated issues in the rate unbundling and stranded costs proceedings. Key elements of the Initial Decision are summarized below.

A. Stranded Costs

1. PSE&G=s Estimate of Stranded Costs and Proposed Recovery

The Company=s filing identifies the following major stranded cost components and amounts: nuclear generation, $3,119,023,000, and fossil generation, $787,008,000, for a total of $3,906,031,000. In addition, the Company has identified $1,589,030,000 of Non-Utility Generation (ANUG@) contracts for stranded cost recovery. At page 9 of the I.D., the ALJ finds that the Company=s broad characterization of nuclear and fossil generation stranded costs and above market NUG contract costs "are reasonable categories to be included in the final computation of a stranded costs number." The ALJ makes no findings with respect to the issue of revenue loss to on-site generation and a competition transition charge, finding that the Board has reserved these issues unto itself in a separate docket. I.D. at 10. Additionally, the ALJ makes no findings regarding the existence of a regulatory compact with respect to capital expenditure recovery. Id.

2. Post-1992 Rate Case Capital Additions to Owned Generation

The Company=s filing requested stranded cost recovery for capital additions made since its last base rate case was decided in 1992, including approximately $471 million in nuclear and $962 million in fossil capital expenditures during the period January 1, 1993 through December 31, 1998. An issue addressed at length in the record and in the I.D. at pages 10 through 15 is whether the Board=s "market test" policies apply to several major capital addition projects, including the Bergen Phase I repowering, the Linden Generating Station combustion turbine project, and the Salem I steam generator replacement.

Relying on a number of past Board decisions, PSE&G argued that it was not required to perform an up-front economic analysis for these projects and that it has submitted substantial proofs to validate the prudency of these additions. The Ratepayer Advocate, Enron and other intervenors argued that PSE&G failed to meet its burden of proof, as set forth at page 106 of the Final Report, regarding these capital additions, in that it has not provided proof that a market test was undertaken to demonstrate the economics of these expenditures.

As a preliminary matter, the ALJ finds that previous Board Orders cited by PSE&G were only intended to relieve the Company of the need for an up-front economic review and prior Board approval before commencing these capital projects, and do not relieve PSE&G of any duty to present persuasive testimony that a market test was performed to justify the economics of these projects and that the economics were validated. Nonetheless, the ALJ concludes that the Company has submitted substantial justification for the inclusion for the bulk of its post-1992 capital additions, as summarized below, and that the Board should recognize their inclusion for stranded cost calculation purposes. I.D. at 15.

a. Bergen I Repowering

PSE&G requested stranded cost recovery of approximately $126 million associated with the Bergen I facility repowering, out of a total repowering cost of approximately $400 million. Based upon his assessment of the record as set forth on pages 15 to 18 of the I.D., the ALJ concludes that "the moneys expended by the Company in the Bergen repowering were reasonable, and that the economic and environmental benefits the Company has demonstrated on the record were such that not only the prudency of the project was proven, but sufficient economic data can be found in the record to justify an *ex post facto* market test as to the reasonableness of this expenditure." I.D. at 18. The ALJ concludes, therefore, that the stranded costs associated with Bergen should be recognized by the Board. Id.

b. Linden Combustion Turbine Project

PSE&G requested stranded cost recovery of approximately $53 million for the Linden facility. The ALJ concludes that the Company provided sufficient data to satisfy a market test requirement and that the costs should be included in the stranded cost calculation. I.D. at 18.

c. Mercer Rehabilitation Project

PSE&G identified three major projects at the Mercer Generating Station, totaling approximately $140 million. The ALJ concludes that the expenditures on the Mercer facility were reasonably incurred and should be recognized by the Board in its stranded cost calculation. I.D. at 19.

d. Other Fossil Capital Addition Project Disallowances

The Auditors recommended that two fossil projects be disallowed from inclusion in the stranded cost calculation, namely, $1.977 million associated with the Burlington auxiliary power system replacement and $0.222 million associated with the Mercer CEM data acquisition system. PSE&G argued that these projects were mandated by state or federal environmental regulations. The ALJ concludes that these expenditures were reasonable and should be included in the stranded cost calculation. Id.

e. Salem Nuclear Capital Additions

The Company requested recovery of approximately $308 million of Salem Nuclear Generating Station capital expenditures incurred since the 1992 base rate case, including $73 million for the replacement of a steam generator at Salem 1. The Ratepayer Advocate and a number of intervenors objected to the inclusion of these expenses. Based upon an assessment of the record as set forth at pages 19-21 of the I.D., the ALJ concludes that a sufficient quantum of evidence exists on the record for the Board to include $73.19 million associated with the steam generator replacement and $118.493 million associated with pre-steam generator projects in the stranded cost calculation. I.D. at 21.

3. Applicable Test/Methodology

In its filing, PSE&G made no provision for the divestiture of existing generating facilities. Several parties recommended divestiture as the most appropriate gauge of the actual market value of the facilities in the review of stranded costs. The ALJ notes that the Board had specifically reserved unto itself the issue of whether it would be appropriate to direct the electric utilities to divest themselves of their generating facilities and he therefore does not make any rulings on this question. I.D. at 22.

The ALJ notes that absent divestiture, an administrative determination must be made to arrive at a quantification of stranded costs. He further notes that the Company's methodology, which was broadly followed by all intervenors in their studies, is premised on the theory that market value can be estimated administratively by utilizing a market price forecast. The forecasted market energy price and capacity price (otherwise referred to as the market clearing price or AMCP@), applied to the forecasted output of particular generating assets, was used to derive a projected market revenue of each facility on an annual basis. Forecasted annual cash expenditures including fuel, operation and maintenance ("O&M") expenses, capital additions, taxes, administrative and general ("A&G") expenses and other ancillary costs were then subtracted from the projected annual market revenues. A comparable analysis was performed for each generating facility, as well as for each power purchase agreement with NUG generators. The net results were discounted back to present value using a 8.42 percent discount rate, based upon the Company=s 1992 cost of capital, using the Company=s capital structure provided in the last base rate case. This net present value cash flow for each generating facility was subtracted from the net book value of each generating asset to derive the stranded cost. Using this methodology, PSE&G identified approximately $3.9 billion, net of tax, generation-related stranded costs.

As summarized in detail in the I.D. at pages 22 through 40, numerous parties challenged various aspects of the Company=s quantifications, and the Ratepayer Advocate, Enron and the Auditors each performed independent studies, using a similar methodology, but with varying assumptions and inputs. The RPA recommended a net of tax generation related stranded cost level of $1.898 billion. Enron recommended that fossil generation stranded costs be reduced to $47 million and that nuclear generation stranded costs be reduced to $2.335 billion, producing a total recommended net of tax generation related stranded cost of approximately $2.4 billion. The final estimate provided by the Auditors was $2.852 billion. (Exhibit S-15).

Based on his review of the record, the ALJ recommends that certain adjustments be made to the Company's quantification of stranded costs. I.D. at 40-43. With respect to the forecast MCP, the ALJ was not persuaded by the RPA=s and Auditors= calculations and methodologies concerning the cost and performance of new generating plants, concluding that they inappropriately failed to credit demonstrated savings associated with technological improvements. At the same time, he concludes that the Company=s assumptions were overstated. He concludes that the RPA's quantification of future output from the Bergen and Mercer facilities is appropriate, notwithstanding that his calculations assume a much higher-than-average future capacity, since the Company's substantial recent investment in these facilities makes it reasonable to assume that the facilities will be in a position to operate more efficiently in the future than they have over the past five years. I.D. at 40. The ALJ also finds the RPA's quantification of the cost of fuel and resulting dispatch rates and its position regarding PJM imports to be persuasive. Id.

With regard to projected capacity prices, the ALJ concludes that the RPA and the Auditors each overstated escalation factors, resulting in inappropriately high capacity costs; on the other hand, he concludes that PSE&G's capacity escalation factor is understated, notwithstanding technological improvements. He also concludes that the $7.50 capacity price recommended by Enron is insupportable. Accordingly, he recommends that the Board calculate capacity prices by escalating at the anticipated general inflation rate during the forecast period. I.D. at 41. The ALJ concurs with the RPA=s contention that the PJM market is moving from a cost-based to a market-based rate, and recommends adoption of the RPA=s dispatching modeling proposal. He also concurs with NJPII's adjustment to reflect nitrogen oxide and sulfur dioxide emission credits. Id.

Regarding future capital additions included in the stranded cost projection, the ALJ asserts that it reasonable to assume that some level of ongoing capital additions beyond normal O&M expenses will be needed to maintain the facilities in safe operational condition; however, he recommends that PSE&G's estimates, while facially reasonable, should be subject to ongoing review. Additionally, the ALJ agrees with Staff that the anticipated replacement of the steam generator at Salem should be removed from the calculation. He also concurs with Enron's position to reflect cost values associated with ancillary services. Id.

The ALJ concludes that the Company=s capital structure and cost of capital has changed in the six years since the last base rate case decision and, while recognizing that this is not a base rate case, finds it reasonable to adopt, for purposes of calculating stranded costs, the revised discount rate proposed by the RPA, which includes a 10.25 percent cost of common equity. I.D. at 42. The ALJ agrees with Staff and the RPA that certain adjustments should be made regarding the issue of FASB-90. He also agrees with Staff and the RPA that an adjustment to Salem O&M expenses proposed by RPA witness Henkes should be recognized. The ALJ rejects the RPA's proposed adjustment for post-retirement benefits (FAS-106), finding the Board=s accounting treatment of this issue to be dispositive. Id. The ALJ concurs with Staff and the RPA that an appropriate adjustment should be made to reflect the timing and actual future expected costs after the cessation of the Levelized Energy Adjustment Clause (ALEAC@) and roll-in into base rates and that a final LEAC true-up should be conducted, to safeguard ratepayers and prevent the Company from earning an excessive return. Id.

Given the numerous adjustments which he recommends be made to the original PSE&G proposal, the ALJ was unable to quantify a specific stranded cost amount for the Board's consideration. However, he recommended that the parties conference on this issue and submit to the Board a stranded cost figure that incorporates his findings and recommendations. I.D. at 42-43.

The Board notes that the parties did indeed conference on this issue, but were unable to reach a consensus view on the precise quantification of the ALJ=s decision. By letter dated November 18, 1998, Staff forwarded to the Board, the ALJ and the parties the results of a quantification of stranded costs resulting from the I.D. as computed by the

Auditors using the models they sponsored during litigation. Three scenarios were provided in that analysis, which varied by the treatment of inflation adjustments which were unspecified in the I.D. The three scenarios ranged from a low, net of tax stranded cost quantification of $2.485 billion, to a medium $2.949 billion, to a high of $3.310 billion. These calculations represent the Auditors' interpretation of the I.D. and do not necessarily represent the position of Staff or the Auditors in the case.

B. Mitigation Strategies to Meet Rate Reduction Targets

The ALJ notes that the Board made clear in its discussion of the question of stranded cost recovery in its Final Report that, prior to the Board entertaining a utility's request for a level of stranded cost recovery, the utility must make a good faith effort to undertake appropriate strategies to mitigate the level of stranded costs. I.D. 43-44. At pages 43 through 54 of the I.D., the ALJ summarizes the Company=s case with respect to mitigation, and discusses in detail the testimony and positions of the parties as well as the Company=s response thereto with respect to this issue.

The ALJ's findings on this issue are discussed at pages 54 through 59 of the I.D. While noting the Board=s prior statements that the instant cases were not to be construed as base rate cases, the ALJ also cites and relies upon the Board=s determination, in a February 1998 Order, that testimony addressing the Company=s current cost of capital should not be struck and that a reevaluation of the cost of capital could be viewed as a legitimate mitigation measure. He concludes that a 10.15 percent cost of equity, with the capital structure recommended by the RPA, is reasonable for purposes of calculating funds available for possible mitigation. The ALJ finds that the analysis provided by Dr. Vander Wiede on behalf of PSE&G, supporting a return on equity for the Company of 12.3 percent, is inaccurate and skewed and results in an exceedingly high return on equity. The ALJ utilizes the study performed by the RPA=s expert, but adjusts that recommendation by 100 basis points to reflect higher risk associated with the move away from traditional regulation. The ALJ emphasizes however, that this finding is solely for the purpose of quantifying stranded costs and should not be used to infer that the Company is earning an excessive rate of return vis-a-vis its currently existing base rates. I.D. at 54-55.

With regard to the objection raised by the Company to RPA witness Henkes= analysis of 1996 earned return, specifically concerning Accumulated Deferred Investment Tax Credits ("ADITC"), the ALJ finds merit in the Company=s objections. He also concludes that Mr. Henkes did not make a weather normalization adjustment in his analysis. I.D. 55-56.

The ALJ concurs with the RPA=s position that due consideration should be given to the expected $35 million annual cost savings from the expiration of certain plant abandonment amortizations. The ALJ concurs with the Staff and RPA argument that the LEAC should be reviewed prior to its roll-in into rates to ensure that an appropriate going-forward level of recovery is rolled into base rates, and finds that rolling the current level of recovery into rates would clearly and inappropriately produce excessive earnings. I.D. at 56. He also concludes that the RPA position, joined in by Staff and the CFC, that competitive services revenues be recognized as an offset to stranded costs, is appropriate and should be given recognition by the Board. Id.

With regard to NUG contract cost mitigation, the ALJ concludes that the Company appears to be making a good faith effort to renegotiate these contracts, and that any recommendations to penalize the Company at this point for failing to renegotiate contracts with its affiliates is, at best, premature. He finds that the Company=s performance can be reviewed and the ratepayers sufficiently protected via the annual NUG recovery mechanism. I.D. at 57. The ALJ finds in favor of the Staff position that any revenue enhancements that the Company experiences during the transition period should be used to mitigate stranded costs.

The ALJ disagrees with the elasticity adjustment proposed by Staff, since the underlying DSM and private plant assumptions are highly speculative. Moreover, he rejects the Auditors= overall elasticity adjustment as being misplaced, dated and fatally flawed, since the underlying study is not based on PSE&G-specific factors. I.D. at 58. The ALJ also rejects the Auditors= estimate that the Company could realize up to $850 million of additional mitigation with cost savings in the areas of capital, operation and maintenance, administrative and general, fuel, etc., finding that such savings are overstated and unobtainable. The ALJ notes that it was demonstrated that the Company is a regional leader in cost containment and finds that PSE&G has made a reasonable forecast regarding future cost reductions.

The ALJ also rejects Staff=s recommendation to reflect Anatural mitigation@ initiatives, finding insufficient record support to demonstrate that the depreciation of existing generation assets will mitigate stranded costs. I.D. at 59. He also rejects the Auditors= conclusion that the Company will experience a reduced cost of capital during the transition period (other than through securitization), finding it highly speculative. Id. He also rejects the Staff=s contention that sales levels as of 1997 have already reached the projected levels for 2002. Finally, the ALJ finds some merit in the NJICG and NJBUS recommendation that stranded assets are no longer used and useful and should earn a reduced rate of return as a further form of mitigation, but cautions that such adjustment could have deleterious effect on the Company, suggesting that the Board may wish to consider such an adjustment in the total context of the rate reduction award and the final restructuring plan.

C. Rate Reduction

In its Final Report, the Board stated as one of its primary goals in the restructuring of the electric industry, the provision of a near term reduction in rates "on the order of 5-10%." Final Report at 114. At pages 60 through 64 if the I.D., the ALJ provides a discussion of the various parties' positions and arguments with respect to the appropriate level of rate reduction. The Company proposed a rate reduction of 6.7 percent, based upon its proposed level of securitization, as well as its proposal to extend distribution depreciation lives and to amortize the excess distribution depreciation reserve of $568.7 million. The RPA recommended a 15 percent rate reduction, assuming a seven year transition period. NJICG and NJBUS recommended an immediate 10 percent rate reduction, and another 2 percent reduction by October 1, 1999, producing a total reduction of 12 percent. NJCU recommended a 10 percent rate reduction. The Auditors recommended a range of reductions from 8½ to 14 percent. The ALJ notes that Staff did not articulate a specific number, but implicitly adopted a 10.37 percent recommended reduction in its brief, based upon the Auditors' findings, and offered various recommendations for consideration. The ALJ concludes that the most appropriate level of rate reduction lies in a range of from 10 to 12 percent and that this level of rate reduction will not unduly impair the Company's financial condition. I.D.at 64-65.

D. Securitization

The Board's Final Report recognized that securitization is one of the elements that a utility may employ in developing a program to achieve rate reductions. At pages 65 through 67 of the I.D., the ALJ discusses PSE&G's proposal to securitize $2.5 billion of its total net of tax stranded costs with 15 year bonds, as well as the parties' positions related thereto. PSE&G's proposal was projected to produce annual savings to customers of approximately 2.7 percent, based upon an assumed interest rate of 7.5 percent. The ALJ concludes that the Company's proposal is consistent with the Board's Final Report, and that it will result in reasonable savings which will be flowed back to ratepayers, and should be adopted. I.D. at 68. The ALJ declined to consider Staff's objections, which were adopted by the RPA, to the proposed collection of taxes through the securitized bond charge, since Staff's alternative proposal, including schedules supporting Staff's position, was not introduced until the briefing stage of the case.

E. <u>Unbundled Rates</u>

1. Use of 1995 Cost of Service Study

At page 69 through 71 of the I.D., the ALJ discusses the Company=s reliance upon a 1995 cost of service study ("COSS") in support of its rate unbundling filing, and the objections of numerous parties (Staff took no position on this issue) to this study as not complying with the Final Report, as well as certain recommended adjustments thereto. The Board's Final Report had directed that rates be unbundled based upon "the cost of service study utilized, consistent with BPU-approved cost allocation methodologies, in the last base rate case when current base rates were established." Final Report at 151. PSE&G's last base rate case was based upon a test year ending June 1992, with a cost of service study based on calendar year 1990. At page 71 of the I.D., the ALJ concludes that the Company=s actions in filing a 1995 study were inappropriate and deserving of adverse comment; however, he notes that this is the only evidence available in the record and that all parties have had an opportunity to review and criticize it. He therefore concludes that the Board will be presented with a full factual record upon which to decide whether the updated 1995 cost of service study will satisfy its requirements, or whether it would be more appropriate to order the Company to submit a study based on the 1992 base rate case.

2. Functionalization of Costs

The Board's Final Report provides for the unbundling of existing rates and for rates based upon the proper functionalization of costs and expenses to production, transmission, distribution, and customer components. Final Report at 151. At pages 71 through 78 of the I.D., the ALJ discusses the Company=s proposed functionalization of costs in PSE&G=s cost of service study, and the parties= positions related thereto. He concludes that the Company=s use of a 1995, as opposed to a 1992, cost of service study has resulted in substantial shifts in the functionalization of costs among various classes, and particularly between distribution and production classes. I.D. at 77. He concludes that the proposed functionalization is proper, except as follows. He accepts the RPA position that Gross Receipts and Franchise Taxes ("GR&FT") should be reallocated to reflect the new tax law, and that the requested reallocation of the GR&FT in the 1995 period is also justified. He concurs with recommendation of MAPSA's witness to reallocate $13.7 million in marketing and sales expense to generation. He concurs with Staff's recommendation to reject the proposal to use a $19.84 million placeholder for ancillary services. He also concurs with Staff that the Federal Energy Regulatory Commission (AFERC@)-approved tariff rate of $161.5 million for unbundled transmission is more appropriate than the Company=s proposed $173.2 million. He concurs with Enron=s witness that $22.49 million associated with bad debts and uncollectibles and $2.3 million for regulatory commission expense should be separated from the distribution function. He further concludes that the Lower

Delaware Valley transmission system costs should be reallocated on a dual demand and energy basis. I.D. at 78.

F. Segregation of Rates into Functional Components

1. Unbundling/Rebundling

The ALJ notes that, notwithstanding the Board's directive in the Final Report, PSE&G did not submit fully unbundled rates in its filing, and discusses the objections of numerous parties to the PSE&G proposal. I.D. at 79-81. The ALJ also notes that the Auditors discussed certain potential benefits and shortcomings of the PSE&G proposal and suggested two possible alternatives to the Company's proposal. I.D at 81 to 82.

The ALJ finds that the Company=s failure to fully unbundle rates is not in accord with the Board=s directives in the Final Report and will have the effect of stifling future competition and making customer choice difficult. He further finds that the Auditors= second suggested alternative, to partially rebundle non-competitive rates and implement an implicit Market Transition Charge (AMTC@) including a rate cap, with explicit and separate energy and capacity credits, has merit and warrants the Board=s consideration. I.D. at 83.

2. Market Credit/Capacity Credit

The ALJ describes the Company=s proposal to implement a market energy credit (AMEC@), by which customers who choose a third party supplier would receive a credit on their PSE&G bill based on their hourly usage at each hour=s market price of energy, defined as the PJM hourly wholesale spot market price, as well as PSE&G=s proposal to implement a capacity credit in the future only when a liquid and visible PJM capacity market develops. Id. The ALJ summarizes the concerns with this proposal raised by the RPA, Enron, NJBUS, NJICG, MAPSA, and Staff. I.D. at 84-87. These concerns include arguments by a number of parties that an energy-only credit would be extremely difficult for suppliers to beat, and arguments that the credit must include a retail cost adder.

The ALJ concludes that an energy-only MEC is not responsive to the Board=s Final Report and may well have the effect of stifling competition by making it extremely difficult for alternative suppliers to compete against the Company. I.D. at 87. He disagrees with the Company=s assertion that third party suppliers can easily dispose of their capacity through sales to other buyers, and finds unpersuasive the Company=s arguments that it must maintain the capacity obligation to assure generation adequacy and reliability during the transition. Id. He endorses the proposal sponsored by Enron that, until a liquid and visible market for capacity exists in the PJM system, the market capacity credit should be based on the loss-adjusted market capacity prices that PSE&G used to develop its stranded cost estimates, and should be included as a component of its MEC. Id. The ALJ concludes that the Company has already understated the level of credit that should be reflected in customer bills, and finds merit in the arguments of those parties that argued for the inclusion of some level of retail adder. I.D. at 88-89.

3. Implicit/Explicit MTC

The Board directed in its Final Report that a specific market transition charge, in the form of a separate non-bypassable component of each customer's electric bill, must be established for each utility. Final Report at 116. The Company chose not to include a specific market transition charge in its proposal, but instead proposed to freeze rates for a seven year transition period. The ALJ summarizes the Company's position as well as various parties= objections to or positions regarding that proposal. I.D. at 90-92. The ALJ concludes that the Company=s proposal fails to comport with the specific directive of the Final Report that an explicit MTC calculation be made and that this be reflected as a separate unbundled charge. I.D. at 92. He further concludes that the Company=s proposal for an implicit MTC, absent any form of tracking, periodic review or true-up, creates the real possibility that PSE&G may over-recover stranded costs. Id. The ALJ finds no specific merit in the PSE&G proposal that would outweigh the clear dangers associated therewith and, as a result, concludes that PSE&G should be required to develop an explicit MTC. I.D. at 92-93.

4. Societal Benefits Charge

The Board directed in the Final Report that each utility include in its rate unbundling filing a societal benefits charge (ASBC@), as a per unit charge, to separately collect the costs currently embedded in rates associated with the current provision of "DSM, gas plant remediation, nuclear decommissioning and societal programs including winter moratorium, 'bad debt' customers, low income assistance and weatherization and existing late payment and deposit policies." Final Report at 149. At pages 93 and 94 of the I.D., the ALJ discusses the Company=s proposal in its filing for the implementation of an annually-adjusted SBC, which provides for interest on both under and over-recoveries and which includes the collection of NUG costs and gross receipts and franchise taxes in addition to other elements such as demand side management, environmental remediation costs, nuclear decommissioning, nuclear fuel disposal, uncollectibles and restructuring costs. The ALJ notes that GR&FT and NUG costs are not provided for in the Board=s definition in the Final Report of a SBC. The ALJ discusses the parties= opposition to various aspects of the Company=s proposal. I.D. at 94-96. The ALJ concludes that the Company=s proposal is reasonable, since the annual adjustment mechanism allows for annual review of the SBC sub-components and will allow the Board full control over the level and reasonableness of these charges. I.D. at 96. However, he agrees with the position expressed by Staff and other parties that NUG costs should be removed from the MTC and that a separate NUG charge be created instead, which charge will be reviewable on an annual basis, as will the SBC. This will permit the timely pass-through to ratepayers of the benefits of any NUG contract renegotiations. I.D. at 97. He further agrees with the Staff position that restructuring expenses, when they are readily ascertainable, should be shared equally between customers and shareholders. He rejects the claims by certain intervenors that the SBC does not fully allocate costs in conformity with the Company=s cost of service study, and disagrees with the RPA proposal that the benefits of NUG renegotiation be shared, finding it premature, given his finding that there be an annual review of NUG costs. Id. The ALJ concurs with the RPA position that the inclusion of GR&FT in the SBC is misplaced, since such treatment would have the effect of shifting costs from the generation to the distribution function. I.D. at 97-98.

5. Securitization Transition Charge

With regard to the Company=s securitization transition charge (ASTC@) proposal, the ALJ concurs with the RPA that the Board should expressly order that the securitization funds collected through the STC be used solely to benefit ratepayers. I.D. at 98. He further concurs with the RPA and finds that the expenses of the securitization financing should not be borne solely by ratepayers, but rather should be shared, since both customers and stockholders will benefit by securitization. Id.

6. Competition Transition Charge

The ALJ makes no findings with regard to the Company=s proposal to implement a competition transition charge (ACTC@) applicable to on-site generation. The ALJ notes that the parties= objections related to this issue were of a generic nature, and that the question is before the Board as a separate matter. The ALJ leaves this issue to the Board for evaluation in the confines of that docket after the Legislature has addressed this issue. I.D. at 99.

7. Impact of Proposed Unbundled Rates/Revenue Neutrality

In the Final Report, the Board directed that rates be unbundled based on an embedded cost of service analysis which would achieve complete revenue neutrality on a company-wide basis relative to existing rates, and inter-class and intra-class revenue neutrality relative to existing bundled rates. Final Report at 150. The ALJ summarizes PSE&G=s proposal with respect to this issue and the various parties= exceptions thereto.

I.D. at 100. The ALJ finds and recommends that, assuming the Board employs the 1995 cost of service study, the Company be required to reevaluate its unbundled rates, via the customer charge, to more appropriately reflect actual revenue neutrality. Id.

III. EXCEPTIONS AND REPLY EXCEPTIONS

Numerous parties filed extensive Exceptions and Reply Exceptions to the Initial Decision. These largely reiterated the positions advocated by the parties during the hearings. Some of the key arguments raised by the parties in their Exceptions and Reply Exceptions are summarized hereinbelow.

A. Exceptions

1. PSE&G

While noting that the ALJ has "substantially agreed" with the Company as to the recommended level of stranded costs, PSE&G filed 119 pages of Exceptions, wherein it takes issue with a number of positions adopted by the ALJ. Among the issues addressed by PSE&G relative to stranded costs are post-1992 base rate case capital additions to generation (PSE&G Exceptions at 4-11); applicable test methodology (Id. at 12-54); mitigation strategies (Id. at 55-71); rate reductions (Id. at 72-80); securitization (Id. at 81-82); and electric and gas allocators (Id. at 83-84). Specifically, with respect to post-1992 capital additions, the Company argues that a retroactive market test is not applicable (Id. at 4), and takes exception to the ALJ's removal of $85 million budgeted for the Salem Unit 2 Steam generator replacement. Id. at 9.

With respect to unbundled rates, PSE&G defends its use of the 1995 COSS (Id. at 85-95) and takes exception to a number of the ALJ's recommendations concerning functionalization of costs (Id. at 96-102); segregation of rates into functional components (Id. at 103-116); and revenue neutrality (Id. at 117-118).

2. Ratepayer Advocate

The RPA similarly filed 120 pages of Exceptions addressing numerous aspects of the ALJ's recommendations with respect to PSE&G's rate unbundling and stranded cost filings. With respect to stranded costs, the RPA argues that PSE&G's claim for automatic, unconditional and full recovery of stranded costs has no basis in law, economics or logic. (RPA Exceptions at 12-32). The RPA contends that the ALJ properly found that PSE&G

was required to meet a market test for post-rate case capital expenditures and asserts that PSE&G has not satisfied that test. Id. at 33-34. Specifically, the RPA takes exception to the ALJ's allowance of post-rate case capital additions for Bergen 1, Mercer and Salem. Id. at 33-48.

Among the other stranded cost issues addressed by the RPA are: NUG contract related stranded costs (Id. at 52); quantification of stranded costs (Id. at 53-87); mitigation (Id. at 87-92); rate reduction (Id. at 92-95): securitization (Id. at 95-99); the market transition credit (Id. at 99-100); and the energy-only credit and shopping credits. (Id. at 100-102).

With respect to rate unbundling, the RPA objects to the Company's use of the 1995 COSS, arguing that it pervaded and distorted the Company's entire unbundling case, resulting in massive cost shifting among functions and a lack of revenue neutrality. Id. at 105. Among the other unbundling issues addressed by the RPA are cost functionalization issues (Id. at 109-115): the societal benefits charge (Id. at 115--118); and the securitization charge (Id. at 118-119).

3. BPU Staff

In its Exceptions, Staff notes that the ALJ had chastised Staff for introducing in its Initial Brief positions and recommendations for the first time. Staff contends that this is not a new issue in administrative proceedings but, rather, is an issue which has been repeatedly decided in Staff's favor in multiple forums. New Jersey Dep't of the Pub. Advocate v. New Jersey Bd. of Pub. Utils., 189 N.J. Super. 491, 518 (App. Div. 1983); I/M/O New Jersey Natural Gas Company, BPU Docket No. GR90030335J (July 17, 1990); Coalition for Fair Competition v. New Jersey Bd. of Pub. Utils., A-6069-95T1, page 23 (App. Div. 1998). Staff argues that there was no basis for the ALJ to ignore these precedents and reject certain of Staff's positions and recommendations as set forth in its brief as being extra-record. (Staff Exceptions at 4).

Staff takes exception to the inclusion of certain post base rate case capital additions. Id. at 5-11. Staff argues that PSE&G should be held responsible for the above market costs of Bergen I. Id. at 8. With respect to the Salem steam generator replacement, Staff notes that while it has opined that the steam generator project could be deemed recoverable under a specific test if applied by the Board, there clearly is sufficient basis for the Board to put PSE&G at risk for those expenditures and deny recovery as stranded costs. Id. at 10. Staff continues to recommend its positions set forth in its brief with respect to certain exclusions of pre- and post-steam generator projects. (Staff Initial Brief at 13-14).

Staff takes exception to the recommendation of the ALJ that market clearing price forecasts of PSE&G be adjusted to determine a single specific level of stranded costs. Id. at 12-20. Staff also argues that the ALJ, in discussing the Company's stranded cost estimates, fails to distinguish between net-of-tax and revenue requirement amounts. Id. at 21-25. Staff further argues that the ALJ erred in allowing a 100 basis point risk premium in his calculation of return, if any, allowed as a component of generation related stranded cost recovery through the MTC. Id. at 26-31.

Staff argues that the ALJ failed to propose adequate mitigation strategies. Id. at 32-34. Staff takes the position that the proposed gross-up for taxes related to securitization is not required nor appropriate for inclusion in the securitization transition charge. Id. at 35-39. Finally, Staff takes exception to various adjustments and positions of the ALJ concerning unbundling. Id. at 40-50.

4. Co-Steel Raritan

Co-Steel takes service from PSE&G pursuant to a ten-year service agreement. It argues that its contract precludes the imposition of all stranded cost related charges regardless of the precise form they may take once this proceeding has run its course. This includes any stranded costs related charges that may exist after the current contract expires. Co-Steel argues that such post-contract stranded cost charges would violate the terms and intent of its contract and constitute an unconstitutional contract impairment. (Co-Steel Exceptions at 2). Co-Steel notes that the ALJ did not address this issue in the I.D. and contends that the I.D.'s silence on this issue "implicitly" appears to determine that stranded costs charges would apply to Co-Steel. Co-Steel contends that this is improper and contrary to "substantial evidence" in the record on this issue. Id.

5. The Coalition for Fair Competition

The CFC objects to the ALJ's determination to exclude from evidentiary consideration testimony filed by its expert witness relating to issues of fair competition and argues that stranded costs cannot be accurately quantified unless and until the utilities are required to mitigate fully by dedicating revenues from competitive assets. The CFC argues that the Board should remand this docket to the ALJ along with instructions that the record be re-opened in order to hear and consider testimony submitted by the CFC and all interested parties concerning the issue of fair competition. (CFC Exceptions. at 1-3).

6. County of Passaic

The County of Passaic agrees with the ALJ's finding that PSE&G's failure to fully unbundle rates is not in accord with the Board's Final Report and will have the effect of stifling future competition and making consumer choice difficult. (Passaic Exceptions at 2). The County of Passaic argues that the Board should ensure that all rate classes, and particularly Street Lighting Service, are unbundled. Id. at 4.

7. Independent Energy Producers of New Jersey

IEPNJ asserts that the I.D. should have more clearly stated that the NTC should be trued-up annually. (IEPNJ Exceptions at 3). Additionally, it asserts that for the I.D. should have recommended that the NUG recovery cost vehicle be made part of the SBC. Id. It also argues that the I.D. should be clarified with respect to "going forward costs." While IEPNJ agrees that some ongoing level of capital expenditures will be necessary to factor into PSE&G's market valuation of its generating assets, it argues that a "bright line" test is needed to ensure against anti-competitive subsidization of the utility generation function. Id. at 2-3.

8. Mid-Atlantic Power Supply Association

MAPSA endorses the ALJ's finding that there is a need for a retail adder to provide a reasonable Market Energy Credit. It argues, however, that the Initial Decision does not reflect in the MEC the full retail cost of supplying electricity at retail. It argues that costs such as generation-related customer service costs, generation-related auxiliary service costs, marketing and advertising costs and generation-related administrative and general expenses need to be added to the MEC. (MAPSA Exceptions at 2-5). MAPSA asserts that its witnesses provided reasonable quantifications of the retail costs that need to be reflected in the MEC and urges the Board to implement the I.D.'s findings on the need for a retail adder using its witnesses' retail adder quantifications. Id. at 2. MAPSA further argues that there should be annual true-ups of the MEC to allow customers sufficient time to decide whether or not to shop. Finally. MAPSA argues that the ALJ erred in failing to utilize different rates of return in functionalizing costs. Transmission and Distribution Services assertedly are not as risky as generation and, thus, have different appropriate rates of return. Id. at 8-10.

