BEFORE THE STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES
OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF CHANGES IN ELECTRIC RATES, FOR CHANGES IN THE TARIFF FOR ELECTRIC SERVICE, CHANGES IN ITS ELECTRIC DEPRECIATION RATES AND FOR OTHER RELIEF	**)))))))**	**DOCKET NO. ER02050303** **OAL DOCKET NO. PUC 5744-02**

INITIAL BRIEF OF THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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PROCEDURAL HISTORY

On or about May 24, 2002, Public Service Electric and Gas Company ("PSE&G"or "Company") filed a petition ("Petition") with the Board, seeking approval of changes in electric rates, changes in the tariff for electric service, B.P.U.N.J. No. 14, Electric pursuant to *N.J.S.A.* 48:2-21 and 48:2-21.1 and for changes in its electric depreciation rates pursuant to *N.J.S.A.* 48:2-18. This case was transmitted to the Office of Administrative Law ("OAL") on June 26, 2002, as a contested case and assigned to the Honorable Richard McGill, Administrative Law Judge, ("ALJ") for evidentiary hearings.

In addition to the Company, the parties to this proceeding are the Staff of the Board of Public Utilities (AStaff@), the New Jersey Division of the Ratepayer Advocate (ARatepayer Advocate@) and several other parties. Several entities moved to intervene in the proceeding. Co-Steel Raritan, Inc. ("Co-Steel")[1]; New Jersey Large Energy Users Coalition ("NJLEUC"); Independent Energy Producers of New Jersey ("IEPNJ"); New Jersey Transit Corporation ("NJ Transit"); Delaware River Port Authority; New Jersey Commercial Users ("NJCU"); and the Township of Hamilton ("Township") were granted intervenor status. Several Municipal Utility Authorities ("MUA") including: Stoney Brook Regional Sewerage Authority; the Mt. Holly MUA; Secaucus MUA; Cinnaminson Sewerage Authority; East Windsor MUA; Riverside Sewerage Authority; Evesham MUA; Willingboro MUA; Somerset Raritan Valley Sewerage; Bordentown Sewerage Authority; Morris Township; Monroe Township MUA; and Pemberton MUA were collectively granted intervenor status. Other movants were granted participant status. The participants are Jersey Central Power & Light Company ("JCP&L"); PPL EnergyPlus, LLC ("PPL"); Rockland Electric Company ("RECO"); and one individual, Allen Goldberg ("Goldberg").

[1]After a merger, Co-Steel became Gerdau Ameristeel Perth Amboy, Inc.

A pre-hearing conference was held on July 19, 2002. On July 22, 2002, the Board issued an Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals. On July 24, 2002, the OAL issued a Prehearing Order outlining the proceeding and issues. In accordance with the schedule set forth in the Prehearing Order, discovery was propounded. Public hearings were held on September 25, 2002, in New Brunswick, New Jersey; September 26, 2002, in Mt. Holly, New Jersey; and September 20, 2002, in Hackensack, New Jersey. Additional public hearings were held on January 30, 2003, in Trenton and Mt. Holly, New Jersey, and in Newark, New Jersey, on January 31, 2003.

In support of its base rate case, concurrent with its filing, the Company filed the testimony of Peter A. Cistaro, Robert C. Krueger, Jr., Albert N. Stellwag, Robert L. Hahne, Robert A. Morin, and Gerald W. Schirra. On August 28, 2002, the Petitioner filed Supplemental Direct Testimony of their witness, Robert C. Krueger. On September 3, 2002, the Company filed the Direct Testimonies (6+6 Update) of the following witnesses: Messrs. Krueger, Stellwag, and Hahne. PSE&G also filed the Revised Testimony of Mr. Schirra on September 8, 2002. On September 9, 2002, PSE&G submitted revised pre-filed testimony, including exhibits, of its witness, Mr. Schirra. On November 15, 2002, the Direct Testimony Update of Mr. Morin was filed by the Company.

The Company further filed Direct Testimonies (9+3 Update) of the following witnesses: Messrs. Cistaro, Krueger, Stellwag and Hahne on December 3, 2002. The revised schedules (12+0 Update) of Messrs. Krueger, Stellwag and Hahne based upon twelve months of actual test year data were filed on February 14, 2003. The revised schedules of Mr. Schirra based upon twelve months of actual test year data were filed by the Company on February 19, 2003, and the revised schedules (12+0 Update) for Mr. Krueger were filed on February 25, 2003. Revised Schedules GWS-4-RB and GWS-6-RB based upon twelve months of actual test year data were further filed by the Company on February 27, 2003.

The Ratepayer Advocate filed the Direct Testimonies of Michael J. Majoros, Jr., Robert J. Henkes, and Basil Copeland, Jr. on October 15, 2002. On October 22, 2002, the Ratepayer Advocate filed the Direct Testimony of Brian Kalcic. An Errata Sheet correcting the Direct Testimony of Mr. Copeland was filed by the Ratepayer Advocate on December 20, 2002. On December 27, 2002, the Supplemental Direct Testimony of Mr. Henkes was filed. The Supplemental Direct (6+6 Update) Testimony of Mr. Kalcic was filed on January 24, 2003. The Direct Testimony of David A. Peterson concerning the street lighting and service company issues was filed on February 13, 2003.

Intervenor NJLEUC filed the Direct Testimonies of Jeffry Pollock and Nicholas Phillips, Jr. on October 22, 2002. On March 14, 2003, the Supplemental Direct Testimony of Mr. Pollock was filed by NJLEUC. Intervenor NJCU filed the Direct Testimony of Dr. Dennis Goins on October 22, 2002. The Supplemental Testimony of Dr. Goins was filed on March 14, 2003. On October 22, 2002, Intervenor Co-Steel filed the Direct Testimonies of Howard S. Gorman and Darren MacDonald. On March 14, 2003, the Supplemental Testimony of Mr. Gorman was filed. Intervenor NJ Transit filed the Direct Testimony of Theodore S. Lee on October 22, 2002.

On November 15, 2002, the Company filed the Rebuttal Testimonies of Messrs. Cistaro, Krueger, Stellwag, Hahne, Morin, James I. Warren, Robert W. Bachmura and Richard F. Meischeid. On November 22, 2002, the Rebuttal Testimony of Mr. Schirra was filed, and on November 22, 2002, the Updated Rebuttal Testimony of Mr. Morin was filed.

On December 16, 2002, the Ratepayer Advocate filed the Surrebuttal Testimonies of Messrs. Majoros, Henkes, Copeland and Kalcic. The Ratepayer Advocate filed the Supplemental Surrebuttal Testimony of Mr. Henkes on December 27, 2002. The revised schedules (12+0 Update) of Mr. Henkes based upon twelve months of actual data were filed by the Ratepayer Advocate on February 28, 2003.

Intervenor NJLEUC filed the Surrebuttal Testimonies of Messrs. Pollock and Phillips on December 6, 2002. Intervenor NJCU filed Surrebuttal Testimony of Dr. Goins on December 16, 2002, and Intervenor Co-Steel filed Surrebuttal Testimony of Mr. Gorman on December 16, 2002. On March 10, 2003, Co-Steel filed the Surrebuttal Testimony (12+0 Update) of Mr. Gorman.

Evidentiary hearings were held on January 13, 14, 17, 21, 24, 27, 28, and 29, 2003, as well as February 24, 2003, and March 19, 2003. At the close of the evidentiary hearings, a briefing schedule was established with the initial brief due on March 3, 2003, and the reply brief due on March 17, 2003, subsequently the initial brief was extended to April 3, 2003, and the reply brief extended to April 17, 2003.

STATEMENT OF THE CASE

At a time when relatively high energy prices (including natural gas, gasoline, and oil) already compete for consumers' budgets, Public Service Electric and Gas Company (PSE&G or Company) proposes to raise rates for electric distribution service by $250,000,000 per year, and would further strain the finances of its residential and business customers. The weakened condition of our national and state economy also creates additional stresses on utility customers' ability to maintain their standard of living and on businesses struggling to achieve or maintain profitability. While the timing of this instant electric base rate case was not of PSE&G's choosing, the level of rate relief requested was well within its power to limit, but it has instead chosen to inflate its requested revenue requirement with unsupportably high costs, an unreasonably pessimistic view of pro forma revenues, and an unjustifiably high requested rate of return.

These defects in its filing are further exacerbated by the expected expiration of the 13.9% rate reductions required by the Electric Discount and Energy Competition Act (EDECA)[2] and the higher costs for electric supply that will be effective when the results of the recent auction for Basic Generation Service are implemented. The expiration of those rate reductions alone will present customers with a serious challenge to meet their costs of living and doing business. If Your Honor and the Board should grant PSE&G's unreasonably high base rate request, this would only worsen an already trying situation. As will be discussed more fully below, the Ratepayer Advocate proposes a lower and reasonable level of rate increase of $82,231,000 after carefully culling the utility's testimony, data responses and other relevant information to remove unneeded cost, adopt a more realistic view of expected pro forma revenues and establish a prudent and fair rate of return.

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[2] *N.J.S.A.* 48:3-49 *et seq*.

We have also allocated our recommended rate increase in the fairest manner among the various tariff classes to achieve interclass rate equity and made reasonable proposals concerning other tariff changes that will assist customers in controlling their energy usage and costs. The Ratepayer Advocate's proposed revenue allocation accounts for the rate effects of the expiring Market Transition Charge (MTC) and how the MTC was formulated in PSE&G's restructuring cases when the Board first unbundled the utility's rates. The expiration of the MTC will decrease customers' bills by $367,000,000 and more than offset the utility's requested $250,000,000 distribution revenue increase.[3] To ignore the rate effects of the MTC would unreasonably apportion any rate increase largely to the rate classes of smaller customers and violate the mandate of EDECA that the restructuring of the electric industry should not improperly shift costs from class to class. That view ignores the facts and deserves to be rejected.

It is understandable that all customers are highly sensitive to increased electric costs as they struggle to pay their bills, compete in their respective industries, and fight through the weakened economy. However, that does not support proposed rate class revenue allocations that arise from cost of service methodologies that the Board has long since discarded as unrepresentative of how costs are incurred on the electric distribution system and unreasonable as to how costs should be apportioned among the various rate classes. The Ratepayer Advocate also recognizes the plight of these customers, but the final revenue requirement allocation must balance all parties' interests and comport with utility law. The final revenue requirement allocation should not unreasonably include in the utility bills of any class those costs that the Board has previously determined are more reasonably assigned to other classes. The Ratepayer Advocate's overall revenue requirement proposal and allocation of that proposal among the rate classes are clearly reasonable and should be adopted.

[3]However, as stated above, the simultaneous reversal of the EDECA-mandated rate decrease of 13.9% will also increase customers' bills.

As will be set forth more fully in the sections which follow, with complete citations to the most persuasive evidence in the record, the Company proposed an unreasonably high rate of return, used a rate base figure which did not accurately reflect the actual assets utilized, understated its projected revenue, and overstated its expenses, including an unreasonably high estimate of its depreciation expense.

The Company's overstated claim for rate relief should be rejected. Instead, in accordance with the analyses and recommendations set forth in the testimony of the Ratepayer Advocate's witnesses, a lower rate increase of $82,231,000 is appropriate. As stated below, there is overwhelming evidence in the record that supports the Ratepayer Advocate's recommended adjustments in the Company's proposed return on equity, rate base, and pro forma revenue and expenses. Similarly, there is ample support for the Ratepayer Advocate's recommended changes in the Company's proposal for its tariff and rate design.

Contrary to the authoritative testimony of the Ratepayer Advocate's expert witness, Basil L. Copeland, Jr., that validated the need for a much lower rate of return, PSE&G proposes a return on common equity of 11.6%, which is very nearly the same as the current 12% return on equity established in its 1991 base rate case when interest rates were much higher than today. Based on Mr. Copeland's detailed analysis, the Ratepayer Advocate is proposing a return on equity of 9.5 %. Unlike the 11.6% return proposed by the Company, Mr. Copeland's recommended return on equity stems from the proper application of sound methodology and is consistent with interest rate trends and expected returns in the market. As discussed herein and in Mr. Copeland's testimony, the Company's proposal suffers from a flawed application of the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") methodologies.

The Ratepayer Advocate also proposes the adoption of rate base adjustments totaling $71,675,000 as recommended by our expert accounting and ratemaking policy witness, Robert J. Henkes. The Ratepayer Advocate also recommends other adjustments that properly reflect a reasonable level of expenses and revenues associated with the provision of utility service. Mr. Henkes challenged many components of the Company's claimed operating expenses, including the Company's accounting for labor O&M expense, incentive compensation plans, regulatory expense, and others. Mr. Henkes also recommended disallowing PSE&G's claim for restructuring expenses allegedly incurred due to EDECA, but which the Company could not justify. It is not enough for PSE&G to say that these costs were needed to implement EDECA. PSE&G must always carry the burden of proving that these services were not already included in rates (such as the utility employee labor expense) that customers are already paying for, that the costs were prudently incurred, and that the utility provided the services at the lowest reasonable cost. PSE&G failed to carry that burden, failed to point to any order from the Board approving these costs, and failed to espouse a legal interpretation of EDECA that could contradict the utility's requirement to prove prudence and reasonableness. In fact, EDECA only allows this issue to be raised by the utility, it does not reduce the utility's burden of proof. The net result of the pro forma revenue and expense changes proposed by the Ratepayer Advocate amounts to an increase of $94,731,000 in pro forma utility operating income versus the Company's proposed $88,450,000.

Other recommended adjustments include a significant reduction in the Company's claimed depreciation expense, reducing the pro forma depreciation expense by $42,742,000. As explained in the testimony of Ratepayer Advocate depreciation expert, Michael J. Majoros, PSE&G's claimed depreciation expense ignores the Company's own sworn testimony from its restructuring case, in which it supported changing the composite depreciation rate to 2.49% for electric distribution plant and which testimony was approved by the Board and affirmed by the New Jersey Supreme Court when the Court reviewed the Board decision. In the restructuring case, PSE&G proposed to lower the composite depreciation rate and to use that rate to calculate its excess depreciation reserve of $568,700,000 that the Board ordered be returned to ratepayers over a period of three years and seven months.

PSE&G failed to change that composite depreciation rate to 2.49% as was expected in the restructuring case order. Mr. Majoros recommended rectifying this injustice by using that composite rate prospectively (reducing depreciation expense by the aforementioned $42,742,000) and applying that rate to calculate the new excess depreciation reserve of $115,000,000. Mr. Majoros then recommended that this overpaid depreciation reserve be returned to ratepayers by amortizing it to base rates over two years since this was the time remaining of the three years and seven months period that the Board used for the $568,700,000 excess depreciation reserve in the restructuring case. That will also reduce rates by $57,500,000 and will provide customers with the benefits of the lower depreciation rate that was required in the restructuring case, but which PSE&G now attempts to deny.

After Your Honor and the Board decide on a just and reasonable revenue requirement, that amount must be equitably distributed among the different classes of ratepayers to determine their fair share of the revenue requirement. In this case, that distribution is undeniably entwined with the rate effects of the expiring MTC. The expiration of the MTC will decrease customers' bills by $367,000,000. The MTC rate was originally set at the beginning of electric restructuring at levels that would maintain the Board-approved revenue allocations among the rate classes. This was done so that, when the electric restructuring removed MTC costs from base rates and recovered those costs through the MTC, this unbundling of PSE&G's rates would not shift costs between rate classes. When the new base rates are set in this case, consideration must be given to maintain the avoidance of such cost shifting. The MTC rate recovered costs that were once embedded in base rates. Now that the MTC is scheduled to expire, the new base rates should take into consideration the customer bill impacts caused by that expiration. If new base rates do not include the MTC consideration, then customers will suffer the unfair cost shifting that EDECA and the Board mandated should not occur. The base rate increase should be allocated to the various customer classes, with certain restrictions and adjustments, as proposed by Ratepayer Advocate expert witness Brian Kalcic. As a guiding principle, the Ratepayer Advocate recommends an approach whereby no customer class would receive a decrease more than 1.5 times the Company-wide average decrease, or less than 0.5 times the Company-wide average decrease. This is the same approach used by PSE&G, but is challenged by other intervenors.

Furthermore, the Ratepayer Advocate recommends that certain tariff changes proposed by the Company should be rejected, so as not to unduly burden ratepayers. Some of the issues among these tariff changes are maintaining current monthly charges, eliminating the winter declining block rates, maintaining the current split between demand and energy charges for rate classes with a demand charge, and maintaining the current special provisions for Curtailable Electric Service.

The Ratepayer Advocate also opposes as unduly burdensome and counterproductive the Company's proposal for a 267% increase in its reconnection charge for customers whose service is terminated for nonpayment and the proposed 57% increase in the field collection charge. The Ratepayer Advocate also recommends that the Company be directed to inform customers of the available Residential Load Management service more frequently than the current annual notification and that an investigation should be conducted into PSE&G's meter reading performance that includes the institution of appropriate standards and a penalty mechanism to assure that PSE&G meets its service obligation for meter reading.

In summary, as set forth in the sections below, the Ratepayer Advocate respectfully submits that our recommended adjustments and modifications present Your Honor and the Board with the alternatives in this case that are most reasonable and fair to all the parties. Our recommendations: (1) allow the utility the opportunity to earn a fair rate of return on its investment while still having sufficient revenues to provide safe, adequate and proper utility service; (2) apportion cost responsibility to customer classes in a manner that reflects the mandates of EDECA and the Board's Final Order in PSE&G's restructuring case while avoiding inequitable bill impacts that would be caused by the proposals of other intervenors who cling to outmoded theories of cost allocation that do not reflect cost causation on the utility system; (3) allow both large and small ratepayers to continue receiving affordable electric service at the lowest possible cost; and (4) produce just and reasonable rates overwhelmingly supported by the substantial, credible evidence in the record. For these reasons, the Ratepayer Advocate respectfully urges Your Honor and the Board to reject the unreasonable positions taken by other parties and to adopt our recommendations.

POINT I

YOUR HONOR AND THE BOARD SHOULD ADOPT A 9.5% RETURN, WHICH IS FAIR AND REASONABLE UNDER CURRENT MARKET CONDITIONS AND SUFFICIENT TO MAINTAIN PSE&G'S FINANCIAL INTEGRITY.

Introduction

Regulated companies such as PSE&G typically have utilized three sources of capital to capitalize their utility assets: common stock, preferred stock, and long-term debt. *RA-1*, p. 4. The rate of return for a regulated utility is usually based on the costs of each of the individual sources of capital, weighted by the proportion each component represents in the overall capital structure. *Id.* The costs of PSE&G's long-term debt and preferred stock can be directly measured from the interest rate and related costs on various issuances of debt and preferred stock, and are not a subject of controversy. The issue to be determined by Your Honor and the Board is the proper cost of PSE&G's common equity.

The Company proposes to treat PSE&G as a separate "stand-alone" entity, with a capital structure distinct from that of its parent company, Public Service Enterprise Group. *P-6*, p. 7. The Company suggests an 11.6 percent return on common equity. *P-6 update,* p. 2. This proposal is based on methodologies that substantially overstate the Company's actual cost of capital. The unreasonableness of this result is readily apparent when one considers that the Company's proposed return on equity ("ROE") was set in 1993 at 12% for its combined gas and electric operations. Now, the Company seeks to maintain an 11.6% return on equity for its electric operations only. The questionable nature of the Company proposal is apparent when one considers that the Company's proposed return on equity is only 40 basis points lower than the previously allowed 12% return in 1993, when interest rates were substantially higher than today. *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for*

Changes in the Tariffs for Electric and Gas Service, BPU Docket No. ER91111698J (Final Decision and Order dated May 14, 1993). Your Honor and the Board may also take into account that, recognizing the market changes that have occurred since the Company's previous combined base rate filing, the Board has already approved a 10% return on equity for gas operations. *I/M/O the Petition of Public Service Electric and Gas Company for Approval of an Increase in Gas Rates and for Changes in the Tariff for Gas Service,* BPU Docket No. GR01050328 (Order Adopting Initial Decision Approving Stipulation dated January 9, 2002).

Ratepayer Advocate witness Basil Copeland has properly determined the Company's return on equity capital using a combination of correctly applied methodologies. Based on Mr. Copeland's analysis, the Ratepayer Advocate is recommending a return on common equity of 9.5%.

The Ratepayer Advocate's recommendations are consistent with the Board's recent expression of policy with regard to rate of return in its March 6, 2002 decision in the Unbundled Network Element proceeding, *I/M/O the Board's Review of Unbundled Network Elements Rates, Terms and Conditions of Bell-Atlantic-New Jersey, Inc.*, BPU Docket No. TO00060356 (Decision and Order dated March 6, 2002) (hereinafter the *"UNE Decision"*). In that decision, the Board adopted the Ratepayer Advocate's proposed 10 percent cost of equity, based on methodologies similar to those presented by the Ratepayer Advocate's witness in this proceeding. *UNE Decision,* p. 39.

The Ratepayer Advocate's recommended rate of return is reasonable and consistent with the Board policy. For the reasons explained in detail below, Your Honor and the Board should adopt the Ratepayer Advocate's recommended rate of return, and reject the inflated proposal presented by PSE&G.

The Appropriate ROE for the Company is 9.5%, Based on Appropriate Analyses of Comparable Companies.

A. Overview

As noted above, regulated utilities capitalize their utility assets using common stock, preferred stock, and debt. The cost of common equity, unlike the costs of debt and preferred stock, cannot be determined directly from the interest rates applicable to various issues. Instead, the cost of common equity must be estimated using market-based common stock dividend and price information. *RA-1*, p. 4.

Basing the allowed return on equity on the market cost of equity accomplishes two important regulatory objectives. First, this approach properly balances ratepayer interests in receiving safe and reliable service at the lowest possible cost with shareholder interests in receiving the highest rate of return possible. A market-based return on equity preserves the Company's financial integrity, allowing it to continue providing safe and reliable service for the benefit of ratepayers, while providing shareholders with a return commensurate with the returns they could earn on other investments with comparable risk. Second, an allowed rate of return equal to the market cost of equity provides management with the proper incentives to operate the Company safely, reliably and efficiently. A market rate of return is neither too high, thus encouraging inefficiency, nor too low, tempting management to "cut corners" in order to achieve an adequate return for shareholders. *RA-1*, pp. 5-6.

The Company's proposed 11.6% return on equity is based on Dr. Morin's recommended use of the Discounted Cash Flow ("DCF") analysis and variations of risk premium analyses. The Ratepayer Advocate proposes a 9.5% return on equity, supported by the testimony of Mr. Basil Copeland. The Ratepayer Advocate proposal is based on two variations of the DCF methodology and a risk premium analysis based on the Capital Asset Pricing Model ("CAPM"). The differences between the two witnesses may be summarized as follows:

	Morin	Copeland
DCF Methods:		
Constant Growth	11.4%-14.4%	10.05-10.34%
Multiple Period (DDM)	N/A	10.11-10.27%
Risk Premium/CAPM		
CAPM	10.6%-11.1%	8.12%
"Historical Risk Premium"	10.6%-11.1%	N/A
"Allowed Risk Premium"	10.6%	N/A
Overall	11.6%	9.5%

Source: *P-6 update,* p. 2; *RA-1,* pp. 10, 13, 15.

Mr. Copeland's results were based on the proper application of the DCF and CAPM methodologies. Dr. Morin, on the other hand, has improperly applied the DCF and CAPM methodologies, and has relied upon two methodologies, "Historical Risk Premium" and "Allowed Risk Premium" that have serious conceptual and empirical flaws. The analyses presented by both witnesses, as well as the serious flaws in Dr. Morin's analysis, are set forth in detail below.

B. The Ratepayer Advocate's Recommended ROE is Based on Proper Application of the DCF and CAPM Methodologies.

Ratepayer Advocate witness Basil Copeland based his recommended return on equity calculation on two variations of the DCF methodology (the "constant growth" model and a "multiple period" model), plus a CAPM analysis.

Constant Growth DCF Model

The "constant growth" model is the most basic form of DCF analysis. This model assumes that the investor required return on common equity equals the dividend yield plus the expected rate of growth in the dividend, and assumes further that all three of these factors grow at the same rate in perpetuity. *RA-1,* p. 6. This relationship is expressed mathematically as:

$$k = D/P + g$$

where k it the cost of equity capital, D/P is the dividend yield (the dividend divided by the market price of the stock), and g is the expected growth rate. *Id.*

The principal steps in applying the DCF methodology are (1) selection of a sample of companies with risks comparable to that of the utility to which to apply the method; and (2) determination of growth factors for the comparable companies. The above equation can then be used to calculate an estimate of the cost of equity capital for the utility. *RA-1*, p. 7.

Mr. Copeland applied his DCF model using the same sample of combination electric and gas utilities that were used in Dr. Morin's DCF analysis, with a few exceptions. Specifically, Mr. Copeland excluded companies that have recently reduced dividends, were subject to a merger, were not a combination utility, or had negligible gas operations, as inclusion of these companies distort the results of the DCF model. *Id.*

Mr. Copeland estimates the growth rates for the sample companies using an average of published estimates of growth in earnings per share (EPS), dividends per share (DPS), and growth in book value per share (BVPS) for the utilities contained in his sample of comparable companies. As Mr. Copeland explained, under the assumption of the "constant growth" DCF model, EPS, DPS and BVPS should all grow at approximately the same rate. Where this is the case, one of these measures can be used as a "proxy" for expected rate of growth in dividends. If not, then using just projected earnings or dividend growth will distort the results of the constant growth DCF model. *RA-1*, p. 8. Since EPS growth rates currently are substantially higher than DPS growth rates, the best way to estimate the constant growth DCF cost of equity is to use an average of EPS, DPS and BVPS projections. *RA-1*, pp. 8-9.

Mr. Copeland's analysis of the sample companies yielded a mean (average) estimate of 10.34% and a median of 10.05%. Of the two, the median is more reliable, as the mean reflects the impact of "outliers" in the calculation of the mean. *RA-41*, p. 10.

Multiple Period DCF Model (DDM)

The "constant growth" DCF model produces reliable results when actual market conditions reasonably approximate the basic assumption underlying this model, *i.e.*, that dividends, earnings, book value per share, and share price will grow at a uniform rate in perpetuity. However, when dividend payout rates are expected to increase or decrease over extended periods of time—as in the current market—the "constant growth" model can produce distorted and unreliable results. For this reason, Mr. Copeland also applied a "dividend discount model" ("DDM") requiring less rigid assumptions. *RA-1*, p. 10.

A DDM is a form of multiple-period model, which assumes that dividends will grow at one rate for a fixed period, and thereafter at some other rate in perpetuity. *RA-1*, p. 11. Mr. Copeland's model used published five-year growth rates for 2002 through 2006, and an estimate of long-term growth thereafter. Mr. Copeland's model further assumed that the retention ratios for the sample companies would change from currently projected values to a common value of 0.50 between 2006 and 2021. *RA-1*, p. 12. Using these assumptions, the model generates a series of cash flows which can then be used to solve for an expected return.

Mr. Copeland's DDM model yielded a mean estimate of the cost of equity capital of 10.27% and median estimate of 10.11% for the sample companies, roughly comparable to the constant growth DCF return. *R-1*, p. 13.

Capital Asset Pricing Model (CAPM)

Finally, Mr. Copeland estimated PSE&G's cost of capital using the CAPM. CAPM is a "risk premium" model, meaning that it is a model based on the principle that the cost of equity capital equals the cost of a risk-free investment plus a "risk premium" to compensate for the risks of a specific equity investment. *RA-*

1, p. 13. Under the CAPM methodology, the overall market risk premium is adjusted to reflect the risk of a stock or sample of stocks using a "beta coefficient," which is a measure of the risk of an individual stock relative to the market as a whole. *RA-1*, p. 14.

