BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS RATES AND FOR CHARGES IN THE TARIFF FOR GAS SERVICE	**)**	**BPU DOCKET NO. GR01050328** **OAL DOCKET NO. PUC-5052-01**
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY FOR AUTHORITY TO REVISE ITS GAS PROPERTY DEPRECIATION RATES	**)**	**BPU DOCKET NO. GR01050297** **OAL DOCKET NO. PUC-5016-01**

INITIAL BRIEF
OF
THE NEW JERSEY DIVISION OF THE RATEPAYER ADVOCATE

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PROCEDURAL HISTORY

On May 4, 2001, Public Service Electric and Gas Company (“Public Service,” or “Company”) filed a petition (“Depreciation Petition”) with the New Jersey Board of Public Utilities (“Board” or “BPU”) pursuant to *N.J.S.A.* 48:2-18 for approval of a change in its depreciation rates for its gas property. This case was forwarded to the Office of Administrative Law (“OAL”) on May 8, 2001 as a contested case and assigned to the Honorable William Gural, Administrative Law Judge t/a, (“ALJ”) for evidentiary hearings.

On May 25, 2001, Public Service filed a petition (“Petition”) with the Board pursuant to *N.J.S.A.* 48:2-21, and *N.J.S.A.* 48:2-21.1 for an increase in its gas rates and for changes in its tariff for natural gas distribution service. This case was forwarded to the OAL on May 30, 2001 as a contested case and was also assigned to Judge Gural for evidentiary hearings.

On June 20, 2001, the Board issued an Order suspending increases, changes or alterations in rates for natural gas distribution service, pursuant to *N.J.S.A.* 48:2-21, until October 25, 2001. On October 25, 2001, the Board issued another Order suspending rates, until February 25, 2002. Judge Gural entered an Order on June 27, 2001, consolidating the depreciation case and the base rate case for plenary hearings at the OAL.

In addition to the Company, the parties to this proceeding are the Staff of the Board (“Staff”), the New Jersey Division of the Ratepayer Advocate (“Ratepayer Advocate”) and several other parties. Several entities moved to intervene in the joint proceeding. New Jersey Energy Associates (“NJEA”) was granted intervenor status. Other movants were granted prticipant status. The Participants are South Jersey Gas Company (“South Jersey Gas”); Shell Energy Services, LLC. (“Shell”); Stony Brook Regional Sewerage Authority (“Stony Brook”);

and Enron Corporation ("Enron").[1]

A joint pre-hearing conference was held before Judge Gural on June 27, 2001 and a Pre-hearing Order was entered on that date. In accordance with schedule set forth in the Pre-hearing Order, discovery was propounded. Public hearings were held in Hackensack and New Brunswick on October 9 and 10, 2001, respectively. Additional public hearings are scheduled in Mount Holly and Mercerville (Hamilton, Mercer County), on November 5 and 7, 2001, respectively.

In support of its base rate case, concurrent with its filing the Company filed the testimony of Peter A. Cistaro (Gas Utility Operations), Robert C. Krueger, Jr. (Test Year), Albert N. Stellwag (Pro Formas and Capital Structure), Robert L. Hahne (Cash Working Capital), Dr. Roger A. Morin (return on Equity and Capital Structure), and Gerald W. Schirra (Gas Cost of Service and Rate Design). In support of its depreciation filing, Public Service filed the testimony of Donald S. Roff.

The Ratepayer Advocate filed the Direct Testimony of James A. Rothschild (Cost of Capital) on August 21, 2001. On August 24, 2001, the Ratepayer Advocate filed the Direct Testimonies of Robert J. Henkes (Revenue Requirement) , Brian Kalcic (Rate Design), and Michael J. Majoros (Depreciation). The Ratepayer Advocate filed the Direct Testimony of Roger Colton (Universal service) on August 27, 2001. Intervenor NJEA filed the Direct Testimony of Dr. George Briden on August 27, 2001.

On August 31, 2001, the Company filed the Rebuttal Testimony of Dr. Morin. The Company filed the Revised Testimony -- updated with twelve months of actual data -- of Gerald W. Schirra on September 6, 2001. On that date, the Company also filed the Rebuttal

[1] On October 29, 2001, the Utility Co-Workers Association filed a Motion to Intervene.

Testimonies of Mr. Schirra and the remaining witnesses, including the Rebuttal Testimonies of three Company witnesses who did not file Direct Testimony, Messrs. William J. Walsh, James I. Warren, and David W. Wohlfarth.

On September 12, 2001, the Ratepayer Advocate filed the Supplemental and Surrebuttal Testimonies of Messrs. Henkes and Colton. The Ratepayer Advocate filed the Supplemental and Surrebuttal Testimonies of Messrs. Rothschild and Kalcic on September 13 and 17, 2001, respectively. On September 17, 2001, the Ratepayer Advocate filed the Surrebuttal Testimony of Mr. Majoros.

Evidentiary hearings were held at the OAL on September 20, 24, 25, 26, and 28; and October 1, 2, 3, 4, and 5, 2001. At the close of the evidentiary hearings a briefing schedule was set, with initial briefs due on October 31, 2001, subsequently extended to November 2, 2001, and reply briefs due on November 14, 2001.

STATEMENT OF THE CASE

At a time when relatively high gas commodity prices and a weak economy already strain consumers' budgets, Public Service's proposed rate increase for gas distribution service would inflict further harm to the finances of its residential and business customers. The proposed increase is not insignificant.

The overall rate increase proposed by the Company is approximately $162 million annually. *P-4 R1*; Sch. ANS-2 R1. Consistent with the rate unbundling edicts of the Electric Discount and Energy Competition Act of 1999 (*N.J.S.A.* 48:3-49 *et seq*.) and the Board's Order[2] in the Company's gas unbundling case, the increase would be applied to charges for distribution service only. The proposed increase would not affect charges for the gas commodity.

However, the proposed rate increase must be put in the proper context. Although the proposed increase amounts to 6.04% based on total gas revenues, including commodity charges, the actual proposed overall percentage increase for the delivery charges is much larger. Excluding commodity revenues, the proposed increase amounts to a overall 24.29% increase in delivery charges. *RA-15*, Sch. BK-1R. Furthermore, certain rate classes will face even larger increases if the Company's proposal is adopted. For example, on average, residential customers taking service under the RSG tariff will face an increase in delivery charges amounting to 31.61% under the Company's proposal. *Id*. Commercial customers taking service under the GSG tariff, on average, will face an increase in delivery related charges amounting to 24.75%. *Id*.

As set forth more fully in the sections which follow, and in the testimony of the Ratepayer Advocate's witnesses, the Company proposed an unreasonably high rate of return, used a rate

[2] *I/M/O Public Service Electric and Gas Company's Rate Unbundling Filing Pursuant to Section 10, Subsection A of the Electric Discount and Energy Competition Act of 1999*, BPU Docket No. GX99030121.

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 rate request also presumes Board approve of its proposal to transfer its gas supply-related contracts to an unregulated affiliate, which is still pending before the Board.[3] Furthermore, the Company's proposed changes in its rates and tariffs are anticompetitive and place unreasonable burdens on its most troubled customers.

The Company's overstated claim for rate relief should be rejected. Instead, in accordance with the analyses and recommendations set forth in the testimony the Ratepayer Advocate's witnesses, a rate decrease of approximately $14.5 million is due ratepayers. *RA-1*, Sch. RJH-1R (rev. 10/29/01). As set forth in the sections which follow, there is overwhelming evidence in the record which supports the Ratepayer Advocate's recommend 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 overwhelming evidence calling for a much lower rate of return, Public Service proposes to retain its current 12% return on equity, established in its 1992 base rate case when both interest rates and equity risk premiums were much lower. T-88; Appendix A. Furthermore, the Company's current 12% return on equity figure was based on the risk profile of a combined electric and gas utility, while the current rate request is limited to the Company's less risky gas distribution operations. Based on the analysis of Ratepayer Advocate witness James

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[3] *I/M/O Public Service Electric and Gas Company's Proposal to Transfer its Rights and Obligations Under its Gas Supply and Capacity Contracts and Operating Agreements to an Unregulated Affiliate and for Other Relief*, BPU Docket No. GM00080564.

Rothschild, the Ratepayer Advocate is proposing a return on equity of 9.85 %. Unlike the 12% return proposed by the Company, Mr. Rothschild's recommended return figure is based on the proper application of sound methodology and is consistent with interest rate trends and expected returns for gas utilities. As discussed herein and in the testimony of Mr. Rothschild, the Company bases its proposal on a flawed application of the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") methodologies. *RA-7*. Furthermore, the Ratepayer Advocate proposes the adoption of rate base adjustments totaling over $145 million, as recommended by its witness, Mr. Robert Henkes. *RA-1*, Sch. RJH-1R (rev. 10/29/01) and Sch. RJH-3R (rev. 1/29/01); *RA-2*.

The Ratepayer Advocate also recommends other adjustments which properly reflect a reasonable level of expenses and revenues associated with the provision of utility service. Ratepayer Advocate witnesses also challenged many components of the Company's claimed operating expenses, including the Company's accounting for labor O&M expense, labor cost increases, executive incentive compensation, pension expense, regulatory expense, and others. The net result of the pro-forma revenue and expense changes proposed by the Ratepayer Advocate amounts to an increase of $101 million in pro-forma operating income versus the Company's proposal, from $56 million to $157 million.

The recommended adjustments include a significant reduction in the Company's claimed depreciation expense, reducing the pro-forma depreciation expense from $151 million to $63 million. *RA-1*, Sch. RJH-23R. As explained in the testimony of Ratepayer Advocate witness Michael Majoros, the Company's claimed depreciation expense is the result of grossly excessive net salvage estimates, and unreasonably short service lives. *RA-12; RA-12A*. These adjustments also include an adjustment amounting to $23 million to reverse an adjustment proposed by the Company associated with its plan to transfer of the Company's gas supply, storage and capacity contracts to an unregulated affiliate, which the Ratepayer Advocate opposes. *RA-1*, Sch. RJH-4R (Updated 10/3/01).

In order to equitably benefit the different classes of ratepayers, the rate decrease should be allocated to the various customer classes, with certain restrictions and adjustments, as proposed by Ratepayer Advocate witness Brian Kalcic. *RA-14*. As a guiding principle, the Ratepayer Advocate recommends an approach whereby no customer class would benefit from a decrease more than 1.5 times the system average, or less than 0.5 times the system average. *RA-14*, p.16. Furthermore, Mr. Kalcic moved delivery-related TSG-F and CIG margins amounting to $16 million from the LGAC to the Margin Adjustment Clause ("MAC") so that all firm distribution customers will benefit from these margins.

Furthermore, the Ratepayer Advocate recommends that certain tariff changes proposed by the Company should be rejected, so as not to deter competition or unduly burden ratepayers. The Ratepayer Advocate opposes as impediments to competition: (1) the Company's proposed minimum one-year term for residential customers returning from competitive suppliers; (2) a proposed doubling of security charges for competitive suppliers; and (3) a proposal to offer new optional meter services before competitive suppliers are permitted to enter the market. The Ratepayer Advocate also opposes as unduly burdensome and counterproductive the Company's proposal for a 275% increase in its reconnection charge for customers whose service is terminated for non-payment.[4]

In sum, as set forth in the sections which follow, the Ratepayer Advocate respectfully submits that the recommended adjustments and modifications be adopted by the Board.

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[4] In his testimony, Ratepayer Advocate witness Roger Colton proposed an interim universal service program pending Board action on a permanent universal service program. *RA-39; RA-40*. In light of the Board's action implementing an interim universal service program at its October 25, 2001 agenda meeting, the Ratepayer Advocate hereby withdraws that proposal.

POINT I

THE RATEPAYER ADVOCATE'S RECOMMENDED 9.85% RETURN ON EQUITY IS BASED ON THEORETICALLY VALID AND PROPERLY CALCULATED DCF AND RISK PREMIUM/CAPM METHODS CONSISTENT WITH CURRENT MARKET CONDITIONS AND SHOULD BE ADOPTED BY THE BOARD.

A. Introduction

Since the Ratepayer Advocate's witness Mr. James Rothschild adopted the Company's capital structure in this proceeding (*RA-7*, p. 8; *RA-8*), it is only necessary for the Board to determine the appropriate cost of equity. The Company's current authorized return on equity was set almost ten years ago in 1992 at 12% for its combined gas and electric operations. The Company seeks to maintain its 12% return on equity for its gas operations only. The Company's position was provided through the testimony of its witness Dr. Morin, who quantified the cost of equity through a Discounted Cash Flow ("DCF") method, and several Risk Premium/Capital Asset Pricing Model ("CAPM")[5] methods. The Ratepayer Advocate's position was set forth in the testimony of Mr. James Rothschild, who used two orthodox DCF methods–the single stage or constant growth method and the multi-stage method or complex or non-constant growth method–as well as two different Risk Premium/CAPM methods. The differences between the two witnesses may be summarized as set forth in the following chart:

[5]The concept of the risk premium/CAPM approach is to take a risk premium and add it to a known factor, such as the interest rate on bonds or the rate of inflation. It differs from a straight risk premium approach, because it adjusts the risk premium for the riskiness of the business being evaluated.

	Morin	Rothschild
DCF Methods:		
Constant Growth	11.50%-13.5%	9.22%-9.25%
Multi-stage	N/A	9.84%-9.96%
Risk Premium/CAPM:		
Increment over debt	10.6%-11.3%	7.72%
Increment over inflation	N/A	7.67%-8.03%
Increment for capital structure	0.30%	0.35%
Overall	12.0%	9.85%

Source: *P-6*, p. 42 and *RA-7*, Sch. JAR 2.

As set forth in detail below, Mr. Rothschild's results were based on the proper application of the DCF and Risk Premium/CAPM methods. Dr. Morin, on the other hand, made a number of serious errors which had the effect of significantly overstating estimates of the cost of equity.

As will be demonstrated below, Dr. Morin's claimed constant growth DCF method is constructed improperly, because he relied exclusively on short-term indicators of growth in earnings per share, rather than deriving a sustainable long-term growth rate based on an analysis of expected earnings on levels of capital investment that can be sustained over the long term. Dr. Morin's Risk Premium/CAPM methods suffer from a number of theoretical and mathematical errors. One of his two "CAPM" approaches is fundamentally flawed because he used the upwardly biased arithmetic average, rather than the proper geometric average, to determine his historical actual returns, and because he disregarded the general downward trend in risk premiums over the past three to four decades. His other "CAPM" approach, and one of his three "risk premium" approaches, are based on his flawed DCF method. His second "risk premium" approach is based on the erroneous assumption that achieved rates of return are equivalent to the cost of capital. His final "risk premium" approach, which is based on returns that have been allowed by utility commissions, is circular, and overstates the cost of equity because it does not account for the changes in interest rates between the time evidence is placed on the record and the time a decision is issued. *RA-7*, p. 62-63.

The unreasonableness of Dr. Morin's approach is also apparent from a comparison of market conditions and the company's own risk profile at the conclusion of the company's last base rate case in 1992 and today. Since 1992 there has been a substantial and generally persistent decline in interest rates. Even Dr. Morin acknowledged that there has been a 200 basis point drop in interest rates. T85:L.2-8. The downward trend in interest rates has accellerated in recent months, as the interest rate on long-term treasury bonds is now 4.87%. See Interest Rate Table, *New York Times,* Nov.1, 2001, C-8. This is a material drop, since that same Interest Rate Table also shows that a year ago the interest rate on 30-year Treasury bonds was 5.78%. Furthermore, an accompanying *New York Times* article, in discussing the Treasury's unexpected discontinuance of the sale of 30-year treasury bonds, described this as the government's attempt to lower long-term interest rates. *New York Times,* Nov.1, 2001, C-1, C-7. We are also now in an environment where it is likely that the Federal Reserve may further lower interest rates in the near future.

It is also widely recognized by the investment community that equity risk premiums have been on a downward trend. For instance, on October 4, 2001 Credit Suisse First Boston, a major international banking firm, issued a report concluding that the equity risk premium over long-term treasuries is 3.7% for an equity of average risk. Andrew Garthwaite, *Global Strategy*

Perspectives: Is The Price Right? CREDIT SUISSE FIRST BOSTON WEEKLY INSIGHTS, Oct. 4, 2001, p. 55. (Copy attached as Appendix A). Adding this 3.7% to the current 4.87% interest rate on long-term treasury bonds produces a cost of equity for a company of average risk of 8.57%, a result confirming the eminent reasonableness of Mr. Rothschild's 9.85% recommendation. In Mr. Rothschild's testimony, the comparable number based on the most recent long-term interest rate available at that time of 5.65%, to which is added the 3.7% risk premium, produces a cost of equity of 9.35%. *RA*-7, Sch. JAR-9.