9. New Jersey Business Users

NJBUS argues that PSE&G's post-1992 rate base additions should not be included in calculating its allowable stranded cost recovery. (NJBUS Exceptions at 18). NJBUS further argues that the ALJ correctly concluded that Bergen, Linden and Salem were not grandfathered from the Board's market test requirement, but that he erred by recommending that these projects be included in PSE&G's stranded cost allowance. Id. at 20-37.

NJBUS argues that the ALJ erred in not adopting NJBUS' methodology for calculating PSE&G's stranded costs, and argues that the ALJ's recommendations are flawed in regard to the methodology for calculating the price of capacity and other cost estimates. Id. at 41-53.

NJBUS also raises certain concerns with respect to mitigation (Id. at 54-56) and securitization (Id. at 73-76), and objects to the use of the 1995 cost of service study (Id. at 77). NJBUS argues that there is ample support in the record for a rate reduction of 20% (Id. at 69-72), and further argues that there should be an equal, fixed and explicit MTC for Basic Generation Service (ABGS@) customers and customers of other suppliers (Id. at 84).

10. New Jersey Commercial Users

NJCU argues that PSE&G's proposed distribution depreciation change should not be counted towards the mandated rate reduction. (NJCU Exceptions at 2). NJCU urges that, within 24 months, the Board initiate a detailed review of PSE&G's costing and allocation methodologies to determine whether inter- and intra-class cost shifts are justified under more appropriate cost of service methodologies. Id. at 2. NJCU further urges the Board to initiate a proceeding and determine PSE&G's distribution revenue requirement within 24 months. Id. at 2-3. NJCA also argues that PSE&G should be required to develop an explicit MTC. Id. at 3.

11. New Jersey Industrial Consumer Group

NJICG argues that the ALJ erred by permitting inclusion of virtually all post-base rate case additions in PSE&G's stranded cost calculations, and that PSE&G's submissions concerning these additions fail to meet the standards for recovery set forth by the Board in the Final Report. (NJICG Exceptions at 3-11). NJICG raises concerns about PSE&G's proposal not to divest its generating assets and argues that the Board should permit no equity return on stranded assets. Id. at 11-14. NJICG also argues that the Initial Decision erred in recommending adoption of PSE&G's securitization proposal and that PSE&G's use of an updated cost of service study as the basis for unbundled rates should be rejected. Id. at 19-26.

12. New Jersey Public Interest Intervenors

NJPII argues that it appears that the primary factor that led to the ALJ's recognition of post test year capital expenditures is the voluminous nature of the material presented by PSE&G. (NJPII Exceptions at 2). NJPII asserts that only 10 pages of the 219 page exhibit which addresses PSE&G's post rate case expenditures at Salem provides any alleged economic comparison of the replacement of the steam generator with other supply options. Id. at 2-3. The NJPII also asserts that the ALJ erroneously failed to address flaws in the evidence as identified by NJPII. Id. at 3-6.

NJPII takes issue with the ALJ's refusal to consider the issue of divestiture, and raises concerns regarding recovery of going forward costs, and administrative and general costs. Id. at 11-20. NJPII also reiterates its position that securitization should not be allowed to extend to stranded costs associated with NUG contracts. Id. at 22-23.

13. New Jersey Transit Corporation

NJT notes that the Initial Decision, in spite of its recognition of PSE&G=s failure to use the appropriate COSS, makes no findings as to the appropriate remedy. NJT asks that a second phase of the unbundling proceedings be commenced to update PSE&G=s COSS. (NJT Exceptions at 2). Additionally, NJT argues that the Board should order that PSE&G=s proposed rate decreases be allocated on cost based principles and not on a uniform percentage basis. Id. at 3.

14. Tosco

Tosco argues that PSE&G's proposed Departing Load Tariff undermines Board policy because it would lead to less choice and higher monopoly rates. (Tosco Exceptions at 6-14). It further argues that the proposed Departing Load Tariff is not a legitimate stranded cost that any customer should pay for. Id. at 14-20.

B. Reply Exceptions

In light of the vast record in this case, most of the parties either relied upon earlier submissions in lieu of filing Reply Exceptions or filed limited Reply Exceptions reiterating key points or responding to specific assertions made the Company in its Exceptions. Two parties, however, PSE&G and the RPA, filed extensive Reply Exceptions of 170 and 80 pages respectively. In general, these Reply Exceptions reiterated PSE&G's and the RPA's previously articulated positions. PSE&G and the RPA also addressed and responded to certain positions advocated by Board Staff in its Exceptions, as well as the arguments raised by various other parties in their Exceptions. While the Board has reviewed and carefully considered all the Exceptions and Replies to Exceptions, because of the voluminous record, we will highlight only a few of the arguments made by PSE&G and the RPA in their Reply Exceptions.

1. PSE&G

With respect to post-rate case capital additions, PSE&G argues that Bergen, Linden, Mercer and Salem were all not subject to a market test. With regard to Salem, PSE&G argues that the intervenors' assertion that the ALJ has improperly shifted the burden of proof is incorrect and further argues that the various arguments of other parties for disallowance of the post-1992 capital additions are without merit. (PSE&G Reply Exceptions at 39-76).

With respect to unbundling, PSE&G again argues that use of the 1995 COSS is practical and correct and provides the Board with a reasonable basis upon which to proceed to authorize the commencement of competition. Id. at 144. The Company notes that its last base rate case was resolved by Stipulation and that there was no explicit Board-approved COSS. PSE&G argues that reliance upon the 1995 COSS is appropriate based upon the record that was developed in this case and that reconstruction of a COSS based upon a 1992 revenue requirement would cause unnecessary controversy, litigation and delay.

With respect to the argument raised by Co-Steel in its Exceptions, PSE&G contends that there is no language in the Service Agreement that absolves Co-Steel from paying any stranded costs either during or after the term of its Service Agreement. During the term of the agreement, to the extent it takes power under the HTS Tariff rate, it would be subject to whatever happens to that rate as a result of restructuring, After the Service Agreement expires in 2005, Co-Steel would be no different than any other customer on its distribution system. Id. at 169-170.

2. Ratepayer Advocate

With respect to post-rate case capital additions, the RPA again reiterates that PSE&G was required to meet a market test for inclusion of stranded costs related to post-rate case capital additions and that PSE&G did not satisfy the market test for the post-rate case capital additions for which it is requesting stranded cost recovery. (RPA Reply Exceptions at 5-18).

The RPA also argues that the ALJ properly concluded that PSE&G's use of the 1995 COSS was inappropriate and will not yield revenue neutral unbundled rates. Id. at 64-72.

IV. RESTRUCTURING PROCEEDING

As noted above, evidentiary hearings were held before Commissioner Carmen J. Armenti on certain identified restructuring issues from April 27, 1998 through May 28, 1998. This was followed by the submission of Briefs and Reply Briefs on generic and non-generic restructuring issues. Key elements of the briefed positions of various parties with regard to certain specific, non-generic restructuring issues of relevance to the PSE&G filing are summarized hereinbelow, by issue.

A. Basic Generation Service

1. Pricing and Contract Terms and Options

PSE&G did not propose a specific BGS rate, but rather has proposed a monthly pricing option, whereby the Company will either buy power from the spot market to supply BGS customers or purchase wholesale power via monthly contractual obligations. (Exhibit PS-32, pp. 3-4). Under the PSE&G proposal, the BGS rate would change monthly. PSE&G indicates that under its proposed pricing option, the customer would not be required to make a long term commitment for BGS service.

The RPA proposes that all utilities solicit competitive bids for sufficient capacity and energy to supply BGS for an initial two year period. The RPA proposes that energy suppliers would put in a bid to the local distribution company (" LDC") to provide energy and capacity for BGS for a two-year period. (Exhibit RA-13, p. 49). The RPA indicates that this could include short-term, as well as portfolio purchases. The RPA asserts that this will ensure that BGS customers will benefit from a competitive energy market, and will also result in less price volatility than with a BGS price that fluctuates over a short time frame. The RPA points out that under its proposal there would be no need for a true-up, because the risk of market price fluctuations would be on the successful bidder.

Staff, in its Initial Brief, supports the concept advocated by several of the utilities in this proceeding by which the utility/basic generation provider would match supply commitments with customer commitments. (Staff Initial Restructuring Brief ("IRB") at 70). Proposed options include a monthly pricing option for customers who do not want a long term BGS commitment, where supply is purchased from the spot market, geared to customers to whom price stability is not of greatest concern and who will most likely choose to participate in customer choice; or an annual or a six month fixed pricing option for customers not choosing to participate in customer choice, who are looking for price stability similar to that experienced prior to restructuring, where supply is purchased by the utility on either an annual or bi-annual contract. Staff points out that the aim of any matching concept is to have a portfolio of supply commitments which matches customer commitments, both in terms of price paid versus the price received for power by the utility and the duration of the purchase commitments. Staff further indicates that under the matching concept there is a limited opportunity for a large under- or overrecovery of deferred balances to accumulate, thus limiting any distortion of the prices for basic generation service. Id. Staff maintains that price distortion has the potential to lead to gaming by market participants, and can otherwise send incorrect pricing signals to customers. Accordingly, it is Staff's position that, in order to provide a smooth transition to competition, the Board should require each electric utility to provide BGS customers the opportunity to select from either a fixed price option, or a monthly pricing option for BGS service. Id. at 70-72.

2. BGS Price/Shopping Credit

PSE&G proposed that its BGS rate/shopping credit should be set at the sum of the PJM market price for energy, plus the cost of line losses, associated taxes and the avoided incremental administrative and general cost of power procurement associated with the energy delivered, referred to by PSE&G as the retail adder. PSE&G estimates this retail adder to be .0014 cents per kilowatt-hour. (Exhibit PS-32, p.14). PSE&G further indicates that as soon as a liquid and visible market for capacity is established, the generation component of the BGS rate will include a capacity component as well. PSE&G asserts that the retail adder should be based on the avoided incremental administrative and general cost of PSE&G providing power to customers and not the imputed costs of a hypothetical marketer. PSE&G indicates that the product of this calculation is the amount that customers on BGS will pay for the generation component of BGS and will also act as the amount that customers who choose an alternative supplier will receive a bill credit. PSE&G asserts that this credit will serve a competitive benchmark for customers choosing an alternative supplier and should be equal to the total avoided cost of PSE&G for serving that customer. (PSE&G IRB at 68).

The RPA proposes that the BGS rate/shopping credit be based on a competitive bid process for both energy and capacity. (Exhibit RA-15, p. 4). The RPA asserts that the competitive low bid, which should be reviewed by the Board, would become that utility=s standard offer rate for generation under BGS, and would also need to include a retail margin encompassing administrative and general costs incurred serving retail customers, including a cost for marketing. The RPA argues that the competitive bid process will also provide the Board with a benchmark price for both energy and capacity, which will provide a starting point for the determination of the appropriate shopping credit, including a retail margin composed of marketing and A&G costs associated with generation for customers who exercise their right to choose an alternative supplier. The RPA proposes that the shopping credit be set at a level that appropriately reflects PSE&G=s generation and marketing costs to serve retail customers, and is sufficient to attract alternative energy suppliers.

Enron proposes that the rate for BGS should be the sum of the prices for the unbundled components of BGS, capped (after any Board mandated rate reductions) as approved by the Board. In Enron=s view, the sum of these components would also become the shopping credit for those customers who choose to use an alternative energy supplier. (Exhibit Enron-35, pp.34-35). Enron defines the shopping credit for generation as the amount remaining after the individual prices for transmission service, distribution service, and intangibles (societal benefits, stranded costs, securitization bond charge, etc) are deducted from the total rate cap. Enron asserts that the shopping credit should equal the utility=s fully embedded cost for generation less the market transition charge, which is a fixed charge. (Enron IRB at 104).

Enron argues that in developing the shopping credit, in order to ensure that competition develops in New Jersey, the Board should impute a cost to the wholesale price of energy for BGS that bears a meaningful relation to the cost of electricity for retail customers. As such, Enron asserts that the shopping credit would be the benchmark against which customers would determine whether it is financially beneficial for them to remain with BGS or consider choosing an alternative supplier.

MAPSA, representing many of the alternative suppliers in this proceeding, asserts that in order to set the proper generation rate, all components of retail cost must be reflected in the BGS rate. MAPSA indicates that the BGS rate will be the retail rate against which all suppliers will compete. As such, MAPSA asserts that the BGS rate should include the wholesale price of energy and capacity, as well as marketing and administrative costs involved in providing competitive retail service, thus reflecting the full cost of supplying electricity at retail. MAPSA indicates that these marketing and administrative costs would result in about a 0.4 to 0.5 cents per kilowatt-hour increase to the BGS rate. (MAPSA IRB at 28).

New Jersey Citizen Action indicates that to the greatest extent possible, BGS pricing should be at the same level as the market clearing price, plus additional costs incurred by the LDC for purchasing electricity for BGS customers. (NJCA IRB at 13).

Staff, in its Initial Restructuring Brief, takes the position that the BGS price and/or the shopping credit should be based on market prices, resulting in BGS customers having access to market based pricing. (Staff IRB at 72). As such, Staff asserts that a BGS price and/or shopping credit that is based upon the market will most appropriately reflect the value of supply and therefore send the most appropriate price signals. Staff further asserts that a BGS price which reflects current market conditions will provide the most appropriate benchmark for comparison shopping by BGS customers considering offers from competing alternative suppliers. Staff asserts that the BGS price must equal the shopping credit, that is, the amount being charged for generation services being supplied by the utility must be the same as the amount deducted (e.g. credited) from the utility portion of the bill if the customer no longer takes generation service.

Staff also shares the concern express by many of the alternative suppliers in this proceeding that a market-based BGS price or shopping credit must reflect the full cost of providing retail generation service and not simply reflect the wholesale price index. Id. at 75. Staff, however, points out that an artificial adder or margin should not be included in the BGS rate simply to stimulate the marketplace, since such artificial stimuli will only serve to distort the marketplace. Staff, however, asserts that in order to provide alternative suppliers with a fair opportunity to compete, appropriate retail-related generation costs must be included in the BGS price as an adder to the wholesale cost of power. Id.

B. Horizontal Market Power

PSE&G submitted a market power analysis prepared by witnesses Joskow and Frame in support of the argument that the Company lacks horizontal market power. (Exhibit PS-46). PSE&G argues that the record in this proceeding demonstrates overwhelmingly that it does not possess market power in the generation and power supply markets for the following reasons: the region's generation market is highly competitive; transmission constraints where PSE&G can impose market power are infrequent during the few hours of system constraint, markets in the eastern PJM region are competitive in every time period; concerns with local Aload pockets@ and must-run generation have been exaggerated and, in any event, are fully addressed through the PJM supporting companies=s market based pricing proposal to the FERC, incorporating a bid cap proposal; and PSE&G=s rate cap proposal precludes it from exercising market power even if it had the ability to do so. (PSE&G IRB at 97-127).

The RPA, relying upon the testimony of its witness Peter Lanzalotta and MAPSA witness Craig Roach, asserts that none of the electric utilities have complied with the Board=s directive to supply a comprehensive market power analysis, since those submitted by the electric utilities are flawed. (RPA IRB at 112). The RPA asserts that the record in this proceeding demonstrates a significant potential that, absent corrective action, one or more of New Jersey=s incumbent electric utilities will be able to exercise horizontal market power within their service territories and in more localized areas. As such, in order to mitigate the potential for horizontal market power, the RPA urges the Board to direct each electric utility within New Jersey to submit a comprehensive market power analysis and mitigation plan, which should include divestiture, and to establish information reporting requirements and monitoring procedures. Id. at 121.

Enron asserts that because serious issues exist regarding the potential exercise of horizontal market power by New Jersey=s utilities, the Board should actively monitor the competitive marketplace as it develops and take all necessary steps to prevent the exercise of market power by the utilities both within New Jersey and the PJM control area. (Enron IRB at 132.)

MAPSA, relying upon the testimony of its witness Craig Roach (Exhibit MAPSA-2), asserts that objective measurements of market power for firm power indicate that PSE&G maintains an unacceptable level of market power and, in an unregulated market, would be able to impose prices higher than those that a competitive market would provide. MAPSA asserts that the Board must mitigate PSE&G=s horizontal market power, which, it suggests, could be remedied by at least a partial divestiture of its generation capacity. (MAPSA IRB at 39).

Staff asserts that on a region-wide basis and, importantly, based upon the current ownership configurations, there is no conclusive evidence of imminent market power problems in the PJM power pool. Staff further indicates that an updated market power assessment must be required as part of the review of any proposed sale of generating assets by ACE and PSE&G. As such, Staff recommends that an empirical market power study should be part of an ongoing regulatory monitoring process of potential or actual market power abuse, including a look at localized load pockets during certain hours. This monitoring process must include a cooperative effort of the Board and the PJM Independent System Operator ("ISO"). Staff asserts that the Board should obtain regular reports from the PJM ISO on information being obtained through its Market Monitoring Plan. Staff further points out that the price cap proposal by PSE&G does not, in and of itself, mitigate market power concerns. (Staff IRB at 86-92).

C. <u>Incentives For Divestiture</u>

PSE&G argues that it must retain its generation assets during a proposed seven year transitional period in order to offer a rate reduction and reliability guarantee, and that a forced divestiture of its generation assets will not advance the achievement of the Board=s restructuring goals. (PSE&G IRB at 139). PSE&G further proposes that at the conclusion of the transition period, all its generation assets will be transferred at "net book value" to an affiliate of its parent company, Public Service Enterprise Group ("PEG"), that will be "functionally independent" of the utility. (Tr. 3129-3130). PSE&G asserts that the Board has no authority to order divestiture, particularly in light of the Company's statutory obligation to serve. PSE&G takes issue with arguments raised be other parties who have cited examples of fossil generation asset sales above "book" value as evidence that forced divestiture will reduce the Company's stranded cost estimate and asserts that those arguments are flawed. PSE&G argues that the vast majority of its fossil generation assets are valued above book, and the cited examples of above Abook@ value sales from other jurisdictions are irrelevant. <u>Id</u>. at 141.

The RPA argues that the divestiture of generation assets constitutes the most significant step in advancing the goal of retail competition in the market for electricity and realizing the attendant consumer benefits which flow therefrom. (RPA IRB at 138). The RPA points out that divestiture would provide an objective measure of stranded cost valuation and, in light of recent above-book value sales of generation facilities, a way to mitigate stranded costs. The RPA further points out that divestiture would also effectuate the ultimate form of functional separation, eliminating the need for extensive regulatory policing and potential for cross-subsidization, while simultaneously dispersing the ownership of generating units to alleviate market power concerns. The RPA urges the Board to require divestiture of generation assets as a precondition to any stranded cost recovery. <u>Id</u>. at 141.

Enron submits that the Board should reject PSE&G=s Adivestiture@ proposal to move its generation assets to an affiliate at book value at the end of the transition period. (Enron IRB at 169). Enron contends that the proposal to shift PSE&G=s generation assets to an affiliated company at an Aaccounting value@ is fraught with the danger that ratepayers who paid for the PSE&G system will not receive sufficient value for their very significant investment and PSE&G could potentially obtain this portfolio of valuable resources at a fraction of their true value. <u>Id</u>. at 170.

Enron argues that the Board should encourage PSE&G to divest its generation assets in the near term to avoid the market power, functional separation and cross-subsidy issues that will otherwise hamper the Board in its efforts to monitor PSE&G and to likely reduce stranded costs. Enron suggests that one incentive the Board could offer PSE&G would be to condition PSE&G's ability to securitize its stranded costs (or a larger percentage of those costs) upon PSE&G=s agreement to divest. Id. at 171.

MAPSA indicates that failure to take steps to require PSE&G to divest its generation assets will harm ratepayers by forcing them to overpay for regulated services and depriving them of the fruits of competition. (MAPSA IRB at 43).

IEPNJ identifies two incentives that the Board can consider relating to the divestiture of PSE&G=s generation assets: the level of securitization which the Board permits on utility generation assets could be tied directly to divestiture; and/or, after determining the most reasonable estimate of stranded costs of utility assets through an administrative estimate, the Board could allow the utility to retain a share of any divestiture proceeds above that amount. (IEPNJ IRB at 8).

The New Jersey Public Interest Intervenors argue that to ensure that the emerging markets develop most efficiently, while providing utilities with the appropriate level of cost recovery for investments made under regulation, the Board must implement policies that encourage or require divestiture of utility owned generation. (NJPII IRB at 2-3).

New Jersey Citizen Action supports divestiture by all of the incumbent utilities as the fairest and most efficient mechanism for resolving a magnitude of restructuring issues, principally stranded cost recovery and market power. NJCA indicates that the Board should establish minimum requirements as a condition of such recovery. (NJCA IRB at 16).

Staff indicates that any incentives for divestiture should be related to stranded cost recovery assets, since divestiture removes the substantial uncertainty associated with administrative estimates. Staff further indicates that divestiture has the potential to reduce stranded costs below levels that might otherwise be experienced based upon administrative estimates, since significant premiums over book value have been experienced in recent generation divestitures. (Staff IRB at 104).

Absent divestiture, Staff asserts that the Company should have undertaken significant stranded cost mitigation measures, as a means to reduce the uncertainty associated with administrative stranded cost estimates. Staff suggests that it would be reasonable for the Board, in setting a stranded cost level for non-divesting utility, to impute a discount to projected stranded costs and/or to give greater weight to the higher end market value estimates for these foregone cost and risk mitigation measures. Staff further recommends that the Board should set a lower cap on the level of securitized bonds which a utility may issue when it has not established its generation market value via divestiture. Id. at 105-106.

D. <u>PSE&G=s Energy-Only Proposal</u>

PSE&G in its filing proposes that during the transition period, all of its customers, except those taking service under specific contracts, be able to purchase their energy requirements from third party suppliers, while PSE&G would remain the provider of capacity for its customers. PSE&G indicates that an approach which would allow customers initially to purchase both energy and capacity from third-party suppliers is unworkable. In order to ensure that reliability is not sacrificed, PSE&G proposes to maintain all capacity obligations in its service territory, and will not offer a capacity credit to its customers choosing a third-party supplier until a liquid capacity market that provides a visible price for capacity is established within PJM. (Exhibit PS-11, pp.10-11).

The RPA indicates that PSE&G=s energy-only credit proposal would discourage competitors from entering its service territory during crucial, initial period of retail choice. The RPA points outs that PSE&G's proposal would require customers who select an alternative supplier to effectively pay for a large portion of generation costs twice, once to PSE&G through its remaining bundled rates and once to a new supplier. (Exhibit RA-13, p. 54). The RPA further points out that the energy-only proposal is a concept that would stifle competition in PSE&G's territory before it begins, and result in PSE&G having a *de facto* unregulated monopoly over generation suppliers. (RPA IRB at 41.).

Enron indicates that the record reveals that the energy-only proposal is a sham and a pretext for an unprecedented and unjustified attempt to erect a formidable barrier to competition that would virtually eliminate the benefits of competition to energy consumers in PSE&G=s territory, as well as shielding PSE&G from financial risk should consumers elect to switch suppliers. (Enron IRB at 72-96).

PP&L argues that PSE&G=s energy-only proposal is an unnecessary major barrier to competition in New Jersey=s retail electric market. PP&L asserts that the PSE&G energy-only proposal would undercut competition and lead to a new phase of monopolistic control by PSE&G in its service territory. (PP&L IRB at 15).

MAPSA also opposes the energy-only proposal and raises substantially the same arguments against PSE&G's proposal as voiced by the other marketers. (MAPSA IRB at 22-24).

NJBUS argues that the PSE&G proposal would prohibit anyone but PSE&G from offering capacity contacts in PSE&G's service territory for at least two years. NJBUS points out that such a fragmentation of the New Jersey electric power market would frustrate the BPU=s goal of uniform, statewide rules governing the introduction and implementation of competitive access, and should be rejected. (NJBUS IRB at 27-32).

1. Reliability Obligations Within PJM

PSE&G indicates that during the transition period, it will maintain the responsibility for reliability and customers' capacity requirements, thereby assuring electric customers that they will be able to freely shop for energy without reliability concerns. PSE&G argues that it should maintain this reliability responsibility because the Reliability Assurance Agreement (RAA) being developed for the PJM system is a work in progress, and undue reliance on the RAA, PJM and the market during the transition period would, in PSE&G's view, be premature and pose an unacceptable risk. PSE&G points out that even after the RAA is executed and approved by FERC, it must still be tested and proven. PSE&G asserts that there is substantial evidence in the record supporting its reliability concerns that cannot be minimized. (PSE&G IRB at 34-45).

Enron indicates that the RAA is now and will continue to be the operative document that creates the approved method for assuring long term capacity adequacy in the PJM control area. Enron argues that the RAA will provide the appropriate operative backstop for capacity adequacy, not an individual utility such as PSE&G that would purport to be the self-anointed Aguardian@ of reliability within its service territory. (Enron IRB at 77-83).

PP&L asserts that the rationale for PSE&G=s energy-only proposals, that it must supply capacity to protect system reliability, is fallacious. PP&L argues that in addressing PSE&G's refusal to give a capacity credit based on PSE&G's reliability rationale, the Board should consider and give weight to the proposals of the other LDCs, which are not limited to an energy-only format. (PP&L IRB at 17-23).

MAPSA asserts that PSE&G=s energy-only proposal will harm reliability in the long term because the proposal creates a significant barrier to entry into the generation market. MAPSA points out that barrier to entry arises by inhibiting potential sellers from selling what most consumers want to buy, both energy and capacity. MAPSA further argues that the energy-only limitation, by excluding capacity as a competitive product, would limit the value of new power plants, resulting in fewer new power plants from being built, thereby harming long term reliability. (MAPSA IRB at 23).

NJBUS also asserts that the PSE&G proposal to defer capacity competition is not justified by its concerns about reliability. NJBUS points out that, although all New Jersey electric utilities are concerned about reliability, no other utility supports the prohibition on capacity competition inherent in PSE&G=s proposal. (NJBUS IRB at 27-28).

IEPNJ argues that the structure and foundation of the PJM completely obviates PSE&G's position that it will maintain the responsibility for reliability and customers' capacity requirements. IEPNJ points out that PJM has, and will assure reliability of supply to customers, through requirements which will be imposed equally on all suppliers, both utility and non-utility. As such, IEPNJ asserts that PSE&G need not be the monopoly provider of capacity services. (IEPNJ IRB at 5-6).

Staff concurs with PSE&G's observation that the RAA is as yet untested, at least with respect to the retail marketplace. However, Staff notes that the RAA is hardly a radical or new concept, and will serve as a conservative mechanism for PJM to provide for supply adequacy as the retail marketplace is opened to competitive markets. Staff maintains that the RAA mechanism that is and will be in place provides sufficient assurance to conclude that there is no reliability-driven basis for maintaining PSE&G as a monopoly supplier of retail capacity service in its service territory. Staff recommends that the Board should require all load serving entities ("LSEs") serving retail load in PSE&G's territory and throughout the State to adhere to all RAA and other PJM reliability criteria as a condition of doing business in the State. Staff also recommends that the Board should closely monitor the implementation of the RAA as the retail markets open up, to assure that reliability, in fact, is not compromised. (Staff IRB at 43-56).

2. Capacity Market

PSE&G indicates that it will not offer a capacity credit to its customers choosing a third-party supplier, until a liquid capacity market that provides a visible price for capacity is established within PJM. PSE&G points out that an actual, not estimated or assumed market capacity price is required because in the absence of a visible and liquid market for capacity, an administrative credit is certain to be wrong on a consistent basis. (PSE&G IRB at 46-55).

The RPA asserts that the rationale for PSE&G refusing to allow its customers to shop for capacity is that it is waiting for a liquid and visible capacity market to emerge within PJM. The RPA points out that the rationale appears to be based on PSE&G's fear that it will not be able to sell its unneeded capacity once other suppliers begin providing PSE&G customers with their own capacity. The RPA asserts that this rationale does not justify PSE&G's energy-only proposal. (RPA IRB at 37).

Enron indicates that notwithstanding PSE&G's suggestion to the contrary, a viable and visible capacity market presently exists within the PJM control area. Enron asserts that PSE&G's energy-only proposal would greatly inhibit the further development of the capacity market by significantly limiting participation of suppliers within the PSE&G territory, and argues that it should be rejected. (Enron IRB at 84-91).

PP&L submits that competition has been occurring in Pennsylvania, with parties buying and selling capacity in the bilateral market to meet their obligations within PJM. PP&L asserts that, all in all, there is a vibrant market that is quite liquid and pricing is known to the capacity market participants. (PP&L IRB at 17-24)

MAPSA indicates that the record in this proceeding is replete with evidence that there is an active bilateral capacity market, that capacity is regularly bought and sold and that despite the confidentiality of the marketplace, utilities, other participants and regulators can and do obtain information necessary to make pricing decisions. Furthermore, MAPSA asserts that there is no need to know the price of capacity for everyone, only PSE&G=s price for capacity for its regulated BGS service. MAPSA therefore points out that there is no basis for PSE&G=s contention that open published rates for capacity are a prerequisite for competition. (MAPSA IRB at 23-24).

NJBUS also argues that a liquid and visible or transparent wholesale capacity price is not a prerequisite to competition. While a transparent price may be useful in the competitive markets, the market itself will accomplish that goal. NJBUS feels the proposal by PSE&G is solely a market strategy, having nothing whatsoever to do with the public interest. (NJBUS IRB at 30-32).

NJCU also argues that PSE&G=s arguments on this issue are without merit. NJCU disagrees with the notion that a liquid and visible capacity market will exist only when the PJM/ISO post prices and quantities for capacity products. NJCU points out that capacity products are currently bought and sold each day in the wholesale market. (NJCU IRB at 9-16).

Staff asserts that the capacity credit can be determined based on relevant market information. Staff points out that the other LDCs have proposed in varying ways to procure both energy and capacity for their BGS rate, which will be transparent to the Board, and should reflect the competitive market price for capacity. Staff further asserts that these capacity prices can act as market indices when setting the capacity credit while the PJM capacity market takes hold and develops. Staff asserts that this method will, in the short run, give customers the ability to have sufficient information to comparison shop, while a liquid and visible capacity market develops. (Staff IRB at 56-63).

V. <u>SETTLEMENT PROPOSALS</u>

As noted above, by Order dated February 11, 1999, the Board, noting the enactment of the Electric Discount and Energy Competition Act on February 9, 1999, adopted a preliminary schedule to render decisions in the pending PSE&G and other three electric public utility restructuring related proceedings, consistent with the requirements of and the timetables required by the Act. In so doing, the Board encouraged the parties in each of the respective proceedings to attempt to negotiate a settlement of the outstanding issues, in the unbundling, stranded costs and restructuring proceedings. The Board established a preliminary deadline of March 3, 1999, for the submission of any negotiated settlement in the PSE&G dockets, in advance of an anticipated March 31, 1999 date for deciding the PSE&G matters. The parties commenced settlement discussions and, at the request of Staff, the deadline for the submission of any negotiated settlement was subsequently extended.

A. Stipulation Filed by PSE&G and Other Parties

On March 17, 1999, a Stipulation (AStipulation@) was filed by PSE&G on behalf of eight parties to the proceedings, including PSE&G, NRDC, NJCU, IBEW Local 94, New Jersey Transit, Enron, Tosco and IEPNJ ("the stipulating parties"), representing a proposed resolution by these parties of the issues in the stranded cost and rate unbundling proceedings and all of the non-generic restructuring proceeding issues included by the Board in its February 11, 1999 Order encouraging the settlement process. The key substantive elements of the Stipulation are summarized hereinbelow.

1. The stipulating parties have agreed that the following rate reductions should be implemented, consistent with subsection 4(d) of the Act, N.J.S.A. 48:3-52(d):

a) A 5% reduction from current rates, for service rendered on and after August 1, 1999. This reduction includes a 1% reduction relating to the savings from securitization.

b) An estimated reduction of an additional 2% from current rates for service rendered on or after January 1, 2000, subject to the prior receipt of a Bondable Transition Cost Rate Order establishing a securitization bond charge and providing for the securitization of $2.475 billion of generation-related stranded costs, and the recovery of related taxes, issuance costs and transaction costs. The level of rate reduction provided to customers will reflect the actual savings from the issuance of the bonds, less the 1% savings already provided to customers as of August 1, 1999, and the actual date of the rate reduction will be the same date as the securitization bond charge is established. This rate reduction and all subsequent rate reductions as set forth below are contingent upon the implementation of the securitization bond charge.

c) A further rate reduction for service rendered on and after August 1, 2001 to bring the total rate reduction to 8.25% from current rates.

d) A final rate reduction for service rendered on and after August 1, 2002 which will result in each customer class receiving a rate reduction of 10% relative to the rates in effect as of April 30, 1997.

e) All rate reductions will be applied to customers' bills pursuant to the rate design set forth in Attachment 2 to the Stipulation.

f) The final rate reduction will be sustained until July 31, 2003.

2. There shall be a four year transition period commencing on August 1, 1999 and terminating on July 31, 2003 ("Transition Period").

3. Unbundled rates for each rate class have been developed using the Company=s 1995 cost of service study, using the parameters defined in Attachment 2 to the Stipulation. Each customer=s bill shall indicate the dollar savings resulting from the rate reductions.

4. An excess depreciation reserve in the amount of $568.7 million is to be amortized over three years and seven months, beginning on January 1, 2000 and ending on July 31, 2003, under the following schedule: $125 million each in 2000 and 2001, $135 million in 2002, and $183.7 million in 2003.

5. Consistent with subsection 12 of the Act, N.J.S.A. 48:3-60, PSE&G will establish a Societal Benefits Charge Clause, which will include costs for social programs (including a universal service fund), nuclear decommissioning costs, demand side management costs, manufactured gas plant remediation costs and consumer education costs.

6. The SBC will be set at the level of costs included in rates as of February 9, 1999, the effective date of the Act, and will remain constant at that level through the Transition Period. The difference between actual costs incurred during the Transition Period, and the level of costs reflected in the SBC will be subject to deferred accounting. Interest on any under/overrecovery will be computed at a seven-year single A debt rate. At the completion of the Transition Period the SBC will be reset and then reset annually thereafter.

7. DSM generation-related lost revenue created subsequent to August 1, 1999 will no longer be reflected in the calculation of costs eligible for DSM cost recovery.