Mr. Copeland estimated the overall market risk premium using the premium earned by common stocks over long-term U.S. treasury bonds over the past 75 years, about 5.85%. For the beta coefficient, Mr. Copeland used the published estimates of beta coefficients for the same group of comparable companies that he used in his DCF analyses. The median beta coefficient for the comparable utilities is 0.55. *R-1*, p. 14. Mr. Copeland used the current long-term Treasury bond rate of 4.9% as the risk-free interest rate. The equation is as follows: $k = 4.9 + (0.55 \times 5.85) = 4.9 + 3.22 = 8.12$. Therefore, using this methodology, Mr. Copeland estimated PSE&G's cost of equity at 8.12% (4.90% plus 3.22%). *RA-1*, p. 15**.**

Estimated Cost of Equity for PSE&G

Based upon the results set forth above, Mr. Copeland concluded that PSE&G's cost of equity is in the range of 9.0 % to 10.0 %, with the CAPM results indicating a cost of equity at the lower end of the range and the DCF results indicating a cost of equity at the upper end of the range. Mr. Copeland therefore recommended an allowed rate of return at the midpoint, 9.5%.

The methodology used by Mr. Copeland is consistent with that adopted by the Board in the *UNE Decision.* In that proceeding, Verizon NJ had a 15.0% return on equity based solely upon a DCF analysis of "publicly traded competitor companies." *UNE Decision,* p. 31. The Ratepayer Advocate in that proceeding recommended a 10% return on equity, based on an average of the results of a DCF analysis and a CAPM analysis. As the Board noted, the Ratepayer Advocate used an average in order to reduce any upward bias in the DCF analysis. *Id.* at 39. Intervenor AT&T had presented a similar analysis resulting in a 10.24% rate of return. *Id.* The Ratepayer Advocate's analysis was adopted by the Board as "the most reasonable one contained in the record." *Id.* Mr. Copeland's analysis in this proceeding similarly relies upon consideration of both his DCF and CAPM analyses. The results of this analysis provide a reasonable return on equity.

C. PSE&G's Proposed 11.6% ROE is Based on Flawed Applications of the DCF and CAPM Methodologies, Invalid "Risk Premium" Methodologies, As Well As A Speculative "Flotation Cost" Adjustment.

PSE&G's proposed 11.6% return on equity should be rejected. The Company proposal is based on Dr. Morin's flawed applications of the DCF and CAPM methodologies and invalid "risk premium" methodologies, all of which substantially overstate the Company's actual cost of equity. Further, the proposed rate of return includes a "flotation cost" adjustment, which is based on hypothetical assumptions rather than actual issuance costs. The flaws in the Company's cost of equity analyses are discussed in detail below.

Improper Implementation of the Constant Growth DCF Model

For his DCF analysis, Dr. Morin used a simple "constant growth" DCF model. Dr. Morin's DCF analysis substantially overstates the cost of equity, as his estimated growth rates rely solely upon estimates of earnings growth, ignoring estimated growth rates for dividends and book value per share.

The significant defect in Dr. Morin's DCF analysis is his sole reliance on two sources of <u>earnings</u> growth projections for his growth rate. *RA-1,* p. 16. As noted above, the "constant growth" DCF model assumes earnings, dividends, and book value per share all grow at the same uniform rate indefinitely. Thus, it is appropriate to rely solely upon earnings projections in applying a constant growth DCF model only if payout ratios are relatively stable and earnings, dividends, and book value per share are all projected to grow at roughly the same rate. *R-41,* p. 16. In the current market, in which earnings per share growth rates are higher than dividends per share growth rates, the earnings per share growth rates overstate investor long-term growth expectations. *Id.*

In his rebuttal testimony, Dr. Morin argues that the dividend growth rate should be dismissed as an "outlier," because it is lower than the growth rates for retained earnings and book value per share. *P-6 RB,* p. 14. This argument is baseless. As Dr. Morin acknowledges in his own testimony, projected dividend growth is lower than projected earnings growth not because of some aberration in the data, but because utilities are increasing their earnings retention ratios and thus reducing their dividend payout ratios. *P-6 RB,* p. 5*; RA-3,* pp. 6, 7. Dr. Morin has, in effect, failed to take account of the reduced value of expected dividend yield in the near term. *RA-3,* pp. 6, 8-9. The result is a substantially overstated cost of common equity. *RA-1,* p. 16.

Another flaw in Dr. Morin's DCF analysis is that he uses a functional form of the model which overstates the "dividend yield" portion (D/P) of the DCF calculation. Dr. Morin calculates the dividend yield by dividing the "next period" dividend by the stock price. *P-6,* pp. 34-35. This overstates the dividend yield, because it divides dividends paid out over a period of time by the current stock price at a discrete point in time. *RA-3,* p. 5. To properly match earnings, the dividends paid out over a year should be matched with the average value of the stock that produces the dividend over that same year. There are two ways to accomplish this: dividing the dividends for the forthcoming year by the average of today's price and the expected price a year from now, or by averaging the current dividend and the projected "next period" dividend and dividing by the current stock price. The latter method was used in Mr. Copeland's DCF analyses. *RA-3,* p. 6. Dr. Morin's analysis does nothing to address the mismatch, and thus overstates the dividend yield. *Id.*

Improper Implementation of CAPM

Dr. Morin has presented two different forms of the CAPM approach: a traditional CAPM analysis, and an empirical approximation to the CAPM, referred to by Dr. Morin as "ECAPM" Dr. Morin's CAPM analyses substantially overstate the cost of capital for two reasons. First, he used two incorrect methodologies to estimate the market risk premium. The result is a substantial overstatement of the risk premium (7.0%

compared to Mr. Copeland's 5.85%). *P-6,* pp. 19, 25*; RA-1,* p. 14. Second, he further overstated the cost of capital in his ECAPM analysis by using the wrong kind of data. *RA-1*, p. 19.

Overstated risk premium

Dr. Morin's first risk premium estimate is based on the Ibbotson Associates analysis of stock market returns versus long-term bonds. *P-6*, p. 25. This estimate is based on a simple arithmetic mean of the annual return differences between common stocks and long-term treasury bonds. *RA-1,* p. 17. The correct approach for determining a "long-horizon" risk premium is based on a geometric mean. *Id.* The difference between the two approaches, and the correctness of the geometric mean, can be seen from a simple example. Suppose an investor invests $1.00, and realizes a return of –50% the first year and +50% the second year, for an ending value of $0.75. The arithmetic mean is zero:

$$r_a = \tfrac{1}{2}(0.50 - 0.50) = 0.0$$

Calculating a result of zero would mean that the investor earned an average return of zero over the two years in this example. That is clearly an incorrect result.

The geometric mean, defined as the rate which, when compounded, will produce the ending value of $0.75, is –13.4%:

$$r_g = (0.75/1.00)^{\frac{1}{2}} - 1 = -0.134.$$

As Mr. Copeland explained, "[n]o investor with a portfolio originally worth a dollar and only worth $0.75 two years later would conclude that his or her average return over those two years was zero." *RA-1, Technical Appendix at 27-28.* The geometric average correctly determines that the average return was –13.4 percent. As noted in Mr. Copeland's prefiled testimony, Ibbotson Associates' defense of this methodology is internally inconsistent and includes an example which actually proves that the geometric mean is the correct approach. *RA-1, Technical Appendix at 29.*

Dr. Morin's states in his rebuttal testimony that he does not "know" of any textbook or journal article that advocates the use of the geometric mean for the purpose of computing the cost of capital . *P-6 RB,* p. 23. However, Mr. Copeland refers to just such an article in his pre-filed direct testimony, and a copy was provided to PSE&G in response to a discovery question. *RA-1,* p. 18, citing Russell J. Fuller and Kent A. Hickman, "A Note on Estimating the Historical Risk Premium," *Financial Practice and Education,* Fall/Winter 1991, Vol. 1, No. 2, pp. 45-48. *P–18.* If Dr. Morin does not "know" of this article, this is presumably because he has not thoroughly read Mr. Copeland's testimony or the discovery response. The article concludes that the geometric mean is the correct method by which to calculate the risk premiums. *P-18.*

Dr. Morin's second risk premium estimate is based on what he refers to as an application of a "DCF analysis to the aggregate equity market …." *P-6,* p. 27. This appears to be based upon a simple "constant growth" DCF model and, thus, is subject to the same problems described above with respect to Dr. Morin's DCF analysis.

Improper use of data in ECAPM analysis

The "ECAPM" methodology is based on empirical findings that the CAPM methodology produced downward-biased risk premiums for companies with betas less than 1.00. The ECAPM model compensates for this bias by producing a risk-return relationship that is "flatter" than that produced by the traditional CAPM methodology. *P-6,* p. 29. Dr. Morin, however, has misused the ECAPM model. The empirical studies upon which the model was based employed "raw" or "unadjusted" betas. However, Dr. Morin has utilized published Value Line betas which are <u>already adjusted</u> to compensate for the bias found in the empirical studies. *RA-1,* p.

19. In effect, he has double counted the adjustment needed to reflect the results of the empirical studies. *RA-1*, p. 20.

Invalid Risk Premium Methodologies

In addition to the improperly applied CAPM analyses described above, Dr. Morin has presented two additional "risk premium" analyses. Neither analysis presents a valid approach to estimating the risk premium.

Dr. Morin's Schedules RAM-2 and RAM-3 present a risk premium analysis comparing returns on electric utility stocks and gas distribution utility stocks to the yield on long-term government bonds. *P-6,* pp. 30, 31. These schedules improperly base the long horizon risk premium on an arithmetic average. The result is a substantial overstatement of the risk premium. *RA-1,* pp. 20-21.

Dr. Morin's final "risk premium" analysis purports to estimate the cost of equity by comparing the historical risk premiums allowed by regulatory commissions to the contemporaneous levels of long-term Treasury bond yields. *P-6,* p. 31. Based on this analysis, Dr. Morin concludes that there is an inverse relationship between allowed risk premiums and interest rates–in other words, that risk premiums are higher when interest rates are lower, as in the current market. *P-6*, p. 32. This analysis should be rejected because it is wrong in concept, and because it is based on an invalid statistical analysis.

Conceptually, the "allowed risk premium" approach assumes that all electric utility companies are comparable in risk and have a constant risk premium over time. This approach also assumes that regulatory commissions do not consider any extraneous factors in determining allowed rates of return. As Mr. Copeland observes, "[n]either of these assumptions is even remotely plausible." *RA-1*, p. 21.

Dr. Morin's statistical analysis is invalid, because the data he uses do not meet the conditions for a valid linear regression. One of the necessary conditions for a valid linear regression is that the data be randomly distributed about the fitted line. *RA-1,* p. 23. As is evident from the time plot on page 32 of Dr. Morin's testimony, this is not the case with the data used for his analysis. Dr. Morin's data points are below the line in the early years of the time plot and all above the line in the later years of the time plot. *RA-1,* p. 23. Dr. Morin attributes this to competition and restructuring, while Mr. Copeland believes it is due to regulatory lag. However, in either event, this relationship undermines the validity of Dr. Morin's statistical analysis. *RA-1*, p. 24.

Improper Flotation Cost Allowance

Finally, Dr. Morin has further inflated his proposed return on equity by adding a 5 percent allowance for "flotation costs." Dr. Morin makes this adjustment to allow for the costs associated with issuance of common stock. *P-6,* pp. 40-41. However, Dr. Morin's proposed adjustment is based on purely hypothetical assumptions, even though Public Service Enterprise Group issued 17,250,000 shares of common stock in November 2002, and actual issuance costs could have been utilized in Dr. Morin's flotation cost analysis. As Mr. Copeland explained, the market cost of capital is a forward looking concept. Thus, if the Company can finance its future capital requirements solely through retained earnings, a flotation cost adjustment will merely provide a windfall to shareholders. *RA-1,* p. 25. Further, Dr. Morin's proposed adjustment substantially overstates any plausible estimate of actual flotation costs. Dr. Morin is proposing an allowance that equates to an annual equity return requirement of $6,750,000. Based on Dr. Morin's theory, this represents 5 percent of the equity capital raised every year through public offerings of common stock. Thus, Dr. Morin implicitly assumes that PSE&G issues $135,000,000 in public stock offerings <u>every year</u>.

Further, the annual equity return requirement of $6,750,000 equates to a revenue requirement of $11,400,000. This is a substantial burden on ratepayers to reflect a cost which is hypothetical at best. The proposed flotation cost adjustment should be rejected as unfounded.

Reversal of $170,000,000 Common Equity Infusion

In its 12 + 0 updates, PSE&G modified its proposed capital structure to include $170 million in common equity additions that the parent company, PSEG, made to the utility. *P-4 (U 12+0), Schedule ANS-20.* Mr. Stellwag's schedule shows that this capital infusion was made on January 21, 2003, *i.e.*, after the end of the 2002 test year. Mr. Henkes determined that this adjustment was unwarranted and removed it from his proposed 12+0 schedules. *RA-60, Schedule RJH-2R (12+0 Update), footnote 2.* PSE&G's adjustment was removed from the pro forma test year capital structure because the capital infusion was made outside of the test year. In a base rate case, the expenses, revenues, rate base, and the capital structure must match each other by relating to the same test year. Mr. Stellwag's adjustment violates that ratemaking principle by including an adjustment that was made after the test year closed. For that reason, this adjustment should be rejected. Mr. Henkes' recommendation changes the ratio of common equity in the capital structure from PSE&G's 41.4450% to a lower amount of 39.5609%. *RA-60, Schedule RJH-2R (12 + 0 Update).*

POINT II

PSE&G'S DEPRECIATION RATE FOR ITS ELECTRIC DISTRIBUTION PLANT SHOULD BE CHANGED TO REFLECT A 45-YEAR SERVICE LIFE FOR THOSE ASSETS, THE RELATED DEPRECIATION EXPENSE SHOULD BE ADJUSTED, AND THE EXCESS DEPRECIATION RESERVE ASSOCIATED WITH THE USE OF AN EXCESSIVE RATE SHOULD BE AMORTIZED AND RETURNED TO RATEPAYERS OVER A TWO-YEAR PERIOD.

Depreciation expense is included in PSE&G's revenue requirement and is passed on to its ratepayers on virtually a dollar-for-dollar basis. Annual depreciation is determined by applying depreciation rates to plant investment.

The Company proposes to change its depreciation rates for its electric General and Common Electric plant. *P-1*, pp. 3-4. Specifically, the Company proposes to conform them to the gas general plant depreciation rates which were agreed upon by the parties to the Stipulation resolving the Company's recent gas base rate case.[4] *Id*. The Ratepayer Advocate's depreciation witness in the instant case, Mr. Michael J. Majoros, Jr., testified that although he believes those rates were overstated, he does not object to their use here because of the much larger depreciation issue in this case, involving the Company's electric distribution plant depreciation rates. *RA-6*, p. 4. For that reason and to focus on more material depreciation issues, the Ratepayer Advocate does not object to the use of the Company's proposed depreciation rates for its electric General and Common plant. However, the Ratepayer Advocate does not concede to any underlying methodology or calculations underlying those rates, specifically noting that the proposed rates for General and Common plant were the product of an earlier Stipulation.

At issue in the instant proceeding is the proper depreciation rate for the Company's electric distribution plant. One factor in the development of depreciation rates is the service life of the asset. As set forth below,

[4] *I/M/O PSE&G*, BPU Docket Nos. GR01050328, GR01050297 (Order dated January 9, 2002).

the Company proposes to use a rate which does not accurately reflect the service lives of its electric distribution plant assets and, moreover, is in conflict with the rate used as the basis for computing its excess depreciation reserve in its restructuring, stranded cost and unbundling case.[5] The Company is proposing a test year depreciation expense of $178.4 million. *RA-60,* Sch. RJH-18R (12+0), line 10.

For the reasons set forth below, the Ratepayer Advocate recommends that Your Honor and the Board adopt a depreciation expense of $78.1 million, based on the use of a reasonable depreciation rate for the Company's electric distribution plant assets. *RA-6*, p. 2, MJM-6; *RA-60,* Sch. RJH-18R (12+0). Moreover, as set forth below, the depreciation rate proposed by the Ratepayer Advocate is the same as that used by the Board to establish the Company's excess depreciation reserve in its Restructuring Case, in an Order subsequently upheld by the New Jersey Supreme Court.[6]

A. PSE&G'S Depreciation Rate for its Electric Distribution Plan Should be Adjusted to Reflect the Rate Used in Its Restructuring Case.

At issue is the proper depreciation rate for PSE&G's electric distribution plant. The depreciation rate is a product *inter alia* of the service lives of the underlying assets. PSE&G argues that the depreciation rate for its electric distribution assets should not be changed, notwithstanding the fact that the corresponding rate was in effect for at least 26 years.[7] The Company's proposed rate, 3.52 percent, is based on a 28-year service life for the assets. The Ratepayer Advocate recommends that a rate of 2.49 percent be used for the electric

[5] *I/M/O PSE&G's Rate Unbundling, Stranded Costs and Restructuring Filings*, BPU Docket Nos. EO97070461, EO97070462 and EO97070463 ("*Restructuring Case*").

[6] *I/M/O PSE&G's Rate Unbundling, Stranded Costs and Restructuring Filings*, BPU Docket Nos. EO97070461, EO97070462 and EO97070463 (Final Decision and Order dated August 24, 1999) ("*Restructuring Case Final Order*"); *In re Pub. Serv. Elec & Gas Co*., 167 *N.J.* 377 (2001).

[7] Mr. Bachmura's testimony from the Company's 1976 base rate case shows that the electric distribution plant depreciation rate in effect at the time that case was filed was 3.52 percent. *RA-4*, p. 16. Furthermore, at hearing in the present case Mr. Bachmura conceded that the distribution plant depreciation rate of 3.52 percent was in effect before June 31, 1976. T234:L16-20.

distribution plant, reflecting a service life of 45 years. The Company's proposed depreciation rate should be rejected for several reasons, as set forth below.

First, the Company's proposed depreciation rate is not the rate used to set its excess depreciation reserve in its Restructuring Case. In its Final Decision and Order in that case, the Board found that PSE&G had an electric distribution plant depreciation reserve excess of $568.7 million.[8] Notably, the Board's Final Decision and Order in that case was subsequently upheld by the New Jersey Supreme Court.[9]

An excess depreciation reserve means that the reserve is too high. Ratepayer Advocate witness Michael Majoros found that PSE&G's depreciation reserve was too high because of the service life parameter underlying the current depreciation rate. *RA-6*, p. 5. The Company's depreciation rate for electric distribution plant was last set in its 1993 base rate case, with a 28-year service life and zero percent salvage value. *RA-6*, MJM-3 (response to RAR-DEP-53). Mr. Majoros found that the 28-year life is too short, thus resulting in an excessive depreciation rate. *RA-6*, p. 5. The application of an excessive depreciation rate to plant balances results in excessive depreciation expense. *Id*. An excessive depreciation reserve is the result. *Id*.

The most compelling evidence supporting the use of a longer service life for PSE&G's electric distribution plant comes from the Company itself. In testimony filed in PSE&G's Restructuring Case, Company witness Mr. Robert C. Krueger, Jr. specifically requested "that the average service life used to establish depreciation for the Company's distribution plant investment, identified on the attached Schedule RCK-E2, be extended from 28 to 45 years."[10] In that testimony, Mr. Krueger also set forth the appropriate depreciation rates for both a 28-year and 45-year service life:

> "[o]ur specific proposal in this proceeding is to remove the amount in excess of the calculated theoretical reserve and amortize it over seven years. <u>In addition, the depreciation rate would</u>

[8] *Restructuring Case Final Order*, p. 115.
[9] *In re Pub. Serv. Elec & Gas Co.*, 167 *N.J.* 377 (2001).
[10] *RA-6*, MJM-3 (testimony appended to response to RAR-DEP-53).

> be recalculated to reflect a 45-year life instead of the current 28-year life. By way of example, balances at December 31, 1996 produces [sic] an approximate $32 million expense reduction attributable to the depreciation rate change from an average rate of 3.52 percent to 2.49 percent and a further reduction of $62 million per year attributable to the accelerated amortization of the excess reserve balance over the transition period.[11]

The Board adopted the excess depreciation reserve calculation of $568.7 million, which resulted from the application of the parameter changes advocated by Mr. Krueger, namely the extension of the useful life from 28 years to 45 years.[12] Furthermore, in its Per Curiam Opinion upholding the Board's ruling in PSE&G's Restructuring Case, the New Jersey Supreme Court acknowledged the import of lengthening the service (useful) lives of the Company's electric distribution plant assets:

> The excess depreciation reserve fund resulted from changing the useful life of the company's distribution plant assets from twenty-eight years to forty-five years. By lengthening the useful life of its assets, a substantial excess depreciation reserve accrued on PSE&G's balance sheet. *In re Pub. Serv. Elec & Gas Co.*, 167 *N.J.* 377, 388-389 (2001).

Although the 28-year life parameter and resulting 2.49 percent depreciation rate formed the basis of the Company's excess depreciation reserve approved by the Board in its Restructuring Case, the Company did not subsequently adjust its electric depreciation rates to reflect those changes.[13] As a result, Mr. Majoros found that the Company's additional excess depreciation reserve has grown.

The excess depreciation reserve amount cited in the Restructuring Case, $568.7 million, was calculated as of December 31, 1998. *RA-6*, p. 6. PSE&G's additional excess depreciation reserve has grown since then. Mr. Majoros found that the additional excess depreciation reserve created during 1999, 2000, and 2001, amounted to $115.0 million. *RA-6*, p. 9, MJM-5. The additional excess depreciation reserve resulted from the

[11] *RA-6*, MJM-3, (testimony appended to response to RAR-DEP-53), p. 9 of 11.[Emphasis added.]
[12] *Restructuring Case Final Order*, p. 115.
[13] *RA-6*, MJM-4 (response to RAR-DEP-62).

application of the 3.52 percent depreciation rate (based on a 28-year life), instead of the 2.49 percent depreciation rate (based on a 45-year life). *RA-6*, p. 9.

Aside from the ample support set forth above for the recommended change in the depreciation rate for PSE&G's electric distribution plant assets, the rate itself is eminently reasonable in its own right, contrary to the assertions of PSE&G's depreciation witness. PSE&G witness Robert W. Bachmura testified that the 2.49 percent rate would not "survive an end result reasonableness test." *P-9-RB*, p. 4. However, Mr. Bachmura's testimony on reasonableness is clearly at odds with the testimony of PSE&G witness Mr. Krueger in its Restructuring Case, cited above. Furthermore, Ratepayer Advocate witness Mr. Majoros tested the continued reasonableness of the 2.49 percent rate and found it to be a reasonable rate. *RA-7*, p. 5. To test the continued reasonableness of the 2.49 percent rate, Mr. Majoros compared the average service lives underlying the 2.49 percent rate to the lives identified by the Company in a partial year 2000 depreciation study. *RA-7*, p. 4. Mr. Majoros found that the average lives of the plant assets are getting longer and, therefore, concluded that the 2.49 percent rate continues to be reasonable. *Id*.

In the Restructuring Case, Mr. Krueger testified that there were two ways to address the excess depreciation reserve:

> The first is to utilize it in the calculation of the new depreciation rate which would reduce the rate for the remaining 25-year period. The second would be to amortize it over a shorter period of time maintaining the depreciation rate at a higher level."[14]

Mr. Majoros found that under the first alternative, the resulting depreciation rate would be much lower than 2.49 percent, "probably about 2.00% or less." *RA-6*, p. 8, lines 12-13. Under the second alternative, Mr. Majoros found that it would be proper to use the 2.49 percent depreciation rate. *RA-6*, p. 8. Furthermore, Mr. Majoros found that even if either of the alternatives to address the excess depreciation reserve posited by

[14] *RA-6*, MJM-3 (testimony appended to response to RAR-DEP-53), p. 5.

Mr. Krueger in the Restructuring Case were adopted, "in neither case would it be appropriate to retain the existing 3.52% rate." *RA-6*, p. 8, lines 15-16.

Finally, Mr. Bachmura's attempt to use a comparison of the 2.49 percent depreciation rate for electric distribution plant to a sample of the composite rates for a sample of utilities is unconvincing. *P-9-RB*, Sch. RWB-2-RB. Notably, Mr. Bachmura relied on statistics gathered jointly by the Edison Electric Institute ("EEI") and the American Gas Association ("AGA"). *RA-7*, MJM-8 (response to RAR-DEP-73). Both the EEI and AGA are trade groups representing the utility industry. Mr. Majoros examined the support for the survey provided by PSE&G. Mr. Majoros found that the rates are at least four years old and he believes that they are weighted-composite rates, concluding "it would only be coincidental if these composites would be the same today as they were four years ago." *RA-7*, p. 6, lines 6-8. A weighted composite rate might reflect various plant investment mixes, depending on how the dollars of investment are distributed in the function. The plant investment mix would likely vary among the companies listed. A weighted composite rate would also reflect various methods, procedures and techniques to calculate such rates. Mr. Majoros also believed that most of the rates "are incorrect as a result of recent generally accepted accounting principles ("GAAP") and Federal Energy Regulatory Commission ("FERC") actions," namely the adoption by the FASB of SFAS 143. *Id*., lines 8-17. Due to the age of the statistics presented by Mr. Bachmura, none of those rates reflect the current treatment of asset retirement obligations, as required by SFAS 143.

Additionally, Mr. Majoros noted the different circumstances that exist in New Jersey and in the other States represented in the statistics presented by Mr. Bachmura. *Id.*, pp. 6-7. In response to a discovery request, Mr. Bachmura provided additional information regarding each State on his schedule.[15] Mr. Majoros examined the supporting data provided by Mr. Bachmura and found that New Jersey was the only State in the

[15] *RA-7*, MJM-8 (response to RAR-DEP-73).

survey that has both restructured and unbundled rates. *RA-7*, MJM-9. This led Mr. Majoros to conclude that "the circumstances among states are so different as to render Mr. Bachmura's schedule meaningless." *RA-7*, p. 7, lines 6-7. In sum, the summary figures presented by Mr. Bachmura do not support the use of a 3.52 percent depreciation rate for PSE&G's electric distribution plant.

B. PSE&G's Annual Depreciation Expense Should be Adjusted to Reflect the Proper Depreciation Rate.

Mr. Majoros recommends that the electric distribution plant depreciation rate be set to 2.49 percent, instead of 3.52 percent. *RA-6*, p. 9. As set forth above, the 2.49 percent rate is the same as that established in the Company's Restructuring Case and is based on a 45-year service life. In contrast to the testimony supporting a 45 year service life filed by PSE&G witness Mr. Krueger in the Company's Restructuring Case, the 3.52 percent rate advocated by PSE&G in the instant case is based on a 28-year service life.[16] Furthermore, Mr. Majoros found that the 2.49 percent rate continues to be reasonable. *RA-7*, p. 5. The recommended change in the depreciation rate will adjust the depreciation rate to be consistent with the excess depreciation reserve established in the Company's Restructuring Case and amortized in this proceeding. The recommended adjustment will reduce annual depreciation expense by approximately $42.6 million. *RA-6*, p. 9, MJM-5.

C. PSE&G's Excess Depreciation Reserve Should be Returned to Ratepayers Through a Two-Year Amortization Credit.

As a result of the Company's decision not to change the depreciation rate to 2.49 percent on its books, its excess depreciation reserve has grown since 1998. This additional depreciation excess reserve is the differential accumulated on the Company's books since December 31, 1998, as a result of the application of

[16]*RA-6*, MJM-3 (testimony appended to response to RAR-DEP-53).

the current 3.52 percent rate rather than the proper 2.49 percent rate. Mr. Majoros calculated the additional excess reserve depreciation which accumulated in 1999, 2000, and 2001 and found that it totaled $115 million. *RA-6*, p. 9, MJM-5.