Finally, this proceeding involves only Public Service's gas operations, whereas in 1992 the Board allowed a 12% return for both electric and gas operations, including the now-divested electric generating plant, the riskiest part of the combined utility's business. Dr. Morin admitted on the record that the risk profile of a gas utility is now quite similar to that of water companies. T88:L4 -T.89:L1.

All of these factors should result in a lower cost of equity than the 12% allowed for the combined electric and gas utility in 1992. Dr. Morin's recommendation of the same 12% is a clear indication of the underlying flaws in his analysis.

Mr. Rothschild's 9.85% recommendation is, as it should be, somewhat lower than the BPU has allowed in recent years - 10.5% being the return the BPU started allowing beginning with the Consumers Water case, Docket No.WR00030174, Jan. 2, 2001, and was the most recently allowed return. *In re Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Changes*, Docket No. WR00060362, June 6, 2001. Since long-term treasury bond interest rates have dropped dramatically even since the hearings in this case, the fact that Mr. Rothschild's cost of equity recommendation is lower than recent allowed returns simply confirms its accuracy. This recommendation is, on its face, more reasonable than Dr. Morin's recommendation, which appears to give scant recognition to the changes in the market and the company's risk profile that have occurred since 1992.

B. The Cost of Equity Should Be No Higher Than Required By Investors to Buy or Hold the Stock.

The ratemaking process is designed to give a utility the opportunity to recover prudently incurred costs of providing utility service to its customers, including a return on its used and useful utility property. The Board's regulation of a utility's rate of return ("ROR") is intended to identify the fair and reasonable cost of capital invested in the utility's rate base and to approve rates that give a soundly managed utility an opportunity to recover those costs. A utility's ROR should be "reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." *Bluefield Waterworks and Imp't. Co. v. Public Svc. Comm.*, 262 U.S. 679, 693 (1923); accord *Public Svc. Coord'd Transport Co. v. State*, 5 N.J. 196, 225 (1950). In this process, the Board must balance the competing interests of the rate paying public and investors in Public Service's parent corporation, PSEG, to arrive at a figure "within the range of reasonableness, the zone between the lowest rate not confiscatory and the highest rate fair to the public." *In re N.J. Power & Light Co.*, 9 N.J. 498, 534 (1952). A fair return on equity for utility investors is the return investors require to hold or acquire that utility's common stock. Any return higher than necessary to meet investors' requirements would provide them with an unexpected windfall at the expense of ratepayers who would be overcharged for utility service. The investors' return requirement would normally be sufficient to permit the utility to maintain its financial integrity and to attract additional capital. The minimum required return on common equity is the cost of common equity. The cost of common equity must be estimated through analyses of capital market behavior as investors do not directly specify the return they require on their common stock investments.

C. The Cost of Equity Recommendation of the Ratepayer Advocate Is Properly Calculated and Based on Methodologies Accepted by the Investment Community, Whereas the Company's Cost of Equity Recommendation Is Based on Flawed Methodologies and Improper Calculations.

1. DCF Methods.

The DCF method is probably the most widely used approach to return on equity determinations in utility rate cases. This model states that the percent return expected and therefore required by investors equals the discounted value of future expected cash flows with the discount rate being the rate that makes the value of future cash flows equal to the current market price. It is mathematically correct to simplify the DCF relationship to the following formula if and only if, the future growth in earnings, dividends, book value and stock price are estimated to grow at the same constant rate sustainable over the long term:

cost of equity=dividend yield + future expected growth (*RA*-7, p. 22)

Mr. Rothschild used two DCF approaches : the single-stage or constant growth method, and the multi-stage method. The constant growth, or single-stage version of the DCF model, determines the cost of equity by adding the dividend yields and a constant future expected growth rate. The multi-stage DCF model separately discounts each future anticipated cash flow and therefore does not require estimation of a constant, long-term growth rate. *RA-7*, p. 9-10.

Constant Growth DCF Method.

As emphasized by Mr. Rothschild, " this constant growth method only produces a valid result if the value used for the growth rate is reasonably representative of investors' future expectation of a constant growth rate for earnings, dividends, book value, and stock price." *RA-7*, p. 9. For this method, it is of utmost importance to choose the appropriate *long-term sustainable* growth rate that is *equally applicable* to all these elements. *Id.*, p. 10.

As noted above, the cost of equity is determined under the DCF method by adding two components, the expected dividend yield and the expected growth in earnings. Mr. Rothschild derived the current annual dividend yield for each company in the comparative group of gas utility companies chosen by PSE&G, using the stock price of each company determined both by the actual stock price as of June 30, 2001, and the average of the high and low stock price for the year ended June 30, 2001. He then estimated the dividends over the next year by adding one-half the future expected growth rate to the dividend yield. *RA 7*, p. 33.

Mr. Rothschild's derivation of the expected growth rate is based on the principle that earnings growth that is sustainable in the long term is based on the company's re-investment of retained earnings. Thus, his estimate is based on the so-called "b x r" method, where "b" is the portion of a firm's earnings that is re-invested in the business, and "r" is the firm's anticipated return on new equity investments. *Id*. p. 35. In essense, this method measures the future capital appreciation that investors are expecting. *RA-7*, p. 21. As noted in Mr. Rothschild's testimony, the "b x r" method is supported by a number of scholarly sources. *RA-7*, p. 34-35.

To apply the constant growth DCF method, Mr. Rothschild first determined the expected rate of return on equity using a variety of indicators of the expected return on equity for gas distribution utilities. *Id*., p. 38-39. He then derived the retention rate, or “b” using a calculation recognizing that “b” is merely the residual of the dividend rate and the future expected return on book equity or “r”. *Id*., p. 39-40. Mr. Rothschild also recognized that another source of sustainable growth is sales of new common stock above the book value. Thus, he made an addition to the “b x r” formula to account for this additional growth factor. *Id*., p. 35. Mr. Rothschild’s application of the constant growth version of the DCF method to the comparative group of gas utilities resulted in a cost of equity range from 9.22% to 9.25%. *RA-7,* sch. JAR-2.

As cogently expressed by Mr. Rothschild, the chief problem with Dr. Morin’s DCF method is that he claims to have used a constant growth version of the DCF model, but in reality he used short-term indicators of earnings growth as proxies for long-term sustainable growth. *RA-7*, p. 65. Specifically, Dr. Morin used the Institutional Brokers’ Estimate System’s (“IBES”) monthly publications for the long-term growth forecasts, as proxies for investors’ growth expectations. He also used the Value Line’s earnings growth forecast as an additional proxy. Both IBES and Value Line, the two measures used by Dr. Morin, are short-term forecasts of growth in earnings. *RA-7*, p. 65. Thus, in contrast to Mr. Rothschild’s methodology, which derived a long-term sustainable growth rate based on estimated returns on equity applied to projected retained earnings, Dr. Morin simply applied the DCF method directly to an estimate of

short-term earnings growth. *RA-7*, p. 65.

As Mr. Rothschild explained, “it is improper to directly use a five year earnings per share forecast as a proxy for long-term sustainable growth in the constant growth DCF model." *RA-7*, p. 29. These forecasts are not representative of long-term, sustainable growth because they "include the often substantial impact of bringing earnings up and down to a normal earned return in equity from whatever return on equity was achieved in the most recently completed fiscal year." *Id*. Further, there is a well-documented tendency for analysts to be overly optimistic on their estimates of future earnings. *RA-7*, p. 29-30. This habitual optimism has the effect of causing short-term earnings forecasts to reflect high growths rates over existing earnings that cannot be sustained over the long-term. *Id*., p. 30.

The appropriate and inappropriate uses of earnings growth forecasts were reflected in the above-cited recent report issued by Credit Suisse First Boston. That report correctly used the Instutional Brokers' Estimate System ("IBES") consensus growth rate for only the first five years of a multi-stage DCF analysis, switching to an estimate of a sustainable growth rate for the remainder of the analysis. Garthwaite, *supra*, p. 57 (Appendix A). The same report also notes that "over the last 10 years I/B/E/S earnings have on average been 6% too optimistic 12 months prior to a reporting date." *Id*., p. 58.

Further, the use of short-term earnings growth as a proxy for sustainable, long-term growth leads to conflicting, non-constant growth rates, a direct violation of the requirements of the constant growth formula required for the single stage DCF model. This was demonstrated in an example set forth in Mr. Rothschild's testimony. As shown in his Schedule JAR-3, while the earned return on book equity for the comparative group of gas distribution utilities was 12.53% in 2000, the average forecasted return on equity in five years that is consistent with the analysts' consensus earnings per share growth rate is 15.40%, and the median forecasted amount is

14.64%. *RA-7*, Sch. JAR-3, p. 2-3. For this increase to occur, earnings would have to be forecast to grow more rapidly than book value– a result that is inconsistent with the fundamental requirements of the constant growth DCF model. *RA-7*, p. 65-66.

For the above reasons, Mr. Rothschild's constant growth DCF analysis is based on a properly derived estimate of long-term sustainable growth, while Dr. Morin's analysis improperly used short-term earnings growth estimates as a proxy for long-term growth. Dr. Morin's analysis, which substantially overstates the cost of capital, should be rejected by the ALJ and the Board.

Multi-Stage DCF

Mr. Rothschild also performed a multi-stage DCF analysis. In this analysis, Mr. Rothschild performed a DCF analysis in two stages, the first based on short-term growth projections for the 2000-2005 period, and the second based on projections 40 years into the future.

For his first-stage determination, Mr. Rothschild used Value Line's estimates of dividends per share and earnings per share for 2001 through 2005 for the companies examined. This is the same indicator used improperly by Dr. Morin for his long-term growth projection. However, it is properly used in a multi-stage DCF analysis which, as noted, does not require the use of a single, constant, estimate of sustainable long-term growth. Since Value Line does not show a specific earnings and dividend projection for every year from 2001-2005, Mr. Rothschild interpolated from the available data, and mechanically used Value Line's projections for the period. *RA-7*, p. 40.

For the second stage of the multi-stage or non-constant DCF model, Mr. Rothschild determined future earnings by multiplying the future book value per share by the future expected earned return on book equity, using the same future expected return on book equity used in the constant growth, single-stage or "simplified" DCF version. *Id.*, p. 40-41. For the second stage of this DCF model, projections were made 40 years into the future, and relied on a constant dividend payout ratio set equal to the payout ratio for 2001. *RA-7*, Sch. JAR-5, p. 1. Mr. Rothschild derived the estimated future stock price from the projected book value using the same market-to-book ratio at the time of sale as exists today. The stock price used was both the spot stock price as of June 30, 2001 and the average stock price for the year ended June 30, 2001. *Id.*, p. 41. The retention rate for the second-stage was set equal to the retention rate of 39.16% forecast by Value Line for 2002, which is higher than the current rate of 30.85% (based upon the actual earnings per share of $1.88 from *RA-7*, Schedule JAR 3, p. 2 and the average dividends per share of $1.30 from JAR 6), but lower than the rate forecast by Value Line for 2005 of 50.10%. In Mr. Rothschild's judgment, it is unlikely that investors expect such a large change in the retention rate. *Id.*, p. 42. This multi-stage version of the DCF Method indicates a cost of equity between 9.84% and 9.96% for the comparative group of gas distribution companies. *RA-7*, Sch. JAR 5, p. 1-2.

2. Risk Premium/ CAPM Methods -

a. Overview

The concept of the risk premium/CAPM approach is to take a risk premium and add it to a known factor, such as the interest rate on bonds or the rate of inflation. As explained by Mr. Rothschild, the risk premium/CAPM method estimates the cost of equity by analyzing the historic difference between the cost of equity and a related factor such as the rate of inflation or the cost of debt. *RA-7*, p.43 Mr. Rothschild used both an "inflation risk premium" approach and a "debt risk premium" approach. The inflation risk premium approach, based on an analysis of the earned total return on equity investments compared to the inflation rate, indicated a cost of equity between 7.67% and 8.03%. *RA-7* p. 10-11. The "debt risk premium" approach, based on an analysis of the difference between actual total returns earned on common stocks, indicated a cost of capital of 7.72%. Dr. Morin used a variety of "debt risk premium" approaches to arrive at a recommended cost of equity of 10.6% to 11.3%. As explained below, Mr. Rothschild properly applied his risk premium analyses, while Dr. Morin approaches overstated the cost of equity.

b. The Ratepayer Advocate's Risk Premium/CAPM Methods

Mr. Rothschild applied the inflation risk premium method by adding investors' current expectations for inflation to the long-term rate earned by common stocks net of inflation. This result was then adjusted downward for the lower risk for the average gas distribution utility. *RA-7*, p. 49. As Mr. Rothschild explained, since the U.S. government now issues inflation-indexed treasury bonds, it has become possible to analytically determine investors' expectations for inflation. By comparing the interest rate on conventional U.S. treasury bonds with the interest rate on inflation-indexed U.S. treasury bonds, the future inflation rate anticipated by investors can be quantified. Mr. Rothschild estimated this rate as of early July 2001 at about 2.25% by subtracting from the 5.63% rate of long-term non inflation-indexed treasury securities, the long-term inflation indexed treasury securities of 3.48%. *RA- 7*, p. 50 & Sch. JAR 9. This result was rounded up to 2.25% and when added to the 6.6 % - 7.2% range produces an inflation risk premium of 8.85%-9.45% for an equity investment of average risk. This then was adjusted downward for the lower risk of the comparative gas companies. *Id.*, p. 50 & Sch. JAR, p. 3. Mr. Rothschild arrived at an indicated inflation premium cost rate of 7.67% - 8.03%, with a midpoint cost of equity of 7.85%. *Id.*, p. 51 & Sch. JAR 9.

Mr. Rothschild's second approach was to add a risk premium to the cost of debt. *RA*-7, p. 11. To determine his debt risk premiums, Mr. Rothschild performed an analysis of the historic difference between actual total returns on common stocks and total returns on bond investments. *Id.* Mr. Rothschild's analysis included separate determinations of the proper risk premiums for long-term treasury bonds, long-term corporate bonds, intermediate-term treasury bonds and short-term treasury bonds. *RA- 7,* p. 51; Sch. JAR 10. According to Mr. Rothschild, this resulted in a wide array of data points across the yield curve, and made it less likely that the result would be affected by temporary imbalances that may exist in individual debt maturity yield curves. *Id.*, p. 51.

Mr. Rothschild explained that risk premiums are not quantifiable with absolute certainty, since they change over time, and at different rates, depending upon the term of the bond or the nature of the company. Because of such short-term fluctuations, a risk premium method that looks at the entire yield curve, rather than just one component such as 30 year bonds as Dr. Morin has done, has a better chance of being accurate. *RA-9*, p. 60-61.

Mr. Rothschild further explained that, in determining his debt risk premiums, he took account of the decline in risk premiums that has occurred in recent years. *RA-7,* p. 51-52. As Mr, Rothschild noted in his testimony, the recent persistent decline in risk premiums is widely recognized. In a recent speech, Federal Reserve Chairman Alan Greenspan stated "That equity risk premiums have generally declined during the past decade is not in dispute." *RA-7*, p. 43. A number of other sources, discussed in detail in Mr. Rothschild's testimony, confirm this observation. *RA-7,* p. 44-49. To further confirm the downward trend in risk premiums for stocks, Mr. Rothschild reviewed the historic actual earned returns on common stocks and bonds from 1926 through 1999, as well as a 30-year moving average of the earned returns. Mr. Rothschild relied on the 30-year data as a long enough time period to even out potential short- term imbalances due to initial market responses to reductions in risk premiums. This analysis showed that the "decline in the risk premiums is persistent and undeniable, confirming the experts' opinion that equity risk premiums have declined. *RA-7,* p. 51-22.

Mr. Rothschild's analysis indicated a risk premium of 3 to 4 percent over 30-year United States treasury bonds. Mr. Rothschild used the conservatively high estimate as the risk premium over 30-year treasuries, and then adjusted this estimate as warranted by the historic data to determine risk premiums for long-term corporate bonds, intermediate-term treasury bonds and short-term treasury bonds. *Id.*, p. 54.

c. Analysis of Company's risk premium/CAPM methods

Dr. Morin presented five different debt risk premium studies: two CAPM studies which purport to analyze risk premiums based on aggregate stock market premium evidence, and three other risk premium studies purporting to analyze the gas distribution industry. *P*-6, p. 18, p. 42. Each of these studies suffers from serious mathematical and theoretical errors.