8. PSE&G's unbundled rates will include a non-utility generation market transition charge ("NTC") to recover above-market stranded costs of existing NUG contracts. The contracts will remain the obligation of PSE&G during their lives. PSE&G will sell the energy and

capacity from these contracts at wholesale PJM locational marginal prices and at wholesale, respectively.

9. The initial level of the NTC will be set to recover $183 million of above-market NUG costs (based upon Exhibit PS-20, Schedule CJL-F3 and more fully defined in Attachment 2). This level will remain constant for four years from August 1, 1999. The difference between this collection level and the actual above-market NUG costs during the Transition Period will be subject to deferred accounting. Interest at the seven year single A debt rate will be calculated on over/underrecoveries. After the Transition Period, the NTC will be reset annually. Board-approved NUG contract buyout and buydown costs will be reflected in the NTC, consistent with subsection 13(l)(3) of the Act, N.J.S.A. 48:3-61(l)(3).

10. While PSE&G maintains that its generation assets stranded cost valuation of $3.873 billion is supported by the record, the stipulating parties, including PSE&G, have agreed that the Company is entitled to recover $3.30 billion of its generation-related stranded costs resulting from a market valuation of $0.046 billion and $1.722 billion for nuclear and fossil generating assets, respectively. The stipulating parties have agreed to a total reduction of $225 million in unsecuritized stranded costs including: (1) to reflect the estimated Levelized Energy Adjustment Clause overrecovery as of July 31, 1999 ($60 million after-tax); and (2) a reduction of $90 million of Salem stranded costs. The stipulating parties have agreed that the Company will be provided an opportunity to recover up to $3.075 billion of generation related stranded costs, through securitization of $2.475 billion and an opportunity to recover up to $600 million of unsecuritized generation related stranded costs on a net present value basis.G72

11. With respect to securitization, the stipulating parties have agreed that: (I) consistent with section 14 of the Act, N.J.S.A. 48:3-62, PSE&G will utilize the net proceeds of securitization to refinance or retire its debt and/or equity; (ii) that such refinancing and/or retirement of such debt may occur as a result of mandatory and/or optional redemption, repurchase and/or tender, which may be at a premium; and (iii) the Board should authorize PSE&G to employ such methods as are reasonable and necessary to achieve the overall intent and purposes of the Act.

> a) The stipulating parties have further agreed that the Board should issue a financing order authorizing PSE&G to issue up to $2.6 billion of transition bonds, representing $2.475 billion of stranded costs and an estimated $125 million of transaction costs. The stipulating parties, other than the NJCU, have agreed that all taxes related to securitization will be separately stated on the tariff and will be recovered through Board-approved transition bond charges. The NJCU has reserved its right to comment on this tax issue.

12. PSE&G has requested (and the stipulating parties do not object) that the Board issue a number of findings pursuant to section 14 of the Act, N.J.S.A. 48:3-62, in connection with its review of PSE&G's stranded costs filing, including that:

> a) PSE&G has taken reasonable measures to date on mitigation of stranded costs (Exhibit PS-14) and the terms of the Stipulation, including rate reductions, rate freezes, and other mitigation measures will create appropriate incentives in place to mitigate the total amount of its stranded costs;
>
> b) PSE&G will not be able to achieve the level of rate reduction deemed by the Board to be necessary and appropriate pursuant to the provisions of sections 4 and 13 of the Act, N.J.S.A. 48:3-52 and 61, absent the issuance of transition bonds; and
>
> c) The issuance of such bonds will provide tangible and quantifiable benefits to ratepayers, including greater rate reductions than would have been achieved absent the issuance of such bonds and net present value savings over the term of the bonds.

13. The stipulating parties have agreed that PSE&G should be provided the opportunity to recover up to $600 million of its unsecuritized stranded costs on a net of tax, net present value basis, calculated at a 8.42% discount rate, over the Transition Period. This recovery is to be accomplished via a 2 mill per kwh retail adder, an explicit Market Transition Charge, exclusive of the NTC, and the amount funded by the excess depreciation reserve amortization. The stipulating parties recognize that as BGS customers leave PSE&G for third party suppliers, full recovery of these costs is not assured and represents a risk of undercollection to PSE&G.

14. At the end of the Transition Period, the recovery of the $600 million will be reconciled to actual collections based on actual sales, the net present value of the recovery from the MTC (exclusive of the NTC), collections from the 2.0 mill per kwh adder for all customers retained on BGS, the depreciation amortization, and any payments to PSE&G resulting from BGS bidding in year four of the Transition Period. PSE&G will be at risk for any shortfall. In the event the Company collects over $600 million, such overrecovery will be used to reduce the SBC at the end of the Transition Period when the SBC is reset.

15. The Company's shopping credit shall equal its BGS rate, which shall be inclusive of an allowance for the cost of energy, capacity, transmission, ancillary services, losses, taxes

and retail adder. The shopping credit levels should be established and fixed for the duration of the transition period without adjustment or true up of any kind. The stipulating parties have agreed to the following shopping credits:

	1999	2000	2001	2002	2003
RS	5.71	5.86	5.86	5.86	5.86
GLP	5.30	5.35	5.39	5.44	5.44
LPL-S	4.84	4.88	4.93	4.97	4.97
LPL-P	4.54	4.58	4.62	4.66	4.66
HTS-SubT	4.30	4.35	4.40	4.44	4.44
HTS-HV	4.12	4.16	4.21	4.25	4.25
Overall	**4.95**	**5.03**	**5.06**	**5.10**	**5.10**

Additional shopping-related savings, resulting from customers receiving electric generation service from a supplier at a price less than the applicable rate schedule shopping credit, are above and beyond the rate reductions set forth in paragraph 1 of the Stipulation.

16. The stipulating parties have agreed that the stipulated BGS rates/shopping credits meet the shopping credit definition in the Act and resolve the issue of BGS pricing and the shopping credit in a manner that satisfies the requirements of subsections 9(a) and 9(d) of the Act, N.J.S.A. 48:3-57(a) and (d).

17. Under the Act, PSE&G has a three year obligation to provide BGS through July 31, 2002. The stipulating parties support the bidding out of the BGS to be provided after July 31, 2002. The first year bid will be a pre-payment method based upon the pre-established shopping credit for year four. If the bid results in a payment to PSE&G, it will be considered as a part of the MTC. If the bid requires a payment by PSE&G, such payment will be subject to deferral and subsequent recovery with interest at a seven-year single A debt rate. PSE&G's unregulated affiliate will be authorized to bid for such BGS to be provided after July 31, 2002, pursuant to Board-approved procedures.

18. PSE&G has agreed not to promote its BGS as a competitive alternative.

19. The stipulating parties will not object to the Board approving the transfer of the Company=s electric generation-related assets and their operation, as identified in Attachment 3 to the Stipulation, and all associated rights and liabilities, into a separate corporate entity or entities ("Genco") to be owned by Public Service Enterprise Group Inc. and not by PSE&G.

20. The stipulating parties have agreed that the final and fixed transfer value, pursuant to subsections 7(d) and 13(e) of the Act, N.J.S.A. 48:3-55(d) and 61(e), for the generation

facilities to be transferred is $2.368 billion, which is the fair market value of the transferred assets. In addition, PSE&G will transfer other generation-related assets including materials, supplies and fuel, at book value. PSE&G will not retain any liabilities associated with the transferred generation facilities. No land held for future use (Account 105) will be transferred to Genco. All generation related expenses and capital expenditures related to generation will be borne by Genco.

21. The BGS contract between PSE&G and Genco will contain the following provisions:

a) The transfer to Genco shall be accompanied by Genco and PSE&G entering into a BGS contract whereby Genco would provide full requirements service for energy, capacity, losses and ancillary services needed by PSE&G for BGS and Off-Tariff Rate Agreement ("OTRA@) customers.

b) The BGS contract shall provide that the consideration paid by PSE&G for such full requirements service shall be (i) an amount equal to the full amount charged for BGS to PSE&G=s retail electric customers (less sales and use tax and transmission); (ii) an amount equal to PSE&G=s retail delivery to OTRA customers, multiplied by the comparable BGS rate for such customers as set forth in paragraph 15 (less sales and use tax and transmission); and (iii) an additional charge for price stability services provided by the combustion turbine assets of Genco, payable based on the installed capacity of those assets, equal to the full actual amount collected pursuant to paragraph 13 of the Stipulation, excluding the 2.0 mill per kwh retail adder. Pursuant to subsection 9(b)(3) of the Act, N.J.S.A. 48:3-57(b)(3), no net revenue from this contract may be used to reduce the MTC or distribution rates.

c) The BGS contract shall also provide that PSE&G will transfer to Genco the authority to act as its agent for the purpose of scheduling, electing and/or using all rights, including Fixed Transmission Rights, associated with transmission delivery of full requirements service for PSE&G=s customers.

d) The BGS contract shall be filed with the Board.

22. For the term of the BGS contract, PSE&G will continue to supply, on an as needed basis, dedicated intrastate natural gas transportation services for Genco=s own gas supplies from PSE&G=s city gate to the transferred generating facilities, under current Board-approved rates, terms and conditions.

23. During the Transition Period, the transferred generating facilities may only be sold or transferred by Genco to any other party if the other party agrees to enter into a comparable

BGS contract with the same considerations, including the right to recover the MTC allocated to such generating facilities. If a sale of the transferred generating facilities occurs within the Transition Period, any net after-tax gains from such sales will be shared equally between shareholders and customers, in a manner to be determined by the Board.

24. The Company requests, and the stipulating parties do not object to, certain specified findings by the Board with regard to the transfer of the generating assets in accordance with the designation of such facilities as Exempt Wholesale Generators (AEWG@) under section 32(c) of the Public Utility Holding Company Act of 1935 (APUHCA@). In addition, the stipulating parties agree that Genco, as an EWG, will not offer retail electric service.

25. PSE&G requests, and the stipulating parties do not object to, the Board finding that in accordance with section 32(k) of the PUHCA, the Board has sufficient regulatory authority, resources and access to books and records of PSE&G and any relevant associate, affiliate or subsidiary company, to ensure that the BGS contract with: (a) benefit consumers; (b) not violate any State law; (c) not provide the Genco any unfair competitive advantage by virtue of its affiliation or association with the Company; and (d) is in the public interest.

26. PSE&G shall submit, within 60 days of the Board:s written approval of the Stipulation, a tentative schedule for the receipt of necessary authorization for the transfer from other agencies. Within 60 days of such approval, PSE&G shall file with the Board copies of any documents evidencing the transfer and related assumption of liabilities. Upon receipt of approval from other agencies, PSE&G will provide a filing which reflects the terms of such approvals and accounting implemented.

27. The stipulating parties have agreed that the Board should order that all contracts (except NUG contracts) associated with the electric generating business be transferred to Genco from PSE&G simultaneously with the transfer of the generating assets, along with all rights and obligations in connection therewith.

28. The stipulating parties recognize that various federal and state approvals and third-party consents will be necessary and will result in a delay between the date that the Board may approve the Stipulation and the date the generating facilities are actually transferred to Genco. In order to maintain the intent of the Stipulation during this period of transfer and to effectuate the purposes of the Act under subsection 9(b)(3), N.J.S.A. 48:3-57(b)(3), the stipulating parties have agreed that provisions of section 7 of the Act, N.J.S.A. 48:3-55 which require a payment of a percentage of net revenues for the sharing of common assets and personnel is inapplicable.

29. Generating capacity transferred to Genco will be maintained as a capacity resource within PJM for the Transition Period. During that period, Genco may sell said capacity outside of the PJM system for periods of less than one year after it makes a good faith effort to sell the capacity into the PJM system at market rates.

30. The stipulating parties, other than Enron, have agreed that in addition to any other affiliate standards of conduct that might apply to PSE&G, the following shall apply until the expiration of the MTC or until appropriate and applicable safeguards or code of conduct are adopted by the FERC:

> Neither [PSE&G nor any related business segment of Public Service Enterprise Group selling electric power at retail in New Jersey] shall receive from Genco an unreasonable preference over a non-affiliated retail electric supplier ("RES") that is not comparable to that afforded a non-affiliated RES in the purchase, sale, use or conveyance of goods and services. This provision shall not apply to the BGS Wholesale Supply Agreement entered into between Genco and [PSE&G] and approved by the Board.

30A. Enron contends that the affiliate Standard of Conduct that should apply is as follows:

> Genco shall not offer power or other services to any of its affiliates which are not made generally available to non-affiliated companies, nor shall it offer such power or other services to affiliates at prices more favorable than those generally available in the competitive marketplace and/or to those offered to non-affiliated companies. This provision shall not apply to the BGS Wholesale Supply Agreement entered into between Genco and [PSE&G] and approved by the Board.

31. PSE&G requests, and the stipulating parties do not object to, a finding by the Board, pursuant to <u>N.J.S.A.</u> 48:3-7, that the transfer of generating facilities to Genco is in the public interest, will not jeopardize system reliability, and will not adversely impact PSE&G=s ability to meet its pension obligations to its employees.

32. The Company requests, and the stipulating parties do not object to, a finding by the Board that, because of the extensive nature of the record regarding valuation of the assets being transferred, the requirements of <u>N.J.A.C</u>. 14:1-5.6 should be waived.

33. Upon the transfer of the nuclear generation assets, neither PSE&G or its retail customers shall be responsible to decommission its previously owned nuclear units, subject to Nuclear Regulatory Commission (ANRC@) approval. That responsibility will pass to Genco with the transfer of the nuclear generation and associated assets described in Attachment 3 to the Stipulation and the Decommissioning Trust Funds.

34. The stipulating parties have agreed that the proposed Third Party Supplier Master Service Agreement and associated electric tariff modifications filed by PSE&G on February 1, 1999 should be approved subject to: (1) conformance with the balance of the Stipulation; (2) conformance with the Act; (3) changes resulting from the resolution of restructuring issues; and (4) changes as a result of the Third Party Supplier Master Service Agreement resolution. These changes will be included in a completely new tariff which will be filed with the Board after approval of the Stipulation and resolution of other restructuring issues.

35. The stipulating parties agree with Staff=s recommendation that the Board work cooperatively with the PJM-ISO to monitor actual market behavior in connection with the FERC=s ordered market monitoring plan.

36. The stipulating parties have agreed to work cooperatively to conclude the billing and metering proceeding in an expedited fashion, which proceeding the parties request that the Board conclude by May 1, 2000.

B. <u>Alternative Stipulation Filed by the RPA and Other Parties</u>

By letter dated March 29, 1999, the Ratepayer Advocate submitted an alternative Stipulation of Settlement to the Board for its consideration on behalf of a number of parties to the proceedings, including the RPA, MAPSA, NJBUS, NJICG, NJPII (excluding the NRDC), and NEV. The RPA indicates in its letter that, while it had sought in good faith to negotiate issues related to the proceedings with PSE&G over the previous month, an agreement could not be reached. The RPA urges the Board to reject the Stipulation sponsored by PSE&G and certain other parties and instead adopt its proposed alternative Stipulation of Settlement (@Stipulation II@) accompanying its March 29, 1999 letter, which it asserts represents an alternative compromise to resolve the issues in these cases which will safeguard rate discounts into the future, provide greater selections and savings in the electricity market to jump start competition, and give PSE&G a substantial opportunity to recover the same amount of stranded costs with the same level of securitization proposed in its own plan.

The key elements of Stipulation II are summarized below:

(a) Stipulation II proposes that PSE&G be ordered to reduce its overall rates, cumulatively, by the following amounts, pursuant to the following schedule:

August 1, 1999 5.0% from current rates;

January 1, 2000 7.0% from current rates (assuming a 3% reduction from securitization; any additional reductions over 3% would be passed through to ratepayers);

August 1, 2001 8.25% from current rates; and

August 1, 2002 13.9% from current rates.

Contrary to the PSE&G Stipulation, these rate reductions would not be contingent on securitization, but reflect guaranteed minimums. Savings from securitization would be passed on as further rate reductions.

(b) Under PSE&G's proposal, the rate decreases in years one to four would be reflected in a separate transition rate credit or negative MTC, which would be eliminated in year five. To avoid the asserted rate shock in year five attendant to PSE&G's proposed Stipulation, Stipulation II proposes that the following cost reductions be applied as offsets to the rate increases:

(1) Approximately 60% of the $569 million excess depreciation reserve should be applied to offset the rate increases in years five and six;

(2) The value of expired amortizations still in rates ($35 million) should be applied to offset rate increases;

(3) $90 million of Salem related stranded costs as reflected in the PSE&G Stipulation should be applied to further offset rate increases;

(4) The $90 million (after tax) overcollection in the LEAC as of July 31, 1999 should be applied to further offset rate increases.

The parties to Stipulation II assert that failure to recognize such cost reductions would result in PSE&G's rates being overstated by approximately $900 million (grossed up for taxes), which would allegedly occur under PSE&G's proposed Stipulation. Stipulation II proposes to use a portion of PSE&G's rate credits to eliminate rate increases that would otherwise occur after the 48 month Transition Period. In addition, Stipulation II suggests that rates should stay at the reduced levels in year seven and thereafter unless PSE&G proves the need for a higher rates in a rate proceeding.

(c) Stipulation II proposes that the rate decreases be allocated to reflect the impact of the 1998 Demand Side Adjustment Factor ("DSAF") increase. Transition bond charges would be grossed up and collected via a per kwh charge to reflect the manner in which the revenue requirement associated with generating assets is currently being collected in rates. These elements are asserted to be consistent with the PSE&G Stipulation and would ensure that all customers receive the same rate reductions among and between rate classes.

(d) Stipulation II proposes that distribution rates be reduced by $20 million to reflect the current risk adjusted cost of capital, which reduces the average distribution rate from 2.08 cents to 2.03 cents per kwh. This is consistent with PSE&G's proposed Stipulation.

(e) Stipulation II proposes that stranded cost recovery be as follows:

Total Stranded Costs	$3.30 billion
Securitized Amount (including issuance costs)	$2.54 billion
Contribution from Retail Adder	$54.6 million
Distribution Depreciation Amortization	$170.35 million
Genco Transfer Premium	$600 million
Non-Credited Cost Reductions	$3 million
Mitigation Opportunities	$828 million
Total	**$4.23 billion**

While the stated level of stranded costs is identical to the amount in PSE&G's proposed Stipulation, Stipulation II would require PSE&G to fund the unsecuritized portion of this amount through recognition of the actual value of the transfer of the Company's generation assets and other related assets to an unregulated affiliate as well as through mitigation cost savings and non-credited cost reductions.

Genco Transfer Value

Stipulation II would reduce PSE&G=s MTC to zero. In this manner, it is asserted that ratepayers will actually receive the $600 million premium for the assets transferred. By contrast, while PSE&G's proposed Stipulation appears to acknowledge that the fair market value of the assets transferred to Genco is $600 million greater than the nominal net book value less assumed stranded costs, it recognizes this higher value, not by an offset to stranded costs, but rather, through a string of MTC payments to be made by ratepayers and from foregone future rate reductions.

Other Sources of Stranded Cost Funding

In addition to the $600 million market value adjustment described above, Stipulation II identifies the following other sources of recovery opportunity for non-securitized stranded costs:

(1) Distribution depreciation reserve amortization: In contrast to the PSE&G Stipulation, under which PSE&G would retain the entire excess depreciation balance (estimated by PSE&G to be $569 million), to be applied towards its opportunity to recover non-securitized stranded costs, Stipulation II would permit the Company to retain approximately 40% of the net present value of the amortization as a contribution to stranded costs.

(2) Retail adder: Stipulation II recognizes that a contribution to stranded costs is made by customers who do not shop but rather remain with the Company for BGS. For such customers, the retail adder in their shopping credit also remains with PSE&G. Based upon a levelized retail adder of 7.3 mills per kwh, Stipulation II identifies an additional contribution of $54.64 million contribution to stranded costs by non-shoppers.

3) Non-Credited Cost Reductions: Stipulation II would permit PSE&G to retain over $40 million in expired amortizations and other cost reductions, which might otherwise be passed to ratepayers via rate reductions.

(4) Mitigation opportunities: Stipulation II assumes over $800 million in future cost mitigation opportunities for PSE&G, based upon the mid-range of mitigation cost savings estimates identified by the Auditors.

In total, Stipulation II assertedly would provide PSE&G the opportunity to recover over $2.8 billion for stranded costs, without even considering the Genco transfer premium or mitigation savings opportunities.

(f) Under Stipulation II, BGS would be bid out on a Aprepayment basis@ in year three, to be effective in year four, and would be rebid annually thereafter.

(g) Stipulation II accepts the proposed generation asset transfer envisioned in PSE&G's proposed Stipulation, subject to the following conditions:

(1) The assignment of a $600 million transfer premium or market value adder to benefit ratepayers;

(2) The establishment of detailed Affiliate Relations rules;

(3) The initiation of a Genco Code of Conduct for PSE&G, including a requirement that PSE&G or its affiliated supplier would not receive an unreasonable preference over non-affiliated suppliers. Excess power generation should be sold to the highest bidder through an accessible bulletin board type system.

(4) Generating capacity transferred to Genco would be maintained as a capacity resource within PJM for the first four years; and

(5) Consistent with the Act, the submission of a detailed plan and proposal for the transfer.

(h) Stipulation II proposes to offer higher customer shopping credits than PSE&G's proposed Stipulation. Specifically, Stipulation II proposes the following shopping credits, inclusive of transmission:

1999	4.95 cents per kwh;
2000	5.40 cents per kwh;
2001	5.40 cents per kwh;
2002	5.40 cents per kwh;
2003	5.40 cents per kwh.

The 5.40 cent per kwh system average shopping credit is proposed to be distributed as follows:

RS	6.28 cents per kwh;
GLP	5.50 cents per kwh;
LPL-S	5.00 cents per kwh;
LPL-P	4.80 cents per kwh;
HTS-SubT	4.50 cents per kwh;
HTS-HV	4.16 cents per kwh.

Stipulation II recommends that the Board establish a special incentive customer shopping credit for RS and GLP customers located in Urban Enterprise Zones, and proposes the following additional conditions:

> (1) Actual customer shopping credits should be calculated on a rate class basis as the residual after all other unbundled elements are calculated so long as the results do not produce credits that are lower than those proposed hereinabove;
>
> (2) The shopping credits should be allocated between demand and energy for all schedules with separate demand charges;
>
> (3) If PSE&G=s transmission charges increase during the transition period, shopping credits should be increased accordingly.

The parties to Stipulation II assert that PSE&G's proposed Stipulation provides shopping credits which are inadequate to allow robust competition, particularly in the residential market. These parties further assert that the shopping credits provided in PSE&G's proposed Stipulation are significantly below the shopping credits established in Pennsylvania in the PECO Energy ("PECO") service territory, when those shopping credits are updated for New Jersey-specific costs and increases in the wholesale market. While the PECO shopping credits have been described as reflecting a level that is necessary to make robust competition possible for all customer classes, the parties to Stipulation II assert that Ablindly@ applying the PECO credits to other jurisdictions without updating them for jurisdictional cost differences and changes in market conditions Amakes little sense.@ (Stipulation II at 25). Attachment D to Stipulation II contains an affidavit by John Rohrbach, on behalf of MAPSA, explaining the market factors to be considered when updating the PECO Shopping Credit for application in New Jersey. It is asserted that aggregate transmission costs, congestion costs and tax rate differentials between New Jersey and Pennsylvania amount to 0.11 cents per kwh on average, and 0.24 cents per kwh for serving residential customers. (Stipulation II at 26). In addition, it is asserted that since the PECO case, there have been long term increases in wholesale forward energy and capacity market costs amounting to 0.495 cents per kwh on average, and 0.561 cents per kwh for residential customers, and that these increases will be present Aat least for the next several years.@ Id.

(k)[6] Stipulation II incorporates the PSE&G Stipulation's proposal with respect to the Societal Benefits Charge.

(l) Stipulation II incorporates the PSE&G Stipulation's proposal with respect to non-utility

[6] We have followed the enumeration set forth in Stipulation II, which does not include a provision "(I)" or "(j)".

generation issue, with the proviso that PSE&G must seek to maximize value from NUG contracts by selling all portions of the contract at the market clearing price.

(m) Stipulation II lists several additional terms which should be adopted at the same time the other issues in these proceedings are decided, including:

1. Third Party Supplier Agreement and Retail Tariff issues must be satisfactorily resolved, including the establishment of the Agreement as a supplier tariff; customers should be permitted to change suppliers at will without incurring large Aswitching@ fees, and not be locked in for a minimum of one year as proposed in the PSE&G Stipulation;

2. Necessary Electronic Date Interchange (AEDI@) protocols and procedures should be established via a collaborative process; certification of third party suppliers= and PSE&G=s EDI systems as being compliant with EDI protocols and Board standards should be done by an independent third party, and not PSE&G;

3. PSE&G may continue to serve existing Off-Tariff Rate Agreements consistent with the provisions of the Act;

4. The Board will begin proceedings as soon as possible to establish rules for unbundling and competitive provision of metering and billing at the earliest possible date, but no later than January 1, 2000. In the interim, third party suppliers should be permitted to bill for their own services.

(n) To facilitate successful municipal aggregation in PSE&G's service territory, Stipulation II finds the following provisions to be appropriate:

1. Within two weeks of receipt of a customer=s request, PSE&G shall provide the usage data or load profiles for the past twelve months to the customer making the request, at no charge to the customer;

2. PSE&G shall provide area based aggregate load profiles by municipal boundaries and rate class upon request by a government aggregator and shall also provide the government aggregator, free of charge a list of addresses (excluding names) of all energy customers who receive services within the boundaries of the town or municipality; and

3. PSE&G shall maintain and disseminate a Board approved list of licensed third party suppliers to its customers free of charge twice a year.

VI. COMMENTS ON THE SETTLEMENT PROPOSALS

Upon receipt of the Stipulation and Stipulation II, the Board established a comment period to allow interested parties to submit comments to the Board with respect to both proposals. The parties were advised via letters from the Board's Secretary that comments with respect to the two proposed settlements were to be filed by April 5 and April 7, 1999, respectively. Comments were received from numerous parties, several participants, as well as several non-parties including: PSE&G, the Ratepayer Advocate, MAPSA, NJBUS, NJPII (except for NRDC), NEV, NJICG, NJCA, IEPNJ, Tosco, Enron, NJCU, PP&L Energy Plus ("PP&L"), Co-Steel, CFC, RECO, National Energy Marketers Association ("NEMA") and Exelon Energy. Letters generally supporting the PSE&G Stipulation were also received from the Commerce and Industry Association of New Jersey and the New Jersey Business and Industry Association. Key elements of the comments are summarized hereinbelow.

A. Comments on the PSE&G Stipulation

1. PSE&G

PSE&G, a signatory party to the Stipulation, indicates that the Stipulation contains mutually balancing and interdependent provisions and reflects compromises reached among all the signatories after consideration of the record evidence. PSE&G asserts that the Stipulation is reasonable and in the public interest, is fully supported by the record, is wholly consistent and in compliance with the Act, and should be adopted by the Board. PSE&G asserts that, in contrast to other jurisdictions undertaking electric industry restructuring, where either rate reductions or a shopping credit were awarded, the Stipulation provides both generous rate reductions and large shopping credits which are among the largest awarded anywhere in the nation to date, and which include a retail adder. PSE&G asserts that any larger rate reductions or shopping credits would be unreasonable and would jeopardize PSE&G's financial viability, its workers' jobs, and would impact quality of service. PSE&G indicates that it has agreed in the Stipulation to forego the opportunity to recover over three quarters of a billion dollars of stranded costs compared to its original request for $3.9 billion, and to significantly shorten the recovery period from seven to four years. Moreover, the proposed transfer of generating assets addresses concerns raised by customers, suppliers and cogenerators during the proceeding regarding the ability of the utility to favor its own generation in the retail markets.

PSE&G notes that the Board has long relied on stipulations to assist it in resolving issues before it and that the Courts have upheld that reliance, recognizing that the parties themselves are often in the best position to determine a reasonable outcome in view of their familiarity with the issues and the evidence. I/M/O Petition of PSE&G, 304 N.J. Super 247, 266-267 (App. Div. 1997) Cert. Den., 152 N.J. 12 (1997). PSE&G asserts that in the above cited case the Court upheld reliance by the Board on a stipulation executed by less than all the parties to a case, calling stipulations "fact-finding tools" and concluding that "so long as the Board independently examines the existing record and expressly finds that the stipulated figures yield rates that satisfy the statutory standard, the Board may adopt the stipulations," Id. at 268, 270.

PSE&G asserts that the rate reductions provided in the Stipulation are consistent with the requirements of the Act, will produce approximately $1.5 billion in customer savings over the four year transition period, and are among the largest restructuring rate reductions reported in cases throughout the country. PSE&G notes that during the proceeding the Company proposed a 6.7% rate reduction, the Auditors proposed reductions ranging from 8.58% to 12.01%, the NJBUS and NJICG recommended a 10% rate reduction which would grow to 12% the following year, NJBUS and NJCU recommended a rate reduction of Aat least@ 10% and the RPA recommended a reduction of 15% without the Company=s depreciation proposal and a 19% reduction with the depreciation adjustment. Based upon this record, the ALJ recommended a 10% to 12% range for the rate reduction. PSE&G argues that the stipulated rate reductions, reaching 13.9% during the last year of the transition period, are clearly in line with the record and the majority of recommendations in the case, and comport with the requirements of the Act.

PSE&G asserts that paragraph 3 of the Stipulation and Attachment 2 therein provide unbundled rates consistent with section 4 of the Act, N.J.S.A. 48:3-52, including a separate charge for BGS and a shopping credit, a separate transmission component of BGS based on the current PJM Open Access Tariff, discrete charges for customer services and distribution, assurances that there will be no reallocation of costs between or among customer classes, and a mechanism for showing the impact of the required rate reductions on the bill. PSE&G contends that the Stipulation=s reliance on the 1995 cost of service study modified to accommodate updates and recommendations of the parties, is reasonable and consistent with the Act. PSE&G argues that the 1995 cost of service study was utilized by the Company from the start of the proceedings and the parties had ample opportunity to analyze and comment thereupon, and that the Act does not require use of the cost of service study from the last base rate case as argued by some parties. The signatory parties to the Stipulation have agreed to adjust the 1995 cost of service study to incorporate a $20 million decrease in distribution rates to reflect a more current cost of capital of 9.5%. Adjustments were also made to reflect changes in Post-Retirement Benefits other than Pension (APBOP@) accounting and energy tax law.

The Company asserts that the use of the amortization of the excess electric depreciation reserve is reasonable and consistent with its original proposal in this matter, and provides a source of funds to achieve the mandated rate reductions without jeopardizing the financial health of the Company. The SBC provided by the proposed Stipulation includes only those cost categories identified in section 12 of the Act, N.J.S.A. 48:3-60, consistent with the Act's sustained rate reduction requirements, and is capped at current recovery levels during the transition period, in contrast to PSE&G=s original proposal that the SBC be exempt from the rate cap. PSE&G argues that the deferred accounting with interest will provide PSE&G the opportunity for full recovery of these costs, which are not under the Company's control but are dependent upon regulatory action by the Board or other State agencies. The NTC charge will permit recovery by PSE&G of contractually-incurred NUG costs, and will also provide a mechanism to reflect future buyouts or buydowns of NUG contracts, consistent with the provisions of section 13 of the Act, N.J.S.A. 48:3-61. Deferred accounting with interest will assure full recovery of these costs consistent with the Act and case law in New Jersey.

With regard to stranded cost levels, PSE&G asserts that the record demonstrates, and the ALJ concluded, that recovery of the majority of the Company=s post-1992 rate case capital additions is justified, and asserts that the record demonstrates that the standards for such recovery as set forth in subsection 13(d) of the Act, N.J.S.A. 48:3-61(e), have been met. With regard to overall calculation methodology, the Company asserts that it used a modeling technique that was followed by all parties, as recognized by the ALJ, and that this methodology is fundamentally no different than the process a prospective buyer of the generating assets would go through. PSE&G argues that this technique satisfies the requirement in subsection 13(e) of the Act, N.J.S.A. 48:3-61(e), that the full market value of each asset over its remaining useful life be demonstrated. PSE&G asserts that this methodology is superior to a comparison to sales of generating assets by other utilities, as argued by Stipulation II=s proponents, because such a comparative sales approach cannot reflect the vast differences between plants with respect to numerous factors, including heat rates, future capital additions, environmental regulations, energy prices, taxes, transferred or retained liabilities and pre-closing conditions. The record includes a range of owned generation stranded cost estimates using various versions of the Company=s approach and different assumptions. The Company filed a quantification of $3.9 billion. The RPA recommended generation stranded costs of $1.898 billion, but PSE&G asserts the record reflects that the RPA=s actual position at the close of hearings was $2.308 billion. The Auditors quantified a range from a low of $2.485 billion, to a medium of $2.949 billion and a high of $3.310 billion, based on the ALJ=s I.D. The stipulated level of eligible generation-related stranded costs of $3.3 billion, therefore, is asserted to be within the range of the parties= recommendations on the record. Moreover, PSE&G agreed via the Stipulation to forego recovery of $225 million of this eligible amount, thereby capping recovery at $3.075 billion.

The Company asserts that there are substantial grounds for Board approval of the level of securitization in the Stipulation pursuant to subsection 14(b) of the Act, N.J.S.A. 48:

3-62(b), because the record demonstrates that the Company has taken reasonable mitigation measures, that it will not be able to achieve the necessary rate reductions absent securitization, and that the bonds will result in tangible and quantifiable benefits to ratepayers.[7] PSE&G also points to the Auditors' recommendation that the Company be allowed to securitize $2.4 billion of generation stranded costs. PSE&G asserts that in order to fully recover the bonded stranded costs of $2.475 billion, approximately $1.710 of state and federal income tax that are triggered by recovery of the bonded stranded costs must also be recovered, and that inclusion of the taxes in the non-revocable bond charge, as provided in the Stipulation, provides assurance of such collection. PSE&G argues that this position is supported by the definition of "bondable stranded costs" in section 3 of the Act, N.J.S.A. 48:3-51, as well by subsection 15(a)(2) of the Act, N.J.S.A. 48:3-63(a)(2). PSE&G raises concerns with an alternative suggestion raised by the RPA and others that the taxes should be separately collected through the MTC, asserting that it is questionable whether the Act would permit a 15 year MTC to recover these tax expenses, with the only possible, but in its view still questionable, vehicle being subsection 13(l)(3) of the Act, N.J.S.A. 48:3-61(l)(3). It further argues that use of the MTC is not needed, since it would be a simple matter to require a true-up of the bond charge if statutory tax rate changes occur. Thus, PSE&G maintains that use of an MTC rather than the bond charge would put PSE&G at risk for these taxes, is really not needed, and should not be implemented, and that the inclusion of taxes in the bond transition charges, as provided in the Stipulation, should be approved.