The Final Decision and Order in the Company's Restructuring Case set forth the method by which the December 31, 1998 excess depreciation reserve would be amortized:

> An excess electric distribution [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 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.[17]

Mr. Majoros recommended that the excess depreciation reserve which developed since December 31, 1998, be amortized to base rates over the remaining two years of the original amortization period set forth in the Board's Final Decision and Order in the Company's Restructuring Case. *RA-6*, p. 9. Mr. Majoros' amortization recommendation is consistent with the Board's ruling in the Restructuring Case.

D. Conclusion

As demonstrated above and in the testimony of Ratepayer Advocate witness Michael J. Majoros, the Ratepayer Advocate respectfully submits that Your Honor and the Board should adopt the following recommendations:

(1) The depreciation rate for electric distribution plant should be set at 2.49 percent and the expense allowance for depreciation should be adjusted accordingly; and

(2) The excess depreciation reserve which developed since December 31, 1998 should be amortized to base rates over the remaining two years of the original amortization period set forth in the Board's Final Decision and Order in the Company's Restructuring Case.

[17] *Restructuring Case Final Order*, p. 115.

POINT III

PRO FORMA UTILITY OPERATING INCOME

The Company has proposed a total pro forma test year operating income of $88,450,000 based on its 12+0 filing data. *P-3 U 12+0,* Schedule ANS-3, p. 2. PSE&G's original rate increase request in this matter is $250,000,000. *P-4,* p. 1, l. 13-16. As shown on exhibit RA-60, Schedule RJH-4R (12+0 Update), Mr. Henkes recommends operating income adjustments that would increase the Company's proposed pro forma operating income to a recommended pro forma test year operating income level of $183,181,000, or an increase of $94,731,000. Each of these recommended operating income adjustments is discussed below. Mr. Henkes' recommended revenue requirement increase is $82,231,000. *RA-60,* Schedule RJH-1R, line 7 (12+0 Update).

A. Other Operating Revenue Adjustments

In Mr. Henkes' original testimony and the supplemental 9+3 testimony, he made nine adjustments that increased the Company's operating income. *RA-49,* Schedule RJH-8 *and RA-50,* Schedule RJH-8R. These adjustments were based on comparing the Company's original and 6+6 filings to later updates. In Mr. Henkes' Schedule RJH-8R (12+0), all but one of these adjustments has been replaced by the Company's actual revenue figures, so that the only remaining issue is the fiber optic construction revenues and pole and duct rental revenues.

> Q [MR. HOFFMAN] Now, again we go to RJH-8R for a second and this is the other operating revenue position?

A [MR. HENKES] Correct, right.

Q And is it correct that the only issue that is going to be left here is the fiber optic construction and pole and duct rental revenues? Is that correct? . . .

A Yes.

Q When you - - when you update the late payment charges, this will be whatever, whatever they will be. Is that correct?

A That's correct.

T1380:L13 - T1381:L5

As shown on line 5 of exhibit RA-60, Schedule RJH-8R (12+0 Update), the Company includes no revenues from fiber optic construction and pole and duct rental, while Mr. Henkes includes $3,413,316.[18] That figure is admitted by the Company in its exhibit P-43. These are revenues received for the installation and maintenance of telecommunication equipment on the Company's poles and ducts. *RA-49*, p. 24, lines 11-15.

The Company proposes to account for these revenues and expenses "below the line" and, therefore, all of the net margins would go to the benefit of shareholders. The Company's justification for this unfair treatment is that the activities to which these revenues and expenses are related are a competitive wholesale service and not a retail electric distribution service. T1230:L4-15. However, the Company has also admitted that the poles, duct banks and towers to which this communications equipment is attached are all included in the Company's utility plant in service in rate base. T1230:L16 - T1231:L6; *RA-33*. Obviously, the ratepayers are paying for the utility plant in service and are entitled to all the net margins that are created by using that equipment. *RA-51*, pp. 6-7. PSE&G has also admitted that the depreciation expenses, property taxes and operations and maintenance expenses associated with this utility plant are also included in the utility's cost of service. T1231:L7-17; *RA-33*. It would be entirely unreasonable to require customers to pay for the plant and

[18] Mr. Henkes adopted the Company's removal of prior years' revenues and deducted the 2002 expenses from the 2002 revenues.

the expenses to maintain and operate the plant, but deny them the revenues that arise solely from the use of this plant for communications equipment. Therefore, the only reasonable treatment for these net revenues is to credit them against the utility's expenses in base rates.

That is the same ratemaking treatment that is afforded to the utility's appliance services business. T1232:L4-24. PSE&G uses utility equipment and utility employees to maintain, repair and replace heating and cooling equipment and other appliances such as dishwashers and refrigerators. The utility charges the customers who use these appliance services separately from the charges for their utility service. However, the Board has consistently required the utility to account for the net margins for the services "above the line" so that the ratepayers who fund the equipment and employees who perform these appliance services receive the net benefits that come from the use of those employees and that utility plant. Your Honor and the Board should reject PSE&G's refusal to provide the ratepayers with the net benefits arising from the equipment they fund and should adopt the Ratepayer Advocate's proposal to treat these net revenues above the line.

The Ratepayer Advocate's recommendation is fully consistent with Board policy on these issues as can be seen from the Board's decision in other cases. *I/M/O the Petition of Gordon's Corner Water Company*, BPU Docket No. WR00050304 (Order dated July 12, 2001). Similarly, the Board required an electric utility to apply all net revenues derived from use of its facilities, including revenue from leased fiber optic capacity, to be applied to the benefit of ratepayers. *I/M/O JCP&L*, BPU Docket No EE97050350 (Order dated December 17, 1997).

B. Year End Customer Revenue Annualization Adjustment

Mr. Henkes recommended an adjustment to PSE&G test year revenue to account for growth in the number of customers from the beginning of the test year to the end of the test year. His adjustment is $9,220,000 prior to associated Board and Ratepayer Advocate assessments and income taxes. After accounting for these associated expenses and income taxes, his recommendation increases operating income for the test year by $5,453,000. *RA-60,* Schedule RJH -9R (12+0 Update). By contrast, PSE&G's proposed test year revenues are inappropriately based on the average number of customers in the test year and not the number of customers on the utility's system at the end of the test year. *RA-49,* p. 30, lines 8-9.

PSE&G contradicts its own position on customer growth at the end of the test year by proposing to use the amount of dollars invested in rate base at the end of the test year rather than using the average test year plant. The figure for rate base at the end of the test year is higher than the average test year plant investment. Using the year-end figures for rate base and using the average test year figures for the number of customers results in a mismatch because the test year revenues would not properly match the year-end plant investment. PSE&G also proposes to annualize its depreciation expense based on plant investment at the end of the test year. That proposal further emphasizes a mismatch in PSE&G's decision not to annualize revenues to account for customer growth throughout the test year.

As stated by Mr. Henkes, "The BPU has a long-standing and well-established policy that the ratemaking use of test year-end rate base and annualized depreciation expenses based on test year-end plant be appropriately 'matched' with the ratemaking use of annualized test year revenues based on customer growth up to the end of the test year." *Id.*, pp. 30-31. Mr. Henkes cited two previous PSE&G base rate cases in which the Company refused to annualize revenues to account for customer growth up to the end of the test year. In those two cases the Board adopted the Administrative Law Judge's (ALJ) decision to require the customer growth revenue adjustment.

In the first cited case, the ALJ stated:

> . . . a normalization adjustment should be made for test year-end customers. It is a proper adjustment because it matches the (test) year-end plant with the (test) year-end level of customers, and thus is consistent with the Board's clearly enunciated "matching" principle.

BPU Docket No. 837-620.

Mr. Henkes noted that the Board adopted the ALJ decision on this issue.

In the second cited case, the ALJ stated, "I agree with Staff and Rate Counsel that the Board has consistently recognized the appropriateness of this adjustment." *BPU Docket No. ER85121163.* Mr. Henkes noted that the BPU also adopted the ALJ decision on this issue in the second case. Mr. Stellwag argued in his rebuttal testimony that this customer growth revenue adjustment should not be made so that the Company would be afforded an attrition allowance. *P-4-RB*. Mr. Henkes pointed out in his surrebuttal testimony that the Board previously rejected this same attrition argument that PSE&G made in the previous base rate case under docket number ER85121163. *RA-51,* pp. 7-8. In that case, the Board adopted the Initial Decision that concluded:

> . . . petitioner's attrition argument has been expressly addressed by the Board in Atlantic City Electric's most recent rate case, BPU Docket ER8504434, Decision and Order of the Board dated April 3, 1986 at p.3. After considering petitioner's earnings attrition argument I noted that the Board obviously considered same in the Atlantic City Electric case and that there is no just reason presented in this case to depart from Board policy. . . ..

[ALJ Initial Decision, pp.119-120, OAL Docket No. PUC 231-86].

When calculating his customer growth revenue adjustment, Mr. Henkes recognized that he should not simply use the number of customers on the utility system at the test year end on December 31, 2002. The reason for this is that the number of customers on the utility's system fluctuates somewhat from month to month. *RA-49,* p.32. Mr. Henkes used the following method to calculate the adjustment:

> It is reasonable to assume that the Company's actual average test year plant in service is approximately equivalent to the actual plant in service level during the mid-point of the test year. Therefore, the difference between the proposed test year-end plant level and the average test year plant level essentially represents one-half year's worth of growth in the Company's plant investment level. Since the Company's proposed test year revenues are based on the average number of customers, the appropriate revenue annualization adjustment should similarly be based on one-half year's worth of growth in the number of customers of the Company. From the response to RAR-A-87, original filing workpaper 110 and 6+6 filing workpaper page 27, one can calculate that the 3-year average annual compound growth rate for the Company's average number of customers during the most recent period 1999 B 2002 (6+6) has been as follows:

Residential:	0.8%
Commercial	1.3%
Industrial	(0.9)%
Street Lighting	0.8%

I recommend that the revenue annualization adjustment for customer growth up to the end of the test year be calculated by (1) taking one-half of the above-referenced annual growth rates; (2) applying this half-year growth rate to the average number of customers for the 6+6 test year to determine the test year "annualized" number of customers, consisting of the average test year number of customers plus one-half year's worth of customer growth; (3) determine the margin revenues by applying the weather-normalized test year consumption per customer to the "annualized" number of customers determined in step 2 and pricing the resulting kwh consumption out at current tariffs; and finally (4) comparing these annualized margin revenues determined in step 3 to the margin revenues reflected in the 6+6 test year filing, in total and by customer category.

RA-49, pp. 33-34.[19] As stated above, after updating the data for the 12+0 test year results, Mr. Henkes' adjustment is $9,220,000 prior to income taxes and BPU and Ratepayer Advocate assessments. After accounting for these associated expenses and income taxes, his recommendation increases operating income for the test year by $5,453,000. *Schedule RJH -9R (12 + 0 Update).*

C. Reversal Of Labor O&M Ratio Normalization Adjustment

In his exhibit RA-60, Schedule RJH-4R (12+0 Update), Mr. Henkes recommends reversal of PSE&G's expense adjustment in which the Company increased the ratio of labor expense that it books to O&M. This recommended adjustment increases PSE&G's operating income by $9,892,000. PSE&G increased its labor O&M ratio for the test year 2002 above the actual operating results because it claimed that the test year would not be representative of the time when the new base rates would be effective. PSE&G claimed that unseasonably warm weather in 2002 increased the capital additions for the test year and thereby reduced the ratio of labor expense booked to O&M. T1207:L19-25; T1412:L14-18. For this reason, PSE&G increased the labor O&M ratio to 62.7%, thereby increasing its proposed revenue requirement. T1208:L2-6. Mr. Henkes did not find the Company's reasoning convincing and reversed the increase and adopted the actual test year labor O&M ratio:

[19] This method was updated to reflect the 12 + 0 actual results.

> I'm aware of the testimony of Mr. Cistaro where he says that due to the unseasonably warm weather in the 2002 winter that suddenly now this labor O & M ratio, that's why it's so abnormally low.
>
> I don't buy that theory at all. I think it's low or much lower than it was in prior years because of this very large employee transfer to the service company. If you buy into this theory, then you may as well say that I believe the fall and the winter of 2002, and by that I mean October, November and December of 2002 were unseasonably cold.
>
> I think it was very abnormally cold weather, and that will result in accordance with his theory in a higher labor O & M ratio. That will be reflected in your 12 and 0 update.
>
> So I think once the 12 and 0 update is in, those two allegedly weather related impacts on the labor O & M ratio will offset each other.

T1412:L14 - T1413:L10.

PSE&G modified its adjustment to the labor O&M ratio several times in this case and did so in a contradictory manner. As outlined in his surrebuttal testimony, Mr. Henkes stated:

> Mr. Stellwag's rebuttal testimony regarding the normalization of the O&M expense ratio represents a clear example of two opposing and internally inconsistent arguments made by him on the same subject in his direct and rebuttal testimonies with the clear intent to increase the Company's indicated revenue requirement in this case. As shown on his Schedule ANS-22 (6+6 Update), in the Company's direct case, Mr. Stellwag proposed specific fringe benefit expense normalization adjustments based on the argument that the pro forma fringe benefit O&M expense ratio should be equal to the pro forma salary/wage O&M expense ratio of 65.1%. In other words, at that time it was Mr. Stellwag's position that, since salaries and wages and labor related fringe benefits are so closely related, the O&M expense ratio applicable to salaries/wages and fringe benefits should be the same. As shown on his Schedule ANS-22 (6+6 Update), Mr. Stellwag's proposed adjustment based on this argument increased the Company's revenue requirement. . . . .
>
> In his rebuttal testimony, Mr. Stellwag is suddenly taking the opposite position of what he argued in his direct testimony. Specifically, Mr. Stellwag is now claiming on page 16 of his rebuttal testimony that the labor and fringe benefit O&M ratios should never be equal and that the labor O&M ratio "is always higher than the corresponding year's fringe O&M ratio. . . ." Mr. Stellwag then estimates, without any support, that the labor O&M ratio "tends to be approximately 2% higher" than the corresponding fringe benefit O&M ratio. He then adds this 2% to the average fringe benefit O&M ratio of 60.8% from the Company's 2003 Operating Plan in order to justify the new labor O&M ratio of 62.7% which the Company is now apparently proposing to use for ratemaking purposes in this case.
>
> Your Honor and the Board should summarily dismiss the inconsistent positions and the unsupported newly proposed labor O&M ratio of 62.7% reflected in Mr. Stellwag's rebuttal testimony. Instead, they should rely on the information contained on pages 35 B 41 of my

> direct testimony in their determination of the appropriate labor O&M ratio to be used for ratemaking purposes in this case.
>
> In his "9+3" updated direct testimony, Mr. Stellwag has once again changed course and is taking a position completely opposite of the position he takes in his rebuttal testimony. While he argues in his rebuttal testimony that the labor O&M ratio should never be equal to the fringe benefit O&M ratio, in his "9+3" updated direct testimony (see schedule ANS-22 Update 9+3) he takes the position that the test year labor and fringe benefit O&M ratios should be equal to each other. This is another reason why Your Honor and the Board should reject Mr. Stellwag's ever-changing and inconsistent positions regarding the normalization of O&M expense ratios.

RA-51, pp. 8-10.

Another reason to reject the Company's position is that it has made several mathematical errors in calculating the labor O&M ratio adjustment. These errors are described more fully in Mr. Henkes' supplemental direct testimony. *RA-50*, pp. 11-12; T1335:L9 - T1338:L10. These provide ample reasons to reject the Company's adjustment and adopt the recommendation of the Ratepayer Advocate.

D. Removal Of Incentive Compensation Expense

Mr. Henkes has proposed to remove $3,378,000 from test year expenses that PSE&G included for the incentive compensation program for its officers, top management and other employees. *RA-60*, Schedule RJH-10R (12+0 Update). This adjustment would increase the utility operating income by $1,998,000. *RA-60*, Schedule RJH- 4R (12+0 Update). Mr. Henkes describes the Company's incentive compensation plans in his direct testimony:

> The response to S-PREV-56 has the following descriptions of these three incentive compensation plans:
>
> <u>Long-Term Incentive Plan (LTIP)</u>
> Participation in the LTIP is limited to officers and senior level associates. Stock options granted at fair market value are the primary vehicles used in the LTIP.
>
> <u>Management Incentive Compensation Plan (MICP)</u>
> MICP is considered a short-term annual incentive compensation plan for PSE&G officers as well as other officers throughout the Enterprise. MICP is designed to motivate and reward officers for achievement of individual goals, business unit goals and overall company results. This plan, together with salary and benefit programs, is designed to provide overall compensation which is competitive. Individual officer incentive goals are based on a "balanced

scorecard" approach in each participant's area of responsibility and relates to business plans, financial targets, customer service and other key objectives. A portion of an individual's award is influenced by overall corporate financial performance.

Performance Incentive Plan (PIP)

All PSE&G MAST associates participate in PIP. Similar to MICP, the Performance Incentive Plan is considered a short-term annual compensation plan. The overall objective of the program is to provide market based total compensation opportunity (salary plus incentive) that is competitive with similar positions found in other energy services organizations. Similar to MICP, awards are driven, in part, by overall corporate performance as well as business unit results which measure customer service/satisfaction, productivity, and employees safety.

RA-49, pp. 42-43.

The incentive compensation is being paid to the Company's officers, senior management and MAST[20] employees in addition to their current "regular" compensation. Mr. Henkes noted that this "regular" wage/salary compensation has experienced steady increases from year to year including increases of 3.5% to 5.1% during the years 2000 to 2002. *Id.*, p. 43. The Company also increased its revenue requirement to reflect salary increases of 4% effective April 2002 and another 4% effective April 2003. Mr. Henkes gave several reasons for his recommendation.

Under the LTIP, the criteria for determining the plan awards are solely a function of corporate financial performance and are intended to more closely align the executive's interests with the long-term interest of PSEG shareholders. Similarly, for the MICP and PIP plans a portion of an individual's awards under these plans are determined by the achievement of pre-determined overall corporate financial performance goals such as improvements in return on investment, earnings per share, *etc.* The shareholders of the parent corporation, PSEG, are the primary beneficiaries of such corporate financial performance improvements. For those reasons, PSEG's stockholders should be made responsible for these discretionary costs.

Furthermore, the Company's recent (2000 - 2002) overall average wage and salary increases for executives and MAST associates have averaged between 4.1% and 4.3% per year and the Company has proposed pro forma wage and salary increases of a similar magnitude in this case. Given the recently

[20] MAST employees stand for Management, Administrative, Secretarial and Technical employees.

experienced and currently continuing low inflation rates, the Company's recent actual and proposed pro forma wage and salary increases would appear to be quite generous and more than adequate. It would be excessive to have the ratepayers additionally fund the incentive compensation expense claimed in this case.

Also, the Company has not presented any evidence demonstrating the specific benefits that are accruing to the ratepayers as opposed to PSEG's shareholders as a result of these incentive compensation plans for which these same ratepayers are asked to pay 100% of the costs. Neither has the Company presented a shred of evidence in this case showing that there is any appreciable difference in the productivity level of PSE&G's executives and MAST employees as a direct result of the incentive compensation paid out by the Company. *Id.,* pp. 44-45.

More importantly, Mr. Henkes pointed out that the Board has a specific policy disallowing these types of incentive compensation plans from rates. Mr. Henkes quoted from two base rate cases in which the Board disallowed these expenses. In its Final Decision and Order in the Jersey Central Power & Light Company (JCP&L) base rate case, Docket No. ER91121820J, dated February 25, 1993, the Board stated on page 4 of this Decision and Order:

> We are persuaded by the arguments of Staff and Rate Counsel that, at this time, the incentive compensation or "bonus" expenses should not be recovered from ratepayers. The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills or otherwise remaining profitable. These circumstances as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.

Mr. Henkes also criticized Mr. Cistaro's statement that the circumstances in the JCP&L case were different than those now in this PSE&G case. The conditions in this instant electric base rate proceeding are strikingly similar to, or even worse than, the conditions surrounding the incentive compensation issue in the JCP&L case. Due to the current economic conditions, it is reasonable to assume that many of the Company's ratepayers are suffering from economic hardships and may have trouble paying their bills and keeping or finding employment. *RA-52,* p. 4. Furthermore, as discussed before, PSE&G's three incentive compensation programs are either fully or partially driven by the Company achieving financial performance goals for the benefit of shareholders of the parent corporation. *Id.,* pp. 45-46.

In the fully-litigated 2001 Middlesex Water Company base rate case, the BPU Staff stated on page 37 of its Initial Brief with regard to Middlesex's incentive compensation expenses:

> Staff is persuaded by the arguments of the RATEPAYER ADVOCATE that, at this time, the incentive compensation expenses should not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RATEPAYER ADVOCATE's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.

While the ALJ in that case ruled that 50% of Middlesex's incentive compensation expenses could be recovered in rates, the Board overruled the ALJ and ordered that 100% of these incentive compensation expenses be removed from Middlesex's rates. *Id.,* p. 46. PSE&G attempted to counter Mr. Henkes' recommendation by claiming that its incentive compensation program is not similar to the one disallowed by the Board in the above JCP&L case. *P-2-RB,* pp. 20-21. Mr. Henkes disagreed strongly with this argument. In his supplemental surrebuttal testimony, Mr. Henkes compared the incentive compensation plans of PSE&G and JCP&L. He quoted from a PSE&G data response saying that the overall objective of these programs is "to provide market based total compensation opportunity (salary plus incentive) that is competitive with similar positions found in other energy services organizations." *RA-52,* p. 2.

Mr. Henkes also pointed out other similarities between the utility plans including the fact that the program awards are paid out as annual lump-sum cash payments and that both programs are tied to financial performance criteria among other criteria. He criticized PSE&G's attempt to distinguish its plan from JCP&L by saying that its plan is not a bonus plan. This is simply a game of semantics. Expenses that are permitted in rates should not be based on a game of semantics. On pages 2 and 3 of his surrebuttal testimony, Mr. Henkes quoted extensively from the Board order in the JCP&L case describing the JCP&L plans and showing their similarities to the PSE&G plans. For the above reasons, Your Honor and the Board should reject PSE&G's attempt to distinguish its incentive compensation plans from those the Board disallowed in the JCP&L case. PSE&G's incentive compensation plans should not be included in rates.

E. Reversal Of PSE&G's Restructuring Cost Amortization

PSE&G proposed to include in rates a four-year amortization of $49.4 million in restructuring expenses.[21] It claimed that these costs were incurred to comply with the Electric Discount and Energy Competition Act (EDECA). Among these restructuring costs are expenses related to the program allowing customers to choose an alternate energy supplier and other costs to transfer the utility's generation assets to its unregulated affiliate. As will be described more fully below, Mr. Henkes disallowed these expenses as being inadequately supported. Mr. Stellwag modified his recommendation by proposing that if the amortization is permitted, then the revenues collected would be compared to the costs deferred and that any revenues exceeding the deferred costs would also be deferred and returned to customers in the next base rate case. T1211:L18-24.

The Company's amortization proposal is not based on any specific Board orders following the deferral and amortization of these expenses, but relies entirely on the Company's interpretation of EDECA and the legislation's requirements. Mr. Henkes demonstrated that PSE&G never showed any extraordinary circumstances that would justify the use of deferred accounting and that the utility never attempted to show that its financial integrity would be endangered without the amortization. Mr. Henkes stated that EDECA did not specify that this type of restructuring costs could be amortized in this way. He also stated that some of these

[21] Approximately $34 million in restructuring costs plus the balance of the $49.4 million consisting of carrying charges calculated on the deferral from June 2000. *RA-49*, p. 50.

cost categories were already included in PSE&G's base rates including expenses for labor, information technology, accounting, tax, human resources, legal and regulatory costs, and outside services for consulting and financial services. *RA-49,* pp. 53-54. It would be patently unreasonable to have charged ratepayers for these categories of costs in base rates during the Transition Period and now also prospectively charge ratepayers for these additional retroactive expenses incurred during the Transition Period without giving ratepayers the benefit of expense reductions that occurred during this retroactive period. For these reasons, the Ratepayer Advocate urges Your Honor and the Board to adopt our recommendation to disallow these costs and the carrying charges claimed by the utility.

However, Mr. Henkes also recommended that if Your Honor and the Board should decide to give rate recognition to the deferred restructuring costs, then the costs to be recognized for ratemaking purposes should exclude carrying charges to be consistent with current Board ratemaking policy. He stated:

> It is my understanding that it is long-standing Board policy that if ratepayers are already being charged in rates for the annual amortization of deferred cost balances, then the unamortized deferred cost balance cannot be included in rate base for a rate of return.
>
> I believe this BPU ratemaking policy is based on the concept that the responsibility for such deferred costs be shared between the utilities ratepayers and stockholders.
>
> The ratepayers would be responsible for the annual amortization and the shareholders would be responsible for the carrying charges on the unamortized balances.

T1330:L7-21. Mr. Henkes also cited two Board orders for this policy:

> A. It's the matter of the Petition of Elizabethtown Water Company, BPU Docket No. 8312-1072, OAL Docket No. PUC 9897-83, Page 3, Paragraph 4, that's the water company.
>
> Q What does it say, Mr. Henkes?
>
> A It says, "We especially concur with the ALJ's analysis with respect to deferred charges. The Board's policy with respect to water companies continues to be that we will not recognize deferred charges in working capital as an undue burden on the ratepayer who will then be required to pay an amortization of these costs and expenses and also pay a return on these unamortized balances included in rate base."

> Then there is another one in the matter of the petition of New Jersey Natural Gas Company for approval of increased base tariff rates, and that is BPU Docket No. GR89030335J, OAL Docket No. PUC 2633-89, Page 12 of that Final Order.

T1418:L13 - T1419:L3.

For the above reasons, the Ratepayer Advocate recommends that the Company's requested restructuring cost deferral and amortization be rejected as factually unfounded, legally unjustified and not known and measurable changes to items already in the test year expenses. The proposal also unfairly would recognize an additional alleged <u>increase</u> in base rate expenses without also recognizing other offsetting expense items that <u>decreased</u> during this same period. Alternatively, if Your Honor and the Board decide to allow deferred accounting and amortization of these alleged expenses, then the amortization should be without carrying charges. As stated above, Board policy requires that deferred accounting treatment and amortization of expenses should not also include them in rate base, since this policy prohibits requiring customers to pay a return on the unamortized balances of those base rate expenses.

F. Rate Case Expense Adjustment

The Company is claiming total expenses of $1,554,000 for this electric base rate case and deferral case audits.[22] *RA-60*, Schedule RJH-13R (12+0 Update). Following long-standing BPU ratemaking policy, Mr. Henkes recommends that the electric base rate case expense of $884,000 be shared on a 50/50 basis between the Company's ratepayers and stockholders. This recommendation is consistent with Board policy on this issue. *Re Elizabethtown Water Co*., 62 *PUR* 4th 613 (1984); *I/M/O Pennsgrove Water Supply Company*, BPU Docket No. WR98030147 (Order dated June 24, 1999); and, more recently, *I/M/O Environmental Disposal Company*, BPU Docket No. WR99040249 (Order dated June 14, 2000).