Historical CAPM study

In Dr. Morin's first CAPM study, he derived a risk premium based on an analysis of historic returns on common stocks versus 30-year treasury bonds from 1926 through 1999. *RA-7*, p. 7. This study overstates the cost of equity for three reasons.

The most serious defect is Dr. Morin's use of an arithmetic average to compute historical returns. *RA-7*, p. 63. Dr. Morin's historical risk premium is based on the average of two estimates, one of which he derived using an arithmetic average of historical returns from an Ibbotson Associates study of historical returns from 1926 to 1999. *P-6*, p. 22-23. Using arithmetic averages overstates significantly the cost of equity, because it is upwardly biased, as has been almost universally recognized by experts in the field. *RA-7*, p. 70-71.

The basic flaw in using arithmetic averages is demonstrated in an illustration provided by Mr. Rothschild. Assume a company has a stock price of $10, at the beginning of the first year of the period, and a $5 stock price at the end of the first year. The return earned by the investor in the first year would be a loss of 50%. If in the second year the stock price returned to $10, this would represent a gain of 100%. The arithmetic average approach would average the 50% loss in the first year with the 100% gain in the second year, to conclude that the total return received by the investor over this two year period would be 25% per year. This is clearly in error, as the investor's actual total return over the two-year period is 0%. In contrast, the geometric average considers only the compound annual return from the beginning $10 to the ending $10, and correctly determines that the annual average of the total returns was not 25% but zero. *RA-7*, p. 68-69.

As pointed out by Mr. Rothschild, numerous textbooks as well as Value Line all recognize that the proper way to measure long-term historic actual earned returns is to use the geometric mean. Furthermore, that is the method adopted by the U.S. Securities and Exchange Commission for its form N-1A wherein it requires mutual funds to report actual returns based upon the geometric average and prohibits the reporting by use of the arithmetic average. *RA-7*, p. 67; *RA-9*, p. 63. As discussed in greater detail below, several sources specifically identified the arithmetic mean as a method that creates upwardly-biased results.

The financial community, as illustrated in articles from the *Wall Street Journal* and *Business Week*, also refers to geometric averages when evaluating historic returns. *RA-7*, p. 69; p. 46-47. The August 16, 1999 issue of *Fortune* magazine simply refers to the return that is equal to the geometric mean from Ibbotson Associates as “the oft-quoted calculation” of historic actual returns without even mentioning the historic arithmetic average. Ibbotson Associates also considers the geometric average as “...the correct average to compare with a bond yield...” *RA-7*, p. 72. Mr. Rothschild also cites to a number of textbooks which support the geometric average of rates of return because arithmetic averages are biased and the geometric mean is the appropriate measure over long periods of time. *RA-7*, p. 70-71. Similarly, Value Line in a May 9, 1997 report entitled “The Differences in Averaging” states:

> (t)he arithmetic average has an upward bias, though it is the simplest to calculate. The geometric average does not have any bias, and thus is the best to use when compounding (over a number of years) is involved. *RA-7*, p. 71.

Financial textbooks also support the use of the geometric averages. Three such sources were cited in Mr. Rothschild's prefiled direct testimony. *RA-7*, p. 70-71.

Dr. Morin relied on one textbook, the 2000 edition of *Principles of Corporate Finance*, by Brearly and Myers, which appears to use the arithmetic average result in certain examples in the text. *P-6RB*, p. 43 However, as Mr. Rothschild noted, even good financial textbooks occasionally err. *RA-9*, p. 63. Furthermore, the Harris study "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", upon which Dr. Morin also relies, specifically notes on page 62 of that study that in checking the risk premiums, it did so by comparing it to a geometric return. *RA-9*, p. 61. Another textbook relied upon by Dr. Morin - *Valuation. Measuring and Managing the Value of Companies*, by Copeland Koller and Murrin c.2000, qualifies its support for arithmetic averages by stating that a measured time period should at a minimum be two or more years, not one. *Id*., p. 64. Dr. Morin used a one-year arithmetic mean return. *Id*., p. 64. In fact, that text shows that using a two- to four- year period instead of only one year produces a result only slightly higher than using the geometric average. The text goes on to advocate reducing the risk premium for a "survivorship bias" and concludes that the market risk premium should be in the 4.5 to 5% range, which is actually .9% to 1.4% below the geometric average. *Id*., p. 64-65.

Mr. Rothschild also demonstrated through a graph showing the actual movement of the S&P Utility Index from 1928-1998 that using the actual average annual growth, the arithmetic average historic growth rate methodology would have overstated the total return for that period by almost 400%, while the geometric method endorsed by the SEC, would have resulted in a close match to actual results for that time period. *RA-7*, p. 72-74. The arithmetic average method produced a risk premium about 1.90% higher for public utility stocks versus public utility bonds (and the arithmetic median produced a 1.85% higher risk premium) than the risk premium indicated by using the geometric average or SEC method. *Id.*, p. 75.

Finally, Dr. Morin himself admits that the geometric average is both correct and appropriate when measuring performance over a long time period. *P-6RB*, p. 47. His insistence that geometric averages are incorrect when estimating a risk premium simply demonstrates Dr. Morin's illogic, for risk premiums also are computed over long periods of time. Dr. Morin's selection of an arithmetic average makes no sense, and his recommendation based on this erroneous method should be entirely disregarded.

Another serious flaw in Dr. Morin's historical CAPM study is that it ignored the general downward trend in risk premiums over the past three to four decades. *RA-7*, p. 63, 75. As discussed in detail above, the decline in risk premiums compared to historic levels is well recognized, and should be reflected in a debt risk premium analysis based on long-term historic trends. *RA-7*, p. 51-57.

Finally, Dr. Morin's historical risk premium approach used historic 30-year treasury bond yields as of March 2001 of 5.5% as a proxy for the risk free interest rate in his CAPM model, adjusted downward for the lower risk profile of gas utilities. *P-6*, p. 20-21; Sch. RAM-4. In doing so he ignored the interest rate risk inherent in long-term investments. *RA-7*, p. 75. As Mr. Rothschild explained, there is an active secondary market in long-term treasury bonds which fluctuates with interest rates, *i.e.* the secondary market prices for long-term bonds go up when interest rates go down, and go down when interest rates go up. *Id.* This demonstrates that investors can sustain gains or losses when they purchase long-term treasury bonds. *Id.* In fact, a chart provided by Dr. Morin shows the total return received by investors who owned long-term U.S. government bonds for each month from 1926 through 1999. There are many months during this time period in which the total return received by investors was negative. *RA-7*, p. 76. Dr. Morin's use of only long-term treasury bonds as a proxy for a security with no risk therefore overstates the cost of equity and his computation of a risk premium based upon the difference between actual return on book equity and long-term U.S. treasury bonds is therefore too high.

Forecasted CAPM Study

Dr. Morin's second CAPM approach purported to estimate a risk premium by comparing an expected return on the aggregate equity market to returns on long-term treasury bonds. *P-6*, p. 24. For this approach Dr. Morin used the same invalidly constructed, constant-growth DCF analysis that he had earlier used to establish a DCF based cost of equity. *RA-7*, p. 62-63, p. 65-67. Since he used the same DCF format he used to calculate his DCF-based cost of equity, this method is invalid for the same reasons stated above – it produces different growth rates among the various factors, not the constant growth rate on which the theory is premised. Using his incorrect theory, he arrives at an incorrect implied risk premium of 7% over long-term U.S. Treasury bonds that are currently yielding 5.5%. *P-6*, p. 24. His 7% risk premium is almost twice as high as the 3.7% found proper in the above-cited report issued by Credit Suisse First Boston. Garthwaite, *supra*, p. 55 (Appendix A). Since Dr. Morin's method is dependent on his incorrect DCF approach, the 7% result is clearly incorrect. *RA-7*, p. 66-67

"Correction" to CAPM Studies.

Dr. Morin compounded the errors in his CAPM studies by making an erroneous "correction" for an asserted "downward bias" in the CAPM method for companies with lower than average risks such as gas distribution companies. Dr. Morin averaged the risk premiums derived under the above two methods (7.8% and 7%, respectively) to derive a market risk premium of 7.4% and recommended cost of equity of 10.3 % before financing costs. *P*-6, p. 22. Dr. Morin used what he refers to as an "expanded CAPM ('ECAPM')" to counteract the claimed CAPM method for companies with lower than average risk, such as gas utilities. He estimated an "empirical" risk premium for the gas distribution industry using Moody's Gas Distribution Utility Index monthly data over the past 15 years arriving at a return on common equity of 11% before financing costs. *P-6*, p. 26. Indeed, he criticized Mr. Rothschild for not being aware of this. *P-6RB*, p. 48. As Mr. Rothschild explained in his rebuttal testimony, Dr. Morin is correct that there is a tendency for low risk companies to earn more than predicted, but Value Line data already accounts for this. *RA-9*, p. 66. Dr. Morin's own adjustment, as well as his conclusion that Mr. Rothschild underestimated equity costs by about 50-60 basis points because of this downward bias, are both entirely unfounded.

Other Risk Premium Approaches

As noted, Dr. Morin used three other risk premium approaches specifically to gas distribution companies. One of these approaches produced a result within the range recommended by Mr. Rothschild despite its reliance on Dr. Morin's flawed DCF method. The other two approaches should be rejected due to fundamental theoretical or mathematical flaws.

The first of the three risk premium approaches purported to derive a "prospective risk premium" for gas distribution utilities by computing a cost of equity capital for gas distribution utilities for each month from 1984 to 1999 using a DCF model, and then subtracting the corresponding yields on long-term treasury bonds for each month. *RA-6* p. 26-27. The implied cost of equity for the average gas distribution utility using this method is 9.7% (the current 30-year Treasury Bonds yield of 5.5% plus 4.2% growth rate equals 9.7%). *Id.*, p. 27. Interestingly, this method produced a result within the range of the DCF results obtained by Mr. Rothschild. *RA*-7, Sch. JAR-2. This is probably due to the fact that over this time period, there were enough years when earnings per share produced a low estimate of the sustainable growth rate to offset years in which the earnings per share growth rate produced an excessive estimate. *RA*-7, p. 64.

Dr. Morin's second risk premium approach purported to examine historical risk premiums for gas distribution companies. *RA-6,* p. 6. In this approach, Dr. Morin estimated a risk premium by computing the actual return on equity for this time period, using actual stock prices and dividends of the Index, and then subtracting the long-term government bond return for that year. He found that the average risk premium over the period was 5.7% over long-term Treasury Bonds, and since these are currently yielding 5.5%, he concluded that the implied cost of equity for the average gas distribution utility under this method is 5.5%+5.8%=11.3%. *RA-6,* p. 27-28. This approach is invalid because it assumes that actual return on equity is a proxy for the cost of equity. As Mr. Rothschild explained, actual return on equity overstates the cost of equity whenever a company's market-to-book ratio is in excess of 1.0. *RA-7,* p. 63.

Finally, Dr. Morin computed a risk premium based upon returns on equity allowed in other jurisdictions over the time period 1987-2000, resulting in a risk premium estimate of 5.3%, and an implied allowed return on equity of 10.8%. *P-6,* p. 28-30. This risk premium method also overstates the cost of equity for two reasons. First, it is based on a comparison of allowed returns on equity with interest rates that prevailed as of the time of rate decision. The overstatement occurs because there is a lag between the time of the record evidence and the commission decision. *RA-6,* p. 64. As Mr. Rothschild explained, during the time period 1987-2000, interest rates on long-term treasury bonds decreased from 8.63% (1987) to 5.93% (2000), resulting in commission decisions issuing when there were lower interest rates than were used in the record evidence. This created an upward bias in the data utilized by Dr. Morin. *Id.* Finally, Dr. Morin's reasoning is circular, because it relies on commission decisions instead of actual market behavior, to determine the cost of equity. As Mr. Rothschild explained, "if commissions used this approach, there would never be an opportunity to evaluate the cost of equity actually being demanded by investors." *Id.*

D. Dr. Morin's Addition to the Cost of Equity of .3% for Financing Costs Is Inappropriate, Especially When the Market/book Ratio Is in Excess of 1.0 as Is the Case Here.

Dr. Morin has added approximately 0.3% to his estimated cost of equity for financing costs. *RA-7*, p. 76. This is an inappropriate adjustment.

As Mr. Rothschild explained, he did not specifically address financing costs in his testimony, since in his experience when utilities actually do financing, such costs tend to be so small that they are eliminated in rounding. *RA-7,* p. 76-77. Indeed, the FERC in its generic rulemaking proceedings on the appropriate cost of equity found that financing costs or flotation costs, were only a few basis points. *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Docket RM87-35-000, flotation section, Federal Register, Vol. 53, No. 24, February 5, 1988, Rules and Regulations, p. 3357; *RA-7*, p. 77-78.

Furthermore, currently most gas utilities have market-to-book ratios considerably in excess of 1.0. Mr. Rothschild in his prefiled testimony showed that the current market-to-book ratio of gas distribution utilities is approximately 2.0. *RA-7*, JAR 3, p. 1. With a market-to-book ratio of this magnitude, external financing actually is profitable, not costly, to the utility. That is because there are sufficient excess profits provided in actual financing to offset the costs of financing. For example, Dr. Morin's Appendix A, p. 7 of 8 in *P*-6 shows that his financing cost allowance is designed to bring the market-to-book ratio up to 1.05. The company's response to a Ratepayer Advocate discovery request shows that it has made five common stock offerings since 1985, and that in all five of these, the net proceeds received was considerably higher than the 1.05 targeted by Dr. Morin. *RA-7*, p. 77. Given the current average market-to-book ratio of approximately 2, external financing costs are more than offset under current conditions. The Board should reject Dr. Morin's request for a wholly undeserved addition of .3% to the cost of equity, which is unsupported both factually and theoretically.

POINT II

THE APPROPRIATE PRO FORMA RATE BASE AMOUNTS TO $1,820,245,000 WHICH IS $145,243,000 LOWER THAN THE PRO FORMA 12+0 RATE BASE PROPOSED BY PUBLIC SERVICE OF $1,675,002,000.

The Company selected the twelve month period ending June 30, 2001 as the test year. *P-4 R-1*, p. 1. The Ratepayer Advocate's witness, Robert J. Henkes, recommended numerous rate base adjustments in his testimonies in this proceeding. The Ratepayer Advocate is recommending a total rate base adjustment of $145,243,000 resulting in a pro forma rate base for the Company of $1,820,245,000. Sch. RJH-1R (revised 10/29/01) and RJH-3R (revised 10/29/01). (Appendix B). Each of those adjustments will be discussed in detail in this section of the brief.[6]

A. Accumulated Depreciation Reserve.

In determining its proposed depreciation reserve balance in this case, Public Service started out with the actual test year-end depreciation reserve balance as of June 30, 2001 of $1,389,956,000, the actual end of test year balance. Public Service's proposed pro forma depreciation expenses in this case are $53,657,000 in excess of its actual test year depreciation expense. Using the half-year convention principle, Public Service then added one half of this excess depreciation expense, or $26,829,000 to the actual June 30, 2001 reserve balance of

[6] The attached schedules reflect a revision in Mr. Henkes' proposed gas inventory balance to reflect gas transportation and injection costs, in accordance with his testimony on cross-examination. See Section II.C.

$1,389,956,000 to arrive at its proposed pro forma depreciation reserve balance of $1,416,785,000 in this case. *(RA-38*, Sch. RJH-6R).

The Ratepayer Advocate, using the same approach in the determination of its recommended pro forma depreciation reserve balance as the above-described approach used by Public Service, recommends a pro forma depreciation reserve balance of $1,373,209,000. The Ratepayer Advocate also used the actual June 30, 2001 test year-end depreciation reserve balance of $1,389,956,000 as the starting point. Since the Ratepayer Advocate has recommended a pro forma depreciation expense level in this case that is $33,494,000 *lower* than the actual test year depreciation expenses, it has taken one half of this pro forma depreciation expense decrease, or $16,747,000, and subtracted this from the actual June 30, 2001 reserve balance of $1,389,956,000. This resulted in the Ratepayer Advocate's recommended pro forma depreciation reserve balance in this case of $1,373,209,000. *(RA-38*, Sch. RJH-6R). This recommended pro forma depreciation reserve balance is $43,576,000 lower than the Company's proposed pro forma depreciation reserve balance.

B. Cash Working Capital ("CWC").

Cash working capital is an element of rate base and can 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. The Company has performed a lead/lag study which indicates a positive cash working capital requirement of $86,315,000 for purposes of this case. *P-5 R-1*, Sch. RLH-2 R1. The Company then offset this positive lead/lag study CWC requirement with a proposed net assets and liabilities balance of ($33,078,000) to arrive at its proposed net CWC requirement of approximately $53,237,000 for inclusion in its proposed rate base. *P-5 R-1*, Sch. RLH-2 R1. Mr. Henkes has recommended that a CWC of approximately $42 million is more appropriate when appropriate adjustments are made to the lead/lag study components as described below. *RA-38,* Schedule RJH-7R.