PSE&G asserts that the shopping credits in the Stipulation, which equal the BGS price, are consistent with the Act, particularly subsections 9(a),(c), and (e) thereof, N.J.S.A. 48:3-57 (a), (c) and (e), and are supported by the record. The BGS charge is required to be based on the cost of power purchased at prices consistent with market conditions in the competitive wholesale market, plus ancillary and administrative costs. The energy and capacity market price estimates testified to by Company witness Loxley, adjusted for losses and taxes and differentiated by rate schedule, time periods and load profiles and consideration of other cost estimate evidence in the record were used by the parties to the Stipulation as the basis for the BGS price/shopping credits. To this was added a retail adder of 2 mills per kwh to recognize related ancillary and administrative costs, consistent with section 9 of the Act, N.J.S.A. 48:3-57, and transmission costs equal to the PJM Open Access Tariff. During the proceeding, certain parties argued for a retail adder ranging up to 5 mills per kwh, while PSE&G and the Auditors took the position in testimony that no retail adder was appropriate since it could be viewed as providing windfall gains to marketers and shopping customers, to the disadvantage of non-shopping customers. Thus, PSE&G asserts, the 2 mill retail adder is within the range in the record. The Stipulation's shopping

[7] PSE&G's April 15, 1999 comments at page 31 list citations to the record which, it alleges, support this conclusion.

credits are higher than any other PSE&G is aware of based on reported decisions in other states.

With regard to the Genco transfer, PSE&G asserts that the transfer is consistent with the record in the restructuring proceeding, where PSE&G said that its objective was to remain in the generation business, and where several parties argued for a divestiture of generating assets or a greater degree of separation from the electric public utility to alleviate market power concerns. Moreover, the contract for Genco to supply PSE&G full BGS requirements at a predetermined price puts considerable risk on Genco that would otherwise have been on the utility. PSE&G asserts that adoption of the Act, particularly subsections 7(f) and (l), N.J.S.A. 48:3-55(f) and(l) reinforced the desire for greater separation by limiting electric utilities= ability to offer competitive services, including electric generation service, but putting no such restrictions on competitive business segments of a public utility holding company. It maintains that a transfer to a related competitive business segment of PSE&G's holding company is consistent with the Act and meets the interests of not having competitive generation service adversely impact PSE&G's regulated service or create the potential for cross-subsidization.

PSE&G further asserts that the transfer is also consistent with subsection 7(d) of the Act, N.J.S.A. 48:3-55(d), which requires that a transfer Ashall be recorded at full value as determined by the board.@ The value of the generating assets was extensively litigated in the proceeding, and the Stipulation sets the value of the generating assets at $1.768 billion, based upon an agreement in paragraph 10 of the Stipulation that recovery-eligible stranded costs amount to $3.3 billion which, subtracted from the net book value of $5.068 billion, equals $1.768 billion. PSE&G emphasizes as noteworthy the fact that Enron and IEPNJ, representing direct competitors of Genco in the generation marketplace, have agreed to this valuation. PSE&G points to a further benefit of the transfer, namely the advance on the $600 million MTC payment which is to be provided to PSE&G, which will be used to retire debt and reduce the utility=s capitalization. As well, per paragraph 33 of the Stipulation, responsibility for nuclear decommissioning will pass to Genco along with transfer of the decommissioning trust fund, thus addressing one of the major concerns of the RPA.

PSE&G asserts that the BGS contract envisioned in the Stipulation is consistent with both subsections 9(b)(2), N.J.S.A 48:3-57(b)(2), in terms of its pricing provisions and 9(b)(3), N.J.S.A. 48:3-57(b)(3), in terms of the alternative cost recovery mechanism tied to maintaining price stability, of the Act. The parties to the Stipulation have requested Board approval of key terms of the transfer as set forth in the Stipulation, and PSE&G has committed to a subsequent timely filing with the Board with the accounting details and other contractual provisions governing the transfer. The Company recognizes the Board=s continued jurisdiction over the transfer until the Board accepts the executed BGS contract, the separate entities are established and capitalized, books of accounts are established and the assets transferred, appropriate monies are paid to PSE&G, and requisite regulatory approvals are obtained. Moreover, PSE&G asserts that, because paragraph 20 of the Stipulation provides that auditable accounting protocols be in place no later than the transfer effective date to assure that all expenses and capital expenditures related to generation are borne by Genco, it is appropriate that the parties agreed in paragraph 28 that net revenue sharing per subsection 7(d) of the Act, N.J.S.A. 48:3-55(d), need not apply during the period after the Board issues an order approving the Stipulation but before all regulatory and other approvals are attained and the actual transfer is effectuated.

PSE&G points to various provisions in the Stipulation as maintaining reliability of service to BGS customers, including the requirement that any sale by Genco of the transferred generating assets include a requirement that the buyer assume the obligations of the BGS contract, continuation of the Board-approved natural gas supply relationships between PSE&G and the transferred generating facilities, transfer of related contractual rights and obligations, and maintenance of the transferred generating capacity as a capacity resource within PJM during the transition period. As to the latter, PSE&G notes that there is no such obligation for any other traditional utility or new load serving entity under the PJM Reliability Assurance Agreement not to sell capacity outside PJM as it loses load to competing suppliers, and instead to market any excess capacity first within PJM.

For Codes of Conduct, PSE&G recommends adoption of the alternative provided in paragraph 30 of the Stipulation. It objects to Enron's proposed alternative in paragraph 30A because its scope encompasses all affiliates, not just those engaged in the retail sale of electricity. PSE&G submits that the Board should approve the transfer of its generation assets to Genco pursuant to its authority to approve dispositions of utility property under N.J.S.A.48:3-7 and it maintains that the only substantive concern in this regard, that the utility's pension obligations continue to be satisfied, is addressed in paragraph 31 of the Stipulation. Moreover, it asserts that the requirements of N.J.A.C. 14:1-5.6(a) will be substantially satisfied on or before the date of transfer, and that a waiver pursuant to N.J.A.C. 14: 1-5.6(l) of any requirement in N.J.A.C. 14:1-5.6(b) that the generation assets be advertised is justified, given the voluminous record in this matter concerning market value of the transferred assets, the uniqueness of the property and the unusual nature of the transaction. Finally, PSE&G recommends approval of paragraph 34 regarding the proposed Third Party Supplier Master Service Agreement, in order that the proposed tariff serve as a template to be modified based upon mandates in the Act and decisions by the Board on related third party supplier agreement issues.

2. Ratepayer Advocate

The RPA, a signatory to Stipulation II, requests that the Board reject the Stipulation and instead adopt Stipulation II. The RPA asserts that the initial 5% rate reduction in the Stipulation violates the Act, arguing that subsection 4(d)(2) of the Act, N.J.S.A. 48:3-

52(d)(2), requires a 5% reduction from April 30, 1997 rates and that the 5% reduction in the Stipulation is from current rates, which include a 3.9% increase effective April 1, 1998. Moreover, it asserts that the Stipulation=s conditioning of the remaining rate reductions upon the implementation of a securitization transition charge violates the Act, which requires that mandated rate reductions be achieved whether or not any portion of stranded costs are securitized. It asserts that, under the Stipulation, at the end of the four year transition period, all of PSE&G=s rate reductions will completely terminate, which it claims is contrary to the subsections 4(f) and 4(j) of the Act, N.J.S.A. 48:3-52(f) and (j). Moreover, the RPA asserts that the proposal to eliminate all rate reductions as of July 31, 2003, including the estimated 3% from securitization, violates section 14 of the Act, N.J.S.A 48:3-62, which requires that the entire amount of savings from securitization shall be passed on to ratepayers over the full term of the bonds, in this case for 15 years. By contrast, Stipulation II provides for sustained rate reductions in years five and six and beyond. The RPA does not object to a four year transition period instead of seven years as originally filed by PSE&G, however, it notes that the significance of this period under the Stipulation is that rates will automatically increase in year five (beginning August 1, 2003).

The RPA does not object to the use of the 1995 cost of service study within the context of the Stipulation II, but if Stipulation II is not accepted in full, the RPA asserts that use of the 1992 cost of service study is contrary to the Board's Final Report, since the 1995 cost of service study was never the subject of review in a base rate case. The RPA also objects to the Stipulation=s proposal to add $80.46 million in costs related to post-retirement benefits other than pensions ("PBOP") to its unbundled distribution rates, for the following reasons. First, using the Company=s established electric/gas revenue requirement allocations, only 76% of this cost (approximately $60.1 million) should be included in electric rates; second, PSE&G=s actual total revenue requirement is only $68.3 million, not $80 million, thus the electric revenue requirement portion would only be $52 million; and third, a portion of the FAS-106 PBOP revenue requirement is properly functionalized to generation, rather than 100% to distribution as proposed in the Stipulation.

The RPA asserts that the proposed amortization of electric distribution depreciation reserve fund in paragraph 4 of the Stipulation should be rejected by the Board because it represents excess money that has been collected from ratepayers, which would normally be returned via a reduction in depreciation rates, but that under the Stipulation would be used to fund statutorily-required rate reductions. Instead, Stipulation II would use 60% of the excess distribution depreciation reserve to fund sustained rate reductions beyond year four, and only the remaining 40% would be used to fund rate reductions in years one to four as an offset to the MTC as in the PSE&G Stipulation.

Regarding the SBC, the RPA asserts that the Board should require a more detailed list than that provided in the Stipulation of all items that may be included in the SBC, and should also provide actual calculations of the DSM charge and its derivation, including the appropriate level of generation lost revenues to be removed per the Stipulation. The collection of interest on the deferred SBC costs, as contemplated in the Stipulation, is not specifically allowed under the Act, and is contrary to the Board=s existing regulations for LEAC underrecovery. Moreover, if allowed at all, interest should be based on the short-term debt rate, not the seven year debt rate, since the transition period is only four years.

The RPA asserts that it is PSE&G=s obligation to maximize the price it gets for NUG power that will flow through the NTC; therefore NUG power should be sold through PJM or at the market, whether inside or outside PJM, whichever is greater. Moreover, the Board should order PSE&G to update the NUG costs to be included in the NTC, and should require PSE&G, at the very least, to attempt to mitigate NUG contracts held by its own affiliates, or demonstrate why it could not mitigate such costs, before it is permitted to recover above-market NUG contract costs. The RPA also expresses the same concerns regarding the computation of interest on deferred NTC costs as articulated above with respect to SBC costs, although noting that, if adopted in full, Stipulation II would allow interest on under-and overrecoveries in the NTC.

The RPA asserts that the recovery of $3.075 billion of stranded costs provided for in the Stipulation is $800 million higher than the stranded cost estimate of every party to the litigated case except for PSE&G, and that the Stipulation provides only one mitigation action; the foregone $90 million in Salem costs. While the Stipulation provides a virtual guarantee of an additional $600 million above the securitized level, Stipulation II would provide the opportunity to recover such costs through mitigation, a portion of the retained retail adder, and a portion of the depreciation reserve amortization. Moreover, the asserted overstated stranded cost level is, the RPA argues, directly related to an undervaluation of PSE&G=s generating plants. While the Stipulation sets that value at $1.768 billion, the most reasonable estimate is between $2.4 billion and $2.9 billion. Accordingly, the RPA asserts that the best estimate of generation-related stranded costs is between $2.2 billion and $2.7 billion, far below the Stipulation's $3.075 billion guaranteed recovery level.

The RPA asserts that it is unclear that the Stipulation=s provision of $2.475 billion of securitization does not violate subsection 14(c)(1) of the Act, N.J.S.A. 48:3-62(c)(1), since the recovery eligible stranded costs provided in the Stipulation appears to be $3.075 billion, 75% of which would be only $2.306 billion, or subsections 13(c) and (f) of the Act, N.J.S.A. 48:3-61(c) and (f), because the $3.075 billion figure appears not to recognize mitigation and the transfer values from asset sales or divestitures. The RPA objects to the Stipulation's proposal that customers pay 100% of securitization issuance costs, and argues that, as the ALJ determined, such costs should be shared on a 50%/50% basis by utility shareholders and customers. It further maintains that issuance costs should not exceed $62.5 million based on current estimates, not $125 million as provided in the Stipulation. The RPA also objects to the recovery through the transition bond charge ("TBC") of taxes associated with securitization, arguing that such costs should be recovered via the MTC as a separate tax

MTC instead. The RPA also objects to the Stipulation's requested findings that PSE&G has reasonably mitigated its stranded costs, since it asserts the Stipulation provides literally no achieved or expected mitigation. Moreover, the RPA contests the requested finding that PSE&G could not achieve the mandated rate reductions absent securitization, since it claims to have proven in the case that PSE&G could reduce rates by 15% from April 1997 levels for a seven year period and maintain its financial integrity, and the ALJ found that rates could be reduced by 10-12% over a seven year period without jeopardizing the Company's financial integrity. The RPA further asserts that the Stipulation provides securitization savings only during the years 2000 through 2003, rather than over the entire 15 year life of the bonds as required in subsections 14(a) and (b)(3) of the Act, N.J.S.A. 48:3-62(a) and (b)(3).

The RPA asserts that the Stipulation's phased distribution depreciation amortization alone will provide the Company a $458 million net present value contribution toward stranded costs, guaranteeing recovery of an "indisputable" 76% of the $600 million of unsecuritized stranded costs which PSE&G is only supposed to have an "opportunity" to recover. In addition, assuming 5% incremental load loss to competing suppliers in each of the years 1999 through 2003, the 2 mill per kwh retail adder retained by PSE&G will produce an additional $271 million nominal, and $120 million after-tax net present value contribution towards stranded costs. Thus, the RPA asserts that these two items alone "guarantee" the recovery of 96% or more of the $600 million, which PSE&G is only supposed to have an "opportunity" to recover.

As to BGS and shopping credits, the RPA reasserts that the level of shopping credits in Stipulation II, as opposed to those provided in the Stipulation, are necessary to stimulate a robust competitive market, and reiterates the arguments on this issue which are found at pages 23 through 27 of Stipulation II.

As to the proposed transfer of PSE&G's generation assets to an unregulated affiliated entity or Genco, the RPA argues that this proposal was not made in the evidentiary record, it implicates many other issues in the case, and the Stipulation would effectuate the Genco transfer without any further filings by PSE&G, or any additional Board review. The RPA asserts that the Board should either defer resolution of the transfer pending evidentiary hearings, or in the alternative adopt Stipulation II on all issues relating to the Genco formation and asset transfer. Moreover, while the Stipulation appears to recognize that the generating assets are worth at least $600 million more than the net book value less estimated stranded costs, it provides for customers to repay the $600 million to Genco; thus the true transfer value is only $1.8 billion. By contrast, as set forth in Stipulation II, a reasonable market value of the assets to be transferred is $2.9 billion based on recent market evidence, which is considerably higher than the Aadministratively determined@ estimate reflected in the Stipulation. The RPA asserts that Stipulation II, which reduces the MTC to zero, recognizes the appropriate transfer value as $2.368 billion, thus providing ratepayers the additional market value for the assets transferred.

The Genco transfer in the Stipulation also entails the transfer of all contracts associated with the electric generating business and other contractual rights and liabilities; however no transfer valuation for, or even a listing of, these rights and liabilities is provided. The RPA also finds objectionable the request in the Stipulation for a waiver of N.J.A.C. 14:1-5.6, since it would allegedly result in a blind approval of an asset transfer without the provision of complete documentation of what is being transferred.

The RPA reiterates the recommended Code of Conduct and Affiliate Relations rules set forth in the Stipulation II. The RPA also requests that the Board order that Genco maintain transferred capacity as a capacity resource within PJM for the first four years, and that the Board require the submission of a plan and proposal for the transfer providing details including a specific list of transferred assets, contracts and intangibles; specific accounting entries; and the effect of the transfer on reliability and existing collective bargaining agreements or workforce levels.

The RPA further asserts that the Board should disregard paragraph 34 of the Stipulation, since the subject tariff modifications are outdated, addressed in the Act, and/or are the subject of generic restructuring proceedings and discussions. Nonetheless, the RPA provides specific comments with respect to specific issues related to the third party supplier agreement, including the customer enrollment package, customer usage records, customer authorization and confirmation, minimum contract terms, switching fees and the billing of customers.

3. Mid-Atlantic Power Supply Association

MAPSA, a signatory to Stipulation II, submits that the Stipulation should be rejected as it fails to properly implement the four principal goals of the Act; specifically: (1) to provide guaranteed ratepayer benefits by implementing the required minimum rate discounts; (2) to provide fair treatment to the utility and its shareholders by giving them an opportunity to recover quantifiable, fully mitigated stranded costs; (3) to create a vibrant competitive environment by establishing appropriate shopping credits; and (4) to assure a level playing field through the establishment of appropriate rules and requirements. MAPSA argues that the Stipulation is flawed because it fails to allow for the development of a competitive market, it does not guarantee fulfillment of the minimum rate discount requirements of the Act, and it does nothing to address rate shock in years five and six.

MAPSA contends that while the Stipulation claims to establish a level of stranded costs of $3.3 billion, and an opportunity to recover only $3.075 billion through unbundled rates, the real opportunity to recover stranded costs is more than $1 billion greater than this claim. It identifies the recovery opportunities as follows: $2.6 billion (including $125 million for bond issuance costs) via the Securitization Transition Charge, $120 million via retained a retail adder, $460.5 million via the distribution depreciation reserve amortization, $90 million via the agreed upon Salem cost reduction, $90 million via the LEAC overcollection at July 31, 1999, $35 million via expired amortizations, $800 million via documented mitigation opportunities, and $600 million via the Genco transfer premium. Moreover, MAPSA asserts that this list does not include a quantification of additional value from the Genco transfer, including the value of purchased power and gas supply contracts, good will, fixed transmission rights, emission reductions and NOX credits, footprint for new plants or plant expansion, avoidance of new plant siting and building costs, the value of capacity in PJM, and the value of ancillary services. Accordingly, MAPSA asserts that the Stipulation provides PSE&G with over $1.5 billion in excess compensation, which leads to inadequate shopping credits, an uncertain level of rate reductions, and rate spikes in years five and six.

MAPSA asserts that PSE&G=s approach to calculating the BGS charge or shopping credit is skewed, by using an out-of-date and understated market line to calculate energy costs and a dramatically understated retail adder to reflect retail delivery costs and the ability to offer savings to customers. The shopping credit or BGS charge is, in MAPSA's view, more appropriately calculated by using the so-called Pennsylvania Aresidual@ method. This method begins with the bundled rate after recognizing the discount, and subtracts from that bundled rate the distribution rate, transmission rate and societal benefits rate and taxes to derive the generation rate; from the generation rate is subtracted the stranded cost charges (STC or MTC); the remainder is the shopping credit. MAPSA adds that if the level of the shopping credit thus produced is not sufficient to produce robust competition, then the structure or timing of stranded cost recovery must be adjusted. Under this method, if an Aexcess@ is created in the remaining rate level, it will be used to enhance competition, as opposed to the PSE&G approach under which any excess would flow to increase the MTC.

MAPSA further submits that savings of at least 5-7% must be offered by suppliers to entice customers to switch; savings at this level can only be offered if the shopping credit is sufficient to cover the cost of procuring and delivering power, the cost of marketing and customer service, and the need to provide a margin. MAPSA asserts that the PSE&G shopping credit understates the forward cost of energy by at least 4 mills, and the retail adder of 2 mills is inadequate for a supplier to cover retail costs and offer savings.

MAPSA asserts that the Pennsylvania experience demonstrates the importance of a shopping credit that offers savings to customers. The shopping credits established for PECO Energy ("PECO") in Pennsylvania have assertedly produced the most robust competitive market in that state; 1/3 of eligible load has switched to alternative suppliers, including 14% of residential customers. In neighboring territories in Pennsylvania, where shopping credits are 6 mills to 18 mills lower (depending on company and customer class) per kwh, shopping is alleged to be virtually non-existent. Thus, MAPSA asserts, the PECO shopping credits should be used as the starting point; but must be updated to account for New Jersey specific costs and generic energy market cost increases

With respect to the Genco transfer, MAPSA notes that the Stipulation acknowledges that the value of the generating assets is significantly higher than the adjusted (net book cost less Astipulated stranded cost@) book value, yet this $600 million premium is to be transferred to PSE&G without ratepayers receiving any benefit via greater rate reductions or larger shopping credits. MAPSA maintains that the benefits of the higher Areal market value@ of the generating assets should be given back to ratepayers. If the Board does not credit the $600 million premium to ratepayers, then it should either disapprove the transfer, require PSE&G to actually divest its generation, or establish a yearly true-up to capture future market events if they show that the assets were transferred at an undervalued amount. Moreover, MAPSA asserts that the Stipulation lacks details concerning the transfer and appears to overlook or dismiss the need for various filing requirements and approvals.

MAPSA asserts that while the Stipulation contains some limited provisions to prevent Genco from exercising anti-competitive behavior, they are limited and must be expanded upon to address the following issues: there should be an absolute ban on Genco from making direct retail sales; the exceptions provided Genco from the requirement that the generating capacity be maintained in PJM for four years could be exercised in a manner which raises capacity prices in PJM; and the codes of conduct must provide a process for allowing competitors to ascertain whether unreasonable preferences are being provided, including reporting and public posting of offers by Genco for sales to affiliates.

MAPSA also comments that the Stipulation is unclear on the process of finalizing PSE&G=s Third Party Supplier Master Service Agreement, which as filed, assertedly contains a number of troubling provisions, nor does it mention an affiliate code of conduct, which must be adopted and implemented before competition commences. Finally, MAPSA asserts that elements of the Stipulation, including elements related to the Genco transfer and the reasonableness of the shopping credits, are not supported by the record, and there is a need for additional hearings and testimony in order to avoid violation of the parties= due process rights.

4. <u>New Jersey Public Interest Intervenors</u>

NJPII (with the exception of the NRDC), a signatory to Stipulation II, urges rejection of the Stipulation and Board approval of the alternative Stipulation II. It argues that the Stipulation does not guarantee the mandated rate reductions, rather the reductions are contingent upon securitization. Moreover, NJPII cautions the Board to take note of developments in Massachusetts and California as evidence that setting shopping credits too low can result in an inactive market, and points to activity in Pennsylvania, specifically the PECO shopping credits, as evidence of how setting the shopping credits at appropriate levels can foster competition. According to NJPII, the Stipulation's shopping credits fail to account for all of the costs to deliver electricity to New Jersey and the empirical data from a year's worth of activity in the PECO service territory. NJPII argues that the market values underlying the stranded costs identified in the Stipulation do not reflect required mitigation activities and ever-increasing empirical evidence that the market value of fossil generation is understated. Recent sales of fossil generation have assertedly resulted in significant premiums over book value and NJPII maintains that ratepayers should receive this benefit.

5. New Energy Ventures

NEV, a signatory to Stipulation II, urges the Board to reject the Stipulation, and instead to approve Stipulation II. NEV submits that robust competition has occurred in the PECO service territory where meaningful shopping credits have been provided, whereas in Massachusetts there has been little competitive activity because the Standards Offer, which is similar to the shopping credit, is low relative to market prices. NEV asserts that the PECO model provides an excellent framework and starting point for New Jersey. However, since the PECO settlement, there have been increases in wholesale market prices, and NEV maintains that certain adjustments should be considered to ensure that New Jersey customers receive rate discounts of equal magnitude as PECO customers. NEV argues that the shopping credits in Stipulation II are more equitable for all customer classes than those in the Stipulation, as evidenced by the broad range of customers signing Stipulation II and the assurance of the discounts that will be offered.

NEV also asserts that the Stipulation contains only vague and insufficient codes of conduct governing PSE&G's relationship with Genco, and that it also tilts the playing field in favor of the incumbent in terms of various customer issues, including fees for switching and obtaining information. NEV urges the Board to develop a forum for resolving these issues. Finally, NEV urges the Board to address metering and billing issues, including a prohibition against PSE&G issuing a single bill for supplier and utility charges, and the promulgation of metering and billing rules by January 1, 2000.

6. New Jersey Industrial Customer Group

NJICG, a signatory to Stipulation II, urges the Board to reject the Stipulation and to instead adopt Stipulation II. It asserts that the Stipulation violates the Act by rendering the achievement of the mandated minimum rate reductions contingent upon securitization, while, in contrast, Stipulation II has no such Astrings@ attached. Moreover, NJICG asserts that the level of securitization in the Stipulation violates the Act because although the Act limits securitization to 75% of "recovery eligible" stranded costs, after recognizing mitigation and the transfer values from asset sales or divestitures, the Stipulation derives the $2.475 billion of securitized stranded cost by multiplying $3.3 billion times 75% without recognition of the factors required by the Act. NJICG notes that if the level of securitization were to be decreased to correct this flaw, PSE&G would not be denied the opportunity to recover the disallowed portion of the securitization figure, but could attempt to recoup these amounts via the MTC.

NJICG argues that the $1.8 billion transfer price for the Genco transfer dramatically understates the actual market value, indeed it has no connection to the market value, which it asserts to be more on the order of $2.9 billion. Moreover, according to NJICG, ratepayers are also shortchanged because the $600 million transfer premium which is included in the Stipulation would be paid directly by Genco to PSE&G, whose shareholders would receive an immediate benefit, and the ratepayers would repay this $600 million to Genco via the MTC revenue stream. NJICG further questions the legality of this arrangement, since the Act only authorizes utilities to recover an MTC based on the Aabove-market@ portion of their generating assets, and the Act also requires Anet proceeds@ from the sale of generating assets to be reflected in a timely adjustment to the MTC. NJICG maintains that once PSE&G receives the $600 million premium, its unsecuritized stranded costs must be reduced to zero. Finally, on this issue, it argues that if, according to PSE&G, Genco is paying Afair market value for the assets transferred,@ then, by definition, there are no stranded Aabove market@ costs for Genco to collect through an MTC, even assuming the statutory authority to do so.

With regard to shopping credits, NJICG asserts that the PSE&G shopping credits are unsupported and are too low to spur competition; they must be set to reflect the real costs of doing business in New Jersey. The PECO level of shopping credits must be updated to account for changes in energy markets since the PECO credits were set, as well as to reflect New Jersey-specific considerations. One or two marketers agreeing to a level of shopping credits is not sufficient to insure that there will be a competitive marketplace; rather, there must be a Asufficient number@ of Agood alternatives@ to basic generation service, such as the four to five good alternatives required by the FERC to demonstrate a competitive natural gas pipeline market.

NJICG asserts that the rate design contained in the Stipulation, which employs a temporary Arate reduction credit@ rather than a reduction to existing rates, will lead to an automatic rate spike after July 31, 2003. Moreover, the use of deferral accounts for the SBC and NUG contract costs in the Stipulation will likely exacerbate rate spikes after July

31, 2003. NJICG maintains that Stipulation II removes the rate spike problem for at least two additional years, and more appropriately leads to a sharing of burdens to recover stranded costs and reduce rates between shareholders and customers.

7. The Coalition for Fair Competition

The CFC, which was not a signatory to either Stipulation, asserts that the Stipulation is not conducive to fair competition or compliant with the Act because it would allow PSE&G to transfer generating assets to an unregulated affiliated Genco at book value, and thereby fails to mitigate PSE&G=s stranded costs through the market-based valuation of assets. To prevent the Genco transfer from acting as a massive subsidy for competitive activity, the CFC argues that the Board should require proper market based pricing of the assets, compensation to ratepayers based upon this market value, and the adoption of stringent standards for fair competition. The CFC also asserts that the rate reductions provided in the Stipulation cannot be tied to securitization, and that PSE&G has not demonstrated the need for securitization to achieve the mandated rate reductions.

The CFC argues that the Board does not have the authority to approve the proposed Stipulation "as is"; that the Stipulation violates the Act, and that there is a need for public and evidentiary hearing to develop an evidentiary record before the Board acts on the Stipulation. The CFC argues that a contested partial stipulation amounts to a joint petition which must be fully reviewed by the Board to assure compliance with the law, to ascertain whether it is supported by the record, and to assure fairness to all affected parties and interests. The CFC argues that because PSE&G failed to submit the evidentiary basis and statutory sources for each position in its proposal, as was done with Stipulation II, the PSE&G Stipulation must be rejected.

The CFC asserts that the excess depreciation revenue amounts to an overcollection of $567 million, which should be refunded to ratepayers with interest and not counted as part of the mandated rate reductions. It recommends that an Order to Show Cause be issued to commence an investigation into whether there are additional overcollections. The CFC also asserts that the provisions of the Stipulation (paragraphs 5-7) providing full recovery of the four categories of costs in section 12 of the Act, N.J.S.A. 48:3-60, providing that the SBC level will remain constant for four years, are not mandated by the Act. It argues that full recovery of costs was only assured in the Act for DSM costs, and that funding levels should not be frozen for four years given the requirement in the Act that the BPU conduct a proceeding to determine the proper level of DSM funding for the next four years.

The CFC further maintains that absent an actual sale or auction of assets, stranded costs must be calculated using comparable sales, which assertedly show that generating assets have netted purchase prices far in excess of book value. The CFC asserts that

PSE&G has not satisfied the Act's requirement that in support of its securitization request it demonstrate that it has taken all reasonable steps to mitigate its stranded costs, including dedication of up to 50% of net revenues from utility-offered competitive services and 25% of net revenues from holding company affiliate competitive services as required by subsections 7(b) and 7(l) of the Act, N.J.S.A. 48:3-55(b) and (l), and that it could not achieve the mandated rate reductions without securitization. The CFC further asserts that there are distinct statutory standards for setting shopping credits and for setting BGS prices. Therefore, rather than simply establishing shopping credits equal to the BGS price, as provided in the Stipulation, the CFC argues that the BGS and shopping credits should each be established, after an in-depth analysis, as separate determinations, with the shopping credits set to create a truly viable and robust competitive marketplace. The CFC also contends that fixing the level of the shopping credits for four years, as provided in the Stipulation, is Afolly,@ and that there should be at least annual resettings to reopen and reevaluate the level of the shopping credit to assure competition as required by the Act. Further, the CFC argues that PSE&G has not demonstrated that the provision of BGS through a bilateral contract with Genco under the terms of the Stipulation is compliant with section 9(b)(2) of the Act; N.J.S.A. 48:3-57(b)(2), since there is no need for PSE&G to supply BGS when there is an abundance of competitive sources from which to choose.

Regarding the proposed transfer of assets to Genco, the CFC endorses PSE&G's decision to start divestiture of competitive business assets and units, but it stresses that there are three keys to a proper transfer: establishment of transfer value and compensation to be paid to ratepayers; establishment of standards of fair competition or affiliate codes of conduct; and a true-up of the MTC. The CFC asserts that the previously-struck testimony it sponsored in the proceedings with respect to transfer pricing must now be admitted and given full evidentiary weight, since the Genco proposal in the Stipulation has Aopened the door@ to this testimony. The CFC further argues that subsection 7(d) of the Act, N.J.S.A. 48:3-55(d), requires the Board to adopt rules and regulations which will govern the transfer of electric utility assets to a corporate affiliate, but that no such regulations have been proposed or adopted. Moreover, the Stipulation reflects a transfer at depreciated book value, which is asserted to be far below market value of the assets as demonstrated by recent generation asset sales (which the CFC claims show sales from 2.5 to 5 times book value), and is therefore in violation of section 7 of the Act, N.J.S.A. 48:3-55, as well as preexisting law. The transfer proposal is also asserted to be in violation of subsection 13(g) of the Act, N.J.S.A. 48:3-61(g), since there is no provision for a true-up of stranded costs after the transfer has been made. The CFC favors the affiliate standards supported by Enron, as reflected in paragraph 30A, of the Stipulation, but indicates that, at a minimum, the Genco/PSE&G relationship must be made expressly subject to the standards the Board adopts pursuant to sections 7 and 8 of the Act, N.J.S.A. 48:3-55 and 56.

With regard to the Stipulation itself, the CFC claims that if fails to meet the standards set forth in I/M/O Petition of PSE&G, supra. The CFC alleges that the signatories to the

Stipulation are not a diverse group of parties with opposing interests who negotiated hard at arms length, as argued by PSE&G, but rather represent a group of parties with close ties to PSE&G, who were chosen by the Company for closed door negotiations and were vulnerable to PSE&G pressure and undue influence, and were Ainduced@ to sign by PSE&G. Finally, the CFC opposes the Stipulation=s requested waiver of certain provisions of section 7 of the Act, N.J.S.A. 48:3-55, (paragraph 28 of the Stipulation), and N.J.A.C. 14:1-5.6 (paragraph 32 of the Stipulation).

8. New Jersey Citizen Action

NJCA, which was not a signatory to either the Stipulation or Stipulation II, simultaneously filed its comments with respect to both the Stipulation and Stipulation II. NJCA asserts that the Stipulation falls short of the legislative mandate on rate reductions, because while the Act requires achievement of the minimum rate reductions as a requirement for securitization, the Stipulation conditions the rate reductions on the approval of securitization. It argues that PSE&G has an obligation to demonstrate that it cannot go beyond the mandated 10% rate reduction without harming shareholders and employees. It also expresses concern regarding potential rate spikes in year five under the Stipulation, which would violate the spirit and the letter of the Act, since it argues the intent of the Act is to provide lower rates in a sustained fashion and create a competitive market. While Stipulation II does address the rate spike in year five, NJCA indicates that it has been unable to independently verify the impact of the allocations on the Company. Additionally, it criticizes the proposal in Stipulation II that allows the Company to wait four years to repay customers for $90 million in Salem related stranded costs, versus the immediate return under the Stipulation. Further, NJCA questions the provision in Stipulation II which would permit PSE&G to retain 40% of the excess depreciation reserve. NJCA questions why rates cannot be reduced further under either proposal given the high level of securitization of stranded costs, since it understands stranded costs as the reason for current high rates. In light of the provisions of the Act permitting an opportunity for full stranded cost recovery, NJCA does not oppose the level of stranded cost recovery and securitization embodied in both the Stipulation and in Stipulation II; however, it expresses concern regarding the valuation of the generating assets proposed to be transferred to Genco, and supports the RPA's request for a further review of the transfer price issue. NJCA also opposes the collection of taxes related to securitized stranded costs via the transition bond charge as proposed in the Stipulation, arguing that such costs should be recovered a separate MTC instead. NJCA further maintains that issuance costs should be borne by shareholders or, in the alternative, be shared, with the ratepayers' share collected through an MTC.