In addition, while the Company proposed to reflect the base rate case expense of $884,000 on an annual basis (as if a rate case will take place every year), Mr. Henkes recommended amortizing half of the

[22] $884,000 for the electric base rate case and $670,000 for the deferred balances audit.

expense over five years. Because the Company's last electric base rate proceeding was more than ten years ago and because it is quite possible that this Company may either never file another electric base rate case or may wait another ten years for its next rate case, using a 5-year amortization period for the ratepayers' 50% share of the rate case expenses should be considered very conservative. In addition, as Mr. Henkes testified:

> I think that this policy is consistent with Board policy, because when I mentioned to you these two orders, the Pineland Water and Wastewater Company order, BPU Docket No. WR000070454, and in the Seaview Water Company Rate Base proceeding, BPU Docket WR98040193, the Board approved ALJ McAfoos' amortization period of rate case expenses over five years.
>
> It even says here "the ALJ further noted that Staff's proposed five year amortization was <u>reasonable given the fact that this company had not sought a rate increase in 12 years.</u> [Emphasis added]
>
> After having reviewed the record in this matter, the Board hereby adopts the ALJ's recommendation, thus the Board finds that rate case expenses in the total amount of $44,000 should be shared 50/50 between ratepayers and amortized over five years."
>
> What this means to me is that if there is no known and certain and known and measurable date for when a particular utility's rate case is going to be in the future, then it's Board policy that one can use as guidance in the determination of the amortization period the length of time since the company's last base rate case, that's what I've done, and I've done five years, not ten or eleven years.

T1356:L22 - T1357:L25.

As to the audit expense, Mr. Henkes modified his original recommendation on expense sharing when his 12+0 updated schedules were filed. His recommendation now is that 100% of the audit expense be charged to ratepayers. He mentioned this possibility at the evidentiary hearing:

If the audit expenses are - - if the company claims that these are audit expenses associated with Board ordered audits that have nothing to do with this rate case and had nothing to do with the deferral case, then the 50/50 sharing shouldn't be applicable.

T1351:L14-24. However, Mr. Henkes retained his original recommendation to amortize the ratepayers' responsibility for this expense over five years for the same reasons he recommended five years for the base rate case expenses.

In summary, the recommended normalized annual rate case expense level to be recognized for ratemaking purposes should be $262,000 as shown on line 9 of exhibit RA-60, Sch. RJH-13R (12+0 Update). This recommendation decreases the Company's proposed test year expenses by $1,491,000 and increases the Company's proposed test year after-tax operating income by $882,000.

G. Gains on Sales of Utility Property

PSE&G proposed to modify existing Board policy on how gains from the sale of utility property are accounted for in base rates. The Board policy is to net the actual gains and losses for the five years before a base rate case and divide the total by five, essentially using 100% of a five-year average net gain to include in utility operating income. This credits ratepayers with the entire net gain for property they have supported in their rates. Before this instant case, PSE&G followed this Board policy in its base rate cases. *RA-49*, p. 61. The Ratepayer Advocate also proposes to follow Board policy on this issue.

However, PSE&G now proposes to retain 50% of the five-year average net gains. T1245:L6-12. PSE&G proposed this despite the fact that it admitted that in the Company's last five base rate cases it followed the long-established Board policy to flow through 100% of the five-year average net gain to customers. *RA-39*; T1245:L13 - T1246:L13. The five-year average net gain is $1,074,000 and PSE&G proposed to deny ratepayers $537,000 of that average net gain. *RA-60,* Schedule RJH-14R (12+0 Update). Mr. Henkes properly recommends rejecting this unwarranted confiscation of funds that rightly belong to ratepayers. His adjustment would flow the entire $1,074,000 through base rates, which is a $537,000 adjustment to the Company's proposal. Mr. Henkes sees no reason or changed circumstances for this proposed change in policy. The actual 2002 test year net gain is $4,738,000. *Id.* So even using the entire $1,074,000 five-year average net gain in base rates would allow shareholders to retain $3,664,000 of the 2002 net gain.

Mr. Henkes testified that the Board has sometimes used a different method in some water utility cases, wherein the Board reviews an individual sale of utility property in a separate filing before the agency. *RA-49*, pp. 63-64. When the water utility files a petition to approve the proposed sale of utility property, the Board has in some cases ordered a 50/50 sharing of the total net gain on that individual sale, but it does not take one-fifth of the total net gain and then split it evenly between ratepayers and shareholders, as PSE&G proposed to do. *Id.* PSE&G is attempting to use the portion of that alternate method it likes (the 50/50 sharing) and apply it to one-fifth of the total average net gain. That is an unfair and unsupported adjustment.

If that alternate method were applied here, the net total gain in question would be the test year 2002 total net gain of $4,738,000. A 50/50 sharing of that total would increase utility operating income (and reduce revenue requirements) by $2,369,000, a much higher amount than the $537,000 recommended by Mr. Henkes. However, the Ratepayer Advocate is not recommending a change in Board policy. Our adjustment to the utility's proposal is undeniably fair and comports with the above-described Board policy. PSE&G's proposal is unreasonable and should be rejected.

Mr. Henkes also makes two other adjustments to the pro forma utility operating income to account for gains on the sale of generating plant and transmission plant. The adjustment for the sale of the generating plant comes from the Board Order in the Company's Restructuring Case.

> 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.[23]

[23] *I/M/O Public Service Electric and Gas Company's Rate Unbundling, Stranded Costs and Restructuring,* BPU Docket Nos. EO97070463, EO9707462, and EO97070461 (Order dated August 24, 1999), p. 115, para. 23.

The Company's generating plants were then transferred to PSE&G's unregulated affiliate, PSEG Power Company (referred to as Genco in the Restructuring Case Order). PSE&G acknowledged in its response to data request RAR-A-26 that during this five-year period, PSEG Power Company sold the Kearny 12 Generating Station for a total net after-tax gain of approximately $10.2 million. In its response to data request RAR-A-100, the Company stated that it intends to apply 50% of this gain, or $5.1 million, as a reduction to the NTC deferred balance in the Company's Deferred Balances Case established by the Board's July 22, 2002 Order. *RA-49*, p. 65, lines 16-22. Mr. Henkes agreed that 50% of this gain should be credited to ratepayers through the SBC and/or NTC deferred balance. *Id.*, p. 66, lines 10-14.

However, there is also the issue of the ratepayers' 50% share of the gain on the sale of utility transmission property. In the response to data request RAR-A-113, PSE&G also admitted to a net after-tax gain of approximately $1.45 million from the sale of electric transmission properties in 2001. Before their sale in 2001, these electric transmission properties had always been included in PSE&G's unbundled rate base. PSE&G proposed that 100% of this after-tax gain of $1.45 million should flow through to stockholders. Mr. Henkes challenged this proposal and recommended that a 50% share of the net gain on this property sale should flow through to ratepayers, similar to the treatment of the Kearny 12 plant sale gain. *RA-49*, pp. 66-67.

Before restructuring, PSE&G's generating plant was always in the unbundled rate base. The Board determined that ratepayers should get a 50% share of the net gains from any sale of this generating plant that was transferred to PSEG Power during the five years after the August 1, 1999 beginning of electric restructuring. That was undoubtedly because the Board recognized that ratepayers deserved at least half of the net gain on property used to provide them service. Ratepayers also deserve at least half of the net gain on the sale of these transmission properties. The similarities between the gains on the sales of Kearny 12 and the transmission properties support our recommendation and are listed below.

Before their sale in 2001, these electric transmission properties have always been included in the Company's unbundled rate base just like the generation plant was (including Kearny 12). The sale of these electric transmission properties occurred during the same five-year period as the sale of the Kearny 12 Generating Station. The transmission properties were also used, like Kearny 12, to provide ratepayers with utility service. Although PSE&G's electric transmission operations are now unbundled from the electric distribution operations, it would still be appropriate to give ratepayers a 50% credit for any gains from the sale of electric transmission property, similar to what was deemed to be appropriate for the sale of any electric generation property divested to PSEG Power. Therefore, the Ratepayer Advocate recommends that 50% of the after tax gain of $1.452 million from the sale of these electric transmission properties, or approximately $726,000, be used as an immediate, upfront offset to any SBC and/or NTC deferral balances in PSE&G's Deferred Balances case.

H. BGS Implementation Costs

PSE&G proposed to include in rates its alleged costs to implement the Board's recent order on Basic Generation Service (BGS). *P-4 (U 9+3),* pp. 21-22 and Schedule ANS-23 (Update 9+3). The proposed cost estimates were later modified to $2,467,000 in the 12+0 update. *P-4 (U 12+0),* Schedule ANS-23 (Update 12+0). The revenue requirement impact would increase customers' bills by $4,179,000.[24] The cost estimates arise from the Company's program to install special meters for large commercial and industrial customers who will receive BGS electric supply from PSE&G at prices that reflect a market price for energy that would change hourly. The new meters are needed to record the large commercial and industrial customers' energy consumption on an hourly basis. Additional costs are included for billing system enhancements. *P-4 (U 9+3),* pp. 21-22.

[24] $2,467,000 x 1.6940 = $4,179,000. The revenue conversion factor to convert an expense to a revenue requirement figure is 1.6940. *RA-60,* Schedule RJH-1R (12+0 Update).

Mr. Henkes recommended removal of these costs from the Company's case because this proposal represents unsupported estimates on the Company's part and are not known and measurable changes to the Company's case. *RA-50*, pp. 12-14. As this proposal was grafted onto the utility's 9+3 filing, which is normally intended simply to substitute updated results for the Company's originally filed request, it was a new issue. However, despite that fact and that PSE&G had to know that the parties had no supporting information on this issue from the discovery to date, the Company included no workpapers or any other factual or documentary support including assumptions made, calculations, actual source references, or any other means to review and justify this last-minute claim. The Company apparently decided that the entirety of its proofs would consist of text from the Board's Order in the BGS docket that created this new issue in the base rate case.

> Costs associated with interval meter installation required by this Order, including capital, operation and maintenance costs and the cost of billing system enhancements, should be determined in the context of the current rate proceedings for JCP&L, PSE&G and Rockland and in the upcoming rate proceeding for Conectiv. Those costs, whether or not incurred during the relevant test year, should be reflected, on a pro forma basis if necessary, in the revenue requirements on which rates will be set in those proceedings.[25]

As stated by Mr. Henkes, the Board Order does not specify that these costs are automatically to be approved without examination.

> What that means to me is that this order doesn't validate the accuracy of the appropriateness of all of the estimates that are shown on schedule ANS-23 which has no supporting assumptions, calculations, or any other documentation other than one page in one schedule in Mr. Stellwag's testimony.

T1394:L25 - T1395:L7.

A showing of prudence is required of all expenses a utility seeks to charge to customers. It is insufficient for the utility simply to present the amounts of expenses booked or projected without additional proof of their prudence and reasonableness. The New Jersey Supreme Court stated this principle at length:

[25] *P-44; I/M/O The Provision Of Basic Generation Service Pursuant To The Electric Discount And Energy Competition Act, N.J.S.A.* 48:3-49 *et seq*., BPU Docket Nos. EX01110754 and EO02070384 (Order dated December 12, 2002), p. 14.

> The dangers inherent in accepting the [utility's] books of account at face value in a rate proceeding are apparent. The prescription of a uniform system of accounts by regulatory commissions, such as the Board of Public Utility Commissioners, has been uniformly accompanied by the qualification that in prescribing the system of accounts, the commissioners do not commit themselves to the approval or acceptance of any item set out in any account for the purpose of fixing rates or in determining other matters before the commission.
>
> Neither this Court nor the Board can accept the books of account of a public utility at face value in a rate case in which reasonableness is always the primary issue.
>
> . . . It must be emphasized that rate making is not an adversary proceeding in which the applying party needs only to present a *prima facie* case in order to be entitled to relief. There must be proof in the record not only as to the amount of the various accounts but also sufficient evidence from which the reasonableness of the accounts can be determined. . . . Lacking such evidence, any determination of rates must be considered arbitrary and unreasonable.
>
> In this proceeding, . . . no proof was offered by the companies or demanded by the Board to support the items therein included, other than the companies' books of account. The record is thus lacking in sufficient evidence from which this Court can determine whether this rate base is reasonable.

Public Service Coordinated Transport v. State, 5 *N.J.* 196, 218-219. (1950)

As can clearly be seen from the above-quoted case, it is insufficient proof for PSE&G to say only that the program underlying the costs was reasonable or that the Board required the costs to be incurred. The Board may have ordered the work to be done, but it is folly to allege that the Board agreed to "rubber stamp" the costs no matter what they turn out to be. Although the Board ordered the issue to be reviewed in this case, it cannot have abdicated its statutory responsibility to require proof that the specific dollar amounts of the costs are reasonable. Absolutely no such proof was ever presented. PSE&G seems to have gambled that it could slide these costs into rates on the strength of the above-quoted BGS order (*P-44*) without evidence proving the prudence of the expenditures or the reasonableness of the amounts requested. Your Honor and the Board should reject this gamble and reject these costs.

PSE&G also attempted to reverse the burden of proof in this case, although it is axiomatic that the burden of proof remains on the utility. "The burden of proof to show that the [rate] increase, change or alteration is just and reasonable shall be upon the public utility making the same." *N.J.S.A.* 48:2-21(d). PSE&G essentially argued at the evidentiary hearing that the utility had no burden to provide substantial and credible factual evidence to justify these expenses, but that it was the Ratepayer Advocate's burden to wring the proofs out of PSE&G in discovery and present them to Your Honor and the Board so that there would be some basis to approve them. This was discussed as set out below in Mr. Henkes' cross-examination by PSE&G:

> Q And did you ask any discovery on this particular item?
>
> A Well, Mr. Hoffman, I mean this issue was introduced by the company on December 3. . . .December 3, 2002, this is six months after you initially filed this case. The parties in this case were never told that this might be an issue that eventually is going to be introduced. Now the company, two weeks after the rebuttal phase, comes in with this one page exhibit and one page of testimony and says, by the way, there's another five million dollar revenue requirement item here that goes to - - because the Board might have an order eventually implementing or approving a certain plan.[26]
>
> I object to that. I said it is a late filed adjustment and it's based on nothing but estimates at this point in time. It is not known and measurable. We ought to look, if you're going to implement this, as far as - - as far away as May 31st, 2004, and as a section now, if you're going to go that far and the Board says, okay, you have to look at that pro forma cost if necessary, and I would argue you look at customer growth through that point in time. You look at offsetting cost savings. There are a whole bunch of other things and other factors that you would have to start considering that are not reflective on schedule ANS-23 of Mr. Stellwag's testimony, and that's why I object to it.

T1395:L11 - T1396:L20.

> Q Why didn't you ask for discovery between now and the 12 Plus 0 update?
>
> A I believe that we then might as well look at other items that are out there that may have another impact. This is an item, in my opinion a selective item that you're introducing the $5 million revenue increase impact. Now there may be other adjustments out there that we don't know about, but maybe you know about because you are much closer to the data than we are, that haven't had an offsetting effect.[27]

[26] $5,000,000 was the revenue requirement for PSE&G's 9+3 estimate of these costs. After the evidentiary hearings on revenue requirements issues were complete, PSE&G's 12+0 estimate reduced the proposed revenue requirement increase to $4,179,000.

[27] As Mr. Henkes also testified, among the items that should be reviewed are whether these costs are "truly incremental costs, truly incremental investments, [and] incremental associated costs savings, incremental revenue growth during the same time

> I mean I object to the rate [*sic*] filed nature of these kinds of selective adjustments that you are going to put on in the 11th hour, and we have very little opportunity to do discovery and review and analysis on. I don't find it appropriate. . . .
>
> It is easy for you to say when you come in with something on December 3 when we had 50 cases going on that to then say, why don't you do discovery on it. If the company had come in with this issue earlier on and said, by the way, we're in this proceeding, this might be coming up, and we have a placeholder for it. It must be that we have time to do an analysis and review on it, and discovery. That is a different story. We had six months of time after December 3rd when we had many things going on. And this was, in my opinion, unfair to then require that we would have to do a full discovery process on it.

T1399:L2-19; T1402:L9-24.

PSE&G's argument appeared to be that the burden of proof is on others to disprove its unsupported allegations. However, Your Honor properly rejected that argument.

> MR. UBUSHIN: Your Honor, I am going to object to any other questions in this line. The company is attempting to shift the burden of proof from itself to the Ratepayer Advocate and I don't believe that that comports with New Jersey law. It is up to the company to provide all the backup for every dollar that it wants to charge ratepayers. It is not up to them to file a one line item and say we would like five million dollars. If you could fight it, go ahead and do it. I don't think it is a fair line of questioning. I don't - - I don't think it is a relevant line of questioning and I think it violates New Jersey law which puts the burden of proof on the utility not upon any of the intervenors.
>
> THE COURT: Well, I don't think the question has any impact on the burden of proof.

T1399:L20 - T1400:L18.

As seen above, Your Honor rejected PSE&G's attempt to shift the burden of proof. Because the burden of proof remains on PSE&G, the utility's request for these BGS costs should be rejected since it provided no evidence to support the prudence or reasonableness of the expenses. Even after having the opportunity to provide substantial, credible evidence, if any exists, in the 12+0 updates, PSE&G decided to forgo that opportunity.

that this is going to be implemented." T1401:L7-13.

Q It's you [*sic*] position that with the 12 and 0 update, you're not going to look at it because it was a late filed adjustment? . . .

A When the 12 and 0 filing comes in, I will certainly consider what the supporting data is and what kind of information the company is going to provide to the Ratepayer Advocate in order for us to appropriately analyze whether the proposed adjustment is accurate or appropriate.

T1404:L2-18.

Having testified to his willingness to review any proofs that PSE&G would present with the 12+0 updates, Mr. Henkes and the Ratepayer Advocate were denied the opportunity to review them because PSE&G decided not to provide those proofs. Instead, it filed nothing more than a one-page update to the list of expenses in exhibit P-4 (U 12+0), Schedule ANS-23 (UPDATE 12+0). Because PSE&G failed to provide any supporting documentation for these costs to the parties, Your Honor and the Board are without substantial, credible evidence in the record to approve these costs.

Attempting to excuse its failure to give sufficient opportunity to review these costs, PSE&G relied on its claim that it had no idea that the Board would order that this issue be included in this base rate case. This was alleged, not by PSE&G's witness, but by its attorney during cross-examination of Mr. Henkes:

Q Do you think the company knew that the Board was going to order that this be considered in this proceeding ahead of time?

A It could well be, sure.

Q You think the company knew?

A Well, Rockland Electric had an anticipation that this was going to happen.

T1402:L25 - T1403:L7.

As can be seen from Mr. Henkes' cross-examination, a different electric utility, Rockland Electric Company (Rockland), was perfectly able to prepare its request for BGS implementation costs when it filed its original base rate case on October 1, 2002. The October 1, 2002 Rockland base rate case was filed one month before the Board orally decided the BGS case at its November 6, 2002 open public agenda meeting and two and one-half months before the Board's written Order on the BGS case.[28] *P-44*. Rockland did not wait until the last minute to present its case on BGS implementation costs the way that PSE&G did and did not feel the necessity to await the issuance of the final BGS order.

> Q [Mr. Hoffman] How could [PSE&G] have filed the adjustment before it got the Board order?
>
> A [Mr. Henkes] The company could have filed - -
>
> Q It had to wait for the Board order that ordered it to do it? Didn't it?
>
> A In the Rockland Electric case, they filed it and they - - they had a case that was way before November when they came in with their case and they notified all the parties that there's something that they may have to deal with.
>
> They put in what they call a place holder adjustment. Everybody had months of time on the discovery on that, and doing review and analysis on it.
>
> In this case, the company was totally silent on it. Nobody knew about this until December 3 that this was going to be an issue in this case.

T1397:L22 - T1398:L17.

When Rockland filed its base rate case on October 1, 2002, the Board had not yet issued its final BGS Order. However, that did not stop Rockland from including the issue in its base rate case and giving all the parties ample opportunity to review, seek discovery, and analyze the data supporting its request. Therefore, it is plain to see that PSE&G is completely incorrect when it attempts to persuade Your Honor and the Board that it was required to wait until the Board's final BGS Order was issued before it could file its request for the BGS implementation costs. For this reason, Your Honor and the Board should reject PSE&G's excuse for filing its request so late in this matter.

[28] *I/M/O of the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, Its Tariff for Electric Service, Its Depreciation Rates, and for Other Relief ("Base Rate Filing")*, BPU Docket No. ER02100724, OAL Docket No. PUCRL 09366-02N.

Furthermore, PSE&G has not provided any factual evidence to show that the BGS implementation has been completed. The attorney for PSE&G seemed to hint at the evidentiary hearing that the implementation program had been completed, but PSE&G has provided no sworn evidence, or any factual evidence of any kind, to prove that this is the case or that these expenses are known and measurable.

> Q [MR. HOFFMAN] And if you were informed that the 800 meters that have all been installed as of this time, would you still object to it?
>
> A [MR. HENKES] We have no data. I have no - - I mean I have one piece of paper that was introduced and - - and at the llth hour, and I cannot speak to it.

T1396:L21 - T1397:L3. PSE&G's witness, Mr. Stellwag, however, seemed to contradict this assertion. Mr. Stellwag appeared to testify that the Company's claim was not for the actual 800 meters installed, but that PSE&G used the 800 meter installations as a proxy for a future, expected cost incurrence.

> The costs associated with this effort were reasonably <u>estimated</u> using some 800 interval meter installations during the test year as a <u>proxy</u> for what are expected to be virtually identical <u>future</u> per unit costs.

T1216:L18-22 (Emphasis added). PSE&G could have better used its time and effort to clarify exactly what it is seeking to include in rates and providing factual proof that these estimates are reasonable and known and measurable. It is far too late to do that now and its claim should be rejected.

PSE&G also tried to bolster its case from the mere fact that the Ratepayer Advocate was a party to the BGS proceeding. T1397:L4-21. However, the fact that our office is a party to the BGS proceeding does not mean that we had the underlying data for PSE&G's BGS implementation costs. The fact that our office received a copy of the BGS Order did not impose upon the Ratepayer Advocate the burden of coming forward with proof concerning those costs. The only party who is required to carry that burden is PSE&G and they have completely failed to come forward with these proofs. For all these reasons, Your Honor and the Board should reject inclusion of these BGS implementation costs in base rates.

The Ratepayer Advocate respectfully recommends that Your Honor and the Board:

reject the Company's request for $2,467,000 in BGS implementation costs because it is factually unsupported by any substantial, credible evidence in the record.

I. Repair Allowance Amortization Adjustment

Pursuant to the Revenue Requirement Stipulation adopted by the Board in the Company's last electric base rate case (combined electric and gas), PSE&G is permitted to use deferral accounting for the cost of new business extensions as repair allowance property. *RA-49*, pp. 67-68. The Revenue Requirement Stipulation set forth the basis for the deferred amount and its recovery:

> The Company has requested the elimination of the flow-through of the tax savings related to certain repair allowance property expenditures related to new business extensions which is a contested issue in the Company's current Internal Revenue Service Audit. This elimination would have increased revenue requirements by $3.4 million. The parties agree to the continuation of the pre-existing accounting and regulatory flow-through treatment of this item. The parties also agree that if the Company is unsuccessful in its IRS audit and is unable to deduct this property under the repair allowance provisions the undersigned parties agree to the Company's recovery through rates of the Federal income tax, interest, and carrying costs related to the disallowance of new business extensions as repair allowance property. In the event of disallowance by the IRS, deferral accounting shall be instituted by the Company for such amounts pending future recovery through base rates. The Company shall have the burden of proving the quantification and reasonableness of the amounts requested.[29]

According to PSE&G, the Company and the IRS subsequently reached a settlement in the dispute which partially disallowed the deductions claimed by the Company. *P-4 (U 9+3)*, p. 17. The Company instituted deferred accounting for the disallowed portion and related interest and carrying charges. *Id.* The Company proposes to recover the related deferred balance over a ten-year amortization period. The Ratepayer Advocate does not object to the rate recognition of the deferred amount. However, as set forth below, the Ratepayer Advocate objects to the Company's use of unreasonable interest rates to compute the carrying

[29] *I/M/O PSE&G*, BPU Docket Nos. ER9111698J, *et al* (Order dated May 14, 1993), Revenue Requirement Stipulation, pp. 16-17.

charges on the deferral balance. At issue in this proceeding is the proper interest rate used to calculate the carrying charges on the deferred amount from the date of the issuance of the Board's Final Decision and Order in the Company's restructuring case through the end of the 2002 test year.[30]

The Company proposes to compute carrying charges using its after-tax overall rate of return. The Ratepayer Advocate respectfully submits that the use of the Company's overall rate of return to compute its carrying cost for the deferred balance after the Board issued its Final Decision and Order is unreasonable. As Mr. Henkes testified, the Company's overall rate of return includes a profit element in the form of a return on equity. Although the Revenue Requirement Stipulation cited above allows the recovery of carrying charges on the deferral balance, it does not specify that the Company is also allowed to earn a profit on this deferral balance. The Revenue Requirement Stipulation merely provides for the recovery of "interest, and carrying charges."[31] Furthermore, the Revenue Requirement Stipulation places the burden of proof on the Company to show the "reasonableness of the amounts requested."[32] As demonstrated below and in the testimony of Mr. Henkes, the Company has not demonstrated the reasonableness of using its after-tax overall rate of return to compute carrying costs.

At hearing, Mr. Henkes provided two strong reasons why the Company's overall rate of return should not be used to compute carrying charges. Mr. Henkes set forth his first reason at length:

> One reason is that I believe the Board has a policy where it says that if there is going to be amortization of a particular deferred item, there ought to be some sharing, and this sharing could take place by the ratepayers' [sic] amortizing it in rates and the stockholders absorbing the carrying charges. Therefore, under that theory, the unamortized balance could not be included in the rate base, and therefore, the Company cannot make the argument that if we are allowed carrying charges, which they are by stipulation, we can equate the carrying charges to an overall rate of return.... The Board policy would not allow that. T1447:L10-24.

[30] Although in his initial testimony, Mr. Henkes recommended the use of a rate based on 7-year Treasuries for the entire period, in his rebuttal testimony, Mr. Henkes refined his recommendation to apply only to the period subsequent to the issuance date of the Board's Decision and Order in the Company's restructuring case. *RA-51*, p. 16.
[31] Revenue Requirement Stipulation, p. 17.
[32] *Id*.

Mr. Henkes went on to provide his second reason:

> ...[T]he second reason is that I do not believe that it is appropriate for the Company to earn a profit on these unamortized balances. If you take the Company's after tax rate of return in this case, which was 7.28 percent, of that 4.8 percent is or represents the Company's return on equity. That's more than 65 percent of that rate. I do not believe it is appropriate that in accordance with Board policy, the stockholders should get this return on equity. T1448:L21-T1449:L8.

For computing the carrying cost for the period starting with the date the Board issued its Final Decision and Order in the Company's restructuring case, Mr. Henkes recommends the use of a rate equal to the rate of 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. *RA-51*, pp.16-17. Specifically, Mr. Henkes recommends that the interest rate used to compute carrying charges on its repair allowance deferred balances be based on the Company's (then authorized) after-tax rate of return from 1996 through July 1999, and on the seven-year constant maturity treasury rate from August 1999 through the end of the 10-year amortization period. *Id*. Mr. Henkes noted that his recommended interest rate for the post-August 1999 period is the same rate as proposed by the Company in this case to calculate the carrying charges associated with its claimed Restructuring Cost deferral balance. *RA-49*, p. 70.