1. Net Assets and Liabilities Balance

The Company, in this case, has proposed to exclude from rate base an amount of $33,078,000 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-1*, pp. 15-16.

2. Lead/Lag Study Cash Working Capital

In calculating the Company's CWC requirement, the Ratepayer Advocate's witness Robert J. Henkes made adjustments to several lead/lag components included in the Company's study. Mr. Henkes noted that while the Company has reflected "0" as the lag days for depreciation expenses, deferred income taxes and invested capital, these expenses related to depreciation, deferred taxes and investment capital should not be included in a lead/lag study. As Mr. Henkes pointed out, these expenses do not represent or require cash outlays during the lead lag study period and were included inappropriately. *RA-1*, p. 17. Mr. Henkes testified that a properly conducted lead/lag study should *exclude* non-cash depreciation expenses and return on equity and should *include* debt interest with appropriate payment lags. *Id*., pp.16-18.

a. Non-Cash Depreciation Expenses Should Be Excluded From The Company's Lead/Lag Study.

The CWC requirement of a company must be based on the timing differences between the payment of cash expenses and taxes and the receipt of cash operating revenues. The expenses that relate to depreciation simply do not represent or require cash outlays by the Company during the study period used in the lead/lag analysis. As Mr. Henkes testified, it is the Ratepayer Advocate's position that a properly conducted lead/lag study should exclude non-cash depreciation expenses. *RA-1*, pp. 16-18. The non-cash expense of depreciation does not produce a need for additional cash to be supplied by the investors during the lead/lag study period.

While the Ratepayer Advocate recognizes that its recommended lead/lag study treatment concerning depreciation expenses differs from current Board policy, it believes that its recommended position is correct and must be accepted. The Ratepayer Advocate therefore recommends that the Board reconsider its current policy on this matter and exclude depreciation expenses from the lead/lag study for purposes of determining the Company's appropriate cash working capital in this case.

b. In Accordance With Board Rate Making Policy, Deferred Taxes Must Be Excluded From Any Lead/Lag Study For Purposes Of Determining A Utility's Cash Working Capital

As pointed out in Mr. Henkes' surrebuttal testimony (*RA-3*, *pp.2-3)*, 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 BPU rate making policy. This policy was first established in a prior Public Service base rate proceeding, BPU Docket No. ER85121163, and was reiterated in a subsequent rate case involving Elizabethtown Gas Company, Docket GR88121321. On page 7 of its Order[7] dated February 1, 1990 in that case, the Board stated with regard to this cash working capital issue:

> Cash Working Capital
> ...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 no 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 FINDS the ALJ's determination on deferred taxes to be reasonable and consistent with Board policy. Therefore, the Board ADOPTS 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 Public Service's cash working

[7] Order Adopting In Part And Modifying In Part The Initial Decision, 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. GR88121321, OAL Docket No. PUC228-89.

capital.

c. The Return On Common Equity Should Not Result In A Cash Working Capital Requirement.

It is the Ratepayer Advocate's position that the return on common equity does not, and should not result in a CWC requirement. (*RA-1*, pp. 16-18) 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. 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.

> It 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.
>
> *Atlantic 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.

d. The Appropriate Payment Lags

Associated With The Company's Debt Interest Expenses Should Be Recognized For General Working Capital Purposes.

The Company has not recognized the actual lag in the payment of debt interest in its lead/lag study in arriving at its CWC needs. Since the Company actually pays its long-term debt on a semi-annual basis, with an average payment lag of approximately 91 days, this payment lag should be considered in the lead/lag study to determine the Company's appropriate cash working capital requirement. *RA-1* , pp. 17-19.

The rates paid by the Company's customers are set to produce, in addition to other amounts, the sums necessary to pay for the Company's interest expense to bondholders. Since the Company pays its bondholders twice a year but collects revenues for such bondholder payments on a daily basis, the Company has the use of funds provided by ratepayers for interest expense as working capital during the interim period between interest payments. The Company's ratepayers provide these funds continuously, in a steady stream, and not in a pattern that matches or coincides with the Company's liability for the expense. Ratepayers, not the Company, are correctly entitled to the benefit of funds collected from them earlier than would be warranted to pay the Company's interest expense. Ratepayers clearly 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. *RA-1* p.18

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, OAL Docket No. 8543-83 (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 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 elements ofa 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 requirments.
>
> *Atlantic 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. *RA-1*, p 18. To refuse to consider the source of cash working capital from the interest payment lag penalizes the ratepayers who are providing revenues to pay all expenses, including interest expenses; and it would provide a "windfall" return to the common stockholders.

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.

e. CWC Conclusion

In summary, based on the above described approach and based upon the cash operating expenses and taxes recommended by the Ratepayer Advocate in this case, the Ratepayer Advocate recommends that a positive lead/lag study cash working capital requirement of $42.3 million. RA-38, Schedule RJH-7R, (updated 10/3/2001).

C. Gas Stored Underground

Gas stored underground has become an issue in this case because the Company has assumed that the Board will approve its proposal in the Board's Docket No. GR00080564 to transfer gas supply, storage and capacity contracts out of the regulated utility into an unregulated affiliate. The Ratepayer Advocate is opposing that proposal. The Company's filed position in the present case has assumed that the Board will permit the transfer of the contracts and has accordingly taken the Company's gas inventory out of rate base. The Ratepayer Advocate's recommended adjustments to rate base in this case assume that the Ratepayer Advocate's recommendation not to permit the contract transfer is adopted by the Board. Ratepayer Advocate witness Robert Henkes calculated the impact of reversing the Company's proposal to remove its entire gas stored underground inventory and propane fuel inventory from rate base. As shown on Schedule RJH-3R updated 10/29/2001, this recommended reversal increases the Company's proposed rate base by $373,088,000. The Company claims that the actual gas stored underground inventory is worth approximately $369,510,000. *RA-38,* Schedule RJH-3R (updated 10/29/01). The Ratepayer Advocate recommends a pro forma gas inventory balance that is significantly lower than the balance of $369,510,000 proposed by Public Service. *RA-24*, 037 workpapers.

The principal problem with the Company's estimate is that it is based on the unusually high gas costs that occurred during the test year. Instead of the Company's $6.96 per Dth, it is more appropriate to use the current estimates for gas prices that will prevail after the rates of this proceeding take effect. Mr. Henkes concluded that it is more appropriate to use the NYMEX Henry Hub Natural Gas Prices for 31 month period from January 2002 through July 2004 as of 9/24/01 of $3.09. *RA-25*.

As stated by Mr. Henkes in his testimony: "[a] the Board is fully aware, starting in the second quarter of 2000 and continuing through the second quarter of 2001, the prices of natural gas have escalated to *unprecedented and historically high levels*. For example, while the Henry Hub average monthly natural gas price was $2.53 per Dth in the first quarter of 2000, throughout the remainder of 2000 and into the first half of 2001, this average monthly natural gas price increased to levels as high as $9 per Dth." *RA-1*, p. 21 (emphasis added). In the 2000-2001 LGAC proceeding, Public Service claimed the necessity of immediate rate relief due to the "continuing dramatic increases in gas prices as reported on the NYMEX." *I/M/O Public Service Electric and Gas Company's Proposal for a Change in its Monthly Pricing Mechanism Within Its Levelized Gas Adjustment Clause For Residential Gas Customers Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1*, Docket No. GR00070491, Order Authorizing Provisional Rates, p. __ (Nov. 1, 2000).

The Company's recommendation to use test year natural gas price of $6.96 Dth for the projected natural gas price in this case improperly captures these unprecedented and historically high price levels to the detriment of the ratepayers. Public Service's misplaced assumption that the average natural gas receipt price of almost $7 per Dth experienced by Public Service during the test year represents a price, on average, that can be expected during the rate effective period of this case, is unsupported. As Mr. Henkes stated, "I believe that the gas prices experienced during the test year ended June 30, 2001 are to be considered aberrational and are not reflective of the average prices that can reasonably be expected during the rate effective period of this case." Public Service's witness, Mr. Stellwag conceded that gas receipt prices have gone to $10 per Dth during the test year. T806:L3-8.

Because of the extraordinary run-up in gas prices resulting in the highest gas prices in history that are reflected in the "12+0" test year, it is inappropriate to use the average test year gas receipt prices to determine the value of average test year gas inventory volumes. As Mr. Henkes and Mr. Stellwag both stated, the NYMEX Henry Hub natural gas futures are accepted in the natural gas industry as an objective source of natural gas projections throughout the United States. T808:L11-22. The NYMEX has consistently been used in the past by Public Service and adopted by the Board in setting the Company's LGAC rates. *Id*. and *RA-1*, p. 22. Mr. Stellwag acknowledged during cross that Public Service uses the Henry Hub Index, most recently in its 2000-2001 LGAC proceeding and its monthly LGAC reports it sends to the Board and the Ratepayer Advocate. T808:L11-22.

Mr. Henkes has estimated the anticipated value of the Company's gas inventories using the average NYMEX futures strip price for the 31-month period from January 1, 2002 through July 2004. Since rates will not be effective until early next year, Mr. Henkes used the average gas price for the 31-month period January 2002 through July 2004 of $3.52 per Dth. Mr. Henkes' prefiled testimony estimated the value of the Company's natural gas inventory using the NYMEX futures listing as of July 20, 2001. Based on the more updated NYMEX futures prices as of September 24, 2001, the average natural gas price for this same 31-month period has decreased from $3.52 to $3.09. *RA-25*.

This price of $3.09 per Dth does not include the costs of transportation and inventory injection, and Mr. Henkes agreed that these costs should be added to his recommended cost for the commodity cost of gas. T996:L12-15. Mr. Stellwag of Public Service claims that the cost per Dth for transportation and inventory injection should be $1.70 per Dth. However, Mr. Stellwag bases his conclusion that $1.70 represents the cost of transportation purely on hearsay, quoting Mr. Wohlfarth who did not testify to the gas price issue in this proceeding:

> Q. Do you have any written support in terms of analysis, studies and/or reports for the Company's claim that the cost of transporting natural gas into New Jersey and injecting it into inventory is $1.70 or is this just something that Mr. Wohlfarth told you?
>
> A. I've got three components here that add up to the $1.70. They are components provided by Mr. Wohlfarth.
>
> Q. What did Mr. Wohlfarth base that on, these three components?
>
> A. Based on Public Service's inventory use, deliveries that we get from our suppliers, the different pipelines that we utilize to get the gas to our storage facilities.
>
> Q. And you based it solely on Mr. Wohlfarth telling you that this is the correct amount, $1.70?
>
> A. Yes.

Q. And did Mr. Wohlfarth in this proceeding testify to where he derived $1.70 from?

A. In this proceeding?

Q. Yes.

A. I don't believe so.

T819:L7-T820:5.

In response to a transcript request to justify the $1.70 and provide all of the underlying assumptions, calculations, workpapers and actual studies and source documentation in support of the $1.70 per Dth number, Public Service provided a one-page response showing ten line items that had an end result of $1.70 per Dth. *Request TR-820*. There were no explanations, no studies and no actual source documentation in support of these mysterious ten line items. The Ratepayer Advocate recognizes that it is appropriate to include a reasonable transportation cost. However some adjustment is warranted in light of the Company's failure to document its requested cost. Therefore, the Ratepayer Advocate proposes a $0.20 per Dth decrease to Public Service's claimed transportation cost.

In light of the foregoing, the Ratepayer Advocate recommends that the Company's average test year gas inventory volume of 53,108,000 Dth be priced out at $4.59 per Dth. This price is based on Mr. Henkes' recommended gas commodity price of $3.09 per Dth based on the most recent available data at the time of the hearings in this proceeding, increased by $1.50 per Dth for the assumed gas transportation and injection cost. The attached schedules RJH-1R, RJH-3R, RJH-4R, RJH-8R, and RJH-25R (Revised 10/29/01)(Appendix B), shows the effect of the $1.50. Multiplying the resulting $4.59/Dth by this price with the test year average gas inventory volume of 53,108,000 results in a Ratepayer Advocate recommended gas inventory balance of $243,766,000.

D. Accumulated Deferred Income Taxes (“ADIT”).

In this case, the Company has taken the position that only those deferred taxes that are associated with other rate base components can be used as a rate base deduction. As a result, the Company has proposed a net rate base deduction for Accumulated Deferred Income Taxes of $257,510,000 based on its “12+0" filing. *RA-2,* Exhibit RJH-9R.

The Ratepayer Advocate’s witness, Mr. Henkes, also followed this principle but additionally recommended that deferred taxes associated with the Company’s rate of return in the capital structure be used as a rate base deduction. *RA-1,* p. 23. Accordingly, Mr. Henkes recommends that the Company’s actual test year-end ADIT balance of $3,732,000 concerning the Loss on Reacquired Debt be recognized for ratemaking purposes as a rate base deduction. *RA-1,* p.25. As Mr. Henkes points out in his Direct Testimony, and as confirmed by Mr. Krueger during his cross examination, the unamortized Loss on Reacquired Debt balance has been used by the Company to increase its effective embedded cost of debt in the Company’s proposed overall rate of return in this case and thus has increased the revenue requirement to be funded by the ratepayers. *RA-1,* p. 26; T653:L2-9. It would therefore be fair and appropriate to also recognize as a rate base deduction the accumulated deferred income taxes associated with this Loss on Reacquired Debt balance, which would have the effect of partially offsetting the revenue requirement increase impact of the use of the unamortized Loss on Reacquired Debt balance in the Company’s overall rate of return determination. *RA-1,* p. 25-26.

The Ratepayer Advocate's position in this matter is consistent with Board rate making policy. In fact, the Board clearly supported its ratemaking policy in the most recent Middlesex Water Company Case when it adopted without modification, the Ratepayer Advocates and Staff's recommendation with respect to ADIT:

> RPA Witness, Mr. Henkes, proposed a rate base deduction in the amount of 9,684,717 for Company-accumulated deferred income taxes (RPA exception to initial brief; Schedule 3). Mr. Henkes proposed that this balance: (1) be synchronized with the recommended utility plant in service; and, (2) include the ADIT balance associated with its bond redemption balance. Mr. Henkes claimed this ADIT balance represents the ADIT related to the bond redemption costs incurred by the Company in the early redemption of eight of its first mortgage bonds, and that these bond redemption costs were used by the Company in the determination of its weighted cost of debt used for purposes of calculating the overall rate of return in this case. Since these bond redemption costs have served to increase the Company's revenue requirement, it would be appropriate to recognize the offsetting revenue requirement reduction impact of the associated ADIT balance (RT-4:27-16 to 27-20 and 29-1 to 29-12). Mr. Henkes recommended balance included $385,723 of deferred income taxes related to the bond redemptions (RPA exceptions to initial brief at 24)...The Board hereby adopts the RPA's and Staff's recommendation that the ADIT balance amount should be $9,684,717.
>
> *I/M/O the Petition of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes*,BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part/Initial Decision (June 6, 2001).

The Board recognized in the Middlesex case that it is only equitable that when the ratepayers are asked to pay through rates the increased cost of debt, the corresponding tax benefits should go to decrease rate base.

The Ratepayer Advocate also recommends the removal of a new and late-filed ADIT component that Public Service suddenly introduced in its "12+0" update. *RA-2*, p. 3. Public Service included for the first time in its "12+0" update a line item of approximately $8 million in the ADIT referred to as the "Depreciation Study Impact." *P-3 R-1,* RCK-8 R1. This proposed ADIT component was filed without any supporting workpapers or other documentation to show the assumptions and calculations underlying this $8 million rate base addition claim. Particularly in light of the accelerated schedule adopted in this proceeding, it is inappropriate for Public Service to propose new adjustments at the eleventh hour without a shred of supporting workpapers, assumptions or calculations. Public Service's proposal to allow an $8 million item in rate base less than two weeks before the start of hearings should be rejected outright when the Company had months to prepare its petition and accompanying exhibits.

It should also be recognized that this Depreciation Study Impact ADIT component would go the other way – i.e., would be a rate base *deduction* – under the Ratepayer Advocate's recommended depreciation study position contained in the testimony of Mr. Majoros. Nevertheless, the Ratepayer Advocate is not reflecting this ADIT rate base deduction position because it would represent an inappropriate late-filed adjustment.