As to the issue of shopping credits, NJCA asserts that while a reasonable shopping credit, similar to levels established in the PECO settlement, can assist in the competition, it is not a "magic bullet." NJCA urges the Board to follow the pattern of both stipulations and set a higher shopping credit for residential customers.

9. New Jersey Business Users

NJBUS, a signatory to Stipulation II, urges rejection of the Stipulation and the adoption in its place of Stipulation II. NJBUS asserts that the initial 5% rate reduction in the Stipulation violates subsections 4(b) and (d) of the Act, N.J.S.A. 48:3-52(b) and (d), by including in that initial reduction a Aprefunded@ 1% of the securitization savings, arguing that, in effect, the initial rate reduction would only be 4%, not the 5% required by the Act. Moreover, NJBUS maintains that there is no basis for a finding that if 1% of the securitization savings is prefunded, there will be net present value savings over the life of the bonds as required by subsection 14(b) of the Act, N.J.S.A. 48:3-62(b). Prefunding, NJBUS alleges, deprives customers of savings equal to 1% of revenues per year for at least two years, or $80 million, because the Act requires that the 5% rate reduction must be implemented whether or not there is securitization, and all securitization savings must be passed through to customers on a timely basis, per subsection 4(l) of the Act, N.J.S.A. 48:3-52(l). Assuming securitization savings of 3%, NJBUS argues that the Act requires rates to be reduced by at least 8% (5% minimum initially plus the 3% securitization savings) as of January 1, 2000. NJBUS also argues that subsection 4(d)(2) of the Act, N.J.S.A. 48:3-52(d)(2), requires that the initial 5% rate reduction be measured against April 30,1997 rates, not against current rates as assumed in the Stipulation. NJBUS asserts that, at best, the third year rate reduction would be worth only $10 million to ratepayers and thus, under the Stipulation's prefunding program, customers would be deprived of $70 million in rate reductions.

NJBUS maintains that the rate reductions must be applied to each of the unbundled rate elements, not as a separate rate reduction line item as provided in the Stipulation; otherwise, there would be an automatic rate increase of at least 13.9% on August 1, 2003 by eliminating this rate reduction line item, in violation of the requirements of subsection 4(j), N.J.S.A. 48:3-52(j) of the Act, for sustainable rate reductions. Stipulation II extends the rate reduction level in year four for another two years, and retains those rates in year seven and beyond, unless rate increases are approved by the Board after a full rate case. NJBUS asserts that there are additional funds available to sustain rate reductions beyond those explicitly contemplated in Stipulation II, including sharing of Genco competitive service revenues pursuant to section 7 of the Act, N.J.S.A. 48:3-55, and application to regulated rates of all net revenues derived from the bilateral BGS supply contract between Genco and PSE&G, pursuant to subsection 9(b)(2) of the Act, N.J.S.A. 48:3-57(b)(2). NJBUS contends that the Stipulation inappropriately attempts to circumvent or otherwise waive these requirements.

NJBUS objects to the generation asset transfer contemplated in the Stipulation, asserting that there is a substantial underevaluation of the assets, and that because the transfer was not presented in PSE&G=s original filing, it does not have record support. Moreover, NJBUS contends that neither the value of the BGS contract nor the other contractual rights being transferred has been calculated. The $2.368 billion transfer value is asserted to be a Asham,@ since $600 million to be collected by PSE&G via the MTC will be repaid to Genco. NJBUS argues that the recovery by Genco of the $600 million is virtually guaranteed; accordingly, the true asset transfer value being paid by Genco is only $1.768 billion. NJBUS submits that, as set forth in the affidavit of Michael B. Dirmeier attached to Stipulation II, a conservative value for the owned generating assets is $2.9 billion, which, after tax, translates to a transfer value of $2.4 billion. This estimate is based on reported sales of utility generating plants over 35,000 megawatts nationwide over the past 18 months. Subsection 13(e) of the Act, N.J.S.A. 48:3-61(e), requires that, in quantifying stranded costs, the full market value of each asset, including value that would not be realized until after the expiration of the MTC must be demonstrated. Mr. Dirmeier=s approach is asserted by NJBUS to do just this. NJBUS maintains that subsection 11(c) of the Act, N.J.S.A. 48:3-59(c), requires the Board to approve any generating asset sale, based on findings that the sale reflects the full market value is in the ratepayers= best interests. NJBUS asserts that because the Stipulation requires ratepayers to repay $600 million, the actual sale price of $1.7687 billion does not reflect full market value. Moreover, absent the asset transfer, section 13(g) of the Act, N.J.S.A. 48:3-61(g) would require a periodic review and true-up of market valuation and adjustment to stranded cost recovery accordingly, which offers ratepayers protection against stranded costs being set too high (because market valuation is too low) based upon an administrative estimate. NJBUS contends that the proposed asset transfer in the Stipulation eliminates this protection, and therefore must be rejected unless the transfer occurs at full market value. It maintains that the Company=s initial filing did not support an immediate transfer of assets, only an asset transfer after the then-proposed transition period, and that the details of such proposed transfer were vague. NJBUS thus asserts that the record does not supply an adequate foundation for the transfer of assets based on a market value of $1.768 billion, as implied by the Stipulation.

NJBUS also claims that the value of the BGS contract is a valuable right afforded Genco above and beyond the asset transfer, which value has not been, but should be, considered. NJBUS further alleges that other valuable contract rights, including power and fuel contracts, real and personal contracts and other contractual rights and liabilities are proposed to be transferred without compensation, and the value has not been, but should be calculated and considered. NJBUS maintains that one of the most important items transferred to Genco is the ability to control the scheduling and use of PSE&G=s transmission assets as PSE&G=s agent, thereby enabling Genco to use PSE&G=s transmission rights to make unregulated sales and bypassing PSE&G=s responsibility to release transmission rights to the market on the electronic bulletin board, and that the generation sites themselves may also have significant value. NJBUS claims as well, that the right to collect net revenues from the use of common assets and personnel, as required in section 7 of the Act, <u>N.J.S.A</u>. 48:3-55, should not be waived, as proposed in the Stipulation.

NJBUS further asserts that the amount of stranded costs which PSE&G seeks to securitize in the Stipulation violates the Act, since the recovery-eligible stranded costs as identified in the Stipulation, consistent with the use of that term in the Act, is $3.075 billion, and the $2.475 billion level of securitization exceeds the 75% limit imposed in subsection 14(c)(1) of the Act, <u>N.J.S.A</u>. 48:3-62(c)(1). NJBUS maintains that the Stipulation also fails to specify how the proceeds from securitization will be used to reduce rates, since it does not specifically identify the proportion of debt and/or equity that will be retired. NJBUS asserts that the Stipulation=s proposal to collect revenue taxes associated with securitization via the transition bond charge, which is to be established in an irrevocable bondable costs rate order, should be rejected; instead, a special tax MTC should be instituted which could be changed to address changes in federal tax laws. It also argues that any overrecoveries of the unsecuritized stranded costs by the end of the transition period should earn interest, which should be returned to customers and that the Stipulation makes no such provision.

Additionally, NJBUS asserts that there is no record evidence to support the Stipulation=s shopping credit levels. All evidence in the record was based on mathematical modeling, not real market evidence; such evidence now exists and should be used, according to the NJBUS. It maintains that the Stipulation=s shopping credits are too low to promote competition, pointing to affidavits attached to Stipulation II for support, including the affidavit of John S. Rohrbach which asserts that the shopping credits are too low when compared to those set in the PECO territory more than a year ago, due to increases in energy costs, capacity pricing, a higher congestion cost, and a higher tax rate in New Jersey as compared to Pennsylvania.

Finally, NJBUS urges rejection of the proposed tariff revisions in Attachment 6 to the Stipulation, which it asserts incorporates numerous provisions which were not available during the OAL proceedings, and which address many issues which the Board has set for generic resolution via restructuring working groups.

10. Co-Steel Raritan

The primary concern of Co-Steel, which operates a steel Amini-mill@ in Perth Amboy, in this proceeding, has been its ten year service agreement with PSE&G under the Experimental Hourly Energy Pricing Service ("EHEP") tariff, and specifically its assertion that its contract precludes the imposition of stranded cost-related charges either during or after the contract term, which extends until November 17, 2005. With respect to the period during the contract term, Co-Steel asserts that the agreement unquestionably precludes the imposition of stranded cost charges, since the bargain was struck and investment decisions made based on the precise terms negotiated, which cannot be altered without the parties= consent. Moreover, Co-Steel argues that imposition of post-contract stranded cost charges based upon Co-Steel=s consumption during the contract term would equate to a price increase during the contract term. Given the 10-year term of the contract and the interruptible nature of Co-Steel=s electric service, Co-Steel maintains that it cannot be deemed to have caused any of PSE&G=s stranded costs. To subject Co-Steel to stranded cost charges would give it the worst of both possible worlds: barred by contract from enjoying the benefits of competition, yet subject to stranded cost charges caused by the arrival of competition. Moreover, it contends that the imposition of stranded cost charges upon it would violate the constitutional prohibition against contract impairment.

Co-Steel, which was not a signatory to either the Stipulation or Stipulation II, raises certain concerns as to how the Stipulation would affect Co-Steel. It maintains that, on its face, the Stipulation is unclear as to what surcharges, if any, would apply to Co-Steel under its contract. Co-Steel contends that it has been advised by PSE&G that under Block 1 of the contract rate, which is pegged to the HTS tariff rate, Co-Steel would receive the same rate discounts provided to all other HTS customers, and that its Block 2 usage would be governed by contract and be unaffected by the Stipulation. Co-Steel contends that if it is determined that the Act requires that stranded cost charges be paid by Co-Steel, then the Act=s requirement that all customers should have the ability to shop as of August 1, 1999 should also apply, and Co-Steel should be permitted to seek alternative suppliers. Imposition of the securitization charge, the NTC and the MTC at the levels envisioned in the Stipulation would, according to Co-Steel, increase its annual bill in the aggregate by as much as $7.3 million, thus wiping out all the benefits derived from the contract the Board approved in 1995. Imposition of stranded cost charges after the contract expires would assertedly impose $4 million or more annually on Co-Steel, which would effectively wipe out whatever benefits it would otherwise derive from seeking an alternative supplier at that time. Finally, Co-Steel argues that the proposed elimination of the current interruptible credit in the HTS tariff for customers who switch suppliers would completely offset the benefits of the HTS shopping credit, thereby economically preventing such a customer from switching suppliers.

11. <u>PP&L Energy Plus</u>

PP&L, which was not a signatory to either the Stipulation or Stipulation II, filed comments addressing both stipulations. PP&L indicates that it has not joined in either settlement proposal, because of significant issues with both. PP&L also indicates that it currently serves a large amount of competitive retail load in Pennsylvania, unlike some other retail suppliers active in these proceedings. It asserts that neither stipulation adequately balances full and fair recovery of validly incurred stranded costs with robust shopping credits. PP&L challenges PSE&G=s assertion that the Stipulation provides the largest shopping credits in the country, indicating that while this may be true on an average basis, the uneven distribution of shopping credits results in certain classes of customers having credits well below those provided to PECO customers, and that this will adversely impact competition for medium-sized commercial and industrial customers. PP&L asserts that the PECO shopping credit and the PECO settlement were addressed in the record in this matter, and argues that while the Stipulation=s shopping credits are 2 mills higher than PECO=s for residential and large industrial customers, representing those customers least likely and most likely to shop, respectively, they are 5.9 mills and 13 mills lower for LPL-S (general service-secondary) and LPL-P (primary distribution) customers, respectively. While Stipulation II does a better job of trying to ensure adequate credits for mid-sized customers, according to PP&L, it still falls short of a balanced, even distribution when compared to PECO=s credits, with shopping credits for residential and large industrial customers even higher than the Stipulation=s, but with LPL-S and LPL-P credits still 11.8 mills and 3.7 mills lower, respectively, than the PECO credits.

PP&L agrees with the supporters of Stipulation II that there are certain cost differences between PECO and PSE&G such as taxes, transmission costs and congestion costs. However, PP&L does not agree with the wholesale forward energy and capacity projections set forth in Stipulation II. Therefore, while generally in favor of higher credits, PP&L proposes alternative shopping credits which, it asserts, are the minimum necessary to support robust competition for all customer classes, while balancing the interests of all concerned. PP&L proposes only modest increases to the shopping credits proposed in the Stipulation for medium-sized commercial and industrial customer classes, which, it asserts, only raise the average system credits by less than 1 mill per kwh over those in the Stipulation.

PP&L also asserts that the manner in which the Stipulation proposes to show rate reductions on customers' bill is confusing, and has provided alternative, simpler billing formats. Additionally, while supporting the generation asset transfer in the Stipulation, it also supports strengthening the codes of conduct language in paragraph 30. Finally, PP&L opposes the Third Party Supplier Agreement embodied in the Stipulation, and favors instead a collaborative approach to these issues as proposed in Stipulation II.

12. New Jersey Commercial Users

NJCU, a signatory to the Stipulation, simultaneously filed its comments in support of the Stipulation and its response to Stipulation II. NJCU asserts that the provided rate reductions in the Stipulation are consistent with NJCU's litigation position that rates be reduced by 13.4% from current rates, the findings of the ALJ that PSE&G=s rates be reduced by 10-12%, and the Act=s requirements that rates be reduced initially by at least 5% from current rates, and by at least 10% from April 30, 1997 rates within 36 months. NJCU indicates that it shares the RPA=s concerns as reflected in Stipulation II with respect to a potential rate spike in year five.

With regard to shopping credits, NJCU takes issue with the RPA=s assertion that the Stipulation II shopping credits Aclosely approximate@ the PECO shopping credits. NJCU asserts that the substantially higher Stipulation II residential shopping credits come at the direct and sole expense of the shopping credits for small businesses, an approach which it maintains is inconsistent with the PECO credits and which will assertedly adversely impact the ability of small businesses to realize savings by shopping. Moreover, NJCU finds the price increases made in the competitive energy marketplace to be Avery troubling@ and inconsistent with the goals of restructuring. NJCU specifically points to the assertions via affidavit by MAPSA that shopping credits must be increased above the PECO levels to reflect higher wholesale power costs. NJCU asserts that such developments are inconsistent with the goals of restructuring as embodied in the Board=s Final Report and in the policy declarations in the Act, specifically that it is the policy of this State to Aplace greater reliance on competitive markets, where such markets to exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service.@ N.J.S.A. 48:3-50(a)(2). It postulates that the early results of competition in Pennsylvania which assertedly have resulted in significant increases despite offsetting reductions, may suggest that marketers are reaping a disproportionate share of the benefits of competition.

NJCU notes that the rate unbundling provisions in the Stipulation reflect and resolve the concerns with respect to the PSE&G filing which NJCU raised during the litigation phase and with which the ALJ concurred in the I.D., specifically, to eliminate the significant intra-class cost impacts in the initial unbundling and instead achieve intra-class neutrality; to develop an explicit MTC as opposed to an implicit MTC; and include a market capacity credit in addition to a market energy credit. These provisions are also consistent with the provisions of the Act, according to the NJCU. It also notes that the Stipulation reflects an adjustment to the 1995 cost of service study which reduces the cost of capital to 9.5 percent to reflect reduced risk associated with the distribution function, which produces a $20 million reduction.

With regard to stranded costs, NJCU asserts that, with one exception, the Stipulation is consistent with its litigated position that there either be a direct sharing of stranded costs or an indirect sharing via implementation of a minimum 10% base rate reduction. The Stipulation, by reducing the stranded cost recovery opportunity from $3.9 billion as requested, to $3.075 billion, produces a 20% reduction in the requested amount. Moreover, such recovery is not guaranteed, while any overrecovery will be returned to ratepayers. NJCU did reserve in the Stipulation its right to challenge the tax treatment on securitization. It does not dispute that there may be certain tax liabilities associated with securitized stranded costs; however it concurs with the position expressed in Stipulation II that actual taxes associated with the transition bonds should be collected through a separate MTC, subject to true-up, rather than through the transition bond charge. With regard to the Genco transfer, NJCU recognizes that reasonable parties can disagree, but believes that the assigned transfer value is within the range of reasonableness and is therefore acceptable. NJCU further notes that, through oversight, paragraph 30A of the Stipulation does not reflect its agreement with the affiliate code of conduct espoused by Enron.

13. Tosco

Tosco, a signatory party to the Stipulation, asserts that the Stipulation represents a full and fair resolution of this matter and will provide for necessary finality and expeditious decision, and that any re-opening of the record, as suggested in Stipulation II, will virtually insure delay such that retail choice will not be implemented by August 1, 1999, as required by law. It argues that competitive markets, asset valuations and restructuring activities are evolving on a continuing basis; if that were the basis for reopening, the record would never close. It submits that the record position of PSE&G has been substantially modified because there is a true cap on all bill elements and accelerated rate reductions for all customers; there is a shopping credit at the very top end of a reasonable range; there are reductions in stranded costs of $0.825 billion; and there is true restructuring, with generation going out to bid on a competitive basis in year four. It also notes that through legislative resolution, on-site generation is enabled to develop without exit or like fees.

14. Independent Energy Producers of New Jersey

IEPNJ, a signatory party to the Stipulation, asserts that the Stipulation succeeds on several fronts, by providing rate reductions of nearly 14%; providing shopping credits well ahead of those in New England and in line with those in Pennsylvania; providing a reasoned approach to the treatment of stranded costs; providing a framework for the development of a competitive market; and complying with all provisions of the Act. It notes that PSE&G has abandoned a claim to recover over $570 million of stranded costs, including significant investment in upgrades and repairs at the Salem nuclear plants, which significantly contributes to the rate reductions being offered, and that PSE&G is also at risk for recovery of the $600 million of unsecuritized stranded costs. It maintains that the Stipulation provides a road map to a competitive energy market by transferring generating assets to a separate, competitive arm of the PSE&G holding company, including the development of accounting protocols and a code of conduct to govern relationships between PSE&G and Genco, with no preference to be offered by PSE&G to Genco. In this regard, IEPNJ recommends adoption of the affiliate code of conduct language proposed by Enron as reflected in paragraph 30A of the Stipulation.

15. Enron

Enron, a signatory to the Stipulation, recommends its adoption as being consistent with the intent of the Act and supported by the record in these proceedings. Enron also notes that the level of shopping credits is consistent with the testimony of Enron and other witnesses during the OAL proceedings who testified in support of shopping credits at levels which will establish a robust competitive marketplace; that the shopping credits in the Stipulation are among the highest in the country; and that the Stipulation is also consistent with the ALJ's recommendation in establishing a 2 mill per kwh adder. Enron also supports the provision in paragraph 36 of the Stipulation wherein the parties agree to work cooperatively to conclude the metering and billing proceeding in an expedited fashion, no later than May 1, 2000, as compared to the legislative requirement in section 6 of the Act, N.J.S.A. 48:3-54, that such proceeding be completed by August 2000. Finally, Enron supports the affiliate relations standards language set forth in paragraph 30A of the Stipulation.

16. Rockland Electric Company

RECO, which was not a signatory to either the Stipulation or Stipulation II, takes no position either in support of or in opposition to the Stipulation. RECO emphasizes that the Board=s ultimate decision in its pending restructuring-related proceedings must be based on the merits of a RECO-specific stipulation or an evaluation of the record evidence submitted to the ALJ and the Board in those proceedings. The PSE&G decision or components thereof should not bind RECO nor be evidentiary with respect to resolution of RECO=s proceedings, nor should it be considered a Athreshold@ for settlement discussions in RECO's proceedings.

17. National Energy Marketers Association

NEMA, a trade association of wholesale and retail marketers of electricity, which was granted participant status in the restructuring proceedings by the Board by Order dated July 30, 1998, was not a signatory to either the Stipulation or Stipulation II. NEMA asserts that the Stipulation falls short of the goals in both the Board's Final Report and in the Act. NEMA is specifically concerned with regard to the valuation and transfer of generation assets, and the development, cost allocation and proper valuation of shopping credits for each ratepayer class. NEMA submits that proper generation asset valuation is critical to a competitively neutral, price-competitive marketplace, particularly in light of a transfer to an unregulated affiliated entity. Absent an actual sale, NEMA is concerned that the valuation placed on the assets based upon an administrative estimate may be understated, and that such undervaluation not only increases stranded costs, but unfairly subsidizes a competitive advantage for the entity receiving the undervalued asset.

NEMA asserts that shopping credits have been used in early stages of restructuring as a proxy for the complete unbundling of otherwise bundled utility generation services. If shopping credits are set too low, competition will not occur, consumers will not be able to experience savings, and competitive suppliers will not participate in the New Jersey market nor make long term investments in infrastructure. NEMA contends that the level of shopping credits in the Stipulation do not properly value the assets and services to be replaced by competition, and are therefore inadequate. NEMA submits that shopping credits developed using actual or projected costs do not reflect the full unbundled cost of generation and related services; consequently the Stipulation's shopping credits undervalue the true cost to ratepayers for these services. It also argues that the shopping credits are also significantly understated relative to both today's market values as well as any reasonable forecast of future market values.

NEMA proposes that the Board commit the parties to reconvene settlement discussions, to address the proper determination of stranded costs implicit in the transfer of generation assets, the development of affiliate rules and codes of conduct, and the development of shopping credits that more accurately reflect the full regulated costs of generation and related services.

18. <u>Exelon Energy</u>

Horizon Energy Company, d/b/a/ Exelon Energy is a marketer/aggregator that provides electric service to retail electric customers throughout Pennsylvania and currently provides natural gas service at retail in New Jersey, and Exelon Management and Consulting is a broker that facilitates transactions between buyers and sellers of energy. A subsidiary and division, respectively, of PECO Energy Company, they are referred to collectively as Exelon. Exelon moved to intervene in the restructuring proceeding on February 4, 1999 and was granted participant status by the Board on March 18, 1999. Exelon asserts to have a substantial interest in the proceeding and submitted comments addressing both stipulations, with respect to certain issues that assertedly are critical to the creation of a competitive retail electricity market. Exelon maintains that the shopping credit is the most critical factor in creating a viable competitive retail electricity market; if the credits are too low, customers, particularly residential, will not shop because the low level of savings will not justify the customer=s time and effort evaluating offers and selecting a supplier. The highest level of residential customer interest in Pennsylvania is in PECO's service territory, which has the highest residential shopping credit. It submits that the shopping credit levels in Stipulation II reflect credit levels that are necessary in New Jersey to create competition. Exelon also suggests that transmission costs should be backed out of the shopping credit to avoid confusion, or that PSE&G should be required to commit to the transmission rates that are incorporated into the shopping credits. Exelon supports Enron=s alternative Code of Conduct as set forth in paragraph 30A of the Stipulation. With regard to Attachment 6 to the Stipulation, Exelon identifies a number of proposed tariff revisions which it maintains are either contrary to the Act or not in the public interest.

B. Comments on Stipulation II

Comments on Stipulation II, to the extent not jointly included in comments previously submitted in response to the Stipulation, were submitted by the following parties: RPA, PSE&G, MAPSA, NJBUS, IEPNJ, GPU and ACE. These comments are summarized below.

1. Division of the Ratepayer Advocate

The RPA's comments in support of Stipulation II repeat many of the key elements and rationale for the proposal which were included in the original submission and summarized previously, and thus will not be repeated at length here. In short, the RPA asserts that Stipulation II is superior to the Stipulation because it does a better job of balancing all of the interests, as it will allow customers to save additional money through a vibrant competitive market; achieve sustained rate reductions beyond year four; and will allow PSE&G to recover and securitize a Agenerous@ level of stranded costs and to earn a fair return, thus maintaining the Company=s financial integrity. The RPA submits that the Board must balance the interests of ratepayers in terms of rates and service with the interests of the utility in maintaining its financial integrity, and must include in its review the policies embodied in the Act. The RPA argues that Stipulation II achieves the appropriate balance of these goals and interests, with appropriate deference to the Act's mandate for rate discounts and the establishment of a competitive energy marketplace.

In support of its assertion regarding the impact of Stipulation II on PSE&G, the RPA points to its testimony in the proceedings which it asserts demonstrated that PSE&G could reduce its rates by 18.9% from current levels (15% from April 30, 1997 rates) for the duration of the then-proposed seven year transition period, not including the savings from securitization, and to the ALJ=s findings that PSE&G could reduce its rates by 10-12% over seven years and maintain its financial integrity. It asserts that the rate reductions proposed in Stipulation II are substantially below and of a shorter duration than both the RPA=s initial proposal and the ALJ=s recommendation, that the level of stranded cost recovery and securitization in Stipulation II are substantially higher than in its litigated case, and that PSE&G=s financial condition has improved since these proceedings began as supported by an attached affidavit from its witness Rothschild. Mr. Rothschild asserts, among other things, that Wall Street analysts are predicting positive earnings potential for PSE&G's parent company, Public Service Enterprise Group (APEG@), which would produce, if achieved, a return on equity of 11.9% to 12.7% for PEG, which is higher than the return found reasonable by the ALJ in this matter; that there has been a substantial run-up in PEG=s common stock price over the past two years; and that debt costs have declined by 50 basis points since the period of time analyzed in the record. All of these factors, it is asserted, lead to the conclusion that rates could be reduced another 6.75% beyond the rate reductions in Stipulation II and be absorbed by what would otherwise be Aexcess earnings.@ Therefore, he submits that the Company will be able to maintain its financial integrity throughout the six years encompassed by Stipulation II.

The RPA further asserts that Stipulation II's proposed treatment of the Genco transfer is far more balanced and appropriate than what is proposed in the Stipulation.

2. PSE&G

PSE&G asserts that Stipulation II should be rejected. It maintains that Stipulation II is not a Astipulation@ at all since it is not the product of negotiations between adverse parties but rather a joint effort by parties with similar positions to reiterate their litigation positions. PSE&G further asserts that Stipulation II is, in effect, a new motion to reopen the record, which the Board has previously denied. PSE&G argues that to the extent Stipulation II constitutes a new motion to reopen, it is barred by the doctrines of Res Judicata and the Law of the Case. PSE&G further argues that Stipulation II inappropriately relies upon inadmissable hearsay affidavits containing extra-record materials, the nature of which the Board has already properly determined it will not consider. PSE&G further argues that the cases cited by Stipulation II regarding the alleged need for further evidentiary hearings are wholly inapplicable.

PSE&G asserts that the rate reductions cannot be sustained as proposed in Stipulation II without securitization. PSE&G submits that subsections 14(a) and 4(i) of the Act, N.J.S.A. 48:3-62(a) and N.J.S.A. 48:3-52(i), contemplates that securitization will provide a source for the funding of rate reductions; however Stipulation II, while suggesting that the rate reductions not be tied to securitization, offers no reasonable alternative source of funding. Moreover, PSE&G argues, Stipulation II ignores the fact that if PSE&G cannot securitize $2.475 billion of stranded costs, it would be forced to recover that amount via an MTC, which would require recovery of $620 million per year, plus a return on the unamortized balance and taxes during the transition period, which would actually produce a rate increase.

PSE&G notes that the proposed extension of rate reductions to distribution rates in years five and six and beyond in Stipulation II is not achievable. PSE&G notes at the outset that the basis for this extension is primarily provided via the affidavit of a new consultant, Mr. Rohrbach, who assertedly relies on hearsay information, is unfamiliar with the relevant testimony and record, and ignores or disregards that record, producing errors and misassumptions. The four alleged sources of rate reductions in years five and six and beyond are addressed by PSE&G as follows: First, Stipulation II claims that $290 million will be available from the use of 60% of the distribution depreciation reserve of $569 million. This ignores the fact, as reflected in the record, and consistent with the Stipulation, that all of the depreciation reserve is relied upon in assisting the funding of stranded costs and achieving the rate reductions during the Transition Period; accordingly none of the depreciation reserve will be left to fund rate reductions in years five and six. Second, Stipulation II proposes to use $35 million of expiring amortizations to offset rate increases. In fact, these amortizations, which terminate in 2000, are already included as a source of funding for the rate reductions in the Stipulation. Moreover, while Stipulation II assumes a gross-up of the expired amortizations to come to a pre-tax value of $63 million, PSE&G contends that this ignores the record evidence that the amortization value of $35 million is already a grossed-up amount. Third, Stipulation II utilizes $90 million of stranded costs related to the Salem generating plant as reflected in the Stipulation to fund additional rate reductions in years five and six. While the ALJ concluded that all Salem capital additions were appropriately included in stranded costs, PSE&G agreed to a $90 million disallowance, which has already been accounted for as part of the $225 million reduction in the recovery of stranded costs from $3.3 billion to $3.075 billion. Fourth, Stipulation II calls for the use of an alleged $90 million LEAC overrecovery to support future rate reductions. PSE&G states that this number is an error; the amount of the overcollection which is relevant is $60 million, not $90 million, and that this LEAC overrecovery is already accounted for in the Stipulation as part of the aforementioned $225 million reduction in recovery of eligible stranded costs.

PSE&G cites additional errors and/or misassumptions in the analysis underlying Stipulation II=s rate reductions in years five and six. First, Stipulation II states that the reductions it proposes in years five and six will require rates to be reduced by $900 million over the two year period. In reality, at the recommended 14.05% rate reduction during years five and six, set forth in Attachment B, Table 2 of Stipulation II, the real value of such reductions would be over $1.2 billion according to PSE&G. Second, Stipulation II provides that certain categories of available sources for reductions in years five and six should be grossed-up for taxes. Specifically, the Abalance in distribution depreciation adjustment@ in Attachment B, Table 1 is erroneously grossed-up, since it applies to a number which is already pre-tax. Combined with the aforementioned tax gross-up error on the expiring amortizations, PSE&G asserts that these two errors alone result in Table I of Attachment B overstating potential sources of funds by $144 million. Third, Stipulation II alleges that the Stipulation understates the savings from securitization because it does not extend the calculation of the benefits of securitization beyond the transition period. PSE&G asserts that this is a "regurgitation" of the RPA witness Dirmeier's testimony in the proceeding which was already addressed and rebutted via its witnesses, Murray and Krueger. In fact, because securitized bonds permanently replace higher cost capital, there is a permanent reduction in revenue requirements accompanying the lower bond payments, the net effect of which is a long term savings which does not expire at the end of the transition period. Fourth, Stipulation II assumes further rate reductions from growth in kwh sales. However, according to PSE&G, this totally ignores the fact that the Stipulation already accounts for the sales growth effect during the transition period which reduced the securitization charge. Fifth, Stipulation II recommends that rates stay at the same reduced level in year seven and thereafter unless PSE&G proves the need for an increase in a rate case. PSE&G points out that for a distribution company with $830 million in revenues, to keep rates reduced by approximately $600 million per year would require more than a rate case; it would destroy the Company financially and/or lead to substantial workforce reductions and threaten service quality.

PSE&G emphasizes the alleged absurdity of Stipulation II by pointing to the unbundled rates it would produce at the end of the transition period. The average shopping credit would be 5.4 cents, or 60% of the bill, as opposed to a distribution rate of 2.03 cents, or 20% of the bill; yet Stipulation II recommends that additional rate reductions come from the distribution business rather than through other parts of the rate. This proposal in Stipulation II would result in the relatively small distribution company subsidizing marketer profits. PSE&G further points out that the affidavit of Mr. Rohrbach supporting the Stipulation II rate reductions, which represents that he participated in the PECO settlement discussions, expresses concern with a possible increase in PSE&G=s 2003 rate from 9.0 to 9.90 cents, while the PECO rate in 2003, which he participated in establishing, will be 9.96 cents.

PSE&G further asserts that Stipulation II=s claim that it provides an opportunity to recover the same amount of stranded costs as the Stipulation, is false. In fact, as evidenced by Attachment A to Stipulation II, the Company will only be given an opportunity to recover $268 million of unsecuritized stranded costs. Moreover, according to PSE&G, while Attachment B Table 1 to Stipulation II creates the impression that PSE&G has $4.3 billion dollars available to cover its stranded costs, other than the listed items concerning securitization (the value of which is assertedly overstated) and the distribution depreciation amortization (listed as available only in the amount of $170.35 million), none of the listed Aopportunities@ are in fact available for stranded cost recovery. First, PSE&G argues that Stipulation II's proposal to disallow one-half of bond issuance and transaction costs, leading to an effective reduction in stranded cost recovery of $62.6 million is not supported by the Act or the evidence. Second, PSE&G takes issue with Stipulation II's retention of a 7.3 mills per kwh retail adder for those customers who do not shop, totaling a $54.64 million contribution to stranded costs. PSE&G asserts that the proposed 7.3 mill adder is unsupported in the record, and cannot be relied upon. Third, Stipulation II relies on the retention by PSE&G of 40% of the net present value of the distribution depreciation amortization, or $170.35 million, as a contribution towards stranded cost recovery. PSE&G maintains that the record in the case demonstrates that all of the depreciation amortization will be needed to fund stranded cost recovery and the rate reductions, and will not be available to pay for rate reductions in years five and six. Fourth, Stipulation II identifies the "Genco Transfer Premium@ as an additional stranded cost recovery opportunity. In fact, PSE&G asserts there is no such premium; the proposal in Stipulation amounts to nothing more than a $600 million disallowance of stranded costs based upon a superficial plant value analysis. Fifth, Stipulation II purports to allow the Company to retain $43 million in Anon-credited cost reductions@ which would otherwise be passed through to customers via rate reductions, for stranded cost recovery. PSE&G asserts that the alleged savings to be used to fund the proposed rate reductions in years five and six will not, in reality, be available for such purposes, because they are already being relied upon to fund the rate reductions during the transition period or stranded cost recovery.

Finally, PSE&G notes that Stipulation II identifies $828 million of Amitigation opportunities@ as additional Astranded cost recovery opportunities.@ PSE&G asserts that these alleged mitigation opportunities, originally proposed by the Auditors, were unfounded and explicitly rejected by the ALJ in his I.D. Moreover, PSE&G contends that use of the $828 million is in error for three reasons: 1) it is a pre-tax number; it would have to be reduced to $330 million to bring it to a net-of-tax basis consistent with the stranded cost amount; 2) approximately half of this amount is related to generating facilities and accordingly these mitigation savings have already been reflected in the reduction of stranded costs from $3.9 billion to $3.3 billion; and 3) a portion of these savings relate to transmission rates which are regulated by the FERC. Correcting these alleged errors reduces the claimed $828 million of mitigation to less than $250 million, which is far less than the amount of stranded cost recovery for which PSE&G is at risk, since it has already agreed to cap unsecuritized stranded costs at $225 million less than the total, and because the primary source of the opportunity is via the retail adder, which PSE&G loses as customers switch suppliers. PSE&G claims that assertion in the Mr. Dirmeier's affidavit attached to Stipulation II, that the Company is not at risk for the $600 million, is in error since he fails to account for income taxes associated with the depreciation reserve amortization and thereby overstates stranded cost recovery by approximately $100 million (from $458 million to $357 million). In addition, PSE&G claims that the contribution to stranded cost via the retail adder is overstated in Mr. Dirmeier's affidavit, since it relies on a very low shopping rate which is not even consistent with the shopping rate assumed in Mr. Rohrbach's affidavit attached to Stipulation II. When these errors are corrected, the actual retention rate from the depreciation amortization and the retail adder is asserted to be $456 million, or 76% of the $600 million, not the erroneous 96%.