The use of a rate which does not include an equity return to compute carrying charges is consistent with prior Board rulings. Mr. Henkes noted that the Board recognized this principle in recent gas adjustment clause proceedings, where several New Jersey utilities were permitted to charge carrying charges on unrecovered deferred gas cost balances, using carrying charges based on certain interest rates found to be appropriate by the Board which did not include an equity return.[33] *RA-49*, p. 69. Furthermore, the rate for carrying charges recommended by Mr. Henkes is the same as that adopted by the Board for deferred cost balances for electric

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[33] *See I/M/O Elizabethtown Gas Company*, BPU Docket Nos. GR00070470 and GR00070471 (Decision and Order dated March 30, 2001); *I/M/O New Jersey Natural Gas Company*, BPU Docket. Nos. GR99100778, *et al* (Decision and Order dated March 30, 2001); *I/M/O Public Service Electric & Gas Company*, BPU Docket No. GR00070491 (Decision and Order dated March 30, 2001); and *I/M/O South Jersey Gas Company*, BPU Docket Nos. GR00050293 and GR00050293 (Decision and Order dated March 30, 2001).

utilities in the restructuring proceedings. *RA-51,* p. 16. Mr. Henkes noted that even PSE&G uses the rate recommended by Mr. Henkes for computing the carrying charges on its SBC and NTC deferred balances. T1449:L9-15.

In contrast, the rates proposed by the Company for computing carrying charges are far in excess of the rate used to compute the carrying charges on the Company's SBC and NTC-related deferred balances. Mr. Henkes identified three periods for determining the carrying charges on the total repair allowance deferral balance. The first period covers the period up until the date of the issuance of the Board's Final Decision and Order in the Company's restructuring case, in August 1999. *RA-51,* pp. 16-17. The second period covers the carrying charges calculated by the Company on the repair allowance deferral balance from inception of the deferral balance from issuance date of the Final Decision and Order through the end of the 2002 test year. *Id.* The third period is for the carrying charges calculated by the Company on the declining deferral balance during the 10-year amortization period. *RA-49,* p. 69. For the first two periods, the Company plans to use a rate of 8.42%, which is the after-tax overall rate of return allowed in its 1991 base rate case. *Id.* For the third period of carrying charges, the Company proposes to use a rate of 7.35%,which is the after-tax overall rate of return requested by the Company in the instant proceeding. *Id*. In contrast, the rate allowed by the Board for deferred cost balances in the restructuring cases - based on the seven-year Treasury rate - is 5.5%. *Id.*, p. 70.

Significantly, contrary to the rebuttal testimony of PSE&G witness Mr. Albert Stellwag, the <u>7-year</u> rate is <u>not</u> a <u>short-term</u> interest rate. *P-4-RB,* p. 31. As Mr. Henkes noted in his surrebuttal testimony, the "seven-year constant maturity treasury rate is obviously not a short term interest rate." *RA-51,* p. 16. Mr. Stellwag's understanding of the term short-term is also at odds with that used by a major bond rating agency. For rating purposes, the bond rating agency Standard and Poors defines “”short term” in the United States as “ ”obligations with an original maturity of no more than 365 days....”[34]

Mr. Henkes computed the carrying charges, using the rate based on the 7-year Treasury rate for periods after August 1999, and recommends an expense adjustment of $2.062 million. *RA-60,* Sch. RJH-15R (12+0). Mr. Henkes’ recommended adjustment reduced the Company’s Repair Allowance Amortization amount from $8.189 million to $6.127 million. *Id*. As set forth above, Mr. Henkes’ recommended adjustment is consistent with the Board’s treatment of similar expenses and should be adopted.

J. Institutional Advertising and Public Relations Expense Adjustment

At issue are the Company’s claimed expense for institutional advertising associated with an industry trade group and certain public relation expenditures. The Ratepayer Advocate’s recommended adjustments are shown on Schedule RJH-16R (12+0). *RA-60.*

The Company’s proposed test year expenses include $280,589 for Edison Electric Institute (“EEI”) dues. *RA-20.* The EEI is a trade group representing electric companies. In response to a discovery request, the Company indicated that approximately 2% of the EEI dues is advertising. *RA-21.* Furthermore, the Company confirmed that “[t]his advertising is not specifically focused on New Jersey or the PSE&G service territory and is national in nature.” *Id*.

In addition, the Company also proposes to charge its ratepayers for certain public relations expenses included in its test year. The total test year amount for these expenses is approximately $83,000, as indicated in response to a discovery request.[35] Mr. Henkes found that the “community affairs/public relations” expenses identified in that response consist primarily of such items as “philanthropic activities, employee volunteer activities, summer concerts for the Newark community, promotional materials for education grants and the

[34] Standard and Poor’s 2002 Corporate Ratings Criteria, p. 7. An excerpt from this document was entered into evidence as *S-57*. The full document is available at www.standardandpoors.com.

[35] *RA-60,* Sch. RJH-16R(12+0), citing response to S-PREV-42 (12+0).

Power of Giving Campaign, and community assistance in raising money for projects." *RA-49*, p. 72, line 27 - p. 73, line 1.

As Mr. Henkes states in his Direct Testimony, these expenses relate to activities that have nothing to do with the provision of safe, adequate and proper electric service. *RA-49*, p. 73. Mr. Henkes recommended that these expenses be removed for ratemaking purposes in this case as

they are related to activities that have nothing to do with the provision of safe and adequate electric delivery service and concluded that these types of expenses should be the responsibility of the stockholders rather than the captive ratepayers.

As set forth below, Mr. Henkes' recommendation is consistent with recent rulings by the New Jersey Supreme Court and the Board and, therefore, should be adopted. The community affairs philanthropic expenses represent charitable contributions by PSE&G which must be disallowed pursuant to a recent ruling by the New Jersey Supreme Court.[36] In the *New Jersey American Water* decision, the New Jersey Supreme Court ruled that no portion of the utility's charitable contributions should be subsidized by consumers and the cost of those contributions should be borne solely by its shareholders. *New Jersey American Water* at 191. While the Ratepayer Advocate commends the Company for making charitable contributions, such contributions should be borne solely by its shareholders.

The Ratepayer Advocate's position with regard to the public relations expenses is consistent with established Board policy, which was reaffirmed by the Board as recently as its May 2001 Middlesex Water Company base rate case Order ("*Middlesex Order*").[37] On page 27 of that Order, the Board states:

> The Company included pro-forma test year expenses of $25,295 relating to public relations expense. These expenses are largely in the nature of support for local and regional organizations.....

[36] *In re New Jersey American Water*, 169 *N.J.* 181 (2001) ("*New Jersey American Water*").
[37] *I/M/O Middlesex Water Company*, BPU Docket No. WR00060362 (Order dated June 6, 2001) ("*Middlesex Order*").

The Board disallowed the $25,295 public relations expense for ratemaking purposes in that case. *Middlesex Order*, p. 28. Clearly, the Board's existing policy supports the Ratepayer Advocate's position with respect to this issue.

As shown on Schedule RJH-16R (12+0), removing these expenses reduces the Company's expenses by $88,000, resulting in a $52,000 increase in its Operating Income. *RA-60*.

K. Miscellaneous O&M Expense Adjustment

At issue are five claimed Operating and Maintenance ("O&M") expense items. *RA-49,* pp. 73-75. The expenses at issue are out-of-period O&M expenses, PSEG expenses allocated to PSE&G, lobbying expenses, and management "perks."

The first adjustment recommended by Mr. Henkes is the removal of $2 million of out-of-period labor O&M expenses. *RA-49*, p. 74. In response to a discovery request, the Company confirmed that a charge for prior-period deferred labor was charged to its 2002 operating expense. *RA-35; P-47* (S-PREV-30, 6+6 update). Furthermore, the Company conceded in another response that this out-of-period expense item "could be eliminated for ratemaking purposes." *P-47* (RAR-A-162).

The second expense adjustment concerns the removal of certain expenses that were allocated by the parent, PSEG, to PSE&G's electric distribution operations. As shown in footnote (2) to *RA-60*, Schedule RJH-17R (12+0), these expenses include charitable donations, contributions to the Liberty Science Center, event tickets, and miscellaneous write-offs. Mr. Henkes recommended that the cost of the charitable donation and Liberty Science Center contributions be disallowed for ratemaking purposes, consistent with the New Jersey Supreme Court ruling in *New Jersey American Water Company*. *RA-49,* p. 74. Included in the event ticket costs allocated to PSE&G were Meadowlands arena tickets totaling $285,255 and New Jersey Performing Arts Center tickets totaling $20,022. *P-53* (TR-524). Clearly, the event tickets are not necessary for the provision of safe and adequate electric delivery service and the related expense should also be disallowed. Furthermore, the Company has not provided any support for the “miscellaneous write offs” amounting to $78,000. These “miscellaneous” write offs should be disallowed as the Company has failed to meet its burden of proof in justifying these expenses.

The third and fifth expense adjustments concern the removal of all lobbying expenses included in the test year expenses. *RA-60,* RJH-17R (12+0). Mr. Henkes found that in responses to discovery, the Company confirmed the inclusion of the lobbying expenses at issue in its test year as above-the-line expenses. *RA-49,* p. 74; *P-47* (S-PREV-43 and RAR-A-90 F). In sum, the Company’s test year includes $42,000 for lobbying expenses. *RA-60*, Schedule RJH-17R (12+0), lines 3, 5. The Ratepayer Advocate rejects the inclusion of these expenses in the Company’s rates. The Company has not met its burden of proof that these expenses have been incurred for the direct benefit of ratepayers.

In many instances, lobbying activities by utilities do not necessarily work to the benefit of the utilities’ consumers and it would be inequitable to charge a utility’s captive ratepayers for expenses related to lobbying activities that may be contrary to their own interests. Furthermore, the Ratepayer Advocate takes the position that legislative advocacy, regulatory advocacy and legislative policy research should be excluded because these categories meet the Board’s definition of political advertising. Many jurisdictions nationwide disallow lobbying expenses for ratemaking purposes.[38] Notably, PSE&G did not present any rebuttal to the Ratepayer Advocate’s position on these lobbying expenses. Accordingly, the Board should disallow the expenses claimed for lobbying, amounting to $42,000. *RA-60,* Sch. RJH-17R (12+0).

The fourth expense adjustment concerns the removal from the test year of expenses associated with the provision of certain financial services to PSE&G’s top officers. Mr, Henkes recommended that the claimed

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[38] *See Re Matanuska Electric Association, Inc.* 2001 WL 604250 (Reg. Comm’n of Alaska March 15, 2001); *Re Connecticut-American Water Company* 200 *PUR 4th* 260 (Ct. DPUC March 23, 2000); *Re St. Joe Natural Gas Company, Inc.* 2001 WL 811272 (Fla. P.S.C. June 8, 2001).

expenses for these management "perks," amounting to $52,000, be removed from the Company's proposed test year expenses. *RA-60,* Schedule RJH-17R (12+0), line 4. As Mr. Henkes describes in his Direct Testimony, these management perks include personal financial counseling and estate planning for PSE&G's top officers. *RA-49,* p. 75. The Ratepayer Advocate submits that if the Company elects to provide such perks to its top executives, the related expenses should be funded by the Company's shareholders, not its ratepayers.

The recommended adjustments amount to a total of $3.2 million. *RA-60*, RJH-17R (12+0). The recommended adjustments have the effect of increasing the Company's proposed after-tax net operating income by $1,897,000. *Id.*

L. Pro Forma Depreciation Expense Adjustment

PSE&G proposes a pro forma annualized 12+0 depreciation expense of approximately $178,359,000. Using Ratepayer Advocate witness Michael Majoros' proposed depreciation adjustments discussed in detail in the Depreciation Section of this brief, the proper level of pro forma annualized depreciation expense is $78,103,000. *RA-60,* Sch. RJH-18R (12+0). Mr. Henkes calculated that this Ratepayer Advocate recommendation will result in an increase of $59,301,000 in the Company's proposed pro forma test year Operating Income. *Id.*

M. Interest Synchronization Adjustment

Because of the Ratepayer Advocate's proposed adjustments to the recommended rate base and weighted cost of debt positions, the Ratepayer Advocate's interest synchronization income tax impact is different from PSE&G's proposed interest synchronization income tax impact. As shown on Schedule RJH-20R (12+0), the Ratepayer Advocate's pro forma interest deduction for income tax purposes is larger than the Company's. *RA-60*. As can be seen from Schedule RJH -20R (12+0), this results in an increase of $353,000 in the Company's proposed pro forma test year operating income. *RA-60,* Sch. RJH-20R (12+0), line 7.

POINT IV

THE APPROPRIATE PRO FORMA RATE BASE AMOUNTS TO $2,886,571,000, WHICH IS $71,675,000 LOWER THAN THE PRO FORMA 12+0 RATE BASE PROPOSED BY PSE&G OF $2,958,246,000.

The Company selected the twelve-month period ending December 31, 2002 as the test year. *P-1,* p. 4. The Ratepayer Advocate's witness, Mr. Robert J. Henkes, recommended numerous proposed rate base adjustments in his testimonies in this proceeding. The Ratepayer Advocate is recommending a total rate base adjustment of $71,675,000, resulting in a pro-forma rate base for the Company of $2,886,571,000. *RA-60*, Sch. RJH-1R (12+0), Sch. RJH-3R (12+0). Each of the recommended adjustments is discussed below in this section of the initial brief.

A. Accumulated Depreciation Reserve

As set forth below, the Ratepayer Advocate recommends an adjustment to PSE&G's pro-forma rate base to reflect the effect of the Ratepayer Advocate's recommended depreciation expense adjustments on the Company's pro forma depreciation reserve balance. *See RA-49*, pp. 8-9; *RA-60*, Sch. RJH-5R(12+0).

As shown on Schedule RJH-5R(12+0), the Company's proposed pro forma test year-end depreciation reserve balance consists of its projected per books depreciation reserve balance as of the end of the test year, December 31, 2002, plus one-half of the difference between the Company's proposed annualized depreciation expenses and the actual test year depreciation expenses. *RA-49*, p. 8; *RA-60*. In determining its proposed depreciation reserve balance, PSE&G started out with the actual test year-end depreciation reserve balance as of December 31, 2002 of $1,476,969,000. *P–3 (U 12+0)*, RCK-4R. PSE&G's proposed pro forma depreciation expense is $16,987,000 in excess of its actual test year depreciation expense. *Id*. Using the half-year convention principle, PSE&G then added one-half of this excess depreciation expense, or $8,494,000 to the actual December 31, 2002 reserve balance to arrive at its proposed pro forma depreciation reserve balance of $1,485,463,000. *Id.*; *RA-49*, p. 8; *RA-60*, Sch. RJH-6R (12+0).

Likewise, the Ratepayer Advocate's recommended pro forma depreciation reserve balance calculation starts with the projected December 31, 2002 per books reserve balance plus one-half of the difference between the Ratepayer Advocate's proposed annualized depreciation expenses and the actual test year depreciation expenses. *RA-49*, p. 8. This results in a total recommended pro forma depreciation reserve balance of $1,435,535,000 which is $50,127,000 lower than the Company's proposed pro forma depreciation reserve balance of $1,485,463,000. *RA-60*, RJH-5R (12+0). The difference of approximately $50.1 million between the Company's proposed and the Ratepayer Advocate's recommended depreciation reserve balances represents the "flow-through" effect of Mr. Majoros' recommended depreciation expense adjustments, as discussed more fully in a separate section of this brief.

B. Accumulated Deferred Income Taxes

The Company's pro forma deferred income tax balance also must be adjusted to reflect the Ratepayer Advocate's recommended depreciation changes. *RA-49*, p. 9. Mr. Henkes recommends an adjustment of $20,477,000 as a result of the previously discussed depreciation reserve adjustment. *RA-60*, RJH-3R (12+0), l. 5. The recommended adjustment increases the Company's deferred income tax balance from $254,817,000 to $275,294,000. *Id*.

C. Cash Working Capital

1. Lead/Lag Study Cash Working Capital ("CWC")

Cash working capital is, of course, an element of rate base and may be defined as monies advanced by the utility's investors to cover expenses associated with the provision of service to the public during the lags between the payment of those expenses and the collection of revenues from its customers. PSE&G has performed a lead/lag study which indicates a positive cash working capital requirement of $118,177,000 for purposes of this case. *P-5, Sch. RLH-1(12+0)*. The Company then offset this positive lead/lag study CWC requirement with a proposed net asset and liabilities balance of $27,179,000 to arrive at its proposed net CWC requirement of approximately $90,998,000 for inclusion in its proposed rate base. The Ratepayer Advocate's witness, Mr. Henkes, has recommended that a CWC of approximately $45,285,000 is more appropriate when appropriate adjustments are made to the lead/lag study components as described below. *RA-60, Sch. RJH-3R, Lines 6a + 6b (12+0).*

The Company, in this case, has proposed to exclude from rate base an amount of $27,179,000 for net assets and liabilities balance. Mr. Henkes has found this amount to be reasonable and has accepted the Company's proposed cash working capital reduction for net assets and liabilities balance. *RA-60, Sch. RJH-3R, Line 6b (12+0).*

The Ratepayer Advocate disagrees with Mr. Hahne's proposal to include in the lead/lag study non-cash expenses (such as deferred expenses, depreciation and amortization expenses, and deferred income taxes) and the return on invested capital with assumed payment lags of "0" days. In calculating the Company's CWC requirement, the Ratepayer Advocate's witness, Mr. Henkes, pointed out that these expenses do not represent or require cash outlays during the lead/lag study period and were included inappropriately. *RA-49*, p. 12.

The Ratepayer Advocate recommends that a properly conducted lead/lag study should: (1) <u>exclude</u> all non-cash depreciation expenses and deferred income taxes; (2) <u>exclude</u> the return on equity; and (3) <u>include</u> debt interest with appropriate payment lags. In general, the appropriate cash working capital should be based on the timing difference between the payment of cash expenses and taxes and the receipt of cash operating revenues. Depreciation and deferred taxes simply do not represent or require cash outlays during the lead/lag study period. Therefore, these non-cash expenses should be removed from the lead/lag study. *RA-49,* pp. 13-16.

As pointed out in Mr. Henkes' testimony *RA-49,* pp. 13-14, the Company's proposal to include deferred taxes in the lead/lag study for purposes of determining the appropriate cash working capital requirement is contrary to Board ratemaking policy. This policy was first established in a prior PSE&G base rate proceeding. *I/M/O the Motion of Public Service Electric and Gas Company to Increase the Level of the Levelized Energy Adjustment Clause,* BPU Docket No. ER85121163 (Order dated July 23, 1985). The Board reiterated this ratemaking policy in a subsequent rate case involving Elizabethtown Gas Company. *I/M/O the Petition of Elizabethtown Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revision,* BPU Docket No. GR8812132 (Order Adopting in Part and Modifying in Part the Initial Decision dated February 1, 1990). On page 7 of its Order, the Board stated with regard to this cash working capital issue:

> <u>Cash Working Capital</u>
> ...Petitioner presented a lead/lag study to calculate cash working capital requirements.... With respect to deferred taxes, Petitioner recommended including deferred taxes of $1,259,000 as a component of its cash working capital requirements. Petitioner argued that there was a collection lag in recovering deferred taxes because of the deferred tax liability associated with utility plant. Rate Counsel recommended that deferred taxes be excluded from the lead/lag study since deferred taxes are a non-cash item and do not require investor supplied capital.
> Staff recommends that deferred taxes be excluded from the lead/lag study. Staff contends that this recommendation is consistent with prior Board treatment of deferred taxes, most notably in the Public Service rate case, (Docket No. ER85121163) wherein the Board removed deferred taxes from cash working capital. The ALJ was persuaded by Staff's argument as to the proper rate making treatment for deferred taxes. The ALJ recommended that deferred taxes be deducted from operating revenues in the working capital allowance for purposes of this proceeding. Initial Decision p. 21. The Board <u>FINDS</u> the ALJ's determination on deferred taxes to be reasonable and consistent with Board policy. Therefore, the Board <u>ADOPTS</u> the ALJ's conclusion on this issue...

Therefore, pursuant to the Board's clear policy on this issue, deferred taxes must be excluded from lead/lag studies when determining the Company's cash working capital.

It is the Ratepayer Advocate's position that the return on common equity does not, and should not, result in a CWC requirement. *RA-49,* pp. 14-15. Even if one were to assume that there is a cash working capital requirement associated with the return on equity, this effect should already be incorporated into the equity return required by the common stock investor. As Mr. Henkes testified, the Company's fundamental assumption that the common shareholder is entitled to the return on his/her equity investment at the exact instant that service is rendered is incorrect. *Id*. The fact is that the shareholder receives his/her return through the quarterly payments of dividends and any gain in the Company's stock. This is the mechanism by which the common shareholder is compensated in the real world. The Georgia Public Service Commission ("Georgia PSC") recognized this timing issue and has held that it is inappropriate to assume that there is a cash working capital requirement associated with the return on equity and thus should be removed from any cash working capital calculation.

> ......(I)t is error to include recognition of an alleged cash working capital requirement associated with a return on common equity. There is no such requirement. Even if one were assumed, an allowance for this has already been made by virtue of how the Commission sets the cost of equity.
>
> *Atlanta Gas Light Company,* 119 *PUR* 4th 404, 408 (1991).

Therefore, the Ratepayer Advocate recommends that the return on equity be removed from the lead/lag study.

Regarding debt interest, the Company has not recognized the actual lag in the payment of debt interest in its lead/lag study. It is the Ratepayer Advocate's position that since the Company actually pays its long-term debt on a semi-annual basis, with an average payment lag of approximately 91.25 days, this payment lag should be considered in the lead/lag study to determine the Company's appropriate cash working capital requirement.

Interest expenses for long term debt are included as part of the Company's revenue requirement. Therefore, the rates paid by PSE&G's customers are set so as to produce, in addition to other amounts, the sums necessary to pay interest to bondholders. As utility services are used, the Company receives money from its ratepayers that partly serve to enable the Company to pay interest to its bondholders. However, the Company does not have to pay its bondholders interest immediately. It only pays interest to its bondholders twice a year. Thus, while long-term interest expense accrues on a daily basis, it is paid out semi-annually in a lump sum. This means that, on average, interest on long-term debt has a payment lag of 91.25 days (365/4). Stated differently, this means that the Company, from the moment it receives the revenues to recover long-term debt interest expenses until the time it actually pays out the interest expenses to its bondholders, has such funds available for general working capital purposes. Clearly, ratepayers should not be required to pay a return on capital which they provide. Accordingly, the actual interest lag should be reflected in the calculation of cash working capital.

There have been several Board decisions holding that long-term debt interest should not be included in a lead/lag study. These precedents hold that a zero (0) day lag should be assigned to long-term debt payments because the return on investment is the property of investors when service is provided. *See I/M/O Atlantic City Electric Company*, BPU Docket No. 8310-883, (1984); *I/M/O Public Service Electric and Gas Company*, BPU Docket No. 837-620 (1984). However, this position is inconsistent with the manner in which other cash flow items are handled in a lead/lag study. Moreover, commissions in other states, such as the Georgia PSC, have held that it is appropriate to include interest on debt and preferred dividends with appropriate payment lags in a lead/lag study:

> As should be abundantly clear, it is error not to include as elements of a lead-lag study the net payments of interest on long-term debts and dividends on preferred stock. These two elements are sources of funds utilized to reduce cash requirements.

Atlanta Gas Light Company, 119 *PUR* 4th at 408.

For example, few would agree that the Company becomes entitled to its revenues on the day that service is provided, or that employees are entitled to their salaries on the day that service to the Company is rendered. The lead/lag study examines the actual cash flows, not the incurring of an expense or liability, in determining the Company's cash working capital requirement. Interest expense should be treated in a similar manner.

The interest payments to be made to the bondholders are fixed by contract. They cannot be made earlier or later than the specified date. In this, the bondholders are like the tax collector or any other creditor of the Company. To refuse to consider the source of working capital from the interest payment lag has the impact of penalizing the ratepayers who are providing revenues to pay all expenses, including interest expenses, and it would provide a "windfall return" to the Company's stockholders. The bondholder, who has a fixed interest on his bond, will not receive any benefits from the act of excluding the interest payment lag from working capital considerations. It will be the common stockholder who will be allowed to earn a return on such available funds, collected from the ratepayer through rates, if this interest payment lag is not recognized for ratemaking purposes. For all of these reasons, debt interest expenses should be included with the appropriate payment lag in the lead/lag study to determine the Company's cash working capital requirement. *RA-49,* p. 16. Therefore, the debt interest expenses should be included with the appropriate payment lag in the lead/lag study for purposes of determining the proper cash working capital requirement.

In sum, the Ratepayer Advocate recommends the adoption of the revised lead/lag study calculations set forth on RA-60, Sch. RJH-6R (12+0). As shown on this schedule, the non-cash deferred expenses, depreciation and amortization expenses, and deferred income taxes are removed, as well as the entire Return on Invested Capital line item, while adjusting the Company's proposed pro forma long term debt interest with a payment lag of 91.25 days.

As shown on RA-60, Sch. RJH-6R (12+0), the appropriate lead/lag study cash working capital requirement to be recognized for ratemaking purposes in this case amounts to approximately $72,464,000. As summarized on Sch. RJH-3R (12+0), this is approximately $45,713,000 less than the lead/lag study cash working capital requirement of approximately $118,177,000 claimed by the Company.

D. Consolidated Income Tax Benefits

PSE&G does not file its federal income tax return on a stand-alone basis, but rather files as a part of its parent company, Public Service Enterprise Group ("PSEG"). *RA-49,* p. 19. Other subsidiaries of PSEG are also included in the consolidated tax filing. *Id*. As set forth more fully below and in the testimony of Ratepayer Advocate witness Mr. Henkes, consistent with Board policy, the Ratepayer Advocate recommends an adjustment to the Company's pro forma rate base to reflect the income tax benefits allocable to PSE&G's regulated operations.

By filing a consolidated return, PSE&G can take advantage of tax losses experienced by its affiliated companies. The tax loss benefits generated by one of the affiliates help to offset the positive taxable income of other consolidated group members. This tax savings must be allocated among the companies in the consolidated group. Therefore, the stand-alone methodology utilized by the Company in this case is clearly incorrect. The Ratepayer Advocate submits that any allocation of tax savings made to PSE&G should flow-through for the benefit of its New Jersey ratepayers. *RA-49,* p. 19. Mr. Henkes recommended an adjustment to the Company's rate base to properly reflect the consolidated income tax savings allocable to the Company. *Id.*. The consolidated income tax treatment recommended by Mr. Henkes and advocated by the Ratepayer Advocate is consistent with recent Board rulings.

The Board has an established policy that any tax savings allocable to a utility as a result of the filing of consolidated income tax returns must be reflected as a rate base deduction in the utility's base rate filing. *See I/M/O The Petition Of Atlantic City Electric For Approval Of Amendments To Its Tariff To Provide For An Increase In Rates And Charges For Electric Service Phase II*, BPU Docket No. ER90091090J, (October 20, 1992) ("*Atlantic City Electric 1992 Base Rate Case Order*"). The Board set forth at length on this policy in a Decision and Order in a 1991 New Jersey Natural Gas Company case:

> ...[i]t has been the Board's long-time policy to adjust operating income to reflect savings resulting from the filing of a consolidated income tax return by a utility's parent company. As early as 1952, the courts recognized that a utility attempting to establish its proper operating income level in a rate proceeding is "entitled to allowance for expense of actual taxes and not for higher taxes which it would have to pay if it filed on a separate basis." *In re New Jersey Power & Light Co. v. P.U.C.*, 9 N.J. 498, 528 (1952). In 1976, the Court affirmed a decision in which the Board indicated that such an adjustment was part of the Board's regular policy, which was made consistently for water and electric holding companies. *New Jersey Bell Telephone Company v. New Jersey Dept. of Public Utilities*, 162 *N.J. Super.* 60 (App. Div. 1978). [39]

The Appellate Division previously affirmed the policy of requiring utility rates to reflect consolidated tax savings. *In re Lambertville Water*, 153 *N.J. Super.* 24 (App. Div 1977), *reversed in part on other grounds*, 79 *N.J.* 449 (1979) ("*Lambertville Water*"). In *Lambertville Water* the Court stated:

> ...[i]f Lambertville is part of a conglomerate of regulated and unregulated companies which profits by consequential tax benefits from Lambertville's contributions, the utility consumers are entitled to have the computation of those benefits reflected in their utility rates. *Lambertville Water*, p. 28

Mr. Henkes recommended a rate base adjustment as the appropriate methodology to reflect consolidated income tax savings. *RA-49*, p. 19. This methodology was adopted by the Board in a 1993 Jersey Central Power and Light Company case. *I/M/O The Petition Of Jersey Central Power & Light Company*

[39] *I/M/O Petition Of New Jersey Natural Gas Company For Increased Base Rates And Charges For Gas Service And Other Tariff Revisions: Phase II; Consolidated Taxes*, BRC Docket Nos. GR89030335J and GR90080786J, (Order dated Nov. 26, 1991)("*NJNG 1991 Base Rate Case*"), p. 4.