In summary, based on the previously described two adjustments to the Company's proposed ADIT rate base deduction balance of $257,510,000, the Ratepayer Advocate's recommended ADIT rate base deduction balance is $269,205,000. *RA-2*, Exhibit RJH-9R. For all of the previously described reasons, the Ratepayer Advocate urges the Board to adopt this ADIT rate base deduction balance of $269.2 million.

E. Consolidated Income Tax Benefits.

Public Service 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. *RA-1*, p. 28. Therefore, the stand-alone methodology utilized by the Company in this case is clearly incorrect. *P-10 RB,* p. 13. By filing a consolidated return, Public Service can take advantage of tax losses experienced by 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. The Ratepayer Advocate's position is that any allocation made to Public Service should be flowed through to the benefit of New Jersey ratepayers. *RA-1*, pp. 27-30. This "flow through" should be done to properly reflect the actual taxes paid by the Company. Public Service, by establishing a revenue requirement based upon a stand-alone federal income tax methodology, overstates its tax expense. This overstatement results in a windfall to the Company and higher rates than are necessary. *Id*. and *RA-2*, RJH-10R. The Company has failed to recognize that its rate base must be reduced by approximately $89,363,000 in order to accurately reflect the impact of the consolidated income tax benefits allocable to Public Service customers. *Id.*

The use of a consolidated income tax adjustment is not a new concept being introduced in this case. The history of consolidated income tax adjustments in New Jersey has been discussed in numerous cases. 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. *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). For example, in the Board's Decision & Order in *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); the Board stated on page 4:

> ...[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).

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).

The Ratepayer Advocate's witness, Mr. Henkes, recommended applying the rate base adjustment as the appropriate methodology to reflect consolidated income tax savings. *RA-1*, p. 27. This methodology was adopted by the Board in *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 Modifications,* Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision, BRC Docket No. ER91121820J, (February 25, 1993), (hereinafter "I/M/O Petition of JCP&L"). 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).

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.

In *Lambertville Water*, *supra*, at page 28, 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.

Mr. Henkes also testified that to properly reflect the consolidated income tax benefits allocable to the Company, he needed to trace the benefits back to 1991 through to 2000. In *I/M/O Atlantic Electric*, *supra,* the Board stated on page 8, "... 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." Furthermore, the Board went on to state on the same page, "[t]his finding reflects a balancing of the interests to reflect the unique period of uncertainty during the period 1987-1991." Additionally, the Board reaffirmed this position in its Decision & Order in *I/M/O the Petition of JCP&L, supra*, p. 8. 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."

The Ratepayer Advocate's witness, Mr. Henkes, reviewed the taxable income of the consolidated group members from 1991 through 2000. Mr. Henkes apportioned the losses to Public Service based on its share of positive taxable income over the same time period. *RA-1*, p. 29. Thus, based upon the well established Board policy regarding consolidated income tax savings, the Ratepayer Advocate respectfully requests that its recommended rate base deduction associated with consolidated income tax savings of $89,363,000 be accepted. *Id.*

In his rebuttal testimony, Public Service witness Krueger argued that Mr. Henkes' consolidated income tax benefit analysis is wrong in that it did not recognize that Public Service's electric generation and transmission operations are no longer regulated by the BPU and that it would therefore be inappropriate to assign consolidated income tax benefits associated with Public Service's electric generation and transmission operations to the ratepayers of the regulated Public Service operations. *P-3 RB*, p. 3. Mr. Krueger then re-ran Mr. Henkes' consolidated income tax analysis with the assumption that all estimated consolidated income tax benefits allocable to Public Service's electric generation and transmission operations would belong to Public Service's non-regulated subsidiaries rather than to the regulated Public Service utility. Based on this analysis, Mr. Krueger then concluded that no rate base deduction for consolidated income tax benefits would be appropriate in this case. *Id*.

The Ratepayer Advocate does not at all agree with Mr. Krueger's consolidated income tax assumptions and conclusions. There are two important reasons why the Ratepayer Advocate urges the Board to reject all of the scenarios and conclusions regarding consolidated income taxes contained in the rebuttal testimony of Mr. Krueger. First, Mr. Krueger's taxable income allocation among Public Service's electric generation, transmission and distribution operations is purely hypothetical and the Ratepayer Advocate does not accept his allocation assumptions. While Mr. Krueger calls this taxable income allocation process "easily and rationally done," it represents a totally hypothetical exercise whereby Mr. Krueger decided that all of Public Service's electric taxable income is allocable between the generation, transmission and distribution operations based on the respective ratios of these operations' net plant investment. *P-3 RB*, p. 3. It is far from clear that this will produce an accurate answer.   In fact, it is the Ratepayer Advocate's opinion that it is not possible to determine the taxable income numbers associated with Public Service's electric generation, transmission and distribution operations in an accurate manner.

Second, the Ratepayer Advocate does not believe that the value received by Public Service's ratepayers as a result of the transfer of Public Service's electric generation assets to the Genco subsidiary included ratepayer compensation for the loss of the consolidated income tax benefits as a result of this transfer. In fact, the Ratepayer Advocate requested evidentiary proceedings to further investigate the electric generation asset transfer valuation, but this request was denied. *I/M/O PSE&G Company's Rate Unbundling, Stranded Costs and Restructuring Filings*, BPU Docket Nos. EO97070461,et al. Final Decision and Order pp. 99-101 (Aug 24, 1999); *See also*, Joint Stipulation of Settlement of Stranded Costs Restucturing and Unbundling

Proceedings "Better Choice Settlement Proposal," BPU Dkt No. EO97070461 *et al*. (Filed March 30, 1999). Nothing in the Public Service Unbundling, Stranded Costs and Restructuring Order reflects any compensation to the ratepayers for loss of consolidated income tax benefits. *Id.* Since Public Service's ratepayers have not been shown to have received any value for the transferred consolidated income tax benefits associated with the electric generation asset transfer to the Company's electric generation affiliate, Mr. Krueger's pro forma adjustment to remove all consolidated income tax benefits estimated to be related to Public Service's electric generation business from Mr. Henkes consolidated income tax benefit analysis is inappropriate and inequitable to the Company's ratepayers.

POINT III

THE APPROPRIATE PRO FORMA OPERATING INCOME AMOUNTS TO $157,194,000 WHICH REPRESENTS A $101,275,000 INCREASE OVER THE COMPANY'S PROPOSED PRO FORMA OPERATING INCOME OF $55,919,000.

The Company utilized test year operating income for the twelve months ending June 30, 2000. The Ratepayer Advocate's witness, Mr. Henkes, recommended numerous adjustments to the Company's Pro Forma operation income in his Direct and Surrebuttal Testimonies and on the record during evidentiary hearings. Each of these adjustments will be discussed in detail below.

A. Customer Revenue Annualization Adjustment

Public Service has proposed a weather normalization adjustment in the present case that will reduce the Company's per book test year revenues by approximately $20 million. *P-2 R2*, Schedule ANS-3 R2, page 1. Public Service normalized the test year customer consumption levels based on 30-year average normalized weather determinants to account for the unusually cold weather, however, Public Service did not adjust the weather normalization test year revenues to reflect the customer levels as of the end of the test year but used the average customer levels in the test year. *RA-1*, p. 32. In other words, the Company did not annualize its proposed test year revenues to account for customer growth through the end of the test year. The Ratepayer Advocate has consistently argued that if the test year-end rate base data is used, it is only equitable that the data reflecting year-end number of customers be used as well. As discussed fully by Ratepayer Advocate witness Mr. Henkes:

> [T]he Company's proposed test year revenues are based on the test

> year's average number of customers. In this regard, it is important to recognize that the plant investment that has supported the Company's average test year number of customers is the Company's average test year plant, not the (higher) June 30, 2001 test year-end plant investment level. <u>Since the Company has proposed the use of the higher test year-end plant in service balance, it would be appropriate and consistent to then annualize the revenues for the growth in customers up to the end of the test year</u>. *RA-1*, p.33 (emphasis added).

In order to calculate the year-end customer growth, Mr. Henkes recommended the use of one half of the average five-year compound growth in customers. *RA-3*, p. 6. The approach recommended by Mr. Henkes is more accurate, eliminates the "biases" due to the fluctuation in customer numbers between summer and winter months, and has been accepted by regulators in several jurisdictions, including New Jersey and Kentucky. *RA-3,* p. 8 and T1067:L22-T1071:L7**.**

This annualization adjustment for end of test year customer increases the Company's proposed test year revenue margins by $819,000 and Public Service's proposed pro forma test year operating income by $484,000. *RA-38,* RJH-4R updated 10/29/01.

During the hearings, Public Service witness Stellwag criticized Ratepayer Advocate witness Henkes' customer growth annualization adjustment based on his argument that the customer growth analysis should have been accompanied by a customer usage normalization adjustment. T798:L7-R799:L8. Mr. Stellwag then went on to state that the Company did not perform a formal customer usage normalization adjustment analysis for the test year. *Id.* The Ratepayer Advocate finds this very odd. In its attempt to discredit Mr. Henkes' customer growth annualization adjustment, the Company took the time and effort to actually re-run its sales and revenue model based on different customer growth criteria and present this information in Mr. Stellwag's rebuttal testimony. *P-4 RB*, p. 6. However, even though it is the Company's position that any customer growth annualization must be accompanied with a customer usage normalization adjustment, the Company did not re-run its sales and revenue model to restate the actual usage per customer during the test year with normalized average customer usage levels based on historic usage patterns as the Company has done in past rate cases.

The reason for this reluctance on the Company's part was explained by Mr. Henkes during his cross examination. During the test year ending June 2001, the customers of Public Service experienced the highest gas prices in history and their gas bills increased by approximately 34% in the test year alone. This clearly has had an impact on the customer's average gas consumption patterns during the test year. Mr. Henkes has stated his belief that, therefore, the actual test year average customer gas consumption levels are severely understated. T1038:L21-T1039:L13. In this regard, the following exchange took place between Public Service's counsel and Mr. Henkes:

> Q. Let me ask you this: When rates go up as you say by thirty-four percent do you think people use a lot more gas, or do they use less gas?
>
> A. That's my whole point, they use less gas I think and that's what is reflected in the test year results and that's why the test year's usage is severely understated.
>
> Because of that, that's why the Company doesn't want to run a model, because if they do a model you would come up with a much higher gas level because we have seen that the gas prices are coming down now and we know with lower gas prices you are going to stimulate demand.
>
> So what is reflected in the test year may not necessarily happen after the test year. I think that my adjustment is quite conservative by not having a usage

adjustment. *Id.*

In summary, the weather normalized test year average usage per customer most probably has been at depressed levels because the ratepayers were faced with the highest gas prices in history leading to average gas bill increases up to 34%. Since the end of the test year, gas prices have come down significantly and this slide in gas prices is continuing. This would suggest making an adjustment to increase the average test year customer consumption. However, since we may be facing a recession, this may counter-balance the increased per customer consumption that can be expected from the lower gas prices. As stated by witness Henkes during his cross examination, the Ratepayer Advocate believes that, therefore, the average test year per customer consumption levels could be considered representative of what can be expected in the near-term future based on today's expectations, and no customer usage normalization adjustment would be appropriate. *Id.*

B. Unadjusted Test Year Labor O&M Ratio

In its initial, "6+6" filing, Public Service proposed a pro forma test period operating expense/capital ratio of 83%. Mr. Stellwag, in his rebuttal testimony, recognized that the O&M ratio in the initial filing must be adjusted downward stating that: "A preliminary review indicates that the test year O&M allocation will be lower than that proposed by both Mr. Henkes and myself." *P-4RB*, p. 7. In his oral testimony, Mr. Stellwag conceded that an O&M ratio of 75.2%, which is derived by dividing O&M gas "test year" labor expense of $163,079,746 by total gas test year labor expenses of $216,844,637, is appropriate for this proceeding and filed an updated Schedule ANS-5 R2 which reflects the new O&M ratio. T796:L7-18. In contrast, Mr. Henkes in his Supplemental Direct Testimony, proposed a 5 year average O&M expense ratio of 72.9% based on the information provided in RAR-A-41 update. *RA-1*, Schedule RJH-12 and *RA-28*. As Schedule RJH-12R illustrates, the Ratepayer Advocate's recommended O&M expense ratio increases the pro forma operating income by $3,159,000.

The gas labor O&M ratio for the last 5 years is as follows:

1996	73.6
1997	70.3
1998	71.2
1999	75.2
2000	74.4
5 year avg.	72.9

Id.

As the chart clearly indicates, O&M ratios fluctuate from year to year. Thus, the use of the 5 year average is more appropriate indicator because the average O&M ratios over time is a better determinant of what can be expected in the future. Moreover, the average of past O&M ratios to predict a representative future O&M expense ratio has been accepted by the New Jersey Board as well as in other jurisdictions. *I/M/O the Petition of New Jersey - American Water Company, Inc for an Increase in Rates for Water and Sewer Service and Other Modifications,* BPU Docket No. WR98010015 (1998) (3 year average O&M expense ratio was accepted by the Board); See also, *Tariff filing of Green Mountain Power Corporation Requesting: 1) a 13.9% Rate Increase, to Take Effect 11/10/94; (2) Approval of Special Contract #159 with IBM; and (3) Approval of Interim DSM Program Designs,* Vermont PSB Docket No. 5780 (May 19, 1995) and *TR-1072* (five year historic O&M ratio average was accepted by the Vermont Board for rate making purposes.)

Accordingly for the above-reasons, the Ratepayer Advocate recommends that the Company's unadjusted test year labor O&M ratio adjustment of $3,159,000 be approved by the Board.

C. Pro Forma Labor Increase Adjustment

Public Service has proposed to reflect the annualized impact of fully projected salary increases for bargaining unit ("BU") and Management Administrative Supervisory and Technical Employees ("MAST") employees to be in effect at different periods within the next two years: 1) May 1, 2001 and May 1, 2002 BU employees increases and 2) April 1, 2001 and April 1, 2002 MAST employee increases. *P-2 R2*, ANS-5 R-2. As the effective dates of the salary increases show, two of the four salary increases are annualization of "in-test period" salary increases (May 1, 2001 BU and April 1, 2001 MAST increases) and two salary increases concern the annualization of anticipated post-test year increases (May 1, 2002 BU and April 1, 2002 MAST increases).

The Board has long standing rate making policy regarding "post-test year" adjustments which does not allow post test year adjustments unless they are "known and measurable." In the *Elizabethtown Water Company Rate Case Decision on Motion For Determination of Test Year and Appropriate Time Period For Adjustments*, Docket No. WR8504330 (May 23, 1985), the Board established the general policy that the test year to be used in a base rate proceeding must be fully historical prior to the close of record in the proceeding. *P-56.* If adjustments are permitted, they will only be recognized for "known and measurable" changes occurring no later than the nine months after the end of the test year. The

Board defined the "known and measurable" standard as follows:

> ....Known and measurable changes to the test year must be (1) prudent and major in nature and consequence, (2) carefully quantified through proofs which (3) manifest convincingly reliable data. The Board recognizes that known and measurable changes to the test year, by definition, reflect future contingencies; but in order to prevail, petitioner must quantify such adjustments by reliable forecasting techniques reflected in the record. *Id.*

The Board further established that only post-test year income and expense items that are: "known and measurable changes to income and expense items for a period of nine months beyond the end of the test year" can be recognized. *Id.* During his cross examination, Ratepayer Advocate witness Henkes explained in this regard:

> The Board's rule says no matter whether there is a known and measurable expense or not, it doesn't make any difference, but we draw the line nine months beyond. I think it [the BPU] recognized in setting that rule that you start losing the proper matching between the components of the rate making formula when you take one of these components and move it too far out.
>
> AWMS I know, Mr. Hoffman, that you have a choice amortization -- no, it is the gas amortization [expense] that is going to expire in February 2003. That's a big one, big expense. Now, that's a known and measurable, you can't get it more known and measurable than that one, [but] I am not recognizing it because the Board draws the line somewhere and that's it.
>
> T1007:L4-20.

Applying the Board's standard to the present case, the May 1, 2002 BU and April 1, 2002 MAST increases clearly fall outside of the 9-month post test year cut-off. The 9-month limit is a double edged sword that must be honored by both the Company and Ratepayer Advocate. As Mr. Henkes points out in his Surrebuttal Testimony (and during his cross examination as referenced above), his recommendations is to disallow for rate making purposes any amortization expenses that are included in the test year but will expire after March 31, 2001. *RA-3,* p. 9. It is only equitable that Public Service be limited to the same 9-month period for any adjustments beyond the test year.