Contrary to the assertions of Stipulation II=s proponents, PSE&G asserts that the generation asset transfer is discussed and supported in the record. It maintains that there was extensive testimony regarding the need for separation of generation from the utility, as well as the value of the assets, and the benefits of removing the risk of nuclear operations from ratepayers. Moreover, contrary to the suggestions by Stipulation II=s proponents, subsection 7(d) of the Act, N.J.S.A. 3-55(d), specifically contemplates the transfer of assets from a utility to a related competitive business segment of the holding company. PSE&G contends that efforts in affidavits attached to Stipulation II to show the $1.768 billion asset valuation too low are flawed, because they rely on hearsay information and a third party report, and because no attempt was made to assess whether any of the data from recent sales is relevant to the specific PSE&G plants being transferred. With regard to the proposal in Stipulation II regarding Codes of Conduct, PSE&G asserts that the proposal assumes market power which has not been proven or found, would render Genco a State-regulated generation company limited to electronic bulletin board transactions, intrudes on FERC-jurisdictional issues, and is inconsistent with the Act. PSE&G asserts that Board regulation of affiliate transactions should be limited to ensure that there is no cross-subsidization or improper exchange of "restricted information."

PSE&G further asserts that, contrary to those in Stipulation II, the shopping credits proposed in the Stipulation are supported by record evidence (Exhibit EN-35(R), pp.10-13; RA-35, pp.3-5), and will encourage competition, while avoiding burdening customers who remain with PSE&G from subsidizing those who choose other suppliers, and maximizing rate reductions. The Stipulation=s shopping credits are fixed, not floating as originally proposed by PSE&G, which marketers testified would be helpful, and they are market based and include a reasonable retail adder. PSE&G contends that the record shows that rate reductions cannot be achieved if the shopping credit is increased unduly. PSE&G further asserts that the "eleventh hour" attempt to increase shopping credits from the range in the Stipulation (5.03 to 5.10 cents) to 5.40 cents is based on erroneous and untimely assumptions and arguments. The assertion that suppliers will be unable to deliver savings at the Stipulation=s Atoo low@ shopping credit levels is undermined by Stipulation II=s own supporting affidavits, which claim that the PECO shopping credits have led to a vibrant competitive marketplace. PSE&G points out that the PECO shopping credits are, on average, virtually identical to those in the Stipulation, that suppliers in PECO are facing the same PJM region market conditions as will be experienced in New Jersey, and that the PECO shopping credits have not been increased to reflect alleged changes in market conditions as is being proposed here. Yet, according to Stipulation II=s own proponents, the

PECO marketplace is successful and PSE&G notes that the record in this proceeding includes testimony extolling the virtues of the Pennsylvania shopping credit. Moreover, PSE&G points out that one of MAPSA=s members sponsored public testimony by former by former Pennsylvania PUC Commissioner Hanger before the New Jersey Senate Committee considering restructuring legislation on November 12, 1998, stating that AGiven present market conditions, New Jersey will not create competition for residential and small commercial customers unless the residential shopping credit is approximately 5.0 to 5.5 cents per kwh.@ The residential credit in the Stipulation, which Stipulation II=s proponents claim is too low, is 5.86 cents, and no one has alleged that market conditions today differ from November 1998. Moreover, the alleged differences in cost between Pennsylvania and New Jersey which necessitate a higher credit than PECO amount to only about 1 mill per kwh; yet the Stipulation=s average shopping credit is this much higher than the PECO credit already.

PSE&G contends that the remainder and majority of the proposed adjustments to increase the Stipulation's shopping credits come from the unsubstantiated market price increase. PSE&G also asserts that there is no assurance that increased shopping credits will result in any savings to customers, as opposed to being retained by marketers as additional profits or to cover inefficient marketing or administrative costs. PSE&G takes issue with additional assertions in the affidavits attached to Stipulation II. While there is an assertion that shopping credits must be increased to 5.40 cents for PSE&G customers to receive the same rate discounts that PECO customers enjoy, in fact, the Stipulation provides shopping credits nearly identical to, and in fact slightly higher than, PECO=s, while regulated rates for PECO will be increasing over the next few years, and PSE&G=s will be decreasing. PSE&G also contends that the retail adder proposed in the Stipulation II is unsubstantiated and could have been presented for cross-examination in the case, but was not. It also argues that the claim that the Stipulation's shopping credit is more like the California and Massachusetts credits than like PECO is simply wrong: the record established that the California credit is a floating credit with no retail adder, as initially proposed by PSE&G, and that the Massachusetts credit was below market wholesale prices. The Stipulation's credits are fixed, not floating, like PECO=s, and are almost identical in magnitude to PECO=s.

3. <u>MAPSA</u>

MAPSA=s comments repeat the arguments accompanying and in support of the original filing of Stipulation II, and point to the support of the Ahuge majority@ of PSE&G customers and government organizations[8] that will be directly affected by this matter as an

[8] On March 30, 1999, the New Jersey State League of Municipalities sent a letter to the Board expressing its "unqualified support" for Stipulation II.

indication of Stipulation II=s superiority over the Stipulation. The MAPSA comments also include a supplemental affidavit by Mr. Rohrbach purporting to explain in further detail certain financial calculations, the impact of the shopping credit on PSE&G's cash flow, the rationale for the higher shopping credits proposed in Stipulation II.

The affidavit is argued to demonstrate that the financial impact on PSE&G associated with the higher shopping credits in Stipulation II would be Anegligible.@ MAPSA=s affidavit asserts that the nominal cost to PSE&G associated with the higher shopping credit, assuming shopping percentages ranging from 15%-25% for residentials to 100% for large industrials, is under $18.6 million per year; however, it is asserted that Genco can sell 50% of the power freed up by customers leaving BGS into the forward market at higher prices, thereby offsetting the net impact of the shopping credit by $6 million per year, to $12.6 million annually. MAPSA also asserts that the higher shopping credits will primarily benefit customers, through the opportunity for savings because in a competitive retail marketplace, marketers will not be able to retain a portion of the shopping credit as enhanced profits, but will have to pass the savings along to customers.

4. <u>New Jersey Business Users</u>

NJBUS reiterates the key reasons as to why, in its view, Stipulation II is preferable to the Stipulation. NJBUS asserts that Stipulation II provides a fair resolution of all the key areas of these proceedings, while at the same time agreeing for the purpose of settlement, to resolve many of the issues in a manner preferred by PSE&G. NJBUS points out that the rate reductions embodied in Stipulation II are identical to those provided in the Stipulation, and asserts that if Stipulation II is adopted, it would waive its objection to the @pre-funding@ of 1% of the securitization implicit in the rate reduction schedule, as well as its objections to the initial 5% reduction being taken from current rates rather than April 30, 1997 rates. Stipulation II also incorporates the implementation of the rate reduction per the PSE&G proposal, that is, via a restructuring rate reduction line item. However, NJBUS cautions that this mechanism will lead to an automatic rate increase of up to 13.9% after the transition period; Stipulation II essentially eliminates this rate shock by applying cost savings to which ratepayers are entitled, and which would otherwise be realized by shareholders under the Stipulation. Absent a settlement, NJBUS asserts that subsection 4(f) of the Act, <u>N.J.S.A</u>. 48:3-52(f), would require that rate reductions come from unbundled rate elements, rather than from credits applied to customers' bills. NJBUS accepts the restructuring rate reduction line item as allocating rate reductions in a fair manner to all customers, provided that increases in years five and six are eliminated.

NJBUS asserts that the Act does not permit securitization at the $2.475 billion level, but it agrees to waive its objection to this level in the interests of settlement based on either the mitigated stranded cost level available for recovery as calculated by PSE&G ($3.075

billion) or by Stipulation II ($2.475 billion). With regard to PSE&G's proposal to include $125 million of bond issuance and transaction costs as part of stranded cost recovery through securitization. NJBUS asserts that it is fairer to ratepayers that PSE&G be required to share the 50% of the bond transaction costs, as proposed in Stipulation II. NJBUS also asserts that Stipulation II is superior to the Stipulation because it properly recognizes the full market value of the Company's owned generation plants. NJBUS maintains that the $600 million of unsecuritized stranded costs can be reduced to zero by properly crediting ratepayers with the $600 million attributable to the above net book market value of the generating assets. NJBUS notes that Stipulation II's agreement to allow the immediate transfer of PSE&G=s generating assets, and thereby waive the protection of an ongoing review and true-up of the amount of stranded costs, is contingent on valuing the assets at $2.9 billion ($2.4 billion net of taxes), as compared to the asset transfer value of $1.768 billion implicit in the Stipulation. NJBUS states that the $2.9 billion asset value is based upon a November 12, 1998 report of Resource Data International, Inc. which sets forth average market recoveries for 35,000 MW of generation plant sales nationally over the prior 18 months. It asserts that subsection 11(d) of the Act, N.J.S.A. 48:3-59(d), requires that the full market value of the assets be credited to offset stranded costs.

Finally, NJBUS reiterates the arguments presented in the Stipulation II filing and summarized above with respect to the need for the higher shopping credits in its proposal.

5. Independent Energy Producers of New Jersey

IEPNJ opposes the adoption of Stipulation II, and reaffirms its support for the Stipulation. In its view, Stipulation II reflects an effort to Acherry pick@ the ideal solution on every issue, and is ultimately illusory and unobtainable and, indeed, disingenuous in many respects. IEPNJ maintains that Stipulation II was crafted in a vacuum, without regard to the record developed in this matter and without an effort to reconcile the diverse interests of the parties. While Stipulation II incorporates the elements of the Stipulation concerning recovery of NUG costs in an NTC, IEPNJ points out that it has no Abetter choice@ than to accept these terms for NUG cost recovery since they are required by the Act as well as by a prior Third Circuit Court decision. However, IEPNJ asserts that the RPA attempts to Atweak@ the legislative guarantee of full recovery of NUG contract costs by arguing that PSE&G should be required to maximize the market value realized from the resale of purchased NUG power and thus mitigate stranded costs, and that PSE&G should attempt to mitigate, in particular, the NUG contracts held by its own affiliates. IEPNJ argues that such efforts to impose a mandatory mitigation obligation on PSE&G are inconsistent with the Act and with applicable case law.

6. Jersey Central Power & Light Company, d/b/a GPU Energy

GPU, which was not a signatory to either stipulation, addresses certain procedural aspects of Stipulation II, but does not discuss any of the specific terms that might be included in any Board Order resolving this matter. GPU argues that Stipulation II should not be considered a competing settlement proposal but, rather, should be regarded as simply joint comments on the Stipulation, or a position paper, rather than a competing settlement proposal. It submits that there can be no true settlement reached that does not include the Company, the primary moving party to the case, particularly when the outcome of the case will primarily and directly impact the financial condition of PSE&G. It notes that conversely, the goals of the parties to Stipulation II, whose interests are all more or less aligned on the same side of the issues, can be achieved essentially without cost to any of those parties, and accordingly, unlike PSE&G, the parties to Stipulation II have few practical restrictions in striking a deal which serves their own interests, without taking into account the impact on PSE&G. PSE&G argues that, by definition, such a one-sided Asettlement@ cannot be viewed as such in the true sense of the word, since it is devoid of the type of give-and-take compromises that are the essence of a true settlement, and thus, it should not be accorded the weight of a true settlement.

7. Atlantic City Electric

ACE, which was not a signatory to either stipulation, neither endorses nor opposes the adoption of the Stipulation, but opposes adoption of Stipulation II, since the principles underlying Stipulation II could have adverse consequences for other utilities, including ACE. ACE submits that the proposals in Stipulation II are not supported by the record, and that their adoption would violate the parties= due process rights. It further contends that Stipulation II includes arbitrary shopping credits set based upon the wishes of large energy marketers and not on the costs of providing basic generation service. As well in its view, the proposal rests on improper interpretations of the Act with regard to securitization and rate reductions. ACE objects to a utility being forced to reduce its stranded cost recovery in order to fund an arbitrarily-set shopping credit, as it maintains is the case with the credits embodied in Stipulation II.

DISCUSSION AND FINDINGS

As noted above, since the close of hearings in these proceedings, the New Jersey State Legislature passed, and on February 9, 1999 Governor Whitman signed into law, the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. The Act in numerous areas sets forth explicit directives with respect to the implementation of electric retail choice and, during the Transition Period, the Act establishes minimum aggregate rate reductions for electric public utilities. It also provides specific guidelines and parameters for the Board to follow with respect to a myriad of restructuring related issues, but in many areas leaves important decision-making details to the expertise of the Board consistent with those guidelines and parameters. The Act requires that each electric public utility submit rate unbundling, stranded cost and restructuring filings to the Board, in a form to be determined by the Board, and it explicitly provides that filings submitted and proceedings conducted prior to the Act=s effective date satisfy such requirements, provided that the Board shall take such actions as may be necessary, if any, to ensure that the requirements of the Act are met in all regulatory actions related to the Act which were commenced prior to its enactment. N.J.S.A. 48:3-98. The Board **HEREBY FINDS** that this requirement of the Act has been met and that the filings submitted and the proceedings conducted prior to the Act's effective date were thorough and complete and provide an adequate record, and therefore satisfy the Act's requirements.

As summarized in some detail hereinabove, the Board has, by virtue of the issuance of its April 30, 1997 Order adopting and releasing the Final Report and the subsequent Board-directed electric public utility filings on July 15, 1997 and ensuing hearings at the OAL and before the Board, caused to be developed an extensive evidentiary record in these proceedings, and has provided substantial opportunity for public input in both the development of its policy findings and recommendations as set forth in its Final Report, and in the subsequent Board-directed rate unbundling, stranded cost and restructuring filings and related proceedings. As noted above, twenty days of evidentiary hearings were held at the OAL on the stranded costs and unbundling issues, and an additional twenty days of evidentiary hearings were held before Commissioner Armenti on the restructuring issues.

In reviewing the voluminous record before us, it is clear that many of the significant aspects of and issues in these proceedings are factually interrelated, with the outcome of one materially impacting decisions in other areas. This is particularly the case with respect to the level of rate reductions, the level of stranded costs, the level of shopping credits, and the various components of unbundled rates. In transmitting these matters to the Office of Administrative Law, the Board, in anticipation of the enactment of legislation in this area, requested that the Administrative Law Judges in this and the other electric public utility proceedings develop a broad record on stranded costs and unbundling issues and, specifically, with respect to the issues of rate reductions, stranded costs and securitization, issue a range of recommendations. With the passage of the Act, with its explicit directives and guidelines and parameters, the Board is now prepared to render decisions with respect to the subject issues in these proceedings in conformance therewith, based upon the record developed and comments provided, and in a time frame necessary to comply with the retail choice time line set forth in the Act.

We acknowledge and appreciate the efforts of ALJ McAfoos in presiding over the stranded costs and unbundling proceedings and in producing a detailed and thorough Initial

Decision. In light of the enactment of the new legislation and the subsequent developments in the case as described hereinabove, we **HEREBY MODIFY** the Initial Decision as follows:

Subsequent to the close of hearings and the issuance of the Initial Decision, shortly after the Act was signed into law, and with the encouragement of the Board, as set forth in our February 11, 1999 Order, settlement conferences were held among the parties. These discussions ultimately led to a crystallization of the issues and the proffer of two alternative settlement proposals which are before us for consideration along with the Initial Decision and the evidentiary record developed before ALJ McAfoos and the Board. We are cognizant of the fact that each of the proposed stipulations before us is non-unanimous. Nonetheless, it is well-established that the Board may consider and rely upon non-unanimous stipulations as fact-finding tools so long as the Board independently examines the existing record and expressly finds that the stipulated rates yield rates that satisfy the statutory standards. I/M/O Petition of PSE&G, supra at 270. We continue to believe that, in complex and technical cases such as this one, "the adversary parties themselves are often in the best position to work out the framework of a reasonable resolution of the issues." Id. at 259. We **FIND** that in the instant matter, all of the parties in this case were given an opportunity and, indeed were urged by the Board, by Order dated February 11, 1999, to participate in an attempt to negotiate a settlement and we **FURTHER FIND** that all parties were given an opportunity, via the submission of written comments, to raise their concerns to the Board with respect to the alternative stipulations which were proffered to the Board for its consideration. Id. at 270. We **HEREBY REJECT** the contention of some of the parties in their comments that there is a need to reopen the record for additional evidentiary hearings in light of the passage of the Act and/or the content of the settlement proposals, essentially for the reasons set forth in our March 25, 1999 Order denying MAPSA's initial motion to reopen and supplement the record. We **FIND** that the evidentiary record before us as summarized hereinabove, is sufficiently comprehensive and detailed to allow us to fully consider all of the issues before us.

As stated in our Summary Order in this matter, and as will be explained below, based on our review of the extensive record in these proceedings, as well as the two alternative stipulations and the comments received thereupon, we **FIND** the PSE&G-sponsored Stipulation to be, overall, more financially prudent and consistent with the Act's requirements and consistent with the record. We **FURTHER FIND** that with the modifications and clarifications to a number of key elements, as set forth in our Summary Order and amplified herein, the Stipulation can serve as a reasonable framework for a fair and reasonable resolution of these matters based upon and consistent with the record before us. Conversely, as described below, we **FIND** Stipulation II, sponsored by the Ratepayer Advocate and other parties, to be, in many significant areas, not supported by the record, reliant upon miscalculations and inappropriate assumptions or conclusions, and not reflective of a balanced consideration of all the issues in these matters. However, a number of specific and legitimate concerns have been raised by the commentors, including the proponents of Stipulation II, and where appropriate and as discussed below, these have been addressed by the modifications and clarifications to the Stipulation set forth hereinbelow.

First, with regard to the issues of the magnitude of the rate reductions and the shopping credits, we note the following with respect to the provisions of the Act. Section 4 of the Act, N.J.S.A. 48:3-52, requires that as of August 1, 1999, each electric public utility must reduce its aggregate level of rates, inclusive of all unbundled rate components, by at least 5%. Section 4 of the Act further provides that the Board may adopt a schedule for the phase-in of additional rate reductions over the ensuing 36 months, except that, in any event, by no later than August 1, 2002, each electric public utility shall reduce its aggregate level of rates by at least 10% relative to the level of bundled rates in effect as of April 30, 1997 (since PSE&G received a 3.9% overall increase in rates subsequent to April 30, 1997 to recover DSM program costs, this provision, in effect, requires a 13.9% reduction from current rates by PSE&G by no later than August 1, 2002), and each electric public utility shall sustain such final level of rate reduction for at least 12 months, through at least July 31, 2003. These provisions of the Act essentially establish a price cap under which all unbundled rate elements must fit during the four year period from August 1, 1999 through July 31, 2003. As such, to the extent one unbundled rate component is increased, all other things remaining equal, either one or more other unbundled rate components must be decreased, or the overall aggregate level of rate reduction must be reduced from what it otherwise would or could have been. This relationship is particularly relevant given the requirements and provisions of subsections 4(b) and 4(f) of the Act, N.J.S.A. 48:3-52(b) and (f), specifically those provisions which require the Board to establish shopping credits, applicable to the bills of retail customers who choose to purchase electric generation service from a duly licensed power supplier, at levels which, among other things, encourage the development of a competitive retail supply marketplace, while at the same time providing and sustaining the required aggregate level of rate reductions. Put simply, under a price cap as mandated by the Act, once the other unbundled rate components, including provisions for stranded cost recovery, are established, higher shopping credits would result in lesser rate reductions, and vice versa, absent a deferral of the recovery of costs into some future period. In a very real sense then, the Board is required by the Act to balance the achievement of two crucial, yet potentially conflicting factors. All other things being equal, a movement too far in one direction, in favor of larger shopping credits at the expense of lesser rate reductions, would benefit electric power suppliers and/or shopping customers, at the expense of customers who do not switch suppliers. Conversely, a move too far in the other direction in favor of lower shopping credits to achieve higher rate reductions would benefit non-shopping customers, while potentially inhibiting the development of a competitive market by making it less attractive for third party suppliers to enter the marketplace, thus resulting in diminished opportunities for customers to switch suppliers.

We **FIND** that the rate reduction schedule provided in the Stipulation meets the legislatively-mandated minimum rate reduction levels for August 1, 1999 and August 1, 2002, and, in fact, exceeds the minimum required rate reductions during the period from January 1, 2000 through July 31, 2002, by introducing additional phased-in reductions, which additional steps are permitted, but not mandated by the Act. These enhanced rate reductions, as set forth more fully below, support the level of bondable stranded costs found to be reasonable by the Board. Additionally, we **FIND** that the Stipulation, specifically the provisions of paragraph 1(b) thereof, complies with the provisions of subsection 4(l) of the Act, N.J.S.A. 48:3-52(l), which require immediate and full pass-through of securitization savings to customers. We note, however, that the Stipulation inappropriately conditions the entire incremental rate reductions in January 2000, August 2001 and August 2002 on the implementation of the securitization bond charge. As noted previously, the 13.9% rate reduction in August 2002, as well as the 5% rate reduction in August 1999, are required minimum rate reductions, and the imposition of the noted condition for these two rate reductions is clearly inappropriate. As discussed in more detail below, we believe, that if securitization is implemented, the two intermediate rate reductions should, at a minimum, be based on certain guaranteed levels even if the estimated savings from securitization are not fully realized. Should greater savings be achievable as a result of securitization as implemented, these additional savings shall be reflected in reductions beyond the requisite minimums.

Moreover, in our view, the level of the BGS rates/shopping credits embodied in the PSE&G Stipulation, while supported in the record and consistent with the provisions of subsections 4(b) and 4(f) of the Act, N.J.S.A. 48:3-52 (b) and (f), exceed those contemplated by many of the parties and indeed the ALJ when the rate reduction recommendations were made. The PSE&G proposal for a 6.7% rate reduction in its July 15, 1997 filing was accompanied by a proposal to set the BGS price at a level consistent with the forecasted 1999 PJM spot energy price. The Auditors= recommended rate reduction range of between 8.5% and 14% was premised on an audit of the Company proposal, including the PJM energy rate proposal for BGS and the shopping credit. As discussed above, the rate reduction proposals sponsored by several parties in the proceeding, including NJBUS, NJICG and NJCU, fell in the range of 10 to 12 percent.

It is clear that the record reflects a wide range of rate reduction proposals, and the ALJ himself recommends a range of rate reductions of between 10 and 12 percent which he finds will not unduly impair the Company=s financial condition. The ultimate rate reduction step in the PSE&G Stipulation of 13.9% from current rates, which level is mandated by the Act, exceeds this range of reductions found reasonable by the ALJ. At the same time, the shopping credit levels in the PSE&G Stipulation are far in excess of the levels originally proposed by PSE&G. We note that the proposed 13.9% rate reduction in the Stipulation is to be phased in over three years. We **FIND** that a phase-in is reasonable in order to provide PSE&G an opportunity for recovery of non-securitized stranded costs, as addressed below, while at the same time establishing the level of shopping credits provided in the PSE&G Stipulation. Nonetheless, even considering the phase-in, the average rate reduction for all customers over the entire four year Transition Period, as provided by the PSE&G Stipulation as modified herein, still exceeds nine percent, and additional savings are made possible by the shopping credit and retail adder, which brings the total available savings to in excess of 10 percent over the entire four year Transition Period. Considering the higher level of shopping credits, including the 2 mill per kwh retail adder embodied in the shopping credits proposed in the Stipulation, we **FIND** that the rate reductions in the proposed Stipulation fall within the range supported by the record and recommended by the ALJ. Moreover, we note and emphasize that, consistent with the provisions of subsection 4(h) of the Act, N.J.S.A. 48:3-52(h), these total rate reductions do not include the additional energy tax savings that customers will realize as a result of the Energy Tax Reform Act, P.L.1997, c.162.

Further, we note that the provisions of subsection 4(j) of the Act, N.J.S.A. 48:3-52(j), require that the maximum level of rate reduction (in the case of PSE&G, 13.9% from current rates) be sustained until at least July 31, 2003. Accordingly it is appropriate, and we **FIND** it to be reasonable and consistent with the Act, that the Transition Period consist of the four year period from August 1, 1999, when the rate reductions begin, through July 31, 2003, at which time the mandated price cap expires and the Board may reset the aggregate level of rates.

We **FIND** that the higher levels and more extended period of rate reductions as proposed in Stipulation II are not supported by the record, and are indeed reliant on assumptions which are plainly incorrect. The proposed use of $290 million, representing 60%,of the distribution depreciation reserve amortization of $569 million as a source of additional rate reductions is inappropriate, since the $569 million amortization is already embedded in the Company=s petition, and fully utilized and relied upon in the ALJ=s recommended range of rate reductions, as well as to partially fund the rate reductions and stranded cost recovery during the Transition Period embedded in the Stipulation. Use of a portion of this amortization in an attempt to justify further rate reductions in years five and six would result in an inappropriate Adouble-count@ of this source of funds. Additionally, and as asserted by PSE&G in its comments, Stipulation II incorrectly relies upon the gross-up of $35 million of expiring amortization levels which, in fact, already represent grossed-up figures, and it also incorrectly relies upon a gross-up of the Abalance in the distribution depreciation adjustment,@ which is applied to a number which is already grossed-up, thus representing two additional examples of Adouble-counting.@ We also conclude that use of $90 million in write-offs associated with the Salem generating plant to fund rate reductions in years five and six, as proposed in Stipulation II, represents yet another Adouble-count,@ since this write-off is already reflected in a reduction in the level of stranded cost recovery provided in the Stipulation, as modified herein. We do, however, concur with several of the comments and the proposal in Stipulation II and **FIND** that the actual LEAC overrecovery balance existing as of August 1, 1999, consists of funds overcollected from and appropriately returned to the ratepayers of PSE&G, with interest, and thus should be utilized for the benefit of customers, not the Company. However, we believe it more appropriate that this be accomplished by utilizing the overrecovered amount as an offset to the NTC deferred balance, rather than to justify and establish a specific level of rate reduction in years five and beyond as proposed by the RPA. By applying the LEAC overrecovery balance to the starting deferred NTC deferred balance effective August 1, 1999, these monies will be available, with accrued interest, to mitigate the impacts of recovery of any other deferred costs in year five and beyond.

Notwithstanding our finding that Stipulation II Adouble-counts@ the expiring amortizations by grossing-up an already Agrossed-up@ number, we do believe that when the $35 million of amortizations indeed expires it can allow for additional rate reductions beyond those contemplated in the Stipulation and beyond those made possible because of the amount of bondable stranded costs authorized by this Order. Accordingly, we believe it appropriate that if securitization is implemented, the proposed 8.25% rate decrease on August 1, 2001 be increased by 0.75% to 9.0%. This figure, as well as the 7% January 1, 2000 rate decrease, shall be a guaranteed minimum decrease and shall not be contingent upon the achievement of any particular minimum level of savings from securitization.

With respect to the levels of shopping credits, it is plainly evident that the shopping credits embodied in the Stipulation are significantly higher than those proposed by the Company in its filing, and reflect consideration of the criticisms leveled at that proposal by the parties to this proceeding, as summarized hereinabove, some of which were found to have merit by the ALJ. The proposed shopping credits in the Stipulation reflect market capacity costs, in addition to market energy costs, and also include a retail adder as recommended by the ALJ. The market energy and capacity costs reflected in the shopping credits contained in the Stipulation are consistent with the market price projections presented in the testimony of Company witness Loxley. The shopping credits in the Stipulation also make provision for transmission costs, and the losses and sales tax which will be incurred by third party suppliers. We note that the shopping credits are on par with, and indeed on average slightly higher than those in the PECO service territory in Pennsylvania. These higher shopping credits are noteworthy because, both during the evidentiary proceeding and in comments on the Stipulation, various marketers have pointed to the PECO service territory as having the most robust and active retail electricity marketplace in the nation, and the PECO service territory lies in the same regional electricity marketplace as PSE&G.

On the other hand, we find that the shopping credits proposed in Stipulation II are excessive, unsupported by the record, and based upon flawed reasoning. First, because of the interrelatedness between the shopping credits and the rate reductions, as addressed above, and having established herein the appropriate levels for the other unbundled rate components, namely the distribution charge, including the Corporate Business Tax ("CBT") and the Transitional Energy Facility Assessment ("TEFA"), SBC, MTC, and TBC, and having found that Stipulation II's underlying financial analysis is flawed, the level of shopping credits proposed in Stipulation II would lead to either lower rate reductions or a significant deferral of cost recovery, which would lead to higher rates in the future.

In addition, while acknowledging that the shopping credits in the Stipulation are higher than those in PECO's territory, the proponents of Stipulation II assert that, on a Areal@ basis, the credits in the Stipulation are lower, citing asserted changes in the PJM electricity market and differences in costs between New Jersey and Pennsylvania. It is asserted in supporting affidavits that the credits in the Stipulation would have to be raised by about 0.6 cents in order to provide a comparable level of competition to that enjoyed by PECO customers. Based on our review of the submissions, the Board concludes that almost all of the claimed differences (approximately 5 of the claimed 6 mill average difference) relate to asserted increases in market prices since the PECO shopping credits were established. We **FIND** the claim that an increase in the shopping credits to reflect alleged market price increases is necessary in order to provide savings similar to those afforded in the PECO territory to be simply untrue; no provision was made in the PECO decision by the Pennsylvania Public Utility Commission ("PaPUC") to update the shopping credits to reflect changed market conditions, as is suggested be done here. To the extent that retail competition is flourishing in PECO's service territory, it is occurring at the fixed levels of shopping credits established by the PaPUC in April 1998, despite alleged increases in market price conditions. Moreover, even assuming arguendo, that the cited market prices presented via a post-hearing affidavit are accurate, it is important to note that while the Stipulation's shopping credits are premised on long-term pricing forecasts which have been the subject of substantial review in the proceeding, the proponents of Stipulation II would have the Board premise a decision to set shopping credits for four years based upon a current price condition; however, such price conditions may change daily, if not more often. Accordingly, the Board is not persuaded that it reasonably could or should base its decision on this "snapshot" market information. Rather, we **FIND** that it is more appropriate to establish the shopping credit levels based upon the market price forecasts over the four year Transition Period which have been presented in this proceeding and which have been the subject of extensive review in the record.

Finally, we **FIND** MAPSA= s arguments in support of higher shopping credits to be internally inconsistent. MAPSA asserts that the BGS charge or shopping credit should be calculated using the Pennsylvania Aresidual@ method, which begins with the bundled rate (recognizing the mandated discount) and then subtracts from that bundled rate the distribution rate, transmission rate, societal benefits rate and taxes. Such a method bears no relation to market prices, either current or projected, and might produce a shopping credit which is reflective of current market conditions only by happenstance. Moreover, the use of such a residual method during the last year of the Transition Period, when the rate discount increases to 13.9 %, would produce shopping credits which are actually lower than the level of shopping credits established herein.

With regard to the total level of opportunity for recovery of stranded costs, a key issue with respect to an assessment of the proposal in the Stipulation is the value assigned to the generating assets as part of the transfer. Before addressing that issue, however, we address a related issue which as described herein has been raised in the comments by MAPSA and other the proponents of Stipulation II, specifically the assertion that the terms of the PSE&G Stipulation actually provide PSE&G the opportunity to recover over $1 billion more than the $3.075 billion net of tax recovery opportunity asserted by PSE&G. As described in our summary of the comments above, this is claimed to occur because, in addition to the $2.6 billion (including transaction costs) from securitized bonds, the Company will assertedly receive $120 million via a retained retail adder obtained from non-switching customers, $460.5 million via the distribution reserve amortization, $90 million via the agreed-upon Salem cost reduction, $90 million via the LEAC overcollection at July 31, 1999, $35 million via expiring amortizations, $800 million via documented mitigation opportunities and $600 million via the Genco transfer premium. After careful review, we **FIND** this assertion to be flawed for a number of reasons. Most substantially, the so-called Genco Atransfer premium@ represents essentially an advance by Genco to PSE&G in the amount of $600 million (which we modify herein to $540 million for reasons discussed below), above and beyond the net $1.768 billion agreed upon value of the assets (which we modify herein to $1.903 billion for reasons discussed below). This premium will be used to further reduce the capitalization structure of PSE&G, and is then to be repaid to Genco via the sources of revenue identified in the PSE&G Stipulation, namely the depreciation amortization, the retained adder, and the explicit MTC charge. In this manner Genco, not PSE&G, assumes any risk associated with collection of the $600 million (modified herein to $540 million) of unsecuritized stranded costs. However, the overrecovery assertion by MAPSA and others is incorrect, because it assumes that both the $600 million premium as well as the sources to repay the premium both count towards the recovery of the unsecuritized stranded costs. This results in a Adouble count,@ and resulting calculation error of $600 million. Moreover, as will be described in more detail below, the inclusion of $800 million of mitigation by MAPSA results in a further Adouble count,@ since mitigation has already been taken into account as part of the reduction in the total net of tax stranded cost quantification from $3.9 billion as filed by PSE&G as well as other elements of this decision. Moreover, MAPSA relies upon the Auditor's Report as the source of the $800 million mitigation opportunity but, as pointed out by PSE&G, ignores the fact that the $800 million figure presented by the Auditors was a gross number, from which income taxes of over $300 million would have to be deducted in order to express the number net of tax, and therefore directly comparable to the stranded cost number which is expressed net of tax.

Accordingly, we **FIND** the assertion that under the terms of the Stipulation PSE&G will overrecover the agreed upon level of stranded costs by over $1 billion to be based upon a flawed analysis and plainly incorrect.