For Approval Of Increased Base Tariff Rates And Charges For Electric Service And Other Tariff Modifications, BPU Docket No. ER91121820J (Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision dated February 25, 1993) ("*JCP&L 1993 Base Rate Case Order*"). In the *JCP&L 1993 Base Rate Case Order*, the Board stated:

> . . . [The Board] ADOPTS the position of Staff that the rate base adjustment is a more appropriate methodology for the reflection of consolidated tax savings. The rate base approach properly compensates ratepayers for the time value of money that is essentially lent cost-free to the holding companies in the form of tax advantages used currently and is consistent with our recent Atlantic Electric decision (Docket No. ER90091090J).[40]

Clearly, the methodology used by Mr. Henkes is consistent with current Board policy. This methodology results in a sharing of tax benefits between the corporation's stockholders and utility ratepayers. This is so because there is a rate base deduction reflecting the cumulative tax savings which results in ratepayers being credited for the time value of money, as well as the carrying costs on these savings resulting from current use of tax losses. The rate base approach allows for future adjustments, as losses turn to positives, yet acknowledges the proper compensation to ratepayers for the time value of money essentially lent cost free to the Company.

Mr. Henkes testified that to properly reflect the consolidated income tax benefits allocable to the Company, it was necessary to trace the benefits back from 1991 through to 2001. *RA-49*, p. 19. Mr. Henkes' capture of accumulated tax benefits is consistent with well established Board rulings. In the *Atlantic City Electric 1992 Base Rate Case Order*, the Board stated: "... it is our judgment that the appropriate consolidated tax adjustment in this proceeding is to reflect as a rate base deduction the total of the 1991 consolidated tax savings benefits, and one-half of the tax benefits realized from AEI's 1990 consolidated tax filing." *Atlantic City Electric 1992 Base Rate Case Order*, p. 8. Furthermore, the Board went on to state,

[40] *JCP&L 1993 Base Rate Case Order*, p. 8.

“[t]his finding reflects a balancing of the interests to reflect the unique period of uncertainty during the period 1987-1991.” *Id*. Additionally, the Board reaffirmed this position in the JCP&L 1993 Base Rate Case Order. Therein, the Board stated, “[m]oreover in order to maintain consistency with the methodology applied in the Atlantic decision, ...a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case.” *JCP&L 1993 Base Rate Case Order*, p. 8.

In his analysis, Mr. Henkes considered PSE&G’s cumulative consolidated income tax benefits beginning with the year 1991 and ending with the year 2001. *RA-49*, p. 20. Mr. Henkes’ analysis of the Company’s tax data for the years 1991 through 2001 was based on PSEG’s actual consolidated income tax returns. *Id*. Furthermore, Mr. Henkes considered PSE&G’s assumed allocable share of PSEG’s Alternative Minimum Tax (“AMT”) payments. *Id*. Mr. Henkes found that the AMT consideration reduced the recommended consolidated income tax rate base deduction. *Id*. Mr. Henkes presented the results of consolidated taxes in his Direct Testimony. *RA-60*, Sch. RJH-7R (12+0). Mr. Henkes’ recommended adjustment would reduce the Company’s rate base by $55,613,000. *RA-60*, Sch. RJH-3R(12+0), line 7, and RJH-7R(12+0).

POINT V

ABSENT THE ADOPTION OF CERTAIN MODIFICATIONS AND CONDITIONS, PSE&G'S PROPOSAL TO TRANSFER PSE&G UTILITY ASSETS TO AN AFFILIATED SERVICE COMPANY IS NOT IN THE PUBLIC INTEREST.

In December 1999, PSEG formed another fourth first-tier subsidiary, PSEG Service Corporation ("Services"), to provide management and administrative services to PSEG and its subsidiaries, including PSE&G.[41] Services became operational in January 2000 and has operated since then pursuant to "service level understandings" initiated between each internal service provider within Services and each operating company.[42]

PSE&G subsequently filed a letter request with the Board for approval of its proposal to transfer assets and contracts to Services and for approval of the proposed Service Agreement between PSE&G and Services.[43] PSE&G's service company petition was subsequently consolidated with the Company's base rate case proceeding.

PSE&G included in its filing a proposed Service Agreement ("Service Agreement") governing the relationship between Services and each operating company together with a list of the categories of services to be provided by Services.[44] PSE&G initially listed 18 categories of services which are to be provided by Services.[45]

The formation of Services requires the transfer of certain PSE&G assets and contracts to Services. Certain assets and contracts which are "necessary to the operation of the Service Company" will be transferred

[41]PSE&G identified 50 subsidiaries which Services is expected to serve. *PS-SC-34*.
[42]*PS-SC-70*.
[43]PSE&G requests approval of its proposal pursuant to *N.J.S.A.* 48:3-7, 48:3-7.1 and 48:3-55(d).
[44]*PS-SC-1*, Exh. A, Schedule I.
[45] 1) Accounting Services;) Auditing Services; 3) Business Development (new business development); 4) Communications (e.g., employee newsletters); 5) Corporate Secretary; 6) Corporate Services (e.g., reprographics, motor pool, etc.); 7) Environmental Health & Safety; 8) Financial Risk Management; 9) General PSE&G Management (misc.); 10) Government Affairs (includes representation before governmental agencies); 11) Human Resource Management; 12) Information Technology; 13) Legal; 14) Marketing Services; 15) Procurement/Materials Management; 16) Public/Media Relations; 17) Strategic planning; and 18) Treasury Services. Marketing Services was later removed from the list of services provided by Services. *Id*.

by PSE&G to Services, using net book value as the transfer price. *PS-SC-1*, p. 6. Assets and contracts "used primarily" by PSE&G will be retained by PSE&G, but those relating to administrative and managerial services will be utilized by Services as necessary. *Id.* The assets and contracts that are to be assigned and transferred generally include office space leases, office furniture and equipment, computer equipment, office supplies, and communications equipment. *PS-SC-1*, Exh. B.

Under PSE&G's proposal, management and supporting services functions that were previously performed by PSE&G employees, under the Board's direct regulatory control, will be transferred to a new, unregulated affiliate. The Service Agreement will govern the prices paid by PSE&G for management services and other duties performed by Services. The Service Agreement does not have a firm expiration date, although it may be terminated on 120 days written notice of either party.[46]

In its earlier comments, the Ratepayer Advocate cited several items of concern.[47] Some of the Ratepayer Advocate concerns were subsequently satisfactorily addressed by the Company, while others remain. At the evidentiary hearing on February 24, 2003, PSE&G modified its proposal, thereby addressing some of the Ratepayer Advocate's concerns, as set forth below:

PSE&G shall be compensated by Services for an allocated portion of the full carrying cost of its assets that are shared with Services, including both a "return of assets" and a "return on assets," as well as other costs. T1499.

During the interim period, PSE&G will be provided with a "return on assets" for the shared assets equal to its rate of return in its last base rate case. T1499.

Full access to the books and records of Services will be provided to the Board, even outside the context of a regulatory rate proceeding. T1499.

[46] *PS-SC-1*, Exh. A; *PS-SC-71*.
[47] *RA-58*, *RA-59*.

PSE&G and Services shall record their cost and allocations of costs in sufficient detail to allow the Board to analyze, evaluate, and render a determination as to their reasonableness for ratemaking purposes. T1499. Furthermore, subsequent to the filing of its service company petition, PSE&G submitted a cost allocation manual.[48] The Ratepayer Advocate's remaining concerns are addressed below.

A. Standard of Review

The Ratepayer Advocate submits that the proposed transaction must be examined not only in the context of the traditional statutory provisions governing utility transfers and contracts, but also in terms of its impact on competition in the new competitive environment.

In drafting the Electric Rate Discount and Energy Competition Act ("EDECA", codified at *N.J.S.A.* 48:3-49 *et seq.*), the Legislature recognized the realities of implementing competitive markets while some areas remain regulated and non-competitive. Cross-subsidies are inimical to a competitive market and adversely affect ratepayers in both the short and long term. Thus, the Legislature also declared that it is the policy of the State to "[e]nsure that rates for non-competitive public utility services do not subsidize the provision of competitive services by public utilities."[49] Hence, the EDECA contains strong prohibitions against cross-subsidization so that captive utility ratepayers will not be forced to subsidize competitive businesses affiliated with the incumbent utility.[50]

Therefore, the EDECA required the Board to adopt affiliate relations, fair competition and accounting standards to protect ratepayers from cross-subsidization and to ensure that electric and gas utilities would not enjoy an unfair advantage over their rivals in a competitive marketplace.[51] The Board subsequently issued an

[48]T1500.
[49]*N.J.S.A. 48:3-50(a)(4).*
[50]*See N.J.S.A. 48:3-55; N.J.S.A. 48:3-56; and N.J.S.A. 48:3-58.*
[51]*N.J.S.A.* 48:3-55; *N.J.S.A.* 48:3-56(f); and *N.J.S.A.* 48:3-58(k).

Order ("Affiliate Relations Standards") on March 15, 2000, setting forth the required standards.[52] The proposed transaction must be examined in the context of the Board's Affiliate Relations Standards.

The Board must also consider the Service Agreement and transfer of assets in terms of other traditional statutory requirements, namely *N.J.S.A.* 48:3-7 and *N.J.S.A.* 48:3-7.1. PSE&G filed its petition requesting Board approval and authorization for the transfer of assets and contracts under *N.J.S.A.* 48:3-7. Management service contracts entered into with entities controlling five percent or more of the utility's capital stock fall under the umbrella of *N.J.S.A.* 48:3-7.1, if the contracts are in excess of $25,000. Under that statute, PSE&G is also required to demonstrate that Services will honor all obligations to transferring employees with respect to pension benefits previously promised by PSE&G.

Approximately 1,250 employees were transferred to Services. For the most part, the employee transfer was transparent. That is, the bulk of the transferred employees continue to perform the same duties and remain in their same work locations. The Company contends that employment status, pay and benefits did not change as a result of the restructuring. PSEG said that it was its intent that employee pay and benefit packages would not be affected by the lateral transfers to Services.[53] Service's Board of Directors adopted employee pension and benefit agreements previous held by PSE&G and Enterprise.[54] Transferred employees were not required to re-apply or interview for positions with Services, nor were employees required to change work locations. Furthermore, employee separations resulting from transfer did not occur, according to the Company.[55] Under *N.J.S.A.* 48:3-7, PSE&G has a responsibility to the employees that are to be transferred to Services. In sum, based on the information provided by the Company, the Ratepayer Advocate finds no basis on which to conclude that the affected PSE&G employees are any worse off regarding employment benefits due to the transfer.

[52] *I/M/O Promulgation of Standards by the Board Pursuant to the EDECA*, BPU Docket No. EX99030182 (Order dated March 15, 2000).
[53] *PS-SC-56*.
[54] *PS-SC-7*.
[55] *PS-SC-55*.

Additionally, under *N.J.S.A*. 48:3-7.1, the Board is required to disapprove of management and service company contracts if it determines that either: a) the contract violates either New Jersey or United States laws; b) the prices contained in the contract exceed a "fair price"; or c) the contract is found to be "contrary to the public interest." Furthermore, precedent for Board action is found in recent Orders where the Board addressed the formation of service companies.[56]

For example, in a Middlesex Water Company service company case, the Board approved the proposed service company agreement reasoning that it "provides for a method of fair compensation for services to be rendered, and is not contrary to the public interest."[57] In a JCP&L/GPU Nuclear service company case, the Board reasoned that the proposed service agreement is "not unreasonable and not contrary to the public interest, is in accordance with the law, and has the potential to attain considerable costs efficiencies and thereby ultimately lower costs to consumers."[58] Similarly, in a United Water Vernon Hills service company case the Board considered whether the service contract was "reasonable, consistent with the law, and not contrary to the public interest."[59]

The "public interest" must be examined in the context of restructuring of the electric industry and the introduction of competition into the energy market. In sum, the Board must ensure that PSE&G's utility ratepayers do not subsidize its unregulated competitive activities, and that PSEG will not enjoy an unfair advantage over its rivals in a competitive marketplace as a result of the proposed transaction.

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[56] *See I/M/O JCP&L for Approval of a Service Agreement with GPU Nuclear Corp*., BPU Docket No. EM950100390 (Decision and Order dated March 15, 1996); *Re: Atlantic City Electric Company*, BPU Docket No. EM97020103 (Order dated January 7, 1998); *I/M/O Middlesex Water Company*, BPU Docket No. WE95050240 (Order of Approval dated November 22, 1995); I/M/O *United Water Vernon Hills*, BPU Docket No. WE95040155 (Order of Approval dated August 21, 1995).

[57] *I/M/O Middlesex Water Company*, BPU Docket No. WE95050240 (Order of Approval dated November 22, 1995).

[58] *See I/M/O JCP&L for Approval of a Service Agreement with GPU Nuclear Corp.*, BPU Docket No. EM950100390 (Decision and Order dated March 15, 1996).

[59] *I/M/O United Water Vernon Hills*, BPU Docket No. WE95040155 (Order of Approval dated August 25, 1995).

As set forth above, PSE&G's proposal to transfer certain utility assets to Services must meet the applicable standards. Absent the adoption of the modifications and conditions set forth below, the proposed transfer and Service Agreement should not be approved.

B. PSE&G Should Not Have to Pay a Return on Assets Transferred to Services That Is Higher than the Return it Would Have Earned Had it Retained Those Assets.

The Service Agreement should be amended to provide that Services' charges shall be based on fully allocated costs. Such costs should include carrying costs (i.e., "return on" and "return of") on the assets used by the Services in the provision of services to PSE&G. For asset-related carrying charges billed to PSE&G, the carrying charges should not exceed Services' actual capital costs, and in no event shall asset related carrying charges exceed the amounts produced by applying PSE&G's currently authorized rate of return and book depreciation accrual rates to Services' investment base. Provisions should be added to limit the charges to the lower of Services' actual capital carrying charges or the Board's authorized rate of return for PSE&G. PSE&G has not specifically agreed to this language, but has only agreed to limit charges to PSE&G's authorized rate of return.

PSE&G also must clarify its policy on the capital costs associated with assets transferred to Services from PSE&G. PSE&G should not have to pay a return on the transferred assets which is greater than the return it would have earned had it retained those assets. The Service Agreement should be amended to include a description of how Services will charge affiliates for the carrying costs and operating costs associated with the transferred assets.

C. The Service Agreement Should Be Amended to Include a Description of How Services Will Charge Affiliates for the Carrying Costs and Operating Costs Associated with the Transferred Assets.

The proposed Service Agreement sets forth how Services will furnish and charge for services to affiliates.[60] PSE&G claims that the services rendered by Services will be priced using a "fully allocated cost methodology," with certain allocations made pursuant to formulae listed on Schedule I. *PS-SC-1*, p. 6. However, the Service Agreement should be amended to provide more specificity as to how Services will charge its affiliate clients for carrying costs and operating costs associated with the transferred assets.

D. PSE&G Should Be Required to Submit Reports to the Board Detailing the Percentage of Direct Billing by Services and its Allocation Factors for Indirect Billing.

PSE&G should be required to prepare and file with the Board an Annual Report covering all transactions between PSE&G and Services for the immediately preceding calendar year. This report, at a minimum, should detail the various categories, and subcategories, of direct and indirect charges billed to PSE&G by Services for the immediately preceding calendar year. The Annual Report should also include a schedule showing the development of all factors that were used to allocate indirect charges to PSE&G and other clients of Services, separately, during the year.

Ideally, a majority of costs incurred by Services should be directly billed to the operating companies that request the service. PSE&G should be required to submit direct billing information in Annual Reports to the Board. Thus, the Board would be able to monitor the direct billing percentages figures on a going forward basis to ensure that Services is achieving this target as the centralized management services concept is more fully implemented.

PSE&G proposes to use a significant number of cost drivers upon which to base its allocation of costs incurred by Services which are not directly billed to affiliates. These cost allocators should be monitored by the Board to ensure that they accurately reflect actual cost-causation activity and do not unduly burden the

[60] *PS-SC-1*, Exh. A, Schedule I.

regulated utility or work to subsidize a competitive service. PSE&G should also be required to file its proposals for allocation factor changes with the Board.

E. PSE&G Must Demonstrate That its Ratepayers Will Benefit from its Proposed Treatment of Intercompany Debt and Working Capital, and Provide Details Regarding the Basis for the Allocation of Borrowing Costs and Working Capital.

PSE&G should provide details on how PSE&G and other participants are allocated borrowing costs and working capital, with respect to the proposed treatment of inter-company debt and working capital. Services was initially capitalized with only a $10,000 equity investment from PSEG.[61] Additional capital required beyond this initial investment will take the form of a loan from PSEG.[62] This means that the assets that Services will acquire will be nearly 100 percent debt financed. This is a much different capital structure than PSE&G's regulated capital structure. The benefits of the highly leveraged capital structure of Services should flow through to ratepayers. PSE&G should be required to demonstrate that its ratepayers will benefit from this arrangement.

In addition, PSE&G and the other operating companies will be required to contribute to a working capital fund held by Services. The Service Agreement contains a working capital account provision whereby Services will pass on to affiliates short-term debt interest charges it incurs on Services' loans from PSEG.[63] PSE&G should be required to detail the basis for the allocation of these borrowing costs for Board review and approval.

F. Services Should Be Required to Follow the Same Capitalization Policy as PSE&G.

[61] *PS-SC-27*.
[62] *Id*.
[63] *PS-SC-28*; *PS-SC-1*, Exh. A, p. 3, para. 7.

Ratepayers should not be exposed to higher charges simply because certain assets are owned by Services rather than the utility. As demonstrated below, PSE&G's proposal for Services' capitalization policy has the potential to adversely affect ratepayers. *See RA-58*, pp. 14-15. Absent a showing that the SEC or its outside auditors require such a departure from PSE&G capitalization policy, the Board should condition any approval of the transfer on adherence to PSE&G capitalization policy. PSE&G has not made that showing. *PS-SC-86*, pp. 15-17.

Services' proposed capitalization policy would permit many expenditures to be currently expensed, rather than capitalized. *See RA-58*, pp. 14-15. While this policy might be consistent with PSEG's other unregulated subsidiaries, it is inconsistent with the policy of its largest subsidiary, PSE&G, a regulated public utility. Treating expenditures as capital items, depreciated over time, works to smooth earnings and more accurately mirrors the service lives of the underlying assets. This is especially important for regulated industries where rates are set periodically based on test year expenses. In contrast, treating expenditures as current expenses might distort earnings for regulatory purposes.

For example, expenditures might increase in a rate case test year with the addition of many items that would otherwise be treated as capital expenditures. Treated as current expenses, such outlays would cause a spike in total utility expenses during the test year. Passed on to ratepayers in the form of higher service company fees, the expenditures would have an adverse effect on the rates ultimately paid by ratepayers. In contrast, if the expenditures were capitalized, the depreciation expense for the items would be spread out over a number of years beyond the test year. Capitalization of the expenditures would thus smooth earnings over time and would result in a more accurate picture of actual costs. Thus, rates based on PSE&G's capitalization guidelines (rather than those proposed for Services) would be more reflective of actual costs.

PSE&G notes that its proposed capitalization policy will result in timing differences – not permanent differences – between PSE&G and Services. *PS-SC-86*, p. 16. However, timing differences in utility ratemaking are important. Concurrently expensing items which might provide benefits in future periods will result in a mismatch between generations of utility customers. Ratepayers in one period would be paying for items which benefit future periods for which other ratepayers would not bear any costs.

For the reasons set forth above and in its Initial Comments, the Ratepayer Advocate respectfully submits that Your Honor and the Board should require Services to adopt a capitalization policy that is no less restrictive than that followed by PSE&G. *RA-58*, pp. 14-15. For PSE&G, the Board had adopted the Uniform Systems of Accounts. For general plant accounts such as those that have been transferred to Services, the Board has approved a $1,000 cost threshold for general plant assets.[64] This means that capital additions costing less than $1,000 are permitted to be expensed. Services' capitalization policy, however, includes a $250,000 cost threshold for capital assets and a $10,000 threshold for general plant assets (*e.g.*, office equipment and furniture).[65] Under this policy, Services can acquire capital equipment for less than $250,000 (or $10,000 for general plant assets) and expense it to the operating companies.

In contrast, PSE&G would be required to capitalize the equipment if it had acquired the same equipment itself. Expensing this equipment through the Service Agreement could result in an unreasonable cost shift for PSE&G's ratepayers. Hence, Services should be required to adopt the same capitalization policy that the Board previously approved for PSE&G.

G. PSE&G and Services Must Agree to Be Subject to the Board's Authority.

Ultimately, Services' billings to PSE&G will affect the rates of PSE&G's utility customers. As set forth above, one of the major concerns regarding the use of shared services through a service company structure is the potential for cross-subsidization. PSE&G intends to rely much on its own accounting policies and practices to prevent cross-subsidization. However, diligent oversight by the Board is needed, including conducting the

[64] *PS-SC-37.*
[65] *PS-SC-26; PS-SC-37.*

audits mandated by the EDECA and the Affiliate Relations Standards.[66] Any approval of the proposed transfer and Service Agreement must be conditioned upon explicit language whereby PSE&G and Services are subject to the Board's authority in matters with respect to rates, franchises, services, financing, capitalization, depreciation, accounting, maintenance, operations or any other matter affecting PSE&G or Services, and its authority to review the reasonableness of charges incurred under the Service Agreement, as well as the Board's authority to review PSE&G's capital cost and operating and maintenance expenses.

PSE&G intends to place much reliance on its SAP data processing system and its own cost accounting policies to prevent cross-subsidization.[67] PSE&G claims that it established Services as a separate company in its SAP accounting data system, with its own set of accounting records and documentation.[68] To monitor compliance, PSE&G also intends to rely on its local management and internal auditing group as well as reporting and variance tools included in the SAP software.[69]

Notwithstanding PSE&G's claims regarding its internal accounting controls and internal auditing procedures, Board oversight is needed and, in fact, required by the EDECA.[70] The Board is obligated to conduct periodic audits to assess PSE&G's compliance with the standards set forth in the EDECA and the Affiliate Relations Standards.[71] PSE&G acknowledges that the Board has the authority to review all transactions between PSE&G and Services " in regulatory rate proceedings."[72] However, the Board should assert its intent to monitor PSE&G's compliance with the relevant standards and EDECA audit mandates even outside the context of regulatory rate proceedings.

[66] *N.J.S.A.* 48:3-55(k); *N.J.S.A.* 48:3-56(f); and *N.J.S.A.* 48:3-58(k); Affiliate Relations Standards, Sec. 7.
[67] *PS-SC-57*.
[68] *PS-SC-53*.
[69] *PS-SC-53; PS-SC-57; PS-SC-19*.
[70] *See N.J.S.A.* 48:3-55, *N.J.S.A.* 48:3-56 and *N.J.S.A.* 48:3-58.
[71] *N.J.S.A.* 48:3-55(k), *N.J.S.A.* 48:3-56(f) and *N.J.S.A.* 48:3-58(k); Affiliate Relations Standards, Sec. 7.
[72] *PS-SC-75*.

The Board clearly set forth Board oversight provisions and reporting requirements in a recent Order addressing the operation of a service company affiliated with JCP&L.[73] The Board should adopt similar measures as a condition for approval in the instant matter.

As a condition of any approval of the Company's proposal, the Board should reassert its authority by embodying the following language in its Order of approval: "[t]his Order shall not affect or in any way limit the exercise of the authority of the Board or of the State in any future petition or in any proceeding with respect to rates, franchises, services, financing, capitalization, depreciation, accounting, maintenance, operations or any other matter affecting PSE&G or Services." The Board should also reserve its authority to review the reasonableness of charges incurred under the Service Agreement, as well as the Board's authority to review capital costs and operating and maintenance expenses.

H. PSE&G and Services Should Prepare Data Relating to the Service Agreement as Requested by the Board, Provide Information Showing the Benefit of the Service Company Structure to Ratepayers upon Request; File with the Board and Ratepayer Advocate Any Proposed Changes to the Service Agreement, Allocation Factors, or Other Changes in Costing and Operations Policies and Procedures, at Least 60 Days Prior to Their Proposed Effective Date.

PSE&G and the Service Company should submit for the Board's prior approval all changes in the Service Company Agreement, including any additions or deletions in the categories of services provided by the Service Company, and including changes in the cost allocation bases and procedures for indirect charges.

As a condition for any approval, PSE&G should be required to prepare data relating to the Service Agreement, as requested by the Board. Furthermore, PSE&G should be required to provide information showing the benefits of the service company structure to ratepayers upon request. Finally, in order to permit adequate and timely analysis, PSE&G should be required to file with the Board and Ratepayer Advocate any

[73] *I/M/O JCP&L for Approval of a Service Agreement with GPU Nuclear Corp*., BPU Docket No. EM950100390 (Decision and Order dated March 15, 1996), pp. 4-6.

proposed changes to the Service Agreement, allocation factors, or other changes in costing and operations policies and procedures, at least 60 days prior to their proposed effective date.

I. PSE&G Should Be Required to Demonstrate That the Provision of Risk Management Services by Services Will Not Violate the Affiliate Relations Standards.

Services should not be permitted to offer shared services which may adversely affect the competitive market for energy services or cause PSE&G's utility ratepayers to subsidize other non-utility activities. The Board's Affiliate Relations Standards permit the sharing of joint "corporate oversight, governance, support systems and personnel."[74] The Affiliate Relations Standards also contain prohibitions against activities and practices which adversely affect competition and cause ratepayers to subsidize competitive activities. The functions which Services intends to perform largely comport with the permitted functions enumerated in the Affiliate Relations Standards. *PS-SC-1*, Sched. I. However, included among the functions which Services intends to provide are services which may adversely impact competition, namely, "Marketing Services", "Business Development", and "Financial Risk Management." *Id.* PSE&G has subsequently removed Marketing Services from the list of Services' activities and has proposed that Service' Business Development activities will not be allocated.

Also among the services that the Affiliate Relations Standards identifies as "[s]ervices which should not be shared" are "hedging, and financial derivatives and arbitrage services."[75] PSE&G describes "Financial Risk Management" as "monitoring risk exposure and reporting to the Risk Management Committee." *PS-SC-1*, Exh. A, Sched. I. Recognizing that the wholesale purchase of energy and natural gas may involve the use of derivative instruments, there is a possibility that this function might lead to the sharing of proprietary trading information kept by the utility and its unregulated affiliates. PSE&G should provide specific information regarding the operation of Services' Financial Risk Management unit. As a condition for approval of its

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[74] Affiliate Relations Standards, Section 5.5(a).
[75] *Id.*

Petition, PSE&G should be required to demonstrate that the operations of the Financial Risk Management unit do not violate the Affiliate Relations Standards.