Moreover, it must be noted that the transfer of large number of employees from the regulated Public Service to the unregulated PSEG Service Company has not been reflected in the Company's unadjusted test year filing data and all of the labor expenses associated with the transferred employees are still included in the unadjusted test year expenses. *RA-3*, p. 10. As Mr. Henkes states in his surrebuttal testimony:

> a representative amount of expense is expected to be charged to PSE&G gas operations for the use of these assets by PSEG Service Corporation may or may not come true and is not known and measurable at this time ... this adds significant uncertainty to the post-test year labor expenses to be incurred by PSE&G, either through direct labor charges or by way of cost allocations from the Service Company to PSE&G and that, given these uncertainties regarding PSE&G's post test year *overall* labor charges, it would not be appropriate to then recognize estimated *increases* in these (already uncertain) post-test year labor charges.
> *RA-3*, pp. 10-11.

Finally, the Ratepayer Advocate has recommended for ratemaking purposes a 5 year average O&M ratio of 72.9% discussed in the O&M Expense Ratio discussion supra and an estimated impact on payroll taxes at 6.8%. For the forgoing reasons, the Ratepayer Advocate recommends that the Board increase pro forma operating income by $3,903,000 to account for pro forma labor expense adjustment.

D. Incentive Compensation Expense Adjustment

In the present case, Public Service is proposing to charge ratepayers approximately

$6.35 million for incentive compensation expenses. *P-45*. The Public Service incentive compensation consists of three programs: Long Term Incentive Plan ("LTIP"), Management Incentive Compensation Plan ("MICP") and Performance Incentive Plan ("PIP"). *P-47.* The incentive compensation is being paid to the Company's officers, senior management and MAST employees in addition to their regular compensation which has also experienced steady increases the last several years. *RA-1*, p. 43.

As shown in Public Service's discovery response to *P-45* (RAR-A-47(B) updated), the Incentive Compensation Expenses incurred by the Company amount to the following annual levels:

1998	$2,546,000
1999	$5,388,000
2000	$6,140,000
Test Year	$6,350,000

RA-2, Schedule RJH-14R shows that of the total test year incentive compensation amount of $6.35 million, approximately $5.1 million represents PIP incentive compensation paid to the Company's MAST employees and approximately $1.3 million represents LTIP and MICP compensation paid to the Company's officers and top management. In addition to this total incentive compensation expense of $6.35 million, the test year expenses also include $20,000 for LTIP administration and brokerage commissions. *P-2 RB*, p. 24.

Public Service witness Mr. Cistaro in his rebuttal testimony asserted that the Company's incentive compensation is not "additive" to the regular base compensation of the Company's employees. *P2 RB*, pp. 30-31. To support this assertion, Mr. Cistaro stated that in 1996 and 1997, when the incentive compensation was being introduced for the MAST employees, the merit salary increases for the MAST employees were "held back." *P-2 RB*, pp. 18-19. Contrary to this assertion, in fact, Public Service has implemented salary increases ranging from 4% to 5.1% in every year since 1996, with the sole exception of 1997. *RA-1*, p. 44. This can be seen from a Company discovery response which shows the annual base salary increases given to the Company's executive and MAST employees:

	Executive	MAST
1996	4.1%	2.0%
1997	1.3%	2.0%
1998	4.0%	4.0%
1999	5.3%	4.0%
2000	4.4%	4.1%
2001	5.1%	4.1%

S-13.

As shown in Mr. Cistaro's Rebuttal Schedule 5, and as confirmed by Mr. Cistaro during his cross examination, starting in the year 1998 all of the Company's employees, including all of the MAST employees, were receiving PIP incentive compensation on a fully phased-in basis. T726:L15-25.

> Q. You stated in your opening statement that your Incentive Compensation Programs have been phased in over some years. And, we can see that from your rebuttal, the Schedule 5, correct?
>
> A. Yes.
>
> Q. Now, what this shows is that by 1998, all the Company's non-represented employees were phased in, correct?
>
> A. That is correct.

During the next 3 ½ years, from 1998 through the test year ending 6/30/2001, the incentive compensation paid out to Public Service's employees increased by 250% from $2.54

million to $6.35 million, as evidenced from the table in *P-45*. At the same time that the Public Service employees received these escalating incentive compensation benefits, they also received annual base compensation increases ranging between 4.0% and 5.3%. *S-13*. This information clearly proves the Ratepayer Advocate's position that, at a minimum starting in 1998, the Company's incentive compensation is to be considered "additive" to the regular base salary compensation.

Moreover, Public Service's incentive compensation program have not been shown to be directly related to the provision of safe, adequate and proper utility service. The criteria established by the Company to grant awards under the compensation plan relates generally to the financial performance of the Company. In RAR-A-47(A) Public Service describes the PSE&G LTIP and MICP. *RA-22*. With LTIP, Public Service describes it as a plan that "motivates and rewards executives for meeting corporate objectives that are intended to more *closely align the executives interests with the long term interest of PSE&G shareholders* as well as to better relate total compensation to competitive practice." *Id*. (emphasis added). With respect to MICP, Public Service states, that a portion of an individual's (i.e., officers) award is *influenced by overall corporate financial performance*. *Id.* (emphasis added).

The Company's proposed *pro forma* test year incentive compensation expenses of $6.35 million should be disallowed for rate making purposes in this case. There are several reasons for this recommendation.

First, since the stated purpose of the plans is to advance the financial interests of Public Service and its stockholders the criteria that determine the awards paid out under the incentive compensation plan relate to financial performances of which the stockholders are the primary beneficiaries. *RA-22.* For those reasons, the Company's stockholders should be responsible for these discretionary costs.

Second, the Company's recent overall average wage and salary increases have been around 4%. The Company has proposed *pro forma* wage and salary increases of a similar magnitude in this case. *RA-1*, p. 44. Given the recently 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 costs. Thus, to disallow the incentive compensation costs but accept the Company's proposed *pro forma* wage and salary increases is consistent with this position, and should be considered a reasonably balanced approach to this overall compensation issue.

Third, the Company has not presented any evidence in this case showing the specific benefits that are accruing to the ratepayers as a result of these incentive compensation plans for which these same ratepayers are asked to pay 100% of the costs.

Fourth, the recent large increases in this expense category should concern the Board. The Company has recently increased this incentive compensation expense level by approximately 250%, going from $2,546,000 in 1998 to $6,350,000 currently. If the Board were to give rate recognition to the expense level requested by the Company in this case, this would provide very little, if any, incentive for Public Service to minimize or contain these incentive compensation expenses.

Finally, the Ratepayer Advocate's position is fully consistent with Board policy. In the Board's Final Decision and Order in *I/M/O of the Petition of Jersey Central Power & Light,* Docket No.ER91121820J, (2/25/93) the Board disallowed all of the costs associated with the utility's incentive compensation plans from its cost of service. The Board found:

> 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. Accordingly, we HEREBY MODIFY the Initial Decision and DENY from inclusion in rates the entire test year compensation expense of $554,000.

The Board also denied a utility's request to include incentive compensation costs in rates in the recent 2001 Middlesex Water Company base rate case. *RA-32.* In rejecting the ALJs recommendation to share incentive compensation costs 50%/50% between ratepayers and shareholders, the Board reiterated its JCP&L position by stating: "The language in the Board's JCPL 1993 Order is especially appropriate today when consumers are still faced with increasing energy costs, as well as other increased costs." *Id*. p. 25.

As correctly observed by the Board in the Middlesex case, denial of Public Service's position is especially appropriate today when consumers are faced with increased LGAC prices in 2000-2001 and the world wide recession and unemployment that is now apart of the reality in the country and especially in the tri-state area. In late 2001, the Board granted Public Service authority to increase its rates by approximately 16% on November 1, 2000 and an additional 2%

each month through July. *I/M/O Public Service Electric and Gas Company's Proposal for a Change in its Monthly Pricing Mechanism Within Its Levelized Gas Adjustment Clause For Residential Gas Customers Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1*, Decision and Order, Docket No. GR00070491 (3/30/01). Although rates may decrease somewhat during this winter heating season, the Company will still continue to recover for gas cost under-recoveries from last year's LGAC Order. Ratepayers should not have to shoulder the additional burden of incentive compensation expenses.

Mr. Cistaro states in his rebuttal testimony that there are "considerable differences" between PSE&G's incentive compensation programs and that of the incentive compensation programs of JCP&L and Middlesex for which the Board disallowed all related incentive compensation expenses. *P2 RB*, p. 28. The major reason mentioned by Mr. Cistaro is that PSE&G pays incentive compensation to all of its non-union employees whereas this is not the case for JCP&L and Middlesex. *Id.*, p. 29. To the contrary, a reading of the Board Orders concerning the JCP&L and Middlesex rate cases clearly shows that these plans involved incentive compensation that is being paid to all employees of JCP&L and Middlesex. *RA-32*, pp.23-25 *I/M/O the Petition of Middlesex Water Company For Approval of an Increase in Its Rates for Water Service and Other Tariff Changes*, BPU Docket No. WR00060362, Order Adopting in Part/ Modifying in Part/ Rejecting in Part, Initial Decision (May 8, 2001); *I/M/O the Petition of Jersey Central Power & Light Company For Approval of Increased Base Tariff Rates and Changes For Electric Service and Other Tariff Revisions*, BPU Docket No. ER91121820, Final Decision and Order, Accepting In Part and Modifying in Part the Initial Decision (June 15, 1993). Moreover, under cross examination, Mr. Cistero conceded that he was not knowledgeable about the Middlesex Incentive Compensation Plan therefore his “expertise” on this issue appears minimal if any and should be given little weight:

> Q. Okay. Would you accept, subject to check, that the Middlesex Incentive Compensation Expenses, that the 100 percent that was disallowed in the last Middlesex Rate Case included Incentive Compensation for all of Middlesex employees?
>
> A. Yes. Subject to check, *I'm not familiar with the specifics of their case, however, or their plan*.
>
> T841:L16-19 (emphasis added).

Accordingly, for the above reasons, the Ratepayer Advocate recommends that the Company’s proposed pro forma test year incentive compensation expenses of $6.35 million, as well as the $20,000 for test year LTIP administrative and brokerage fees, be disallowed for rate making purposes in this case.

E. Pension and FAS 106 Expenses

Financial Accounting Standards Board Statement No. 106 (“FAS-106") is the standard used since 1993 for accounting post-retirement health care benefits. In stating the expenses for pension and FAS 106 in this case, the Company has inappropriately reflected the budgeted 2001 expense for the pension expenses while using the test year level of expenses for FAS 106. The following is from Schedule RCK-14R-1 and Schedule ANS-10 R-1 which illustrates the problem with PSE&G’s inconsistent use of FAS 106 and Pension expenses:

	($Millions)	
	Test Year	Year 2001
Pension expenses	$ 10.2	$10.9
FAS 106 expenses	$ 19.1	$17.2

P-3 R-1, Schedule RCK-14R-1 and *P-4 R-1* Schedule ANS-10 R-1.

Both the Year 2001 pension and FAS 106 expenses are known and measurable at this time because they are based on the most recent June 2001 actuarial reports for pension and FAS 106 expenses prepared by PSE&G's actuary, Hewitt Associates, LLC. *P-4*, p. 11 and RA-3, p.4. For rate making purposes in this case, PSE&G proposes to reflect the Year 2001 pension expenses (which are approximately $700,000 higher than the actual test year expenses). *P-4*, p. 11. The Ratepayer Advocate agrees with this approach because these pension expenses are now known and measurable. However, for its FAS 106 expenses PSE&G proposes to reflect the actual test year expenses of $19.1 million rather than the Year 2001 FAS 106 expenses of $17.2 million. *P-3 RB*, p. 13. This is inconsistent and plain wrong. The Year 2001 FAS 106 expenses of $17.2 million should be recognized for rate making purposes in this case. This recommended approach is entirely consistent with the approach taken for the Company's pension expenses and reflects the fact that these 2001 FAS 106 expenses are known and measurable at this time. This means that the Company's proposed FAS 106 expenses should be reduced by $1,924,000.

F. Gas Supply and Storage Transfer Income

As extensively discussed in the Contract Transfer section of this brief, PSE&G recommended the pro forma adjustments to reflect its proposed transfer of its gas supply, storage and capacity contracts from the regulated PSE&G gas utility to an unregulated affiliate. In assuming that the Board will grant PSE&G's petition to transfer the gas supply contracts, the Company proposed a pro forma adjustment reducing its test year operating income by

$22,999,000 in this filing ("12+0" basis). *P-4 R1*, Schedule ANS-3 R1. Mr. Henkes has reversed this pro forma adjustment to be consistent with the Ratepayer Advocate's position in the Contract Transfer case, that PSE&G's petition be rejected by the Board. *RA-38*, Schedule RJH-4R updated 10/29/01. The results of Mr. Henkes adjustment increases the Company's proposed pro forma operating income by $22,999,000.

G. Regulatory Commission Expense Adjustment

The Ratepayer Advocate's recommended adjustment of regulatory commission expense of $488,000 consists of adjustments to three components: 1) normalized annual rate case expenses; 2) the annual amortization of the depreciation; and 3) a normalized annual expense level for other miscellaneous regulatory activities and dockets.

1. Normalized Annual Rate Case Expense

PSE&G's estimate for the current rate case expense is $800,000 which it claims should not be shared 50/50 and should not be amortized over a period longer than one year. *RA-1*, p. 50. This is a substantial increase from the original rate case expense estimate of $300,000 that PSE&G originally submitted. *S-12*. The entire $500,000 increase reflected in the $800,000 rate case expense is due to outside legal fees. *RA-1,* p. 50. Comparing to the actual rate case expense for the test year of $115,000 and the actual rate case expense for the Company's most recent gas base rate case in 1991 of $384,000, $800,000 is excessive and unreasonable. *Id.* A more reasonable estimate is Mr. Henkes' recommendation of $55,000 for rate case expense which reflects a 1) disallowance of one-half of the outside legal fees; 2) 50/50 sharing; and 3) amortization of the expense over a 5-year period. *RA-2*, Sch. RJH-16R.

First, as Mr. Henkes explains in his direct testimony, he took PSE&G's recommended expense projection of $500,000 for outside legal fees and included only half of the cost in the rate case expense. He correctly notes that: "In my opinion, the Company's proposal to charge its ratepayers with outside legal fees of $500,000 for this single base rate case should be considered excessive by the Board." *Id.* 51. Noting that an outside legal fee of $250,000 for this case is more than sufficient, Mr. Henkes recommended disallowance of the remainder of the costs. *Id.*, p. 51. The Ratepayer Advocate agrees with Mr. Henkes' recommendation on this issue and believes that $250,000 is more than adequate to cover rate case expenses incurred for outside legal assistance when the following are considered: 1) PSE&G has a well staffed experienced Corporate Rate Counsel division that is already paid for by the ratepayers through base rates. To expect $500,000 over and above the costs already charged to ratepayers for rate case expense is excessive. 2) Even assuming that PSE&G's current staff were incapable of competently representing the company in this case without outside assistance which we do not believe is true, the level of expense claimed is excessive. As Mr. Henkes states in his rebuttal testimony, "assuming $250 per hour for outside legal counsel, the additional outside legal fees of $250,000 found adequate by me for rate making purposes in this case would allow for 1000 hours of outside legal assistance in addition to the Company's internal Corporate Rate Counsel legal staff. The 1000 hours of outside legal assistance would be equivalent to one full-time lawyer for a period of six months or on half time lawyer for a period of one year." RA-3, p. 11. 3) The Ratepayer Advocate's position is well balanced taking into concern the Company's needs but protecting ratepayer interests. Compared to the last gas rate case expense claimed by PSE&G, the rate case expense of $550,000 still allows PSE&G an increase of 43%.

Moreover, pursuant to Board policy, the Ratepayer Advocate's position assumed a 50/50 sharing of the outside legal costs between shareholders and ratepayers and then amortized the remaining $250,000 over a 5-year period. The Board reaffirmed its 50/50 sharing policy in the Pennsgrove Water Supply Company's rate case in Docket No. WR98030147:

> Having reviewed the entire record in this matter, the Board <u>ADOPTS</u> the ALJ'S recommendation. In recognition of the argument that stockholders benefit from a rate proceeding, it has been the policy of the Board to utilize 50 - 50 sharing of rate case expenses for larger utilities, including water utilities. In addition, the Board notes that, in this case, since Petitioner's revenues have exceeded one million dollars in each of the last three years (companies with revenues of one million dollars or more are generally classified as Class A water companies), the Board <u>FINDS</u> a 50 - 50 sharing to be appropriate in this matter.
>
> *I/M/O the Petition of Pennsgrove Water Supply Company for an Increase in Rates for Water Service*, Order Adopting in Part and Rejecting in Part Initial Decision, BPU Docket No. WR98030147 (6/24/99).