As described herein, the Board received voluminous comments with respect to the asset valuation associated with the proposed transfer of generation assets to the affiliated Genco, with emphasis on the underlying support for the transfer itself, and particular emphasis on the value to be assigned to the non-nuclear generating units. At the outset, we **FIND** that the proposed transfer of generating assets from PSE&G to Genco and the proposed BGS supply arrangement from Genco to PSE&G are amply supported by the record in this proceeding. The Company=s filing proposed that the Company would remain in the generation business throughout the then-proposed seven-year transition period, with PSE&G utilizing its generation assets to backstop capacity and reliability in New Jersey and the PJM grid during this period, and then transferring its generation assets to an affiliate of the holding company at the end of the transition period. This proposal was submitted in the context of PSE&G=s assertion that a liquid and visible capacity market did not yet exist in the PJM control area, and the resultant proposal by PSE&G that the retail electric market be opened to competition on an energy-only basis, with PSE&G being responsible for continuing to provide capacity for all retail customers. It is clear, and PSE&G has since acknowledged, that a liquid and visible capacity market has, in fact, been developed by the PJM ISO, and that the PJM now conducts regular capacity auctions. Accordingly, we **FIND** that the conditions which were originally assumed to prevail at the end of the then-proposed seven year transition period, and which supported the proposal to transfer the generation assets at that time, are currently in place, and therefore support the immediate transfer of the assets.

We further **FIND** that the proposed BGS supply arrangement between Genco and PSE&G provides known rates and assurances during the transition period. Rather, than having PSE&G and its customers solely and immediately dependent on the wholesale marketplace for the procurement of BGS energy and capacity, the Genco arrangement provides a price guarantee and a capacity backstop, similar to the assurances which PSE&G originally proposed that it provide during the transition period via the retention of the generation assets within the utility. Since all the PSE&G generation facilities, including its nuclear power plants, will be transferred to the unregulated Genco affiliate, customers will no longer be exposed to operational risks associated with these facilities. Until BGS is bid out for year four of the Transition Period, Genco will assume all risks associated with providing BGS service at the pre-determined BGS prices. We **FIND** this reduction of risk and the fixed price to be a substantial benefit to customers. We are also of the view that the provisions of paragraph 29 of the Stipulation, which require that the transferred generation capacity be maintained by Genco as a capacity resource within PJM for at least the duration of the Transition Period is a significant benefit to consumers during periods of heavy demand. We **FIND** this restriction to be consistent with the intent of the originally-filed PSE&G proposal to backstop capacity and reliability with its owned generation and, subject to our modifications to paragraph 29 of the Stipulation delineated below, we **FURTHER FIND** that it will provide a reasonable and appropriate transition mechanism to help preserve the reliability of the PJM grid and foster a competitive capacity market in the region, which, in turn, will inure to the benefit of PSE&G=s customers through lower prices. With regard to paragraph 29 of the Stipulation, we clarify that the Board will retain jurisdiction over and will monitor whether Genco is making good faith efforts to sell excess capacity into the PJM system at market rates.

As pointed out by PSE&G in its comments, the proposed immediate transfer of PSE&G=s generation assets is also responsive to the concerns voiced by a number of parties during these proceedings that the original PSE&G proposal for functional separation of generation coupled with affiliate relations standards might not be sufficient to protect against cross-subsidies and ensure a level competitive electric generation playing field. Indeed, several parties in the proceeding advanced the view during the hearings that structural separation of generation-related assets into a separate corporate entity was necessary to provide adequate protections. The transfer proposed in the PSE&G Stipulation achieves those goals for the foregoing reasons, and we **FIND** it to be reasonable subject to the terms and conditions set forth herein.

Moreover, as evidenced by the language in subsection 7(d) of the Act, N.J.S.A. 48:3-55(d), a transfer of assets from an electric public utility to a related competitive business segment of the utility=s holding company was contemplated by the Legislature and is permitted by the Act, subject to Board approval including a determination by the Board of the Afull value@ of the assets. We also note that the proposed transfer is consistent with the intent of the Act, which in subsections 8(a) and (b), N.J.S.A. 48:3-56 (a) and (b), declares electric generation service to be a competitive service not subject to rate base/rate-of-return regulation, and which in subsection 7(f), N.J.S.A. 48:3-55(f), prohibits an electric public utility or its related competitive business segment from offering competitive electric generation service, but which in subsection 7(j), N.J.S.A. 48:3-55(j), permits a public utility holding company affiliate to offer competitive retail electric generation service or wholesale power service. By the terms of the Stipulation, Genco would not provide retail electric generation service, and therefore would not be in direct competition with electric power suppliers in the State, but would be providing wholesale power services. The corporate structure described in the proposed Stipulation is consistent with the structure permitted in the Act, and warrants our approval of paragraph 24 of the Stipulation, which requests a Board finding that Genco be characterized as an Exempt Wholesale Generator (AEWG@), meaning that it would be a wholesale provider of power not subject to rate of return regulation under the Board's or FERC's jurisdiction.

With respect to the valuation of the assets being transferred, there is a direct link between the value assigned these assets with respect to the transfer, and the magnitude of

PSE&G=s stranded costs: the higher the assigned value, the lower the remaining stranded costs. The issue of the value of PSE&G=s generation assets was litigated at length in the stranded cost proceeding, as described in the Initial Decision and summarized hereinabove. Extensive testimony with respect to both the proper net book value of the assets to be utilized for purposes of stranded costs, as well as the net present value cash flows forecasted to be generated by the generation facilities over their remaining lives was presented in evidence at the Office of Administrative Law. The discounted net cash flow analysis approach, which was utilized by PSE&G in its stranded cost calculation and utilized as well by other parties= witnesses in the case (albeit with different assumptions) represents an analysis that would be undertaken by a potential bidder to determine its offering price in an asset auction process. The ALJ weighed the arguments and rendered findings with respect to the various inputs, variables and assumptions underlying a discounted cash flow analysis, including market energy and capacity price forecasts, forecasted capital additions and operation and maintenance costs, unit output and rates of return. We **FIND** that additional hearings are not required on this issue because there is sufficient basis in the record for a determination of the value of PSE&G=s generation assets, and we **FURTHER FIND** that all parties have had ample opportunity during the proceedings to advance their arguments and introduce evidence with respect to the value of these assets.

As summarized above, in the comments on the proposed Stipulation, a number of parties urged the Board to consider the results of various recent fossil fuel generation divestitures throughout the country, arguing that recent data indicates that, when put up for sale and competitive bid, electric utility fossil fuel generation has fetched prices in excess of book value. While general trends as to the results of industry-wide asset sales may be somewhat instructive and while, as discussed below, we have considered them and taken them into account in our decision, we concur with the comments received from PSE&G that it is impossible to reasonably attempt to extrapolate PSE&G's asset values from the results from sales of other utilities= generating assets. Any number of unique and individual factors associated with a particular utility=s assets may exist which would justify divergent outcomes or plant values. These factors include plant vintage and conditions, heat rates, location, state and/or local environmental regulations or restrictions, environmental liabilities, fuel restrictions, fuel commodity and transportation costs, labor agreements, state and/or local tax liabilities and market price conditions. These factors, as they apply specifically to PSE&G=s assets, were included in this proceeding as part of the stranded cost calculations, as the discounted net cash flow analyses prepared by PSE&G and several other parties considered all future costs and revenues associated specifically with each individual PSE&G generating facility. A proposed analysis to bring the purported comparable sales into comparability was not offered by the proponents of Stipulation II, nor is it likely that such an analysis could be readily performed. We **FIND,** for the foregoing reasons, that it would be unreasonable to rely upon these recent sales as the basis for a determination of the value of PSE&G's generating assets. We **FURTHER FIND** that there is ample support in the record for the Board to determine the market value of PSE&G=s generating assets, and that the discounted net cash flow analyses presented in the stranded cost proceeding are the appropriate mechanism to be utilized to render such a determination.

As described herein, the Company performed a discounted net cash flow analysis to quantify the magnitude of its owned generation stranded cost, which it indicated in its filing amounted to approximately $3.9 billion. I.D. at 9. The Ratepayer Advocate, Enron and the Auditors each performed independent studies, using a similar methodology but varying assumptions and inputs. Numerous parties challenged various aspects of the Company=s quantification. The discounted net cash flow methodology produces, and the $3.9 billion amount represents, a net-of-tax figure. In other words, this does not reflect the actual revenue requirement associated with recovery of generation stranded costs. The net-of tax-figure must be grossed up for federal and state income taxes to obtain the actual owned generation stranded cost recovery level.

The ALJ found a number of the proposed adjustments and assumptions of the parties to be appropriate and adopted same, including a higher future capacity factor for the Bergen and Mercer generating facilities, the cost of fuel and resulting dispatch rates, and PJM import levels supported by the RPA. I.D. at 40. He also found the Company=s assumed escalation rate for capacity prices to be understated, and concluded that such prices should be escalated at the general inflation rate. I.D. at 41. He further concurred with NJPII's recommended adjustment to add the value of nitrogen oxide and sulfur dioxide emission credits to market revenues, as well as with Staff's proposed adjustment to remove the anticipated Salem steam generator replacement from the calculation, and with Enron's proposed adjustment to reflect cost values associated with ancillary services. Id. The ALJ further concluded that the discount rate should be reduced to reflect an updated capital structure and cost of capital vis-a-vis the Company=s last base rate case. Id. at 41-42. The ALJ also concurred with the Staff and RPA-proposed FASB 90 and 106 adjustments with respect to Salem. Id. at 42.

As described hereinabove, pursuant to the ALJ=s recommendation, the parties met to attempt to provide a quantification of the ALJ's stranded cost-findings after the Initial Decision was released. While no consensus was reached among the parties, after the meeting, by letter dated November 18, 1998, the Auditors submitted to the Board a proposed quantification of the ALJ=s stranded cost recommendations, reflecting a range of values based on three scenarios, from a low end of $2.485 billion, to a mid-range of $2.949 billion, to a high end of $3.310 billion. We **HEREBY ACCEPT** as reasonable, with one minor modification discussed below, the Auditors= mid-range quantification of the ALJ=s decision with respect to PSE&G=s net-of-tax owned generation stranded costs of $2.949 billion and, based on that quantification, **HEREBY ADOPT** the ALJ's I.D. with respect to the magnitude of PSE&G=s net-of-tax owned generation stranded costs. We **FIND**, however, that the Auditors did not include any value for nitrogen oxide and sulfur dioxide emission credits, which adjustments the ALJ found appropriate. We note that NJPII, which recommended this adjustment, did not provide a quantification of these credits. While it is difficult to estimate the value of these credits with precision at this time, based on our judgment, we believe it fair to adjust the net-of-tax stranded cost amount of $2.949 billion to $2.94 billion to impute a value for these credits, consistent with the ALJ=s findings.

Accordingly, we **HEREBY FIND** the level of net-of-tax owned generation stranded cost for PSE&G to be $2.94 billion. This amount, when compared to the level of net-of-tax stranded costs which PSE&G would be afforded the opportunity to recover via the proposed Stipulation ($3.075 billion), results in a reduction to net-of-tax stranded cost recovery of $135 million. This decrease of $135 million in net-of-tax stranded cost vis-a-vis the level proposed in the Stipulation represents a finding by the Board that the market value of PSE&G=s owned generation assets is $135 million greater than that assumed in the Stipulation. The comments received in response to the Stipulation, regarding recent industry divestiture information, would suggest that this increased value, vis-a-vis the Stipulation, should be assigned to the Company=s fossil fuel generating units, since these types of units, as opposed to nuclear generation facilities, have obtained sales premiums. We therefore **FIND**, consistent with the general industry trends which have been noted in a number of the comments received, that the transfer value of the Company=s fossil generating assets should be increased by $135 million. Accordingly, we **FIND** that the generating assets shall be transferred to Genco at the following market valuations: $0.046 billion for nuclear; and $1.857 billion for fossil. Thus, the full value of the generating asset transfer is $1.903 billion, in satisfaction of the requirements of subsection 7(d) of the Act, N.J.S.A. 48:3-55(d), which we **FIND** to be the full market value of the generating assets over their remaining useful life in accordance with the provisions of subsection 13(e) of the Act, N.J.S.A. 48:3-61(e).

Additionally, for the foregoing reasons, including the use of the generating assets by Genco to provide BGS at a fixed price over the Transition Period, the removal of operational risk from ratepayers, the removal of nuclear plant decommissioning responsibility and attendant risks, the maintaining of the capacity associated with the transferred generation as a capacity resource for the duration of the Transition Period, and the receipt by PSE&G of full market value for the assets, we **FIND** that the transfer, subject to the terms set forth herein, is in the public interest and will not jeopardize system reliability. Moreover, for the foregoing reasons and because this Order and its implementation will not impair the financial integrity of PSE&G or its holding company, because allowance has been made for continued recovery of post-retirement benefits (except for prospective post-retirement benefits associated with generation employees which become the responsibility of Genco) in PSE&G=s rates, and because the transfer of assets will result in the generation employees remaining employees under the holding company, we **FIND** that the transfer will not adversely impact PSE&G=s ability to meet its pension obligations to its employees.

We note that, as a result of the transfer of all generating assets to Genco, Public Service Enterprise Group will likely have non-regulated assets in excess of 20%. The Board's Decision and Order implementing the results of the Focused Audit (Docket No. EA92040459) ("Focused Audit Order") required the Company to notify the Board if the non-regulated assets exceeded 20% to allow the Board to assess the potential adverse financial effects of under-performing non-regulated businesses on the credit-worthiness of PSE&G, and thereby prevent possible impairment of the utility's ability to render safe, adequate and proper service. Due to significant changes in the industry and in particular, the changes in the Company's corporate structure being brought about as a result of this Final Decision and Order, modifications to the Board's June 17, 1986 Order Authorizing Transfer of Stock and Approving Merger, Docket No. EM8507774, ("Holding Company Order") and relief from or modifications to the Focused Audit Order may be warranted. The Company is **HEREBY DIRECTED** to file a petition to either maintain the existing regulatory parameters or to propose modifications thereto, by no later than the end of the first quarter of 2000. In the interim period, the Board will deem Public Service Enterprise Group and PSE&G not to be in violation of the non-regulated asset ratio established by the Board in May 1993. However, the Board will continue to monitor this issue and reserves the right to make further rulings in this matter as warranted.

With respect to the transfer of the nuclear generation assets (and the related transfer of the decommissioning trust funds in accordance with paragraph 33 of the PSE&G Stipulation), we noted above the benefits associated with the transfer of not only operational risk but, also, decommissioning risk and responsibility to Genco, attendant with Genco=s opportunity to earn non-regulated returns associated with the sale of power and related services from the nuclear units. In order to ensure that the risk and responsibility of decommissioning is fully transferred to Genco along with the transfer of the assets and the decommissioning trust funds, recognizing that funding for decommissioning will remain in the SBC paid by PSE&G customers, we believe it necessary to place parameters on such continued funding by ratepayers and we shall do so. We, therefore, **DIRECT** that, within ninety (90) days of the date of this Order, PSE&G submit to the Board for its approval, a specific proposal a limit to its financial responsibility for funding, and, in turn, for ratepayers= obligation to fund through the SBC, the cost of decommissioning the nuclear units transferred to Genco. We **ADDITIONALLY DIRECT** PSE&G to submit all accounting entries that will be made upon the transfer of the decommissioning trust funds to Genco.

With regard to the level of securitization of stranded costs, the ALJ concluded that PSE&G=s proposal in the case to securitize $2.5 billion of its total net of tax stranded cost with 15 year bonds will result in reasonable savings to ratepayers which will be flowed back to ratepayers through a reduction in base rates, (estimated at 2.7% assuming a 7.5% interest rate), is consistent with the Final Report and should be adopted. I.D. at 68. We further note that subsection 14(c) of the Act, N.J.S.A. 48:3-62(c), provides that the Board may, in the event that an electric public utility has not divested itself of a majority of its generation assets, authorize the issuance of transition bonds for utility generation plant stranded costs determined to be recoverable pursuant to paragraph (1) of subsection 13 (a) of the Act, N.J.S.A. 48:3-61(a), in the amount of 75 percent of the total amount of an electric public utility=s recovery-eligible utility generation plant stranded costs. As set forth herein, the Board has found, pursuant to the provisions of section 13 of the Act, N.J.S.A. 48:3-61, that the net-of-tax level of owned generation stranded cost is $2.94 billion. For purposes of establishing an actual revenue requirement necessary to provide PSE&G an opportunity to recover $2.94 billion in stranded costs after-tax, it is necessary and appropriate to gross-up this amount, to account for the fact that PSE&G will incur an income tax liability associated with the recovery of net-of-tax stranded costs, and to afford PSE&G the opportunity to collect appropriate taxes associated therewith. However, we concur with the concerns raised by Staff during the litigation of these proceedings, as well as the RPA and others during the comment period, and **HEREBY REJECT** as inappropriate and, in our view, inconsistent with the intent of the Act, the proposal within the Stipulation, supported by all signatories thereto except the NJCU, that all taxes related to securitization be recovered through the transition bond charges. We conclude that the transition bond charge is appropriately utilized to provide and ensure collection of the principal and interest payments on the transition bonds. The assured collection of the bond principal and interest provided via the irrevocable transition bond charge is necessary in order to obtain the highest possible rating on the bonds, which, in turn, will result in the lowest possible interest rate on the bonds and resultant maximized ratepayer savings. We do not believe it appropriate, nor consistent with the intent of the Act, that the utilities' tax obligations be collected via the irrevocable transition bond charge. As indicated previously, however, it is entirely appropriate and necessary that the net-of-tax stranded cost number be grossed-up for ratemaking purposes, and that PSE&G be afforded the opportunity to fully recover these taxes.

Accordingly, the Board **HEREBY DIRECTS** that a Market Transition Charge be established, coincident with the establishment of the transition bond charge, pursuant to section 13 of the Act, specifically for the collection of securitization-related Federal Income and State Corporate Business Taxes (AMTC-Tax@). The taxes to be collected through the MTC-Tax shall reflect the grossed-up revenue requirements associated with the net-of-tax amount of stranded costs, together with the estimated level of transaction costs, authorized by the Board herein for recovery through securitization. PSE&G is **HEREBY AUTHORIZED** to impose the MTC-Tax until the related bondable stranded costs including principal and interest have been paid in full. The imposition of the MTC-Tax over the same term as the imposition of the TBC and, as such, beyond the eight year limitation of the Act, is permitted in accordance with the provisions of paragraph (3) of subsection 13(l) of the Act, N.J.S.A. 48:3-61(l)(3), and is, in our view, reasonable and necessary to realize the estimated level of securitization-related rate savings as reflected in the record, since the PSE&G proposal in the proceeding which formed the basis for the securitization savings estimates was to include the collection of the tax gross-up amount in the TBC itself. The collection of the tax gross-up amount through a MTC-Tax with a duration shorter than that of the TBC would have the effect of decreasing the securitization-related savings. The Board therefore, **DIRECTS** that the MTC-Tax be separate and distinct from the MTC established for the collection of stranded costs associated with power purchase agreements with non-utility generators over the life of those contracts and the MTC established for recovery of the unsecuritized utility stranded costs over a four year time period. The Board **HEREBY DIRECTS** that the MTC-Tax shall be subject to periodic review and adjustment, consistent with the provisions of subsection 13(g) of the Act, N.J.S.A. 48:3-61(g), to reconcile the income taxes required to be paid on the taxable net revenue from the TBC collections (we note that any such adjustment will not include adjustments for market price, as market value for the assets is fixed as a result of the transfer). We concur with the concerns expressed in some of the comments that there should be a provision for adjustments in the event the tax laws change and, thus, we **HEREBY DIRECT** that the reconciliation shall include adjustments for changes in statutory federal and state tax rates. The reconciliation shall be formula-driven to reflect the tax requirements arising from the issuance of transition bonds, the collection of transition bond charges and the collection of the MTC-Tax. The Board further **FINDS** that the Company is entitled to the opportunity to full and timely recovery of the associated income taxes for as long as transition bond charges remain collectible.

With respect to the net of tax amount of stranded cost to be securitized, we **HEREBY AUTHORIZE** PSE&G to securitize an amount of up to $2.4 billion, plus an additional amount of up to $125 million for related and reasonably and prudently incurred transaction costs. Upon receipt and review of an application by PSE&G, the Board will consider the issuance of a bondable stranded costs rate Order (AFinancing Order@) authorizing the issuance of transition bonds in these amounts with a scheduled amortization of 15 years and the imposition of a transition bond charge therefore, pursuant to section 14 of the Act, N.J.S.A. 48:3-62. The Board **HEREBY FINDS** that issuance of transition bonds in these amounts is necessary for PSE&G to meet the rate reductions determined by the Board herein to be necessary and appropriate consistent with the provisions of sections 4 and 13 of the Act, N.J.S.A. 48:3-52 and 61, and to meet the other requirements of the Act, specifically, the establishment of shopping credits at a level which will foster a competitive marketplace. Specifically, absent the estimated savings from securitization, PSE&G would not be able to meet the required phased-in rate reduction steps of 7% on January 1, 2000 and 9% on August 1, 2001, or, in the alternative, would have to substantially reduce the shopping credits.

Moreover, we emphasize that, in addition to securitization savings being necessary for PSE&G to achieve phased-in rate reductions on January 1, 2000 and August 1, 2001 which exceed the minimum required rate reductions in the Act, our authorization of the issuance of transition bonds in the amount of $2.4 billion, and PSE&G's receipt of the proceeds therefrom, provides a significant benefit to the Company. It is, therefore, entirely appropriate and necessary that the Board condition the implementation of securitization on the implementation by PSE&G of the herein-directed rate reductions of a minimum 7% on January 1, 2000 and a minimum 9% on August 1, 2001.

We further note that Attachment 1 to the PSE&G Stipulation contains a calculation of the estimated savings related to securitization during the Transition Period, based upon an assumed transition bond interest rate of 6.5%, reflective of the then-prevailing rate, and an amortization period of 15 years. Based upon the assumptions set forth therein, the issuance of transition bonds will provide tangible and quantifiable benefits to ratepayers on the order of 3%. We note that the requested level of securitization of $2.475 billion in the Stipulation is approximately equal to, and indeed modestly ($25 million) lower than the original $2.5 billion proposal found reasonably appropriate by the ALJ. Our determination to require a $75 million reduction in the level of stranded cost securitization, from $2.475 billion as proposed in the PSE&G Stipulation to $2.4 billion, reflects a pro-rata reduction in the level of authorized operation related securitization consistent with the $135 million reduction ordered herein to the requested level of total stranded cost recovery (from $3.075 million to $2.940 billion).

We **FURTHER FIND** that the total recoverable stranded cost revenue requirement, based upon a statutory federal and state tax rate of 40.85% and a net-of-tax recoverable stranded cost amount of $2.94 billion, is approximately $4.97 billion. Accordingly, we **FIND** that the authorized level of stranded cost securitization of $2.4 billion, represents approximately 48% of the total amount of the recovery eligible generation related stranded cost rate recovery authorized, and thereby meets the requirements of subsection 14(c) of the Act, N.J.S.A. 48:3-62(c). The proceeds received by PSE&G from the issuance of $2.4 billion of transition bonds shall be utilized by PSE&G to reduce the capitalization of PSE&G, in a manner which does not substantially alter the overall capital structure of the utility adverse to the interests of bondholders or ratepayers. Consistent with maintaining an appropriate credit rating for the distribution utility, and in order to increase the ratepayer benefits that result from the use of the securitization proceeds, we view an increase in the debt component of PSE&G's (the utility's) capitalization as falling within this requirement.

Having established herein the level of total net-of-tax generation-related stranded cost at $2.94 billion, and having authorized the issuance of transition bonds to Arefinance@ $2.4 billion, PSE&G shall be afforded the opportunity, consistent with the provisions of section 13 of the Act, N.J.S.A. 48:3-61, to recover up to $540 million, net-of-tax, through an MTC, representing the unsecuritized amount of PSE&G's stranded costs. The actual revenue requirement associated with this $540 million recovery opportunity, based upon a 40.85% Federal and State income tax rate, is on the order of $760 million. Consistent with the provisions of the PSE&G Stipulation (as modified herein), the $540 million is to be provided up-front by Genco to PSE&G in the form of a transfer premium. These funds shall be used by PSE&G, much like the proceeds from the transition bonds, to refinance and/or retire its debt and/or equity. This will benefit the utility and, ultimately, the customers of PSE&G by further reducing PSE&G's cost of capital. PSE&G will have the opportunity to recover up to $540 million, net-of-tax, through any retained retail adder associated with non-switching or returning customers, the MTC (exclusive of the NTC and the MTC-Tax) and the amount funded by the excess distribution reserve amortization; which funds, will be, in turn, transferred to Genco as received pursuant to the terms of the BGS contract (as modified and approved herein). At the end of the Transition Period, the recovery of the $540 million will be reconciled with actual collections as set forth herein, with PSE&G being at risk for any shortfall and customers receiving the benefit of any overrecovery via a credit of such excess amount to the SBC. We **FIND** this mechanism to be consistent with the provisions of section 13 of the Act, N.J.S.A. 48:3-61, which require that we afford the utility the opportunity, but not a guarantee, for recovery of generation-related stranded costs, and that (with specific reference to subsection 13(g) of the Act, N.J.S.A. 48:3-61(g)), we reconcile stranded cost recoveries to ensure that the utility will not collect in excess of its stranded costs. The above-described mechanism has the added benefit of transferring the risk of non-recovery of stranded costs to Genco, the unregulated affiliate, and not the utility, since PSE&G will receive the $540 million from Genco up-front in the form of a transfer premium.

With regard to the rate unbundling and rate design proposal in the PSE&G Stipulation, we note the Act requires at subsection 4(c), N.J.S.A. 48:3-52(c), in addition to the mandated rate reductions for each customer class as provided in subsection 4(d), N.J.S.A. 48:3-52(d), that rate unbundling not result in a reallocation of utility cost responsibility between or among different classes of customers. Taken together, it is our belief that these sections require that the Board implement unbundled rate designs which afford, to the extent practicable, each customer within each customer class the mandated level of rate reductions. Moreover, the Act at subsection 4(b), N.J.S.A. 48:3-52(b), explicitly requires that each customer=s bill indicate the dollar amount of the savings attributable to the mandated rate reductions. While we reserve final judgement on the actual proposed rates to be implemented pending our review of PSE&G=s compliance tariff filing, we **FIND** that the overall rate design proposed in the PSE&G Stipulation, and specifically the implementation of the rate reduction credit, and the dollar savings statement on the bill, is consistent with the intent of the Act during the Transition Period. The rate reduction credit, as we envision it, is designed to assure that all customers receive the required reduction off the sum of the unbundled rate components. However, we are concerned that, subsequent to the Transition Period, such rate design could have unintended and unnecessary impacts on PSE&G=s customers, since the termination of the rate reduction credit at the end of year four would, absent any other adjustment, result in an increase in rates in year five which would equal the amount of the credit in effect in year four. Moreover, the elimination of the credit in year five could result in an unpermitted shift in cost responsibility. Although it is not known at this time what the BGS rate will be in year five or what the level of deferred balances for the SBC and NTC will be at that time, the Board is concerned that a simple removal of the rate reduction credit in year five without a reassessment of the other unbundled rate elements, could result in total charges which exceed the total of the otherwise-appropriate unbundled rate elements. We also **FIND** it necessary and appropriate for the Board to review the overall level of rate savings as well as the level of the distribution rate design and the other unbundled rate components, including the SBC and the NTC, prior to the conclusion of the Transition Period to determine, among other things, whether any additional future savings should be passed along to ratepayers prospectively.

With respect to the level and design of distribution rates, we note the ALJ's conclusion that the 1995 cost of service study is the only evidence available in the record with respect to cost of service, and that the parties had an opportunity to review and criticize it. Moreover, we acknowledge that the Final Report indicates that each electric utility's rates are to be unbundled utilizing the cost of service study employed to set rates in each company's last base rate case. However, we are now vested with the responsibility of implementing the Act, which was passed and signed into law subsequent to our issuance of the Final Report and, indeed, after the close of hearings in these matters. The Act requires that rate reductions be implemented over a three year period, and sustained for at least one additional year through July 31, 2003, in effect, resulting in a price cap on the distribution and other unbundled rate components through that date. As such, the price cap will be in effect, and PSE&G will be required to maintain its distribution rate without adjustment, through a date more than ten years from the conclusion of PSE&G's last base rate case. In light of this, and the fact that, unlike other unbundled rate components the distribution rate will not be subject to true-up and reconciliation, it is our judgment and determination that PSE&G should not be required to submit a cost of service study from the 1992 base rate case, but that it instead be permitted to use the 1995 cost of service study which was entered into the record and which the parties had an opportunity to review and critique during the hearing process. Use of the 1995 study provides a greater assurance, in light of the price cap to be imposed through July 2003, that PSE&G's distribution rates are being established at a reasonable level based on the record in this case and is supported by the record. Moreover, the distribution rates set forth in the PSE&G Stipulation, while reflecting the updated 1995 cost of service study, incorporate a $20 million decrease in annual distribution revenue requirements relative to the amount supported by the study, to reflect a more current overall cost of capital of 9.5%. This provides further assurance that the average level of distribution rates being set via the PSE&G Stipulation is reasonable.

With regard to the specific unbundled rate components, we **FIND** that the establishment of an SBC which will include costs for social programs, nuclear decommissioning costs, demand side management costs manufactured gas plant remediation costs and consumer education costs is consistent with the provisions of section 12 of the Act, N.J.S.A. 48:3-60. We also note that the composition of the SBC, as proposed in the PSE&G Stipulation, remedies the deficiency in the Company=s original proposal, which inappropriately included NUG contract costs and gross receipts and franchise tax in the SBC. The Act does not permit the inclusion of NUG contract costs or GR&FT taxes in the SBC. The establishment of the initial SBC at a level of costs included in rates as of the effective date of the Act and sustaining such rate for the duration of the four-year Transition Period is consistent with the provisions and intent of section 12 of the Act, N.J.S.A. 48:3-60, and is also consistent with the imposition of a four-year price cap pursuant to section 4 of the Act, N.J.S.A. 48:3-52. Moreover, it is appropriate and, we believe, consistent with the intent of the Act, that the Company be provided the opportunity to fully recover reasonable and prudent expenditures for the types of programs reflected in the SBC. These programs all provide social and/or environmental benefits, and are mandated to be performed or funded by utilities pursuant to State laws, regulations or agency orders. Accordingly, we **FIND** that deferred accounting treatment of under and overrecoveries, along with appropriate carrying costs to reflect the cost (to the utility or, in the case of an overrecovery, the customer) of financing deferred monies, is necessary and appropriate in order to provide for full recovery under the legislatively required price cap mechanism.

Since PSE&G is being afforded herein the opportunity to recover, beginning August 1, 1999, all of its remaining above-market owned generation costs through the market transition charge, MTC-Tax and transition bond charge, it is our determination that continued collection through the SBC (formerly the DSAF) of generation-related lost revenues attributable to demand side management programs would result in an overcollection of generation costs. Accordingly, we **FIND** that such generation-related lost revenues arising subsequent to that date shall cease to be collected after July 31, 1999.

As noted above, the proposed Stipulation appropriately removes the recovery of above-market NUG contract costs from the SBC, as originally proposed. Instead, these costs are to be collected via a separate NTC, which is to be set at an initial level of $183 million annually and sustained at this level over the Transition Period, with the difference between NTC recoveries and actual above-market NUG contract costs to be subject to deferred accounting, including interest on accrued under or over recoveries. The establishment of a separate charge for the collection of above-market NUG contract costs, subject to reconciliation, is consistent with the findings of the ALJ, who concluded that such a mechanism would permit the timely pass-through to ratepayers of benefits of any NUG contract renegotiations. We note that with the price cap imposed by the Act, the NTC will not be actually adjusted during the Transition Period; however through deferred accounting and interest accrual on cumulative under or over recoveries, ratepayers will be assured of receiving the full benefits of any NUG contract renegotiations, as envisioned by the ALJ and indeed as required by the Act. Section 13 of the Act, N.J.S.A. 48:3-61, permits recovery by an electric public utility through a market transition charge of stranded costs related to long- term NUG contracts, provided that the utility has demonstrated the full market value of each such contract and that it has taken all reasonably available measures to mitigate the contracts' above-market costs, subject to periodic review and adjustment of the charge to ensure that the utility will not collect charges that exceed actual stranded costs, and provided that the charge is not set at a level which prevents the achievement of the mandated rate reductions. Moreover, the Act permits a NUG-related MTC to be set for a term as long as the duration of the NUG contracts, and requires that any and all savings resulting from NUG contract renegotiation, buyout or buydown be passed back to ratepayers in a timely manner. We **FIND** that the establishment of the NTC as proposed in the PSE&G Stipulation and described herein, which NTC we regard as a separate market transition charge dedicated solely to NUG contract stranded cost recovery, is consistent with the provisions of section 13 of the Act, N.J.S.A. 48:3-61. Pursuant to the provisions of subsections 13(e) and 13(f) of the Act, N.J.S.A. 48:3-61(e) and (f), PSE&G will retain the ongoing obligation to demonstrate that it has obtained the full market value for the NUG contract power, and that it has taken all reasonably available steps to mitigate above-market NUG contract costs. Specifically, while we approve herein the proposed sale by PSE&G of NUG contract energy and capacity at wholesale PJM locational marginal prices and at wholesale, respectively, PSE&G will be required to sell such power through alternative means if such means are available at a more beneficial market price, and PSE&G will be required to continue to make reasonable attempts to renegotiate, buy out or buy down its NUG contracts.