Another activity which Services intends to provide is Business Development, including "area development" activities. *PS-SC-1*, Exh. A., Sched. I. This activity might adversely impact competition if it involves the promotion of business activity in PSE&G's service territory, where new or relocating businesses have a choice of using either PSE&G's regulated or unregulated services offered by other market participants. PSE&G should be required to define the scope of its Business Development function, as well as demonstrate that this activity comports with the Affiliate Relations Standards, prior to Board approval here.

J. PSE&G Should Be Required to Report Any Changes to Services' Client Base and Any Changes in the Type and Scope of Services it Performs.

In addition to the scope of services which Services' intends to provide, the "client base" of Services also needs to be monitored. Initially, Services is to support only corporate affiliates.[76] The operating companies are similarly obligated to buy services exclusively from Services.[77] In the future, however, Services might possibly market itself to unaffiliated businesses.[78] Business units may also be able to opt out of buying exclusively from Services in the future.[79] Apparently, no specific time frame has been established for either of these two possibilities. Nor is it certain at this time which support services business units will be entitled to opt-out of buying from Services. If potential providers of competitive services become clients of Services, the Board might need to again review Services' operations.

As a guiding principle, Services should not be permitted to offer shared services which may adversely affect the competitive market for energy services or cause ratepayers to subsidize PSEG's competitive ventures. Thus, in addition to the scope of services which Services' intends to provide, the "client base" of

[76] *PS-SC-12*.
[77] *PS-SC-14*.
[78] *PS-SC-12*.
[79] *PS-SC-13*.

Services needs to be monitored. *RA-58,* pp. 21-22. If potential providers of competitive services become clients of Services, the Board might need to again review Services' operations. The Board should require PSE&G to seek Board approval prior to expanding the "client base" of Services. Similarly, the types of services offered by Services should be monitored.

K. PSE&G Must Submit a Plan for the Timely Inclusion of New Participants in the Service Company Agreement Formulae.

Ideally, ratepayers can expect cost savings through the service company structure if fixed costs are spread over more participants. One rationale behind centralizing management services is the sharing of fixed costs, thereby reducing the fixed cost burden of individual entities. As new operating companies are acquired, fixed management costs should decline for all participants. For this to happen, it will be important that new participants are incorporated into Services' indirect cost formulae in a timely manner.

Presently, Services has no specific plan for timely inclusion of new participants in its shared services formulae, although PSE&G indicates that Services will review its allocation factors annually.[80] Annual reviews are not sufficient, however, if new affiliates are routinely acquired. Newly acquired companies could escape overhead cost responsibility for nearly a year in some cases.

Therefore, as a condition of any approval, the Company should be required to establish policies and procedures for the timely inclusion of new participants in the shared services formulae so that these new participants immediately share responsibility for corporate overhead costs. Furthermore, such savings should be flowed through to PSE&G's ratepayers.

L. PSE&G Must Demonstrate That its Proposal for a Service Company Will Result in Savings That Could Not Be Achieved by Other Means.

It would not be unreasonable to assume that one of the driving forces behind the establishment of a service Company structure is the potential for cost savings. Indeed, PSE&G acknowledged as much in its

[80] *PS-SC-20.*

discovery responses.[81] However, PSE&G claims that it did not quantify the expected savings that it would realize from the switch to a service company structure.[82] The synergies and efficiencies which result from the service company structure will likely generate cost savings. As a condition for approval, PSE&G should be required to demonstrate that its proposal for a service company will result in savings that could not be achieved by other means.

M. PSE&G Must Also Submit Information Such as Provided for Above Simultaneously to the Ratepayer Advocate.

In order to provide for timely and thorough analysis of reports prepared by PSE&G related to Services, PSE&G should be required to transmit copies of such reports to the Ratepayer Advocate at the same time such reports are filed with the Board.

Conclusion

For the reasons set forth above, the Ratepayer Advocate submits that Your Honor and the Board should condition any approval of the proposed transfer of assets and Service Agreement on the following conditions:

(1) PSE&G should not have to pay a return on assets transferred to Services that is higher than the return it would have earned had it retained those assets;

(2) The Service Agreement should be amended to include a description of how Services will charge affiliates for the carrying costs and operating costs associated with the transferred assets;

(3) PSE&G should be required to submit reports to the Board detailing the percentage of direct billing by Services and its allocation factors for indirect billing;

[81] *PS-SC-16; PS-SC-36.*
[82] *PS-SC-36; PS-SC-43.*

(4) PSE&G must demonstrate that its ratepayers will benefit from its proposed treatment of intercompany debt and working capital, and provide details regarding the basis for the allocation of borrowing costs and working capital;

(5) Services should be required to follow the same capitalization policy as PSE&G;

(6) PSE&G and Services must agree to be subject to the Board's authority in matters with respect to rates, franchises, services, financing, capitalization, depreciation, accounting, maintenance, operations or any other matter affecting PSE&G or Services, and its authority to review the reasonableness of charges incurred under the Service Agreement, as well as the Board's authority to review PSE&G's capital cost and operating and maintenance expenses;

(7) PSE&G and Services should be required to maintain their records within the State and provide the Board with full access to their records;

(8) PSE&G and Services should agree to prepare data relating to the service agreement as requested by the Board, provide information showing the benefits of the service company structure to ratepayers upon request; file with the Board and Ratepayer Advocate for the Board's prior approval any proposed changes to the Service Agreement, allocation factors, or other changes in costing and operations policies and procedures, at least 60 days prior to their proposed effective date;

(9) PSE&G should be required to demonstrate that the provision of Risk Management and Business Development services by Services will not violate the Affiliate Relation Standards, and agree to eliminate Marketing as a shared service under Services unless it can be demonstrated that it comports with the Board's Affiliate Relations Standards;

(10) PSE&G should be required to report any changes to Services' client base and any changes in the type and scope of the services it performs;

(11) PSE&G must submit a plan for the timely inclusion of new participants in the service company allocation formulae;

(12) PSE&G must demonstrate that its proposal for a service company will result in savings that could not be achieved by other means; and

(13) In addition to providing identified data, information, documents, reports and notifications to the Board as set forth herein, PSE&G must also submit such information simultaneously to the Ratepayer Advocate.

POINT VI

YOUR HONOR AND THE BOARD SHOULD ADOPT THE RATEPAYER ADVOCATE'S PROPOSED CLASS REVENUE DISTRIBUTION, RATE DESIGN, AND TARIFF MODIFICATIONS.

A. The Ratepayer Advocate's Proposed Distribution Rate Increase Should be Allocated Among Rate Classes Based Upon Consideration of the Combined Impact of the Distribution Rate Increase and the Expiration of the Company's Market Transition Charge.

1. The Ratepayer Advocate's Proposed Class Revenue Distribution Represents a Fair Allocation of the Combined Impacts of the Rate Changes Expected to Occur on August 1, 2003.

PSE&G's Petition in this matter included a cost-of-service study, which was presented by Company witness Gerald Schirra. *PS-7,* p. 23-46*; Schedules GWS-4, GWS-5, GWS-6, & GWS-7*. As discussed in more detail below, the Company's cost-of-service study is not consistent with the policies stated by the Board in its most recent fully litigated base rate case. *I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions,* BRC Docket No. ER91121820J, (Final Decision and Order dated June 15, 1993) (referred to hereinafter as the *"JCP&L 1993 Base Rate Order"*). However, Mr. Schirra's cost-of-service study was employed only as a general guide to development of the Company's proposed class revenue distribution. The Ratepayer Advocate believes that the Company's class revenue distribution method produces reasonable results. Therefore, the Ratepayer Advocate has not performed a cost-of-service study or presented a detailed evaluation of the Company's study. *RA-30,* p. 6. The Ratepayer Advocate's disagreements with specific aspects of the Company's cost-of-service study as they relate to specific class rate design proposals will be addressed as part of the discussion of class rate design issues below.

PSE&G's proposed class revenue distribution methodology is based on the combined impact of the Company's proposed $250.1 million distribution rate increase and the expiration of the Market Transition

Charge ("MTC"), resulting in a decrease of $367.0 million. *RA-29,* p. 6*; RA-61, Schedule BK-1 (12+0 UPDATE).* The net effect of both changes is a rate decrease of $116.9 million, or 2.90% on a total revenue basis. *Id.* PSE&G is proposing to move each class's distribution rates toward the cost of service shown in its study, but subject to the constraint that the total impact on each class of the combined distribution rate increase and MTC expiration is no less than one-half the system average decrease (1.45%) and no greater than one and one-half the system average decrease (4.35%).

The Ratepayer Advocate believes that the above revenue distribution methodology is the proper approach given the history of the MTC. The MTC charges were implemented as part of the Company's restructuring proceeding. In accordance with the "revenue neutrality" requirements of EDECA, the MTC was set for each class so as to preserve the Company's pre-restructuring class revenue distribution. *RA-29,* p. 7*; N.J.S.A.* 48:3-52; *I/M/O Public Service Electric and Gas Company's Rate Unbundling, Stranded Costs and Restructuring Filings,* BPU Docket Nos. EOO9700070461, EO97070462 & EO97070463 (Final Decision and Order dated Aug. 24, 1999), attached "Stipulation," Attachment 2, p. 2 of 40. On August 1, 2003, base rate revenues, which became MTC revenues as a result of restructuring, will again become base revenues. Thus, the combined effect of changes in base rates and the MTC must be considered in order to avoid severe rate impacts on any individual class. *RA-29,* p. 7.

Applying the principles of gradualism in this proceeding is particularly important in light of the other rate changes that will take effect on August 1, 2003. In addition to the distribution rate changes and the MTC expiration, PSE&G's ratepayers will be experiencing rate increases as a result of the expiration of PSE&G's Restructuring Rate Reduction ("RRR") and the implementation of the results of the Board's second statewide Basic Generation Service ("BGS") auction.

The Ratepayer Advocate's proposed class revenue distribution is shown in the updated "12+0" rate design presented by Ratepayer Advocate witness Brian Kalcic. The combined effect of the Ratepayer

Advocate's recommended $82.2 million distribution rate increase and the $367.0 million MTC expiration is a rate decrease of $284.7 million, or 6.93% on a total revenue basis. *RA-61, Schedule BK-2 (12+0 UPDATE).* This rate decrease was allocated subject to the constraint that no class would receive less than half of the system average decrease (3.46%) or more than one and one-half of the system average decrease (10.39%).

The Ratepayer Advocate's proposed class revenue distribution is appropriate as it considers the impacts of the other rate changes expected to occur on August 1, 2003. This methodology should be adopted by Your Honor and the Board because it represents a fair allocation of impacts of the combined rate changes.

2. The Revenue Distribution Methodologies Proposed by Intervenors NJLEUC and NJCU Would Result in Disparate Rate Impacts to Different Rate Classes and are Based on a Cost-of-Service Methodology Inconsistent with Board Policies.

Two of the intervenors, the New Jersey Large Energy Users Coalition ("NJLEUC"), and the New Jersey Commercial Users ("NJCU"), have proposed to allocate the Company's proposed distribution rate increase without considering the impact of the expiration of the MTC. *NJLEUC-3,* p. 8-9*; NJCU-1,* p. 9-10. This approach should be rejected for two reasons. First, the NJLEUC and NJCU proposals would result in widely disparate rate impacts to different customer classes. As shown in the surrebuttal testimony of Ratepayer Advocate witness Brian Kalcic, the combined impacts of the Company's proposed distribution rate increase and the MTC expiration would range from a 15% decrease to a 47% increase under NJLEUC's proposal, and from an 8% decrease to a 39% increase under NJCU's proposal. *RA-30, Schedules BK-1S and B-2S.* Focusing on only those customer classes producing the largest revenues, under the NJLEUC proposal, the residential class would receive a rate increase of 8.69% while commercial and industrial rate classes would receive decreases ranging from 6.91% for the GLP rate class to 10.04% for the HTS-S class. *RA-30, Schedule BK-1S.* Similarly, the NJCU proposal would impose a 3.48% increase on residential customers, while providing rate decreases for commercial and industrial customers ranging from 4.22% to 6.47%. Either result is unfair to the residential class, which would be the only large class required to shoulder a combined base rate / MTC revenue increase in addition to the other rate increases that will become effective on August 1, 2003.

The NJLEUC and NJCU proposals also are flawed because they are based on cost allocation principles inconsistent with those adopted by the Board in its last fully litigated electric base rate proceeding. *JCP&L 1993 Base Rate Order*. In the JCP&L proceeding, the United States Department of Defense and Federal Executive Agencies had proposed to allocate transmission, subtransmission and distribution costs based solely on non-coincident peak demands, while the Division of Rate Counsel proposed an "average and excess" method which considered both peak demand and annual energy usage. *JCP&L 1993 Base Rate Order,* p. 16. Noting that "[e]xclusive demand approaches to the allocation of T&D costs" had been rejected in a previous rate proceeding, the Board adopted the methodology advocated by Rate Counsel. *Id.*

NJCU bases its proposed class revenue distribution on PSE&G's cost-of-service study, while NJLEUC has proposed to use the Company methodology with some modifications. *NJCU-1,* p. 9-13*; NJLEUC-3,* p. 11-12. Contrary to the *JCP&L 1993 Base Rate Order,* the Company's cost-of-service study relies primarily on demand-based allocators to allocate its distribution system and related costs. *P-7,* p. 12. This methodology is based on the assumption that the construction and maintenance of the Company's distribution system are driven solely by peak demand, with no consideration to the year-round energy requirements of the Company's customers. T933:L15-23; T935:L14-20. This methodology over-allocates costs to low load-factor customers, such as residential customers, while allowing some customers to escape cost responsibility entirely if all of their usage is off-peak. For example, PSE&G witness Gerald Schirra acknowledged that his cost-of-service study allocates no cost responsibility for Station Equipment and related expense items to the Company's water heating and street and area lighting customer classes. T939:L13 - T941:L16.

In PSE&G's proposed class revenue distribution, the results of the Company's cost of service study were tempered by consideration of the impacts of the other rate changes expected to occur on August 1, 2003. Since NJLEUC and NJCU are proposing to apply the Company's cost of service study results directly, without also considering the impacts of the MTC expiration and other rate changes, their proposed revenue distributions would result in significant movements toward the erroneous cost benchmarks contained in the Company study.

Following the submission of the intervenors' prefiled direct and rebuttal testimony, the Company prepared an additional cost-of-service study in accordance with directions provided by the Board Staff in Staff's discovery request S-PRD-53. This study and the accompanying instructions have been received in evidence. *S-63, S-64-S-66, S-67.* The supplemental testimony of NJCU witness Dennis Goins opposes the adoption of the Staff cost-of-service methodology. *NJCU-3,* pp. 4-9. However, Dr. Goins suggests that, if the Board adopts the Staff methodology, the distribution rate increase allowed by the Board should be spread by applying the results of the methodology, without limitations on the rate increase received by each class. *NJCU-3,* p. 11-12. This approach, like the other revenue distribution methodologies proposed by NJLEUC and NJCU, would have a disproportionate impact on residential customers. Using this methodology, the combined impact of the Company's proposed distribution rate increase and the expiration of the MTC would be a 91% rate <u>increase</u> for residential customers, and rate <u>decreases</u> ranging from 3.89% to 10.23% for the larger commercial and industrial classes.[83] Thus, residential customers would be the only major customer class

[83] The base revenue increases that would be produced by applying the Staff methodology to the Company's proposed distribution rate increase without constraints are shown in column (6) of page 88 of Staff Exhibit S-63. T2036:L10-20. The total MTC revenue of each class, and each class's present bill revenue excluding the Restructuring Rate Reduction, are shown, respectively, in columns (6a) and (7) of Mr. Schirra's Schedule GWS-10. T2036:L21 - T2037:L15; *P-7 U 12+0, Schedule GWS-10 UPDATE 12+0,* page 1 of 3. Based on these sources, the combined base rate/MTC impacts on the residential and larger commercial and industrial classes that would result from Dr. Goins's suggestion would be as follows:

	Present total bill revenue	**Distribution rate increase**	**MTC expiration**	**Total base rate/MTC**	**Percent Rate Change**
RS	$1,371,583	$ 77,561	$ (51,310)	$ 26,251	1.91%
GLP	883,375	79,378	(118,139)	(38,761)	-4.39%
LPL-S	1,034,238	62,340	(102,592)	(40,252)	-3.89%
LPL-P	316,210	14,235	(33,109)	(18,874)	-5.97%
HTS-S	294,220	12,782	(42,884)	(30,012)	-10.23%

receiving a combined base rate/MTC increase in addition to the other rate increases that will become effective on August 1, 2003.

The interclass revenue allocation methodologies proposed by NJLEUC and NJCU would unfairly single out residential customers for a rate increase–in addition to other rate increases occurring on August 1, 2003–and are based on a flawed cost-of-service study. These proposals should be rejected by Your Honor and the Board.

B. Your Honor and the Board Should Adopt the Ratepayer Advocate's Modifications to PSE&G's Proposed Rate Design and Tariff Changes.

1. The Company's Proposed Increases to its Monthly Service Charges Should Be Rejected.

The Company has proposed the following increases in its monthly service charges for the Residential Service ("RS"), Residential Heating Service ("RHS"), Residential Load Management ("RLS") and General Lighting and Power ("GLP") rate classes:

Rate class	Present	Proposed	% Increase
RS	$ 2.27	$ 2.75	21.1%
RHS	$ 2.27	$ 2.75	21.1%
RLM (<20,000 kWh/yr)	$ 11.43	$ 13.07	14.3%
RLM (>20,000 kWh/yr)	$ 6.41	$ 13.07	103.9%
WHS	$ 2.66	$ 3.23	21.4%
GLP (metered)	$ 3.81	$ 7.62	100.0%
GLP (unmetered)	$ 3.81	$ 3.52	(7.6%)

P-7 U 12+0, Schedule GWS-13 (UPDATE 12 & 0), p. 5, 7, 10, 15, 20. These proposed increases should be rejected.

Mr. Schirra's cost-of-service study does not follow the Board's policies with regard to customer service charges. As stated in the *JCP&L 1993 Base Rate Order*, the customer costs included in the customer charge "should be limited to those costs which are demonstrated to vary directly and linearly with the number of customers on the system, unaffected by either demand or energy consumption." *JCP&L 1993 Base Rate*

Order, p. 17. Moreover, as noted by Ratepayer Advocate witness Brian Kalcic, by limiting the costs permitted to be included in the customer charge, the Board provides customers with more control over their energy bills. T1133:L21 - T1134:L2.

As shown by Staff's cross-examination of PSE&G witness Gerald Schirra, the costs classified as customer-related in his cost-of-service study include a number of indirect costs which the Board has not permitted to be included in the monthly service charge. T1049:L2 - T1050:L11; T1056:L2-9; T1133:l2 -12; *JCP&L 1993 Base Rate Order,* p. 17. Thus, the Company has not met its burden of demonstrating that its proposed customer monthly service charges are reasonable under *N.J.S.A.* 48:2-21 (d).

The Company's proposed monthly service charge increases have not been supported by a proper analysis of customer costs. The proposed increase should be rejected by Your Honor and the Board.

2. The Company's Proposed Steeply Declining Block Rate Structure for Residential Winter Delivery Rates Should be Modified to Preserve the Current "Flat" Rate Structure.

Under the Company's current tariff for the RS rate class, the combined per-kilowatt hour distribution rate and MTC charge during the winter months are slightly higher for usage above 600 kilowatt-hours per month than for the first 600 kilowatt hours of usage. The Company's current distribution charge decreases by 0.16 cents for the "above 600 kilowatt-hours" rate block, while the MTC charge increases by 0.24 cents. Thus, the combined rates are approximately .08 cents per kilowatt hour higher for usage above 600 kilowatt-hours per month than for the first 600 kilowatt-hours. *P-7-RB, Schedule GWS-2-RB;* T677:L3 - T683:L8; *RA-29,* p. 9. Under the Company's proposed rates, the per kilowatt hour rate would decrease by 1.9 cents for usage over 600 kilowatt-hours in a month. T683:L9-24; *RA-29,* p. 9; *P-7 U 12+0, Schedule GWS-13,* p. 5 of 43. The steeply declining block structure is the result of the Company's proposal to collect all of its asserted "customer-related" costs which are not recovered in the monthly service charge over the first 600 kilowatt hours of monthly usage. *RA-29,* p. 10.

The Ratepayer Advocate believes that the Company's proposed change in rate structure is too extreme to implement in this proceeding. The steeply declining block structure would impose a disproportionate burden on lower-usage customers, due to the fact that a larger percentage of their total usage falls within the "up to 600 kilowatt-hours" rate block. *RA-29*, p. 10. The Ratepayer Advocate also believes that the declining block structure is inappropriate given the importance of energy conservation.

Mr. Kalcic has presented an alternative rate design which equalizes the total winter distribution rate over the first and second rate blocks. Under this rate design, the per kilowatt-hour distribution charge would be 2.5819 cents per kilowatt-hour for all usage, rather than the Company's proposed 3.0884 cents per kilowatt-hour for usage up to 600 kilowatt-hours in a month, and 1.1772 cents per kilowatt-hour for usage over 600 kilowatt-hours. *RA-29,* p. 10; *RA-61, Schedule BK-3 (12+0 UPDATE),* p. 1; *P-7 U 12+0, Schedule GWS-13,* p. 5 of 43. Your Honor and the Board should adopt this rate design for the RS rate class.

3. PSE&G's Proposal to Recover All Non Customer-Charge Revenues Through Demand Charges for its Customer Classes With Demand Charges Should be Rejected.

Under PSE&G's current tariff, the Company recovers a portion of its non customer-charge revenues from the General Lighting and Power ("GLP") customer class, as well as other customer classes with demand charges, through the MTC. Since the MTC includes energy usage charges, customers in these classes pay corresponding portions of their electric bills based on energy usage. *RA-31,* p. 6. Beginning August 1, 2003, the Company is proposing to recover virtually all non-customer charge revenues from these classes through demand charges–the only remaining energy-based charge would be the Transitional Energy Facility Assessment ("TEFA"). *RA-29*, p. 12; *RA-31*, p. 6.

The impact on the GLP class is explained in Mr. Kalcic's prefiled direct testimony. The Company currently recovers approximately 53% of its non customer-charge revenue from this class, based on energy usage. *P-7 U 12+0, Schedule GWS-13 (12+0 UPDATE),* p. 20 of 43.[84] With the expiration of the MTC, the Company's proposed rate design would recover a much higher portion of the GLP revenue requirement through demand charges–approximately 91% based on the Company's proposed distribution rates. Only 9% of the proposed revenue requirement would be recovered through the energy-based TEFA. *RA-29*, p. 12. The resulting rate impacts can be seen from Mr. Schirra's Schedule GWS-14 UPDATED 12+0, page 4 of 8, which shows the impact of the Company's proposed rate design on GLP customers segmented by load factor. The GLP class would receive an overall decrease of 2.6%, but the impact on the different customer segments ranges from a 6.1% increase for customers with the lowest load factors, to a 6.7% decrease for customers with the highest load factors.

The Ratepayer Advocate recommends a rate design that will more closely preserve the existing proportions of demand-based and energy-based revenues. *RA-29,* p. 13; *RA-31*, p. 6. Mr. Kalcic has presented proposed rate designs based on the Ratepayer Advocate's proposed "12+0" revenue requirements which maintain the current proportions of demand and energy-based revenues for Rate Classes GLP, Large Power and Lighting-Secondary ("LPL-S") and Large Power and Lighting-Primary ("LPL-P). *RA-61, Schedule BK-3 (12+0 UPDATE),* p. 7, 8, 9. For the Company's two other demand-related Rate Classes High Tension Service-High Voltage ("HTS-HV") and High Tension Service-Subtransmission ("HTS-S"), retaining the current demand/energy split would have resulted in an energy-based rate lower than the current TEFA charge. For these two classes, the Ratepayer Advocate's proposed rate design sets the energy-based charge at the TEFA rate. *RA-31*, p. 6*; RA-61*, p. 3, *Schedule BK-3 (12+0 UPDATE),* pp. 10, 11.

The Company's rebuttal testimony proposes an alternative rate design which would recover some of its non-customer charge revenues through an energy charge. *P-7-RB,* pp. 32-33. However the alternative

[84] The 53% figure is based on the Company's "12+0" update. The 50% figure stated in Mr. Kalcic's prefiled direct testimony was based on the Company's original filing. *RA-29*, p. 12.

proposal would still depart from the current demand/energy split. For example, non customer-charge revenues for the GLP customer class would be recovered 74% through demand charges, compared to the current 47%. *P-7-RB U 12+0, Schedule GWS-4-RB (12+0 UPDATE).*[85] While this is an improvement over the Company's originally filed rate design, the Ratepayer Advocate believes that, given the other significant rate changes expected to occur on August 1, 2003, it is preferable to preserve the current proportions of demand and energy-based revenues for the Company's customer classes with demand charges.

4. The Company Should Be Directed to Inform Customers of the Availability of Residential Load Management Service More Frequently Than the Current Annual Basis.

PSE&G currently provides Residential Load Management ("RLM") service to approximately 14,400 residential customers. *RA-29*, p. 20. RLM is an optional rate schedule, which gives customers the opportunity to achieve savings by moving their electric usage from on-peak to off-peak times during the summer months. *P-1, Schedule 3, proposed Original Sheet No. 89.* The Company currently informs customers of the availability of RLM service on an annual basis, through a bill insert. *RA-29,* p. 20.

Greater awareness of the availability of RLM service would provide customers with the opportunity to reduce their own electric bills, and the resulting lower peak usage could improve reliability and reduce costs for all customers. Therefore, the Ratepayer Advocate believes that RLM service should be promoted on a more frequent basis. *R-29,* p. 21. The Ratepayer Advocate recommends that the RLM rate should be promoted on at least a quarterly basis.

The rebuttal testimony of Mr. Schirra states that the Company does not object to providing residential customers with more information about RLM service "assuming that the Company's costs of providing such notice are recoverable." *P-7-RB*, p. 27. However, as explained in Mr. Kalcic's surrebuttal testimony, the

[85] These figures are based on the Company's "12+0" update. As originally filed the percentages were 67% and 50% respectively, as stated in Mr. Kalcic's prefiled rebuttal testimony. *RA-30*, p. 5.

Ratepayer Advocate is not proposing any new or costly marketing program. The Company could promote RLM service more frequently than annually through existing means of communicating with customers, such as bill inserts and bill messages, at little or no incremental cost. *RA-30,* pp. 4-5. The Company should be directed to use such means to more effectively promote the availability of RLM service. Information on the RLM rate should be provided through bill inserts and/or bill messages on at least a quarterly basis.

5. Your Honor and the Board Should Reject the Company's Proposed 267% Increase in its Reconnection Charge.

Public Service is proposing to increase its reconnection charge for customers whose service has been disconnected from $15 to $55, a 267% increase. *P-7,* p. 86. The Ratepayer Advocate believes that this charge is excessive, unduly burdensome to low-income customers and counterproductive.

The Company's reconnection charge falls most heavily on those customers who are least able to afford it, that is, customers who have difficulty paying their utility bills. *RA-29,* p. 22. Given this reality, the Ratepayer Advocate believes that a 267% increase is particularly inappropriate. The proposed increase is also likely to be counterproductive. If a high fee is imposed on a customer with a limited ability to pay, that customer is less likely to be able to return to the system, resulting in lost revenue and other customers having to bear more than their share of embedded costs.