The 5-year amortization recommendation is based on the frequency of gas rate cases and the possibility of another rate case in the future. The Company's last gas base rate proceeding filed over 10 years ago with a slim chance of another rate case in the near future, the 5-year amortization period is appropriate. *RA-1*, p. 51.

Therefore, the Ratepayer Advocate recommends normalized annual rate case expense level to be recognized for rate making purposes in this case should be $55,000. *RA-38*, Schedule RJH-16R.

2. The annual amortization of the depreciation study

The second component of the recommended total regulatory expenses is the expense projected for the depreciation proceeding that has become a part of the base rate case before the Board. Upon review of PSE&G's estimates, Mr. Henkes did not object to the $145,000 projected for the case. *Id*., p. 52. However, for the reasons outlined for the rate case expense 5 year amortization recommendation, the estimated expense of $145,000 should be amortized over a 5-year rather than the one year proposed by the Company. This results in a recommended annual amortization expense of $29,000.

3. Normalized Annual Expense Level for Other Miscellaneous Regulatory Activities and Dockets

The third and final regulatory commission expense component that should be adjusted is the "other" regulatory expenses. Included in the "other" category are expenses associated with a representative level of miscellaneous regulatory activities and dockets that PSE&G may incur in the future. PSE&G has claimed future other miscellaneous regulatory expense of $1,183,000. *RA-29*. Although PSE&G has been repeatedly requested to provide a breakdown of the costs by activity and docketed matter in support of its $1.183 million claim, the Company was unwilling or unable to do so. *Id.*

Instead of PSE&G's unsubstantiated estimate for other regulatory expense, Mr. Henkes recommended that the Board use the equivalent "other" regulatory expenses that were actually incurred by PSE&G in the last five years to base the expense adjustment. Looking at the other regulatory expense from 1996- 2000 showed a 5-year average of $303,000. *RA-1*, p. 52 and *RA-38* Schedule RJH-16R. This is a more appropriate expense level to be recognized for rate making purposes in this case.

H. Research & Development Expense Adjustment

For the pro forma test year, PSE&G is proposing to increase the test year base rate

Research and Development ("R&D") expense from $1 million to $2.6 million. *P-4 RB*, p. 18. The $1.6 million increase reflects the loss of Gas Technology Institute ("GTI") R&D expense recovery through the LGAC. *P-4 R1*, pp. 20-21. The Ratepayer Advocate recommends that only $529,000 increase in base rate R&D be permitted for ratemaking purposes.

In 1998, the Federal Energy Regulatory Commission ("FERC") eliminated pipeline surcharges paid by pipeline suppliers which was used as a funding mechanism to provide funds for GTI research and development. These surcharges were to be phased out over a 7-year period starting in 1998. *RA-1*, p. 54. The pipeline companies passed the cost along to the utilities who recovered the costs from the customers through the LGACs. Due to the phase out, PSE&G's cost recovery through the LGAC for GTI R&D will continue to decline as follows:

1998	$2.5 million
1999	$2.6 million
2000	$2.0 million
2001	$2.1 million
2002	$1.4 million (projected)
2003	$1.2 million (projected)
2004	$0 (projected)

(*RA-20)*

Because PSE&G will no longer be able to recover the costs of GTI R&D through the LGAC, PSE&G now requests that the cost for GTI R&D be allowed to be recovered through base rates. *P-4 R1*, p. 22. PSE&G stated that, out of the 1998, pre-phase out contribution of $2.5 million, 52.6% (approx. $1.3 million) of the proceeds were applied to gas distribution research, 13.1% (approx. $331,000) to transmission pipeline research and 34.3% ($867,000) to gas production research. T729:L3-T730:L17. In this case, PSE&G is requesting R&D funds equal to the portion of the 1998 FERC surcharge that funded: 1) gas distribution research; and 2) transmission pipeline research totaling approximately $1.6 million. *Id.* This $1.6 million is in addition to test year R&D research level of $1 million, increasing the total R&D operating income to $2.6 million. *RA-2,* Schedule RJH-17R.

The Ratepayer Advocate recommends two adjustments to the Company's calculations.

First, PSE&G's inclusion of the costs of GTI transmission pipeline research in base rates is inappropriate and should be rejected. While PSSE&G currently provides natural gas comodity service, EDECA contemplates that the commodity service will be provided by the competitive market. *N.J.S.A.* 48:3-58. Therefore, PSE&G should not be allowed to pass the costs of GTI transmission R&D of $331,000 through charges for its non-competitive local distribution service. *Id.*.

Second, as stated by Mr. Henkes in his direct testimony, PSE&G has increased its own internal R&D expenses as the phase-out of the GTI R&D became effective. *RA-1,* p. 56. Schedule RJH-17R, line 5 clearly shows, the Company's internal R&D expenses have substantially increased from $378,000 in 1998 to over a $1 million in 2000 and the test year. Mr. Henkes made these observations in his testimony:

> ... it probably is no coincidence that the Company's base rate R&D expenses experienced a significant increase after 1998, the year that the FERC surcharge for the GTI R&D expense recovery in the Company's LGAC started its 7-year phase-out. In other words, it is likely that the Company stepped up its own internal R&D efforts to make up for the reduced GTI R&D efforts as a result of the declining funding levels in accordance with the FERC-mandated phase-out schedule.

RA-3, p. 18.

To allow PSE&G to almost triple its total base rate R&D from 1998 levels and then also allow recovery for GTI R&D is excessive and unjustified. It should be noted that PSE&G will continue to recover a portion of the costs through its LGAC until the costs are fully phased-out at the end of 2004. *RA-20*. If PSE&G is requesting GTI R&D expense levels that existed in 1998 before the phase-out, it is only proper that PSE&G internal R&D expense level reflect the 1998 level as well. This would result in a recommended pro forma test year PSE&G internal R&D expense of $378,000. With these two adjustments, the total recommended pro forma R&D expenses to be recognized for rate making purposes in this case amounts to $1,707,000. The impact of the R&D expense recommendations on PSE&G's proposed pro forma operating income would be to increase the Company's proposed pro forma operating income by $529,000. *RA-2*, Schedule RJH-17R.

I. Deferred Marketing Amortization Expense Adjustment

PSE&G is proposing that certain out of period costs incurred in 1999 for the marketing of its appliance service business that were fully written off the Company's books in October 2000 be charged to the ratepayers on a prospective basis. *P-4 R1*, p. 13. The Ratepayer Advocate believes that PSE&G's proposal is inappropriate and has therefore removed these deferred marketing costs from the Company's proposed pro forma test year operating expenses. This results in a recommended expense reduction of $883,000. *RA-2*, RJH 18R.

In 1999 PSE&G's appliance service business incurred costs for certain marketing activities. Rather than expensing these costs at the time they were incurred, the Company deferred these marketing costs on its books and started amortizing the deferred amount over five years. PSE&G reversed its decision in 2000 and wrote off the remaining unamortized deferred cost balance that was still on its books in October 2000. *P-4 R1*, p. 13 and *RA-31*. The reason for PSE&G's decision to write the entire unamortized deferred cost balance off its books in October 2000 was explained in its response to a Ratepayer Advocate discovery response,

> The American Institute of Certified Public Accountants Statement of Position 93-7, "Reporting on Advertising Costs" states "In order to conclude that advertising elicits sales to customers who could be shown to have responded specifically to the advertising, there must be a means of documenting that response." Initially, the Company believed that it could adhere to the requirements of 93-7, however, in October 2000, *the Company decided to write off the deferral because it was too difficult to track the customers that were obtained as a direct result of the advertising performed.* [emphasis supplied]. *RA-31*.

In his rebuttal testimony, Company witness Stellwag states that even though these deferred costs were incurred prior to the test year, these costs should be recognized for rate making purposes in this case because "customers are still receiving a benefit from these marketing activities today." *P-4 RB*, p. 20. However, as admitted by the Company in the above-quoted discovery response, the Company itself concedes that it cannot identify and measure these "customer benefits" -- and that is exactly why it decided to write the entire deferred marketing cost balance off its books in October 2000. *RA-31*. Furthermore, it is inappropriate to charge to the Ratepayers on a prospective basis a one-time cost incurred between rate cases, particularly when these costs have already been fully written off the Company's books. *RA-3*, pp. 14-15. It is simply wrong to charge the Ratepayers for a cost that no longer exists on the Company's books.

Accordingly, the Ratepayer Advocate recommends that these deferred marketing amortization expenses be removed for rate making purposes in this case.

J. Expired Amortization Expense Adjustments

PSE&G has included in the test year $113,000 for amortization expenses associated with the Company's Integrated Infrastructure System and $182,000 for amortization expenses associated with the Corporate Distributed System Software. *RA-2*, Schedule RJH-19R. These two expense items should be removed for rate making purposes in this case because the $113,000 amortization expense has already expired in February 2001 and the $182,000 amortization expense will expire in March of 2002, around the time that the rates from this case are expected to go into effect. Since these expenses will no longer be incurred by the Company during the rate effective period, they must be removed from the test year as non-recurring expenses.

K. Charitable Contribution Expense Adjustment

The Company has proposed, for purposes of this proceeding, to include $1,523,000 in charitable contributions in its "above-the-line" test year operating expenses, of which 100% would be charged to ratepayers. *RA-38*, Sch. RJH-4R updated 10/29/01. All of PSE&G's charitable contribution expenses should be eliminated from *pro forma* operating expenses and be borne solely by the utility. This is an expense to the shareholders as required by the recent New Jersey Supreme Court case in the *I/M/O the Petition of New Jersey American Water Company, Inc. for an Increase in Rates for Water and Sewer Service and Other Tariff Modifications*, 169 *N.J.* 181 (2001). There the Supreme Court ruled that:

> We agree with the Ratepayer Advocate that the BPU's 50/50 sharing policy is arbitrary and lacks a sufficient evidentiary basis in the record. Accordingly, no portion of American Water's charitable contributions may be subsidized by consumers. Although we commend American Water for making charitable contributions,

> we are convinced that the cost of those contributions should be borne solely by its shareholders.
>
> 169 *N.J.* at 190.

Mr. Stellwag, in his rebuttal testimony questions the wisdom of the New Jersey Supreme court by stating: “While I understand that Mr. Henkes’ recommendation is driven by his review of the recent Supreme Court decision I cannot agree that it is a prudent recommendation ...” *P-4 RB*, p. 21. Although the Company may argue that the Supreme Court of New Jersey has somehow made an imprudent decision, it is now the law of the State of New Jersey. It must be noted that most American corporations recognize that the costs of corporate charity are borne by the company’s shareholders out of profits. *See, e.g., First National Bank of Boston v. Bellotti*, 435 U.S. 765, 792-95 (1978); *Cahill v. Public Service Commission*, 147 A.D 2d 49, 542 N.Y. 2d 394. (1989). PSE&G’s ratepayers are responsible only for legitimate and prudent costs incurred by the Company to provide safe adequate and proper energy service. They are not responsible for the costs associated with PSE&G management’s decision to make charitable contributions to organizations of their choice.

L. Property Insurance Expense Adjustment

PSE&G’s updated “12+0" data shows that the restated actual test year property insurance expense as $362,000. *P-3 RB*, p. 13. The Company conceded in Mr. Krueger’s rebuttal testimony that this restated test year insurance expense amount is overstated by $265,000 and must be adjusted downward to $97,000 based on Mr. Henkes’ methodology. *Id*. Mr. Henkes in his supplemental testimony adopted this latest PSE&G proposal, therefore, there are no issues with respect to property insurance expense adjustments. *RA-2*, Schedule RJH-21R.

M. Miscellaneous Expense Adjustments

\- Public Relations/Community Affairs Expenses

RA-2, Schedule RJH-22R, line 1 reflects the removal for ratemaking purposes of $219,000 for test year Public Relations/Community Affairs expenses. The Company's response to RAR-A-55 shows that these expenses primarily consist of philanthropic activities, employee volunteer activities, community assistance in raising money for projects, and seminars on school violence. *RA-33.* 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 gas service. *RA-1*, p. 65. Moreover, some of these expenses represent charitable contributions by PSE&G which must be disallowed for the reasons described in the Charitable Contribution section above.

The Ratepayer Advocate's position with regard to these Public Relations/Community Affairs expenses is consistent with established Board policy which was reaffirmed by the Board as recent as in its May 2001 Middlesex Water Company rate Order ("Middlesex Order"). 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.....

The Board then went on and disallowed this $25,295 expense for rate making 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.

- Institutional Advertising

RA-2, Schedule RJH-22R, lines 2 and 3 reflect the removal of $26,000 of institutional advertising expenses from the Company's proposed test year expenses. These expenses are for image creation and goodwill building activities that have as their main purpose to promote PSE&G as a good corporate citizen. These expenses are not necessary to provide safe, adequate and proper utility service. *RA-1*, p. 65.

In his rebuttal testimony, Mr. Stellwag criticizes Mr. Henkes for relying on a Board policy which "had its genesis in an almost twenty-five year old Board Order dated May 31. 1977." *P-4* RB, p. 23. Mr. Stellwag suggests that the change in the regulatory environment due to the enactment of EDECA made educating consumers necessary and therefore the well-established Board Policy to disallow institutional advertisement has become obsolete. Mr. Stellwag's observations are wholly without merit and should be rejected by the Board. First, the Ratepayer Advocate does not disagree with Mr. Stellwag's observation that the new regulatory environment does require consumer education. However, what Mr. Stellwag fails to recognize is the millions of dollars PSE&G is already recovering from ratepayers for consumer education pursuant to EDECA. For example, *In the Matter of Public Service Electric & Gas Company's Consumer Education Program on Electric Rate Discounts & Energy Competition,* BPU Docket No. ER00080550, PSE&G filed for, and the Board granted the Company, recovery of education costs totaling approx. $11.86 million which represents the first year education costs of which $7.2 million is allocated to electric and $4.5 million is allocated to gas. EDECA generously allowed for additional education needs of consumers and PSE&G is fully recovering these costs. Ratepayers should not be required to also fund institutional advertising which benefits the

Company's shareholders.

- Lobbying Expenses

The Company's proposed test year above-the-line expenses include approximately $140,000 for lobbying expenses. *RA-2*, Schedule RJH-22R. 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 the 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. For that reason, there are many jurisdictions nationwide which disallow lobbying expenses for ratemaking purposes. *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) . Noticeably, PSE&G did not present any rebuttal to the Ratepayer Advocate's position on these lobbying expenses. Accordingly, the Board should disallow these $140,000 for lobbying expenses.

- Management "Perks"

RA-2, Schedule RJH-22R, line 35 reflects the Ratepayer Advocate's recommendation to remove $35,000 worth of management "perks" from the Company's proposed test year expenses.

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-1,* p. 66. The Ratepayer Advocate is of the position that such expenses like incentive compensation are funded by the shareholders, not the ratepayers.

- Donation Expenses Allocated From PSEG

RA-2, Schedule RJH-22R, line 9 reflects the Ratepayer Advocate's recommendation to remove $26,000 worth of donation expenses allocated to the Company from its parent PSEG from the Company's proposed test year expenses. As Mr. Henkes describes in his Direct Testimony, these expenses include charitable contributions, such as contributions to the Liberty Science Center and New Jersey Aquarium. *RA-1,* p. 67. Mr. Stellwag concedes that these expenses, "assist these organizations in their mission as a public resource for lifelong interactive exploration of science, technology and environmental issues. *P-4 RB,* p. 27. Again, as stated by the New Jersey Supreme Court in the *New Jersey American Water* decision, 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. See also the Charitable Contribution Section above.

- Electric Power Research Institute Expense ("EPRI") Adjustment

The Company 's proposed test year expenses include a total of $61,600 for EPRI related expenses. Even though the Company has conceded that EPRI's primary focus is on "electric" related topics, nevertheless, PSE&G proposes to have its gas ratepayers pay for membership dues and research costs paid to EPRI. In order to explain why gas ratepayers have any interest in a research institute focused on electric energy, PSE&G claimed that the gas side of the business has an interest in projects that encourages the use of natural gas for electric generation such as fuel cell research being funded at EPRI. *P-2 RB*, pp.14-15. Based on this testimony, it appears that the benefits of this research will accrue primarily to the Company's competitive gas supply business. The Company has not justified its proposal fund this research through charges its non-competitve local distribution service.