We also **FIND** that the proposed bidding out of BGS for year four of the Transition Period is consistent with the Act. Subsection 9(a) of the Act, N.J.S.A. 48:3-57, provides that each electric public utility must provide BGS for at least three years subsequent to August 1, 1999 and thereafter until the Board finds that such provision is no longer necessary and in the public interest. Subsection 9(a) further provides that power procured for BGS shall be purchased at prices consistent with market conditions, that the BGS charges to customers shall be regulated by the Board and "based on the reasonable and prudent cost of. . . providing such service. . ", and that the aggregate rate reductions be sustained notwithstanding the resultant BGS charges. The proposed Stipulation provides that PSE&G will provide BGS through July 31, 2002 in conformance with the Act. The BGS pricing provided by the proposed Stipulation, both during the first three years of the Transition Period when BGS is provided by PSE&G as well as during the fourth year when BGS will be provided for the first time by a third party as a result of the bid, is established and is based upon the market price projections (plus a retail adder as discussed herein) for the four year period in the record. In this manner, BGS pricing for the Transition Period is consistent with market conditions as required by the Act. We expect that the bidding out of

BGS for year four as provided in the Stipulation will have the added benefit of creating substantial competition among third party suppliers for the right to provide this service at the pre-established BGS rate/ shopping credit price, thereby potentially producing added benefits to customers consistent with the provisions of paragraph 17 of the proposed Stipulation. This mechanism is consistent with the intent of the Act to place greater reliance on competitive markets to deliver energy services at lower costs (see subsection 2(a)(2) of the Act, N.J.S.A. 48:3-50(a)(2)). At the same time, however, the mechanism provided to have suppliers bid for the right to provide BGS during year four at the pre-established price, will assure that the aggregate rate reductions will be sustained in year four, and will provide price stability as part of a reasonable and appropriate transition mechanism to the reliance on the competitive market for the provision of BGS. Accordingly, subject to the foregoing and to the terms of this Order, we **FIND** that it will no longer be necessary and in the public interest for PSE&G to provide BGS in year four of the Transition Period or thereafter if BGS is successfully bid publicly as proposed in the Stipulation. We **HEREBY DIRECT** that the Company file, by no later than August 1, 2001, a specific proposal for public comment and review and approval by the Board to implement a request for proposals (ARFP@) to supply basic generation service for the period August 1, 2002 through July 31, 2003. Such proposal should include a proposal to assure that any RFP does not provide any undue competitive advantage to an affiliate of PSE&G, and that the selection process does not allow for favored treatment of an affiliate of PSE&G, should such affiliate choose to participate in the bidding process.

Pursuant to the provisions of subsections 7(f), 7(I), 7(j) and 8(b) of the Act, N.J.S.A. 48:3-65(f) (I) and (j) and N.J.S.A. 48:3-66(b), taken together, an electric public utility is not permitted to offer competitive electric generation service and, pursuant to the definitions provided in section 3 of the Act, N.J.S.A. 48:3-51, basic generation service is not a competitive service. Accordingly, we **FIND** the provisions of paragraph 18 of the proposed Stipulation to be consistent with both the letter and intent of the Act. With regard to the relationships and transactions between PSE&G and Genco, other than those specifically governed by the terms of the BGS contract provided for herein and as subsequently reviewed and approved by the Board, rather than adopting either of the standards proposed in the Stipulation, we deem it most appropriate and efficient to subject PSE&G and Genco to the same standards as we shall be imposing on other utilities and their affiliates, and thereby determine that such relationships and transactions between PSE&G and Genco shall be governed by the affiliate relations standards adopted by the Board pursuant to section 8 of the Act, N.J.S.A. 48:3-56.

Notwithstanding the foregoing, and in light of the establishment of shopping credit levels which, while overall reflective of market prices may not adequately reflect the seasonality of market prices and, in order to deter suppliers from offering services to customers that might cause them to leave BGS during low cost periods and return to BGS during high cost periods, thereby Agaming@ the system, the Board **HEREBY ADOPTS** the following protections. PSE&G shall have the option of imposing a one-year commitment on any non-residential customer returning to BGS unless such customer selects a new third party supplier within 30 days of the return to BGS. Notwithstanding the 30 day Agrace period,@ any non-residential customer returning to BGS during May of any year shall become subject to the one-year commitment unless a new third party supplier is selected before June 1 and any non-residential customer returning to BGS during June, July or August of any year will immediately become subject to the one-year commitment without any Agrace period@ to select a new third party supplier. We decline to adopt a similar mechanism for residential customers at this time, because we are mindful that the residential market in general has been a more difficult market for third party suppliers to penetrate, and we wish to minimize, where practicable, restrictions which may dissuade residential customers from switching to a third party supplier. We will monitor developments, including products and services being offered to residential customers by third party suppliers, and will revisit the possible imposition of the one-year commitment provisions on residential customers if it becomes clear that our decision at this time has led to gaming by suppliers and/or customers.

The Board notes that the Stipulation does not provide for the Investment Tax Credit ("ITC") value to be flowed through to ratepayers. The Board **HEREBY DIRECTS** the Company to seek a letter ruling from the IRS to determine whether or not the value of the ITC can legitimately be credited to customers without violating the tax normalization policies of that Agency to the detriment of the Company and the customers, and to provide a copy of that letter ruling once received from the IRS to the Board and the Ratepayer Advocate. In the event that the IRS issues a letter ruling that the ITC cannot be passed onto customers, then this issue will be moot. In the event that the IRS issues a letter ruling which is favorable to the proposition that the ITC can be passed onto customers, then the Board in year four of the Transition Period will consider any action which it may deem appropriate, giving consideration to the issues resolved in the Stipulation of March 17, 1999, the Board's modifications to that Stipulation, and other relevant considerations which the parties might bring to the Board's attention in that review of the issue during year four of the Transition Period.

Finally, we address the issue raised in the proceeding by Co-Steel, described hereinabove, with respect to the imposition of stranded cost or related charges such as the transition bond charge on power consumed by Co-Steel under its special contract dated November 14, 1994 with PSE&G, which issue was litigated during the proceeding before ALJ McAfoos but which was not addressed in the Initial Decision. Block 1 of Co-Steel=s usage under the special contract is based on the Company=s HTS tariff. The Act makes clear that the MTC, TBC and SBC are to be non-bypassable charges (except for eligible on-site generator customers pursuant to section 28 of the Act, N.J.S.A. 48:3-76)). Customers on the HTS tariff, must therefore be assessed MTC, TBC and SBC charges. However, pursuant to the requirements of section 4 of the Act, N.J.S.A. 48:3-52, HTS customers, as well as all other customers, will experience a 5% aggregate rate reduction effective August 1, 1999, a 7% rate reduction on or about January 1, 2000, a 9% rate reduction effective August 1, 2001 and a 13.9% rate reduction effective August 1, 2002. Importantly, all such rate reductions are inclusive of the imposition of the MTC, TBC and SBC charges. Indeed, a portion of the aggregate rate reductions which will be received are a direct result of the securitization approved herein; enjoyment of those price reductions by a customer without paying towards the transition bonds and related costs which helped make such reductions possible would be unfair. Accordingly, we **<u>FIND</u>** that there is no legal basis in the Act for an exclusion for Co-Steel from paying the MTC, TBC and SBC charges, and indeed there is no merit for Co-Steel=s arguments whatever, since the cost of its power consumption under Block 1 of the special contract will be reduced as a result of the Act and this Order and, moreover, as already acknowledged by PSE&G, Co-Steel=s Block 2 usage will be governed by the special contract and, therefore, the price thereof will be unaffected by this Order. We therefore **<u>REJECT</u>** Co-Steel=s arguments, including its assertion that it should be released from its contract and be able to shop for an alternative supplier immediately, since there has been no material change to the contract for which PSE&G and Co-Steel bargained. Moreover, Co-Steel will be receiving power at a net price lower than that originally bargained for as a result of this Order. Finally, we **<u>REJECT</u>** the arguments made by Co-Steel that it should be exempted from the imposition of any stranded cost charges after the expiration of the special contract. Simply put, any special pricing arrangements for which it has bargained expire with the expiration of the special contract. After the expiration of its contract with PSE&G, Co-Steel will be subject to and have all of the options afforded under applicable law, including with regard to utility tariffs, and the ability to shop for an alternative supplier.

Based on the above, we hereby incorporate as a fair resolution of the issues in these proceedings, the elements of Paragraphs 1 to 36 of the Stipulation filed by PSE&G and others, subject to the modifications and clarifications set forth above, along with the specific modifications and clarifications set forth below. To the extent the Initial Decision is inconsistent herewith, it is modified to conform herewith.

Based upon the foregoing, we **<u>HEREBY FIND</u>** and **<u>DIRECT</u>** as follows:

1) Electric rate reductions shall be implemented by PSE&G as follows to comply with the provisions of subsection 4(d) of the Act, <u>N.J.S.A</u>. 48:3-52(d):

   a) A 5% aggregate rate reduction from rates in effect as of the date of the Board=s Summary Order in this matter (hereinafter Acurrent rates@) for service rendered on and after August 1, 1999. This reduction includes a 1% reduction relating to the savings from securitization.

   b) A minimum additional rate reduction of 2% of current rates targeted for service rendered on or after January 1, 2000 subject to the issuance prior to such date of a Bondable Transition Cost Rate Order establishing a securitization bond charge and providing for the securitization of $2.4 billion of generation-related stranded costs and the recovery of up to $125 million of related and reasonable and prudently-incurred taxes, costs of issuance, and transaction costs including costs of refinancing or retirement of debt or equity as provided in paragraph 11 (together ABondable Stranded Costs@) and the sale of the securitization bonds. The date of the reduction will be the same date as the securitization transition charge is established.

c) A further minimum 2% rate reduction for service rendered on or after August 1, 2001 to bring the total rate reduction to 9% from current rates assuming that securitization is implemented should greater savings be achievable as a result of securitization as implemented, the additional savings shall be reflected in reductions beyond the requisite minimums set forth herein in (b) and

d) A final rate reduction for service rendered on and after August 1, 2002, in an amount that, when considered with the above reductions, will result in a rate reduction by customer class of 10% relative to rates in effect as of April 30, 1997.

e) All rate reductions will be applied to each customer=s bill to reflect the above reductions, as set forth on Attachment 2 of the PSE&G Stipulation page 2 of 19. However, as discussed herein, we are concerned that the removal of the rate reduction credit in year five will lead to an undue bill impact, since removal of the entire rate reduction credit would appear to result in a total customer bill which exceeds the sum of the current unbundled rate components, including the distribution rate, BGS rate (including transmission), STC, NTC, and SBC which will remain, prior to adjustment, in year five. Moreover, we are concerned that the particular unbundled rate components, particularly with respect to distribution charges, as provided in Attachment 2 of the Stipulation will, after the expiration of the rate reduction credit, result in a shift in cost responsibility between and among customer classes. As further discussed herein, we also find it necessary and appropriate for the Board to review the overall level of rate savings prior to the conclusion of the Transition Period. We therefore **DIRECT** the Company to file, by no later than August 1, 2002, the proposed unbundled rates and support therefor which it proposes be implemented at the expiration of the Transition Period on August 1, 2003.

f) The rate reduction described in paragraph 1(d) shall be sustained until July 31, 2003.

2) There shall be a four-year transition period commencing on August 1, 1999 and terminating on July 31, 2003 (Transition Period).

3) The unbundled rates to be effective for each rate class in PSE&G=s Tariff for Electric Service have been developed using the Company=s 1995 Cost of Service Study using the parameters defined in Attachment 2 of the PSE&G Stipulation, including the unbundled rates and rate components. Each customer=s bill shall indicate the dollar amount of the difference between what the customer=s total charges would have been without the reduction and the total charges in that bill pursuant to subsection 4(b) of the Act, N.J.S.A. 48:3-52(b).

4) An excess electric distribution reserve in the amount of $568.7 million is to be amortized over three years and seven months beginning on January 1, 2000 and ending July 31, 2003. Amortization amounts will be $125 million in the year 2000, $125 million in the year 2001, $135 million in the year 2002, and $183.7 million in the year 2003.

5) Consistent with section 12 of the Act, N.J.S.A. 48:3-60, PSE&G will establish a Societal Benefits Charge. The SBC will include costs related to: 1) Social Programs (including the Universal Service Fund); 2) Nuclear Plant Decommissioning costs; 3) Demand Side Management Program costs; 4) Manufactured Gas Plant Remediation costs; and 5) Consumer Education Costs.

6) The SBC will be set at the level of costs for the above items included in rates as of February 9, 1999, the effective date of the Act, and as more explicitly defined in Attachment 2 of the PSE&G Stipulation. This SBC level will remain constant through the Transition Period. Actual costs incurred by the Company for each of the cost components enumerated in paragraph 5 will be subject to deferred accounting. Interest adjusted on August 1 of each year of the Transition Period will be accrued on any under- or overrecovered balances. The interest rate will be based on seven year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year plus sixty basis points. At the completition of the Transition Period, the SBC will be reset and then reset annually upon Board approval to amortize any over- or under collected balances.

7) The DSM generation-related lost revenue created subsequent to August 1, 1999 will no longer be reflected in the calculation of costs eligible for Demand Side Management Program cost recovery and deferral as described in Attachment 2 of the PSE&G Stipulation.

8) Consistent with section 13 of the Act, N.J.S.A. 48:3-61, the Company=s unbundled electric tariffs and distribution service rates will include a NTC to recover the above-market stranded costs of PSE&G=s existing non-utility generation contracts. These contracts will continue to remain the obligation of PSE&G during the life of the contracts. The Company will sell the energy and capacity from these contracts at the PJM Interchange Hourly Locational Marginal price and at wholesale within the PJM region, respectively. Notwithstanding the foregoing, the Company has an ongoing obligation to mitigate the above-market stranded costs recovered through the NTC, pursuant to subsection 13(f) of the Act, N.J.S.A. 48:3-61(f).

9) The initial level of the NTC will be set based on the above-market non-utility generation costs for 1999 of $183 million (Exhibit PS-20, Schedule CJL-F3) and as more explicitly defined in Attachment 2 of the Stipulation. This NTC level will remain constant for a period of four years from August 1, 1999. Actual annual payments made by the Company for NUG costs will be reduced by the value received from the sale of the energy and capacity associated with those contracts as described in paragraph 8. For the purpose of calculating the amount of stranded cost which PSE&G is entitled to recover during the Transition Period, any increase or decrease in the above-market costs will be subject to deferred accounting and interest, adjusted on August 1 of each year of the Transition Period, will be calculated on any under- or over-recovered balances. The interest rate will be based on seven year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year plus sixty basis points. After the Transition Period, the NTC will be reset and then reset annually upon Board approval to amortize any over- or under-collected balances. Board approved buy-outs and buy-downs of NUG contracts will be reflected in this clause in a manner consistent with subsection 13(l)(3) of the Act, N.J.S.A. 48:3-61(l)(3).

10) The Company is entitled to recover $2.94 billion net-of-tax of its generation-related stranded costs resulting from a market valuation of $0.046 billion and $1.857 billion for nuclear and fossil generating assets, respectively. As set forth in paragraphs 11 and 13, the Company will be provided with an opportunity to recover up to $2.94 billion of net-of-tax generation related stranded costs through securitization of $2.4 billion and an opportunity to recover up to $540 million of its unsecuritized net-of-tax generation related stranded costs on a present value basis, subject to true-up on the collection of the unsecuritized generation related stranded costs as provided in paragraph 17 hereinbelow. The accumulated LEAC overrecovery balance as of July 31, 1999, including accumulated interest thereon as of that date, shall be applied as a credit to the starting deferred balance for the NTC.

11) In order to comply with the requirements of section 14 of the Act, N.J.S.A. 48:3-62,

PSE&G will utilize the net proceeds of securitization, after payment of all related fees and expenses of issuance and sale, to refinance or retire its debt and/or equity, in a manner that will not substantially alter the Company's overall capital structure to the detriment of bondholders or ratepayers; (ii) such refinancing and/or retirement of such debt may occur as a result of, among other things, mandatory and/or optional redemption, repurchase and/or tender by or on behalf of PSE&G, which optional redemption, repurchase or tender may be at a premium; and (iii) the Board **HEREBY AUTHORIZES** PSE&G to employ such methods as are reasonable and necessary to achieve the overall intent and purposes of the Act.

a) Upon application by PSE&G and determination by the Board that the conditions of the Act are met, the Board will issue a financing order consistent with the provisions of the Act, to authorize PSE&G to issue up to $2.525 billion of transition bonds representing $2.4 billion of net-of-tax generation-related stranded costs and up to $125 million of transaction costs including related fees and expenses of issuance, sale of bonds and to refinance or refund its debt and equity subject to approval of the Board. The taxes related to securitization, which reflect the grossed up revenue requirement number associated with the $2.4 billion in net of tax stranded costs being securitized, are recoverable stranded costs, however they should not be collected through the transition bond charge; rather, such taxes shall be collected via a separate MTC referred to as an "MTC-Tax." The duration of this separate MTC shall be 15 years, or otherwise so as to be identical to the duration of the transition bond charge.

12) a) PSE&G has taken reasonable measures to date on mitigation of stranded costs (Exhibit PS-14) and the terms of this Order including rate reductions, rate freezes, and other mitigation measures will create appropriate incentives in place to mitigate the total amount of its stranded costs;

b) PSE&G will not be able to achieve the level of rate reduction deemed by the Board to be necessary and appropriate pursuant to the provisions of Sections 4 and 13 of the Act, N.J.S.A. 48:3-52 and N.J.S.A. 48:3-61, absent the issuance of transition bonds providing for the recovery of its Bondable Stranded Costs as set forth in paragraph 1(b); and

c) We note that market interest rates are subject to volatility, and the actual interest rates on the transition bonds are not known at this time. Accordingly, it is impossible to reach final determinations at this time with respect to the actual level of savings and benefits associated with the issuance of transition bonds by PSE&G. Indeed, to the extent that the interest rate on the bonds is not fixed until the time of the pricing of the terms and conditions of the transition bonds, such final determinations with respect to savings and benefits could be problematic even at the date of the issuance by the Board of a financing Order. In order to be able to address this issue definitively in the financing Order, recognizing the inherent volatility of market interest rates, we will determine in the financing Order an upper bound for the actual interest rate on the bonds, at or below which would result in a level of savings and benefits for ratepayers which the Board deems appropriate in accordance with the provisions of the Act.

13) Pursuant to paragraph 10, in accordance with section 13 of the Act, N.J.S.A. 48:3-61, and on the condition that the Genco transfer is implemented, and the unsecuritized generation stranded cost level is not subject to true-up (other than as provided in paragraph 17 hereinbelow), PSE&G shall be provided with the opportunity to recover up to $540 million of its unsecuritized generation stranded costs on a net present value (8.42% discount rate) net of tax basis over the Transition Period. This recovery is to be accomplished via a 2 mill per kwh retail adder, an explicit Market Transition Charge (MTC), exclusive of the NTC, as discussed in Attachment 2 to the PSE&G Stipulation, and the amount funded by the excess distribution depreciation reserve amortization. As Basic Generation Service (BGS) customers leave PSE&G for third-party suppliers, full recovery of these costs is not assured and represents a risk of undercollection to PSE&G.

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14) At the end of the Transition Period, the recovery of the $540 million will be reconciled to actual collections based on actual sales, the net present value of recovery from both the MTC, exclusive of the NTC, and collections from a 2.0 mill per kWh retail adder for all customers retained on the BGS, and the depreciation amortization. In the event the Company fails to collect $540 million, it will be at risk for any such shortfall. In the event the Company collects over $540 million, it shall use any such overrecovery to reduce the Company=s SBC at the end of the Transition Period when the SBC is reset and shall in no event be retained by PSE&G or remitted to Geneco or otherwise utilized to recover unsecuritized generation-related stranded costs. The discount rate used in these present value calculations will be based on the same cost of capital/discount rate used to calculate securitization savings on Attachment 1 to the PSE&G Stipulation.

15) The Company=s shopping credit shall equal its BGS rate, which shall be inclusive of an allowance for the cost of energy, capacity, transmission, ancillary services, losses, taxes and retail adder. The Company=s BGS/shopping credit levels shall be established and fixed for the duration of the transition period, without adjustment or true up of any kind, as follows:

	Aug-Dec 1999	**Jan-Dec 2000**	**Jan-Dec 2001**	**Jan-Dec 2002**	**Jan-Jul 2003**
RS	5.71	5.86	5.86	5.86	5.86
GLP	5.30	5.35	5.39	5.44	5.44
LPL-S	4.84	4.88	4.93	4.97	4.97
LPL-P	4.54	4.58	4.62	4.66	4.66
HTS-SubT	4.30	4.35	4.40	4.44	4.44
HTS-HV	4.12	4.16	4.21	4.25	4.25
Overall	**4.95**	**5.03**	**5.06**	**5.10**	**5.10**

The above rates are rate schedule averages, which will differ by blocks and time periods of each rate schedule as defined in Attachment 2. Other rate schedules (RHS, RLM, WH, WHS, HS, BPL and PSAL) will be calculated consistent with the above as presented in Attachment 2 of the Stipulation. Additional shopping-related savings, resulting from customers receiving electric generation service from a supplier at a price less than the above shopping credits, are above and beyond the rate reductions set forth in paragraph 1.

16) The above-referenced pre-established BGS rates meet the shopping credit definition in the Act and resolve the issue of BGS pricing and the shopping credit in a manner that accommodates the parties= concerns and satisfies the requirements of subsections 9(a) and 9(d) of the Act, N.J.S.A. 48:3-57(a) and (d).

17) Basic Generation Service Obligation B Pursuant to subsections 9(a) and 9(b)(3) of the Act, N.J.S.A. 48:3-57(a) and (b)(3), the Company has a three-year obligation to provide BGS to those retail customers who choose to remain with the utility during the three-year period ending July 31, 2002. The BGS to be provided after July 31, 2002 shall be bid out. The first year bid will be a pre-payment method based upon pre-established shopping credit for year four. If the bid for generation results in a payment to PSE&G, it shall be credited to the deferred SBC balance for purposes of establishing the SBC rate in year five. If the bid for generation requires a payment by PSE&G, such payment shall be subject to deferral and subsequent recovery at the Interest Rate. A non-regulated affiliate of Public Service Enterprise Group, Inc.

will be authorized to bid for such BGS to be provided after July 31, 2002 pursuant to terms that apply to other suppliers of electricity, subject to procedures to be determined by the Board.

18) PSE&G shall not promote its BGS as a competitive alternative.

19) Pursuant to the provision of subsection 7(d) of the Act, N.J.S.A. 48:3-55(d), the Board approves the transfer of the Company=s electric generation-related assets and their operation, and all associated rights and liabilities into a separate corporate entity or entities (Genco) to be wholly owned by Public Service Enterprise Group, Inc. and not by Public Service Electric and Gas Company. The specific generation facilities and assets which shall be transferred are identified on Attachment 3 to the Stipulation (the AGeneration Facilities@). PSE&G represented that these facilities and assets constitute all of its electric generation related assets.

20) The final and fixed transfer value pursuant to subsections 7(d) and 13(e) of the Act, N.J.S.A. 48:3-55(d) and 61(e), for the Generation Facilities is $2.443 billion (Attachment 4 to the Stipulation as modified pursuant to this Order) which is the fair market value of the assets transferred considering all revenues derived from the BGS contract described in paragraph 21 hereof. In addition, PSE&G will transfer at book value at the time of transfer other generation-related assets including materials, supplies, and fuel, which book value we find to be the full value for such generation-related assets, in accordance with subsection 7(d) of the Act, N.J.S.A. 48:3-55(d). Such transfer prices ensure that PSE&G receives full value for the Generation Facilities and related assets and that PSE&G will not retain any liabilities associated with the transferred Generation Facilities or other generation-related assets and shall assure that customers= responsibility for stranded costs is established at the lowest reasonable level. No land held for future use (Account 105) will be transferred to Genco. All generation-related expenses will be borne by Genco. The Company shall have auditable accounting protocols in place no later than the effective date of the transfer to assure that all expenses and capital expenditures related to generation will be borne by Genco.

21) The BGS contract between PSE&G and Genco will contain the following provisions:

To ensure the reliability of service to BGS and to remove the risk of price volatility o the regulated Company during the transition to a competitive market and to further ensure that PSE&G can meet its contractual obligations to provide power under certain Off-Tariff Rate Agreements (listed in Attachment 5 to the Stipulation), the transfer to the Genco shall be accompanied by the Genco and PSE&G=s entering into a BGS contract which shall be submitted for approval to the Board, whereby the Genco would provide full requirements service for energy, capacity, losses and ancillary services needed by the Company for BGS and for Off-Tariff Rate Agreements for the period that the Company will be providing BGS under the Stipulation;

b) In exchange for ensuring the reliability of supply for PSE&G's BGS, for removing the risk of price volatility from the regulated Company in providing such service and to further ensure that PSE&G can meet its contractual obligations in its Off-Tariff Rate Agreements, the BGS contract shall provide that the consideration paid by PSE&G for such full requirements service shall be: (I) an amount computed on a monthly basis equal to the full amount charged for BGS to PSE&G's retail electric customers as set forth in paragraph 15 (less any sales and use tax and transmission); (ii) an amount computed on a monthly basis equal to PSE&G's retail delivery to Off-Tariff Rate Agreement customers, multiplied by the comparable BGS rate for such customers (less sales and use tax and transmission); and (iii) an additional charge for price stability services provided by the combustion turbine assets of Genco, payable based on the installed capacity of those assets. The additional charge, set forth in (iii) above, will be an amount computed on a monthly basis equal to the full actual amount collected pursuant to paragraph 13 excluding the 2 mill per kWh retail adder. Pursuant to subsection 9(b)(3) of the Act, N.J.S.A. 48:3-57(b)(3), no net revenue from this contract may be used as a reduction of the MTC or distribution rates.

c) To further ensure the reliability of supply for PSE&G=s BGS and to remove the risk of price volatility from PSE&G, the BGS contract shall also provide that PSE&G shall transfer to Genco, solely for the purpose of Genco meeting its obligations under the BGS contract, including the removal of price volatility, the authority to act as its agent for the purpose of scheduling, electing and/or using all rights, including Fixed Transmission Rights, associated with transmission delivery of full requirements service for PSE&G=s BGS and Off-Tariff Rate Agreement customers. Genco will be responsible for costs related to BGS scheduling activities to the same degree it would be responsible for those costs for other load serving entities.

d) The BGS contract shall be filed with the Board for review and approval to ensure its consistency with the letter and intent of this Order. The parties shall have the right to comment to the Board on terms and conditions which are reflected in the BGS contract but which are not set forth herein.

22) To further ensure the reliability of the BGS after the transfer of the Generation Facilities, PSE&G shall continue to supply, on an as needed basis, dedicated intrastate natural gas transportation services for the Genco=s own gas supplies from PSE&G=s city gate to the transferred generating facilities in accordance with the

Stipulation approved in Docket No. ER94070293, OAL Docket No. PUC 7328-94 on May 5, 1995. Such dedicated intrastate natural gas transportation services shall continue to be supplied by PSE&G to Genco for the term of the BGS contract.

23) To ensure that the goals of reliable service and sustained rate reductions are achieved, the transferred Generation Facilities may only be sold or otherwise transferred by Genco to any other party during the Transition Period if the other party agrees to take the Generation Facilities subject to entering into a comparable BGS contract with the same consideration including the right to recover the MTC allocated to such Generation Facilities. Said contract shall be subject to review and approval by the Board to assure such comparability and to otherwise ensure that the PSE&G customers receive at least the same level of benefits as attendant to the BGS contract between PSE&G and Genco. If a sale of some or any of the transferred Generating Facilities by Genco occurs within five years of August 1, 1999, any net after tax gains from such sale will be shared equally between shareholders and customers in a manner to be determined by the Board.

24) The Board finds that qualifying the Generation Facilities being transferred, either separately or jointly, in accordance with section 32(c) of the Public Utility Holding Company Act of 1935 as Exempt Wholesale Generators will benefit consumers, is in the public interest, will not provide any unfair competitive advantage by virtue of the Genco's affiliation or association with the Company subject to compliance with affiliate relations and fair competition standards to be adopted by the Board, and does not violate State law. As an EWG, Genco shall not offer retail electric service.

25) The Board finds that, in accordance with section 32(k) of the Public Utility Holding Company Act of 1935, it has sufficient regulatory authority, resources and access to books and records of Public Service Electric and Gas Company and any relevant associate, affiliate or subsidiary company, to ensure that the BGS contract will (a) benefit consumers; (b) not violate any State law; (c) not provide Genco any unfair competitive advantage by virtue of its affiliation or association with the Company; and (d) is in the public interest.

26) PSE&G shall submit, within 60 days of the date of issuance of the Board's Order, a tentative schedule for the receipt of authorization for the transfer from other agencies for the Generation Facilities described in Attachment 3 to the Stipulation. PSE&G shall submit to the Board copies of any filings made to other agencies seeking authorization of the transfer, in order to assure that no material changes to the terms and conditions attendant to this Order are being sought. Within 60 days following approval, PSE&G shall also file with the Board copies of any documents evidencing such transfer and assumption of liabilities in connection therewith. Upon

the receipt of approval from other agencies, PSE&G shall provide a filing, which reflects the terms and the approvals received and accounting implemented.

27) In order to ensure that PSE&G does not retain any risks or liabilities associated with the electric generating business after the Generating Facilities have been transferred, the Board hereby orders that all contracts (except for the NUG contracts) associated with the electric generating business, including, but not limited to, wholesale electric purchase and sales agreements, fuel contracts, real and personal property interests, and other contractual rights and liabilities, be transferred from PSE&G to Genco simultaneous with the transfer of all generating assets, and to substitute the Genco for PSE&G as the party(s) to any such contracts.

28) The Board recognizes that various federal and state regulatory approvals, as well as third-party consents, will be necessary to complete the transfer of assets, rights and obligations contemplated by this Order and anticipates that such approvals and consents will result in a delay between the date of this Order approving the transfer and the date that the Generation Facilities are actually transferred. The Board finds that PSE&G will receive from Genco the full market value of the generating assets, and that such receipt will be reflected as an offset to the MTC charged by PSE&G to recover unsecuritized stranded costs. Accordingly, and in order to effectuate the purposes of the Act under subsection 9(b)(3), N.J.S.A. 48:3-57(b)(3), and to ensure that PSE&G is not unduly penalized while diligently complying with this Order and supplying BGS at rates approved by the Board, any requirement under section 7 of the Act, N.J.S.A. 48:3-55, which would require the payment of any percentage of net revenues for the sharing of common assets and personnel is not applicable, provided that the transfer is completed within one year of the date of this Order, unless extended by further Order of the Board.

29) Generating capacity transferred to Genco shall be maintained as a capacity resource within the PJM system for the Transition Period. During that period, Genco will be permitted to sell said capacity outside of the PJM system for periods of less than one year after it makes good faith efforts to sell the transferred capacity into the PJM system at market rates. For purposes of implementing this Order, the Board will retain jurisdiction over and will monitor whether Genco is complying with the terms of this Order during the Transition Period to sell excess capacity into the PJM system at market prices.

30) In addition to any other Affiliate Standard of Conduct that might apply to PSE&G, the relationship and any transactions between PSE&G and Genco, except as such relationship is defined in the BGS contract, as reviewed and approved by the Board, will be governed by the affiliate relations standards adopted by the Board pursuant to section 8 of the Act, N.J.S.A. 48:3-56.

31) The transfer of Generation Facilities and related rights and liabilities contemplated by this Order is in the public interest and will not jeopardize the reliability of the electric power system. Such transfer will not adversely impact the ability of PSE&G to meet its obligations to its employees with respect to pension benefits, as contemplated pursuant to N.J.S.A. 48:3-7.

32) The advertising requirements under N.J.A.C. 14:1-5.6 are waived because of the extensive nature of the record regarding valuation of the assets being transferred and no further authorizations by the Board are required to effectuate this transfer provided that all other regulatory approvals are obtained on a basis consistent with this Order.

33) Upon the transfer of the nuclear generation assets, neither PSE&G nor its retail customers shall be responsible to decommission its previously owned nuclear units, subject to the Nuclear Regulatory Commission approval. That responsibility will pass to the Genco with the transfer of the nuclear generation and associated assets described in Attachment 3 to the Stipulation and the Nuclear Decommissioning Trust Funds.

34) The Third Party Supplier Agreements are subject to an ongoing generic working group under the Board=s restructuring dockets. We will determine the contents and substance of the Third Party Agreement and accompanying tariffs within the context of that generic proceeding.[9]

35) The Board will work closely and cooperatively with the PJM-ISO to monitor actual market behavior in connection with the PJM-ISO=s FERC-ordered market monitoring plan.

36) The Board directs the parties to work cooperatively to conclude the billing and metering proceeding in an expedited fashion, which proceeding the Board will endeavor to conclude by May 1, 2000, but in any event shall conclude by August 1, 2000 pursuant to section 6 of the Act, N.J.S.A. 48:3-54.

37) The Board directs PSE&G to seek a letter ruling from the IRS to determine whether or not the value of the ITC can legitimately be credited to customers

[9] The four electric public utilities and a majority of active third party suppliers in fact reached agreement on a Master Third Party Supplier Agreement and accompanying tariffs, which was approved by the Board at its July 26, 1999 public agenda meeting.

without violating the tax normalization policies of that agency to the detriment of the Company and its customers.

In summary, subject to the conditions embodied herein, the rate discounts provided by PSE&G relative to current rates during the Transition Period shall be as follows:

August 1, 1999	5%
January 1, 2000	7% (minimum)
August 1, 2001	9% (minimum)
August 1, 2002	13.9%

The average shopping credits shall be as follows:

	1999	2000	2001	2002	2003
RS	5.71	5.86	5.86	5.86	5.86
GLP	5.30	5.35	5.39	5.44	5.44
LPL-S	4.84	4.88	4.93	4.97	4.97
LPL-P	4.54	4.58	4.62	4.66	4.66
HTS-SubT	4.30	4.35	4.40	4.44	4.44
HTS-HV	4.12	4.16	4.21	4.25	4.25
Overall	**4.95**	**5.03**	**5.06**	**5.10**	**5.10**

The opportunity for recovery of up to $2.94 billion of net of tax generation stranded costs is afforded via $2.4 billion of securitization and the opportunity for up to $540 million to be recovered via the MTC, the retained retail adder and the depreciation reserve amortization and subsequently remitted to Genco, per the terms of the Stipulation as modified.

The total opportunity for recovery of net of tax generation stranded costs is set at $2.94 billion, with the implementation of the Genco transfer, resulting from an increase in the net transfer value for the generating assets of $135 million from $1.768 billion to $1.903 billion.

The amount of generation stranded costs which is authorized for securitization is $2.4 billion. The Company is also authorized to securitize up to the estimated $125 million of reasonably incurred bond transaction costs.

The amount of unsecuritized net of tax stranded cost which the Company is permitted an opportunity to recover is $540 million, with the implementation of the Genco transfer per the terms of the Stipulation as modified herein, and subject to the true-up provisions provided in paragraph 17 of the Stipulation as modified herein.

DATED: 8/24/99

BOARD OF PUBLIC UTILITIES
BY:

_____SIGNED________
HERBERT H. TATE
PRESIDENT

_____SIGNED_________
CARMEN J. ARMENTI
COMMISSIONER

_____SIGNED________
FREDERICK F. BUTLER
COMMISSIONER

ATTEST: ___SIGNED_______
MARK W. MUSSER
SECRETARY