Further, the Company proposal is based on a cost analysis which overstates the costs properly allocable to customers who have their service restored. PSE&G has calculated its "reconnection" costs by dividing the Company's total costs associated with shut-offs for non-payment by the number of services reconnected–rather than the total number of shut-offs for non-payment. *RA-29, pp. 21-22.* In effect, this calculation allocates costs incurred due to customers who are never reconnected to those customers who do re-establish service. *Id.;* T686:L12 - T687:L21.

The Company's proposal also should be viewed in light of the Board's establishment of a permanent Universal Service Fund, which was announced by the Board on Thursday, March 20, 2003. *I/M/O Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act,* BPU Docket No. EX00020091. As is addressed at length in the testimony, comments, and other submissions by the Ratepayer Advocate in that proceeding, the permanent Universal Service Fund program adopted by the Board is expected to reduce the number of customer shut-offs for non-payment. The Ratepayer Advocate believes that this is a better approach than increasing the amount the Company may collect from customers whose service is restored.

The Company is proposing to address the impact of its proposed reconnection charge increase on low-income residential customers by charging a reconnection fee of $15 to customers eligible for Universal Service Fund benefits, and recovering the remaining $40 from the Universal Service Fund. *P-7,* p. 105. The present base rate docket is not the appropriate venue to consider this proposal. The establishment of a Universal Service Fund, and the types and amounts of the benefits to be provided from the fund, have been the subject of extensive comment and consideration by a wide range of interested parties in the Board's Universal Service Fund docket. Those parties have included, in addition to the Ratepayer Advocate and the utilities, State agencies, members of the State legislature, community-based social service organizations, advocacy organizations, and concerned citizens. The Universal Service Fund docket is the appropriate proceeding for determining what benefits will be funded through the Universal Service Fund, not the present base rate docket. The Ratepayer Advocate recommends that the Company's current reconnection charge of $15 be retained for all customers.

6. Your Honor and the Board Should Reject the Company's Proposed 57% Increase in its Field Collection Charge.

The Company is proposing a 57% increase in its Field Collection Charge, from $14 to $22. *P-7,* p. 103. This charge applies to non-residential customers when a Company representative visits the customer's premises to disconnect service for non-payment, but instead receives sufficient payment from the customer to avoid disconnection. *Id.* The proposed increase would have a disproportionate impact on customers who have difficulty paying their bills, such as small businesses affected by the slow economy. Further, the cost computation provided by the Company in support of the proposed increase improperly includes indirect costs. *RA-29,* p. 23. For these reasons, the proposed increase in the Field Collection Charges should be rejected.

7. The Company's SBC and NTC Charges Should be Based on Kilowatt Hours Delivered to the Customer, Without Adjustment for Loss Factors.

PSE&G is proposing that is Societal Benefits Charge ("SBC") and Non-Utility Generation Transition Charge ("NTC") be established as a uniform per kilowatt-hour charge based on energy delivered at the customer's meter. This is a departure from the current methodology, which took loss factors into account, thus resulting in slightly lower charges for customers taking service at higher voltages. *P-7,* pp. 49-50. Intervenors NJLEUC and Co-Steel Raritan, Inc. ("Co-Steel")[86] have opposed this change. *NJLEUC-3,* p. 27; *CS-2,* p. 24.

The SBC and the NTC should be calculated based on delivered kilowatt-hours, as proposed by PSE&G. As Mr. Schirra explained in his rebuttal testimony, the current charges reflect loss factors for historical reasons, because the SBC and the NTC were established using the Company's previous Levelized Energy Adjustment Mechanism, which collected for costs incurred at the generation level. *P-7-RB,* p. 18. In contrast, the SBC and NTC charges are to collect for social programs and the costs of restructuring, not

[86] During the pendency of these proceedings Co-Steel was acquired by Gerdau Ameristeel and renamed Gerdau Ameristeel Perth Amboy, Inc.

"generation level" costs. The Ratepayer Advocate is in agreement with PSE&G that the most equitable way to share these costs is for all customers to pay uniform charges per delivered kilowatt hour delivered to the customer. *P-7-RB,* p. 19.

8. The Company Should Not be Permitted to Eliminate its Current Curtailable Electric Service Tariff.

The Company's current tariff for Rate Schedules GLP, LPL and HTS include a Curtailable Electric Service ("CES") Special Provision. *P-1, Schedule, Original Sheets 72-73, 88-89, 154-55.* Under these provisions, customers who agree to limit their loads during times of curtailment receive a credit of $6.11 per average kilowatt of load curtailed. *Id; RA-29,* p. 19. The Company is proposing to eliminate its CES program and replace it with a "Customer Voluntary Load Reduction Program," which would provide no compensation to customers for their curtailments. *P-7,* pp. 86, 90, 91; *P-7-RB,* p. 14; *RA-30,* p. 2. The Ratepayer Advocate believes that the elimination of the CES program would be detrimental to ratepayers, and contrary to the Board's most recent Order regarding the CES program.

The CES program provides important benefits for the Company and its customers. Since the curtailments resulting from the CES program reduce loads during times when electricity is in the shortest supply, this program should reduce the cost of BGS. *RA-29,* p. 19; T1092:L17-24. In addition, the load curtailments provide distribution related benefits, helping to maintain the reliability of PSE&G's distribution system and reducing the costs of distribution service by reducing the need for system improvements and maintenance. *Id.* These benefits should be preserved for the Company and its ratepayers.

The Board expressed its concern about maintaining an effective curtailment program for PSE&G in its most recent Order addressing the CES Program. *I/M/O the Petition of Public Service Electric and Gas Company–Review of Experimental Curtailable Electric Service Special Provision and Request for*

Approval of a New Program, BPU Docket No. ET000020102 (Decision and Order dated May 25, 2000) (referred to hereinafter as *"2000 CES Order")* (copy marked as *P-38).* In that proceeding, PSE&G had sought to modify the previously effective version of the CES program to target customers more likely to respond to requests to curtail, to eliminate a "premium credit" for curtailments made during the Company's system peak hour, and to approve the modified program on a permanent basis. *Id,* pp. 3-4. The Board, however, found that permanent approval would be "premature" given the relatively short period during which the Company's proposal was reviewed. The Board therefore approved the modified provisions on a continued experimental basis, pending further review to assure that the modified provisions would "contribute to a greater ability of PSE&G to manage the reliability of its distribution obligations during times of peak demand." The Board therefore approved the CES Special Provision, as modified, on a continued experimental basis "until such time as the parties are able to resolve any outstanding concerns and the Board has further opportunity to consider this matter." *Id.,* p. 4.

The Company is proposing, in effect, to bypass the review process contemplated by the *2000 CES Order.* The CES program would be eliminated with no review to assure that an effective curtailment program will remain in place.

PSE&G apparently does not dispute the benefits of the CES program. However, it argues that the current level of the CES credit, $6.11, was "based solely on generation capacity costs savings," and that, accordingly, the CES program should have been addressed in the Board's generic BGS proceeding, Docket No. EX-01110754. *PS-7-RB,* p. 13. This argument is unfounded. The elimination of the CES Special Provision was proposed by PSE&G in its filing in <u>this docket</u>. *P-7,* p. 86, 90, 91. Thus, assuming that the BGS docket is the exclusive forum in which "the continuance or discontinuance of these types of programs will be decided," it is PSE&G that has made its proposal in the wrong proceeding. *P-7-RB,* p. 14.

The rebuttal testimony of Mr. Schirra argues that the BGS proposal recently approved by the Board reflected an intent to "shift away from flat rates with curtailable incentives" toward the implementation of hourly pricing mechanisms that eliminate the need for incentives. *PS-7-RB,* p. 14. Mr. Schirra apparently intends to imply that the Board, by approving PSE&G's BGS proposal, implicitly authorized the Company to eliminate the CES Special Provision. This argument is baseless. In the Board's Decision and Order approving the proposals of the State's four electric utilities for procuring BGS suppliers for the "post-transition" period beginning August 1, 2003, hourly pricing was authorized only for the largest commercial and industrial customers. *I/M/O the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act,* BPU Docket Nos. EX01110754 & EO020700384 (Decision and Order dated December 18, 2002) (cited hereinafter as the *"Post-Transition BGS Order"*), p. 3. The approval of hourly pricing for a few large customers did not eliminate the need for the utilities' existing load management programs, and nothing in the Board's Decision and Order indicates any intent to eliminate these programs.

Further, PSE&G does not deny that the CES program benefits its distribution system. Rather, the Company appears to be arguing that it can achieve these benefits through its proposed "Customer Voluntary Load Reduction Program," which would provide no compensation to customers curtailing their loads. *PS-7-RB,* p. 14. However, the Company has provided no evidence of the effectiveness of such a program. The Company has failed to meet its burden of proof to justify that the change or alteration is reasonable pursuant to *N.J.S.A.* 48:2-21(d). In the absence of such evidence, the current CES Special Provision should be maintained.

Finally, during the cross-examination of Mr. Kalcic, the Company's attorney expressed concern that, to the extent that the distribution-related saving resulting from the CES program were less than the current $6.11 per kW credit amount, the Company would not be able to recover these costs. T1093:L10 - T1094:L4. This is not a sufficient justification for eliminating a beneficial load management program. Since the Company has made no effort to quantify the distribution benefits of the CES program, the amount of any under-recovery–or, for that matter, any over-recovery– is a matter of speculation. T1095:L3-8. If the Company believes that some of the costs of this program should be recovered through its BGS rates, it is free to make such a proposal as part of future BGS proposals.

The Company's CES program promotes conservation and load management, thus benefitting both PSE&G and its ratepayers. Your Honor and the Board should reject the Company's proposal to eliminate this important program.

9. The Company's Area Development Service Tariff Should be Reviewed Along With Similar Provisions in Other New Jersey Utilities' Tariffs for Uniformity and Consistency with Current State Policy.

Several of the Company's rate schedules include special "Area Development Service" rates for commercial and industrial customers located in specific communities. These provisions date from 1984, when the Board approved Area Development rates for nine communities. *I/M/O the Petition of Public Service Electric and Gas Company for an Increase in Electric and Gas Rates,* BPU Docket No. 837-620 (Decision and Order dated March 23, 1984). Four more communities were added in 1985 and 1986 and two more in 1988. *I/M/O Including the City of Plainfield in Area Development Service Special Provisions Tariff for Electric Service,* BPU Docket No. ET8509-886 (Order dated Oct. 10, 1985); *I/M/O the Request of Public Service Electric and Gas Company to Include Gloucester City, Passaic City and the Township of Weehawken in Area Development Service Special Provisions Tariff for Electric Service,* BPU Docket No. ET85101043 (Order dated March 6, 1986); *I/M/O the Requests of Public Service Electric and Gas Company to Include the Cities of Kearny and Orange in Area Development Service Special Provisions Tariff for Electric Service,* BPU Docket No. ET87080892 (Order dated December 28, 1988). The Ratepayer Advocate does not object to the continuation of these provisions. They should, however, be subject to the Board's continuing review to assure that PSE&G's Area Development tariff provisions are consistent with similar provisions in other utilities' tariffs and in accord with current State policies.

In a recent review of New Jersey Natural Gas Company's ("NJNG") Economic Development Service ("EDS") tariff, the Board expressed concern that the communities eligible for the special rates were based on the Municipal Distress Index compiled by the New Jersey State Planning Commission, which was last updated in 1996 and thus may be outdated. Therefore, the Board approved the NJNG tariff, but subject to a review by the Board's Staff of alternative indices that could be used to determine eligibility for the EDS rate. *I/M/O the Petition of New Jersey Natural Gas Company to Modify and Extend Nunc Pro Tunc its Current Economic Development Service Tariff*, BPU Docket No. GR01040223 (Order dated October 9, 2002). Since there has been no comprehensive review of the communities eligible for PSE&G's Area Development Service rate since it was originally established in 1984, the Board may wish to review this issue in light of the Staff review ordered in connection with the NJNG tariff.

In addition, area development tariffs are not consistent statewide. As an example, the EDS tariff recently approved for NJNG is limited to new customers receiving service at new or previously vacant buildings, and existing customers expanding their operations. Further, all customers applying for the EDS rate must demonstrate that they are adding new jobs. *Id., attached Second Revised Sheet No. 46.* PSE&G's Area Development Service tariff provisions do not include similar provisions. Your Honor should recommend that the Board review the PSE&G's Area Development Service tariff provisions, along with similar provisions in the tariffs of the State's other electric and gas utilities, to assure that they are consistent.

10. The Company's Proposed Tariff Should be Modified to Reflect the Company's Withdrawal of its Proposal to Require Certain Customers to Obtain Remote Metering Equipment at the Customer's Expense.

PSE&G's proposed tariff includes proposed new provisions giving customers the option of having the Company provide certain optional metering services, such as remote meter readings, availability of data pulse information, and advanced interval metering. *P-1, Schedule* 3, *proposed Original Sheet No. 21*. These optional services would all be available at the customer's expense. In addition, the proposed new provisions include the following language that would give the Company the right to require certain customers to pay for the installation of remote metering equipment:

> If the meter is not located in an outside readily accessible area solely due to the customer, Public Service reserves the right to install remote metering equipment at the customer's expense.

Id. Installation of remote meter reading equipment involves substantial expense, including $106.00 in initial set-up charges. *RA-29*, p. 17. The direct prefiled testimony of Mr. Kalcic recommended that the Board reject this provision as unnecessary, because the Board's rules, specifically *N.J.A.C.* 14:3-7.9 (b) , already address situations in which the Company is unable to obtain an actual meter reading. *RA-29*, p. 17.

In response to Mr. Kalcic's testimony, the rebuttal testimony of Company witness Gerald Schirra stated that the Company was withdrawing the proposed new language providing for mandatory installation of remote metering equipment at customer expense. *R-7-RB*, p. 54. The tariff established in this proceeding should reflect the removal of this language.

11. The Proposed Tariff Should Be Modified to Include Language Clarifying the Reasons for and Impacts of a Customer's Generation and Transmission Obligations.

Each of the Company's distribution rate schedules includes a section relating to a customer's "Generation and Transmission Obligations." These obligations do not affect a customer's distribution rates. Rather, they are used to determine the generation capacity and transmission service that must be obtained by Third Party Suppliers providing generation service to PSE&G customers. *RA-29*, p. 18. The Company's proposed tariffs did not explain the reasons for the Generation and Transmission Obligations, or their impacts on customers. As part of the discovery process, the Company provided additional tariff language to address this concern. *RA-29, Schedule BK-6.* The tariffs established in this proceeding should include the clarifying language provided by the Company.

POINT VII

YOUR HONOR SHOULD RECOMMEND AND THE BOARD SHOULD CONDUCT AN INVESTIGATION OF PSE&G'S METER READING PERFORMANCE, AND APPROPRIATE STANDARDS AND A PENALTY MECHANISM SHOULD BE ESTABLISHED TO ASSURE THAT THE COMPANY MEETS ITS SERVICE OBLIGATION IN THIS AREA.

One of the elements of proper utility service is accurate bills, based upon accurate customer usage information. *N.J.A.C.* 14:3-7.9. Accurate meter readings are becoming even more important with the implementation of rates that vary from month to month or from season to season, and with the increasing need for energy conservation. The record of this proceeding, however, suggests that PSE&G's meter reading performance is declining.

Based on data provided by PSE&G, the Company's estimated meter readings increased from an average of 12.4% in 1999 to an average of 14.7% during the first seven months of 2002. *RA-29*, p. 15*; R-10;* T332:L10 - T333:L8. Even more problematic from a customer perspective is the number of accounts with consecutive estimated meter readings. As shown in a Company response to a Ratepayer Advocate discovery request, the number of accounts with four or more consecutive estimated meter readings has grown steadily from 1999 through 2002. *RA-13,* p. 2. The deterioration in the Company's performance is most evident from the number of accounts with <u>nine or more</u> consecutive estimated meter readings. The number of such accounts grew from 38,666 in August 1999 to 66,959 in August 2002. *RA-13,* p. 2; T344:L3-10.

The Company has not provided any convincing explanation for the decline in its meter reading performance. One Company response to a Ratepayer Advocate discovery request stated that the decline was the result of increased vacancies in meter reading positions and increased vacation and sick days. *RA-12.* However, this same discovery response shows that the total "Meter Reading Mandays Lost" due to all of these factors were lower in 2000 and 2001 than they were in 1999, when the Company achieved a higher percentage of actual meter readings. *Id.* T340:L5 - T341:L7. The Company also has not explained why its meter reading performance has declined despite a significant increase in the number of its meters with remote meter-reading capability. *RA-16;* T356:L11 - T359:L3.

Despite the steady increase in accounts with consecutive estimated readings, the Company apparently has not undertaken measures to address this problem. According to Company witness Peter Cistaro, the Company's only meter reading "target" is to read at least 85% of all meters annually; there are no additional "targets" directed to accounts with consecutive estimated meter readings. *RA-12,* p. 1; T350:L8-18. Further, there is other evidence of the Company's failure to minimize the number of accounts with large numbers of consecutive estimated meter readings. The notice sent by the Company to customers with four or more consecutive estimated meter readings does not comply with the Board's meter reading rule. Such notices are supposed to explain "that a meter reading must be obtained" and advise the customer of the "penalty for failure to complete an actual meter reading." *N.J.A.C.* 14:3-7.9(b). The Company's notice does not meet either of these requirements. *RA-14;* T351:L2-21. The Company also does not maintain records of which customers receive the notice, nor does it maintain records of other measures to obtain actual readings, such as telephone contacts and evening and weekend meter reading appointments. *RA-14; RA-15;* T352:L13 - T355:L11.

The evidence discussed above indicates a clear need for PSE&G to improve its meter reading performance. Your Honor should recommend, and the Board should conduct, an investigation of the Company's meter reading performance. Based on this investigation, the Board should establish appropriate meter reading standards for the Company, along with a penalty mechanism for failure to achieve the standards.

CONCLUSION

For the above reasons and based on the substantial, credible evidence in the record, the Ratepayer Advocate urges Your Honor and the Board to adopt our recommendations as outlined herein and summarized below:

A. Rate of Return and Capital Structure

- Establish a 9.5% rate of return on common equity for the Company.

- This recommendation is consistent with recent Board policy with regard to rate of return. In particular, the Board's decision *I/M/O the Board's Review of Unbundled Network Elements Rates, Terms and conditions of Bell-Atlantic-New Jersey, Inc.*, BPU Docket No. TO00060356, Decision and Order (March 6, 2002) reflects the use of methodologies similar to the ones presented by the Ratepayer Advocate's witness in this proceeding.

- The Ratepayer Advocate's recommended return on equity is based upon the correct application of Discounted Cash Flow ("DCF"), Dividend Discount Model ("DDM") and Capital Asset Pricing Model ("CAPM") calculations by witness Basil Copeland.

- Company witness Dr. Morin incorrectly implemented the DCF model by relying solely upon estimates of earnings growth, ignoring estimated growth rates for dividends and book value per share. Dr. Morin also uses a functional form of the DCF model that overstates the dividend yield portion of the calculation.

- In his CAPM analysis, Dr. Morin substantially overstates the cost of capital. This is because he uses the Ibbotson Associates "arithmetic mean" analysis of stock market returns versus long term bonds rather than the correct use of the "geometric mean" to determine a long-horizon risk premium.

- In his second (or "ECAPM") analysis, Dr. Morin incorrectly uses published Value Line betas, which are already adjusted to compensate for the bias found in the empirical studies upon which ECAPM is based. The effect is a double count of the adjustment needed to reflect the results of the empirical studies.

- Both the "allowed risk premium"and "historical risk premium" methods used by Dr. Morin are invalid, for these approaches assume that all electric utilities have a constant risk premium over time, and because the data he uses do not meet the conditions of a valid linear regression, which is evident from the graphical evidence in his testimony.

- Dr. Morin incorrectly inflates his proposed return on equity by adding a 5% allowance for hypothetical flotation costs, rather than taking actual data from the November 2002 stock issuance in order to extrapolate any costs associated with the issuance of common stock.

- The difference between Company witness Morin and Ratepayer Advocate witness Copeland is summarized as follows:

- PSE&G's proposed change to its test year capital structure should be rejected for ratemaking purposes because it is beyond the end of the test year.

B. Depreciation

- The depreciation rate for electric distribution plant should be set at 2.49 percent and the expense allowance for depreciation should be adjusted accordingly.

- The excess depreciation reserve which developed since December 31, 1998 should be amortized to base rates over the remaining two years of the original amortization period set forth in the Board's Final Decision and Order in the Company's Restructuring Case.

C. Revenue Requirement

- Reject the Company's requested rate increase of $250,000,000 and adopt the Ratepayer Advocate's recommendation for an increase of $82,231,000. *RA-60,* Schedule RJH-1R (12+0 Update), line 7.

D. Pro Forma Operating Income

- Increase the Company's proposed pro forma operating income by $94,731,000 to a total of $183,181,000. *RA-60,* Schedule RJH-4R (12+0 Update). The individual components of this total adjustment are outlined below.

- Include revenues from fiber optic construction and pole and duct rental in the amount of $3,413,316, thereby increasing operating income by $2,018,976. *RA-60,* Schedule RJH-8R, lines 5 and 11 (12+0 Update).

- Include $9,220,000 for the year-end customer revenue annualization adjustment, thereby increasing operating income by $5,453,000. *RA-60,* Schedule RJH-9R (12+0 Update).

- Exclude PSE&G's proposed labor O&M ratio normalization, thereby increasing operating income by $9,892,000. *RA-60,* Schedule RJH-4R, line 4 (12+0 Update).

- Exclude PSE&G's requested incentive compensation plan expense of $3,378,000, thereby increasing operating income by $1,998,000. *RA-60,* Schedule RJH-10R (12+0 Update).

- Exclude PSE&G's requested Restructuring Cost Amortization, thereby increasing operating income by $7,397,000. *RA-60,* Schedule RJH-4R, line 7 (12+0 Update).

- Adjust PSE&G's proposed regulatory commission expenses by sharing the base rate case expense of $884,000 equally between shareholders and ratepayers and amortizing the audit expense of $670,000 and ratepayers' share of base rate case expense over five years, thereby increasing operating income by $882,000. *RA-60,* Schedule RJH-13R, line 4 (12+0 Update).

- Increase operating income in the amount of $537,000 by rejecting PSE&G's proposal to retain 50% of the five-year average net gains on sale of utility property. *RA-60,* Schedule RJH-14R, line 3 (12+0 Update).

- Include in the SBC and/or NTC deferred balance an amount of $726,000 for the ratepayers' 50% share of the net gain on the sale of electric transmission property and an amount of $5,101,000 for the ratepayers' 50% share of the net gain on the sale of the Kearny 12 electric generating station during the Transition Period. *RA-60,* Schedule RJH-14R (12+0 Update).

- Reject the Company's request for $2,467,000 in BGS implementation costs because it is factually unsupported by any substantial, credible evidence in the record.

E. Service Company

- Your Honor and the Board should condition any approval of the proposed transfer of assets to the Service Company ("Services") and the Service Agreement on the following conditions:

- PSE&G should not have to pay a return on assets transferred to Services that is higher than the return it would have earned had it retained those assets.

- The Service Agreement should be amended to include a description of how Services will charge affiliates for the carrying costs and operating costs associated with the transferred assets.

- PSE&G should be required to submit reports to the Board detailing the percentage of direct billing by Services and its allocation factors for indirect billing.

- PSE&G must demonstrate that its ratepayers will benefit from its proposed treatment of intercompany debt and working capital, and provide details regarding the basis for the allocation of borrowing costs and working capital.

- Services should be required to follow the same capitalization policy as PSE&G.

- PSE&G and Services must agree to be subject to the Board's authority in matters with respect to rates, franchises, services, financing, capitalization, depreciation, accounting, maintenance, operations or any other matter affecting PSE&G or Services, and its authority to review the reasonableness of charges incurred under the Service Agreement, as well as the Board's authority to review PSE&G's capital cost and operating and maintenance expenses.

- PSE&G and Services should be required to maintain their records within the State and provide the Board with full access to their records.

- PSE&G and Services should agree to prepare data relating to the service agreement as requested by the Board, provide information showing the benefits of the service company structure to ratepayers upon request; file with the Board and Ratepayer Advocate for the Board's prior approval any proposed changes to the Service Agreement, allocation factors, or other changes in costing and operations policies and procedures, at least 60 days prior to their proposed effective date.

- PSE&G should be required to demonstrate that the provision of Risk Management and Business Development services by Services will not violate the Affiliate Relation Standards, and agree to eliminate Marketing as a shared service under Services unless it can be demonstrated that it comports with the Board's Affiliate Relations Standards.

- PSE&G should be required to report any changes to Services' client base and any changes in the type and scope of the services it performs.

- PSE&G must submit a plan for the timely inclusion of new participants in the service company allocation formulae.

- PSE&G must demonstrate that its proposal for a service company will result in savings that could not be achieved by other means.

- In addition to providing identified data, information, documents, reports and notifications to the Board as set forth herein, PSE&G must also submit such information simultaneously to the Ratepayer Advocate.

F. Cost of Service and Rate Design

- The Company's cost-of-service study does not follow the cost allocation principles established by the Board in its most recent fully litigated electric base rate case. Nevertheless, the Company's class revenue distribution methodology, which considers the combined impact of the proposed distribution rate change and the expiration of the Company's MTC, produces reasonable results. The Ratepayer Advocate's proposed distribution rate increase should be allocated using this methodology.

- The proposals of intervenors NJLEUC and NJCU to allocate the proposed rate increase without consideration of MTC expiration and other rate changes should be rejected because of their disparate impacts on different customers classes, and because they would directly reflect the erroneous cost allocation principles used in the Company's cost-of-service study.

- The Company's proposed increase to its monthly service charges are not supported by a proper analysis of customer costs. These proposed increases should be rejected.

- The Company's proposed steeply declining block structure for residential winter delivery rates is a drastic departure from the current "flat" rate structure, and would have a disproportionate impact on low-use customers. The Board should preserve the current "flat" structure.

- PSE&G's proposal to recover virtually all non-customer charge revenues through the demand charge for its customer classes with demand charges should be rejected. Instead, non-customer charge revenues should be recovered from both demand and energy charges, in the same proportions as under current rates.

- The Company should be directed to inform customers of the availability of Residential Load Management service more frequently than the current annual basis, at least quarterly.

- The Company's proposed 267% increase in it Reconnection Charge should be rejected as it is excessive, unduly burdensome to low-income consumers, and counterproductive.

- The Company's proposed 57% increase in its Field Collection Charge would have a disproportionate impact on customers who have difficulty paying their bills, and is based on an improper cost analysis. This proposed increase should be rejected.

- The Company's SBC and NTC charges are to collect for social programs and costs of restructuring, which are most fairly allocated based on energy used by each customer. These charges should therefore be based on kilowatt hours delivered to the customer, without adjustment for loss factors.

- The Company's Curtailable Electric Service Special Provision benefits the Company and its ratepayers by reducing the costs of BGS, improving distribution system reliability, and reducing distribution costs. The Company's proposal to eliminate this provision should be rejected.

- The Company's Area Development Service tariff provisions should be approved subject to the Board's ongoing authority to review these provisions, along with similar tariff provisions of other utilities, for uniformity and consistency with current State policies.

- The Company's approved tariff should reflect the withdrawal of its proposal to require certain customers to obtain remote metering equipment at the customer's expense.

- The Company's approved tariff should include agreed language clarifying the reasons for and impact of customers' Generation and Transmission Obligations.

G. Meter Reading Performance

- Your Honor should recommend and the Board should conduct an investigation of PSE&G's meter reading performance. Based upon the results of the investigation, the Board should establish appropriate standards and a penalty mechanism to assure that the Company meets its service obligation in this area.

Respectfully submitted,

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RATEPAYER ADVOCATE

By:______________________________
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Dated: April 3, 2003.

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