N. Pro Forma Depreciation Expense Adjustment

On May 4, 2001, PSE&G filed for new depreciation rates based on a new depreciation study completed by Deloitte & Touche. *P-8.* The Depreciation Case was subsequently merged with the Company gas rate case. Like the Contract Transfer case, PSE&G assumed that the Board will approve its petition in the Depreciation Case and filed the base rate case with depreciation expenses using the new yet unapproved depreciation rates. PSE&G now proposes a pro forma annualized 12+0 depreciation expense of approximately $150.8 million. Using Ratepayer Advocate witness Michael Majoros' proposed new depreciation rates discussed in detail in the Depreciation Section below, the proper level of *pro forma* annualized depreciation expense is $63,641,000. Mr. Henkes then calculated that this Ratepayer Advocate recommendation will result in an increase of $61,267,000 in the Company's proposed pro forma test year Operating Income. *RA-2,* Schedule RJH-23R.

O. 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-25R updated 10/29/01, the Ratepayer Advocate's pro forma interest deduction for income tax purposes is larger than the Company's. As can be seen from Schedule RJH -25R updated 10/31/2001, this results in an increase of $2,460,000 in the Company's proposed pro forma test year operating income. *P-4 R-1*, Schedule ANS-7 R-1.

POINT IV

THE ALJ AND THE BOARD SHOULD REJECT PUBLIC SERVICE'S UNREASONABLE REQUEST FOR DEPRECIATION RATES AND FOR A 62% INCREASE IN ANNUAL DEPRECIATION EXPENSE AND ADOPT THE RATEPAYER ADVOCATE'S RECOMMENDED 41% DECREASE.

Depreciation expense is included in Public Service's revenue requirement and is passed on to ratepayers on a virtually dollar-for-dollar basis. Annual depreciation expense is determined by applying depreciation rates to plant investment. Depreciation rates are determined in depreciation studies. Typically there are two components to depreciation rates. One is to recover invested capital, that is, money that has already been spent. Another component recovers net salvage, an expense that has not yet been incurred. T285:L6-19. The witnesses for Public Service and the Ratepayer Advocate agree that the treatment of net salvage is the "one overriding issue in this [depreciation] case." T246:L3-7; T285:L20-22.

The ALJ and the Board should reject Public Service's proposed depreciation rates because they will produce excessive depreciation expense and unnecessarily increase revenue requirements. *RA-12*, p. 2, l. 12-14. Since depreciation expense flows dollar-for-dollar into the revenue requirement, excessive depreciation expense results in an excessive revenue requirement. *Id*., p. 6, l. 22-24.

Public Service proposes a $127,171,000 annual expense for depreciation. *P-8RB, Schedule 1*. This is a $48.3 million increase annually or 62% more than the current annual allowance.T254:L4-6. The depreciation expert witness for the Ratepayer Advocate, Michael J. Majoros, proposes $46,759,266 which is approximately $80,412,000 less than Public Service's proposed annual depreciation expense. *Id.* Mr. Majoros' proposal is a $32.1 million decrease or 41% less than currently allowed. *RA-12*, p. 3, l. 4-11; *RA-13*, p. 1, l. 13 to p. 2, l. 1.

Most of the difference is due to the Company's unsupportable and unreasonable net salvage request. Public Service seeks $79.9 million in future net salvage when the utility's actual experience for net salvage is only $6.7 million per year over the past ten years. *RA-13*, p. 3, l. 3-4; *RA-12*, p. 18, l. 7-10; *RA-12A*, Exh. MJM-2, Statement B. That approach defies the utility's recent actual experience and will overcharge current utility customers for future expenses that have not historically reached that level. Mr. Majoros offered an alternative approach, based on the method commonly used by the Pennsylvania Public Utility Commission ("PaPUC"). As Mr. Majoros testified, the Pennsylvania method works well and keeps the utility whole. T345:L3-6.

Public Service generally used the remaining life technique to calculate its recommended depreciation rates. Its depreciation proposal is excessive because several remaining lives it calculated are too short. For example, it understated plant life spans, it improperly included future interim plant additions in the life span calculations, it understated certain mass property account lives, and it exacerbated these conditions by including an unsupportable and unreasonable request for negative net salvage in its depreciation rates. *RA-12*, p. 6, l. 2-8.

The chart below summarizes the components of the $80,412,000 difference in the proposals made by Public Service and by the Ratepayer Advocate.

Difference due to net salvage method	$61,655,000
Difference due to service life changes	$10,065,000
Difference due to interim additions	$329,000
Difference due to interrelationships of above changes	$8,363,000
Total difference	$80,412,000[8]

[8]*P-8RB, Schedule 1.*

A. Public Service's Net Salvage Approach Contradicts The Factual Record And Will Result in Unjust And Unreasonable Depreciation Rates And Expense.

Ratepayer Advocate witness, Mr. Majoros, briefly outlined the background of the net salvage issue. Net salvage is the difference between gross salvage and the cost of removal of the plant. Gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. The cost of removal is connected with disposing of retired depreciable plant. Net salvage is positive when gross salvage exceeds cost of removal. Net salvage is negative when cost of removal exceeds gross salvage. A positive net salvage ratio reduces the depreciation rate and revenue requirement, while a negative net salvage ratio increases a depreciation rate and revenue requirement to collect for estimated future cost of removal. *RA-12,* p. 7, l. 19 to p. 8, l. 5.

The major part of Public Service's depreciation proposal includes a $60.4 million *increase* in the annual charge for negative net salvage (cost of removal). *RA-13,* p. 8, l. 9-13. Several elements of Public Service's net salvage proposals are unreasonable because they would recover inflated future removal costs that for the most part will not be incurred. *RA-12,* p. 9, l. 14-18. It should be beyond doubt that it is unreasonable to charge ratepayers for expenses that are likely never to be incurred and will therefore never provide them with utility services. This section of the Ratepayer Advocate's initial brief will first discuss Public Service's excessive request for net salvage for Production and Storage plant and its mass property plant. The Ratepayer Advocate will then propose a better method to recover a reasonable amount for this item.

Production and Storage Plant

For its Production and Storage plant, Public Service started with cost of removal estimates from dismantlement cost studies for the year 1989[9] (from the last base rate case) and then subtracted the actual cost of removal incurred in the early 1990s. This method is wrong because Public Service has already removed a majority of the assets to which the prior dismantlement cost studies related. *RA-12*, p. 11, l. 9-10. A majority of the dismantlement work contemplated in the 1989 estimate was completed in 1992 and 1993 at costs significantly lower than the 1989 estimates. Thus, most of the remaining dismantlement estimated costs will never occur.

Mr. Majoros' observations during his visit to the plant in question on July 24 and 26, 2001 convinced him that it is highly unlikely Public Service will experience another removal effort at these plants of similar magnitude to the 1992 and 1993 dismantlements. For example, in Exhibit MJM-1 of RA-12A, photo number 9 shows what was dismantled at the Harrison site versus photo numbers 2 through 8 showing what is there now. Photo number 9 shows the old boiler and gas holder structures that were used in the old liquid propane air ("LPA") process at the Harrison plant. The structures were huge and have been removed. Photo numbers 11 and 12 show vacant land where much of the plant once existed. Photos 2 through 8 show the existing plant.

Although there may be some future cost of removal of existing plant, those costs certainly cannot be supported by the 1989 dismantlement studies. This is also the case for other Production and Storage plant for Public Service. *RA-12*, p. 12, l. 3-6. The 1989 dismantlement

[9]The study was done in 1990 using year end 1989 figures. *RA-12*, p. 10, l. 3-6; T256:L9-14.

studies do not provide a reliable estimate for the future cost of removal of the current plant in service. Public Service's reliance on those estimates causes the net salvage portions of its depreciation request for this plant to be highly overstated and unreasonable.

The Company also applied a 3% inflation factor to the remaining amount of the 1989 removal cost estimates, thereby further increasing the costs over time through the proposed terminal retirement date. *RA-12*, p. 10, l. 6-13. T315:L18 to T316:L23. Since the estimated amounts to which the inflation factor was applied are already unjustifiably high, the ALJ and the Board should also reject the use of an inflation factor that would only exacerbate the overcharge to the customers.

<u>Mains and Services</u>

Public Service also proposes an excessive amount of negative net salvage for its mass property accounts. A majority is in the Mains and Services accounts. Public Service's witness, Donald S. Roff, calculated net salvage ratios of -125% for mains and -140% for services. *P-8*, Exh. DSR-3, Sch. 3, p. 17. He arrived at these very negative ratios by comparing current removal costs to retirements of very old assets stated at their original cost. The comparison of current removal costs to these retirements of old plant resulted in the extreme negative salvage ratios shown above. *RA-12*, p. 13, l. 1-16. As observed by Mr. Majoros, Public Service's proposed annual net salvage charge of $69.9 million for gas mains and service lines is more than ten times Public Service's actual experience over the past 10 years and is grossly overstated. *RA-12*, p. 14, l. 1-2. The Company provides no rational basis for why this future expense should be so much higher than what it has actually been incurring recently.

Furthermore, Public Service's proposed annual depreciation charge for mains and services is unreasonable because a majority of the alleged cost of removal for mains and services will not be incurred. *Id*., p. 14, l. 24-25. Public Service's alleged cost of removal will not be incurred because the utility is not removing the existing metallic mains and services that are being replaced by new plastic mains and services. Indeed, Public Service witness, Peter A. Cistaro, testified that the Company is "not aware of any gas distribution company in the nation that removes the abandoned main facilities from the ground." *P-2RB*, p. 5, l. 19 to p. 6, l. 1.

Some metallic mains and services remain in place alongside the new plastic mains and services to help locate the new lines using magnetic devices that cannot detect a plastic main or service alone. Public Service's witness, Mr. Cistaro, confirmed that this is the case. Other new plastic mains and services are inserted inside the old main or service. *RA-12*, p. 15, l. 1-18; *P-2RB*, p. 5, l. 5-13. Mr. Majoros viewed a main and service replacement project in New Brunswick in which these methods were being used.

Leaving the old main and service in place is done for at least two reasons. First, if the new plastic pipe can be inserted into the old metallic pipe, this avoids the excavation cost of digging up the old pipe. *RA-12*, p. 15, l. 8-9. Second, and more importantly, even though plastic is a superior technology (photographs 19 and 20 of Exhibit MJM-1, *RA-12A*), it has the disadvantage that, once the plastic pipe is buried, it cannot be located with magnetic devices when needed. The metallic mains and services are left in place in order to locate the plastic mains later. When the new plastic pipe is inserted into the existing metallic pipe, this also avoids the costs of installing a locating wire along with the new plastic pipe. *P-2RB*, p. 5, l. 12-13. When insertion is used, the existing main or service also provides some level of protection to the newly installed pipe.

The old metallic mains and services continue to provide necessary service to the customers so that the new plastic pipes can be located at a later date when possible leaks need to be investigated and repaired or when the pipe needs to be located so that future excavators can avoid damaging the pipe when digging for other reasons. These are important safety considerations that cannot be denied.

Public Service's witness, Mr. Cistaro, takes the limited view that because the old pipe is no longer used to transport gas, then it is no longer of service to the customers. *P-2RB*, p. 5, l. 13-16. However, not all plant in service is used to transport gas, but still plays a vital role in safe and adequate gas utility service. Safety equipment of various kinds is rightfully considered "in service." Simply because the old mains and services once had two functions, transporting gas and safety considerations, and now have only the safety function, this cannot negate the fact that the safety function is still being served. In reality, the mains and services being replaced continue to provide service and should not be retired. It is Mr. Majoros' opinion that the entire replacement work effort is to install the new main or service, not to remove the old main or service. *RA-12*, p. 15, l. 16-18. Therefore, Public Service's arbitrary assignment of part of the replacement project cost to the cost of removal should be rejected. *Id.*, p. 15, l. 19 to p. 16, l. 2.

Even assuming old mains should be considered out of service, Mr. Cistaro's rebuttal testimony provides proof that the Company's depreciation proposal for net salvage of mains and services is grossly overstated. Mr. Cistaro testified that the costs for abandoning the old pipe are small relative to the cost of installing the replacement main. The cost of abandonment is only about 3% to 5% of the cost of replacing the main. *P-2RB*, p. 6, l. 11-14.[10] In comparison to Mr. Cistaro's 3% to 5% for the cost of abandonment, Mr. Roff calculates a negative 125% salvage ratio for abandonment costs. *P-8, Exhibit DSR-3, Schedule 3,* p. 17. The 125% net salvage rate would be applied to the cost of the new main. This calculation is therefore extremely unreasonable when compared to the Company's own testimony about the cost of abandonment. In contrast, Mr. Majoros' proposal is designed to return to the Company the full 3% to 5% actual cost while also having the beneficial effect of not overcharging the customers. *RA-13*, p. 12, l. 13-18.

Rather than attempting to recalculate Public Service's flawed method for net salvage, Mr. Majoros proposes using a five-year average salvage expense allowance method that is used by other state utility regulators including the Pennsylvania Public Utility Commission and the Kentucky Public Service Commission.[11] *RA-12*, p. 17, l. 17 to p. 19, l. 1. In this approach, no net salvage ratios are calculated and included in the remaining life depreciation rates. Instead, a separate calculation of the average annual net salvage expense is done by averaging the past five years of actual net negative salvage expense. This five-year average is then added to the annual depreciation expense and included in the reserve. This is similar to a normalized expense allowance being included in the Company's revenue requirement. *Id.*

In Mr. Majoros' Exhibit *RA-12A*, Statement B of MJM-2 shows the rolling five year average of Public Service's actual net salvage experience. The most recent average expense amount, $6.7 million, for negative net salvage experience should be added to Public Service's

[10]Mr. Cistaro also said that the abandonment cost is significant when compared to the dollars retired. *Id.* However, that is an irrelevant comparison and provides no useful information in setting depreciation rates.

[11]*Jackson Energy Cooperative*, Case No. 2000-373.

depreciation expense and incorporated into its revenue requirement. Each year the amount should be debited to depreciation expense and credited to accumulated depreciation, just as the rest of the Company's depreciation expense. *Id.,* p. 18, l. 7-12. Using this method provides full capital recovery to Public Service and avoids the excessive charges to ratepayers caused by Public Service's proposals. *Id*., p. 18, l. 19-20.

Although at the September 24 hearing Public Service placed some emphasis on its belief that the five-year average approach is optional when used in utility rate cases, Mr. Majoros stated that in his experience with Pennsylvania ratemaking, only the telephone utilities have used future net salvage calculations rather than the five-year average approach. T314:L6-12. Furthermore, page 2 of 7 of Appendix A attached to Mr. Majoros' direct testimony (*RA-12*) states that Mr. Majoros has participated in numerous Pennsylvania utility rate cases back to 1984. Public Service also produced Exhibit P-27 which allegedly showed that the five-year average approach for net salvage is optional in Pennsylvania rate cases. However, that exhibit clearly states that it applies to the annual depreciation reports that the PaPUC requires utilities to file and does not state that it applies to the ratemaking for depreciation expense.

In addition, several Pennsylvania cases state that the PaPUC uses the five-year average net salvage approach.

> Net negative salvage is a component of a utility's annual depreciation expense; it is the amount of money by which the cost to a utility of removing retired property exceeds that property's salvage value, if any. **It is the Commission's practice in determining a utility's net salvage allowance to average the most recent five years of a utility's actual net salvage.** If net salvage is negative, it is added to the utility's annual depreciation expense.

Philadelphia Elec. Co. v. Pa. Pub. Util. Com'n.,502 A.2d 722, 728 (Pa. Cmwlth. 1985) (emphasis added).

> **We are told that the Commission's practice in determining a utility's net salvage allowance is to average the most recent five years of a utility's actual net salvage.** Net negative salvage is added to the annual depreciation expense. Conversely, when the salvage value exceeds the cost of removal, the net salvage value is positive and is deducted from the annual depreciation expense.

T.W. Phillips Gas and Oil Co. v. Pa. Pub. Util. Com'n., 474 A.2d 355, 364 (Pa. Cmwlth. 1984) emphasis added. *See also Penn Sheraton Hotel v. Pa. Pub. Util. Com'n.,* 184 A.2d 324, 329 (Pa. Super. 1962) (if a utility "incurs actual negative salvage. . ., the expenditure should be capitalized and amortized by some reasonable method and for and over a reasonable length of time", but prohibiting future negative salvage allowance in depreciation rates since it is a prospective expense not yet incurred).

Public Service attempts to criticize the five-year average net salvage method by alleging that Mr. Majoros' proposal would create a capital recovery shortfall. *P-8RB*, p. 8, l. 11-13. However, Mr. Majoros' analysis of the Company's position has thoroughly discredited this allegation. Rather than creating a shortfall, the remaining life formula Mr. Majoros proposes is self-adjusting and will protect Public Service's capital recovery[12]. For example, if remaining life changes occur due to early plant retirements, the retirements are charged to the depreciation

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[12] $$\text{Accrual} = \frac{\text{Plant in Service - Depreciation Reserve}}{\text{Remaining Life}}$$

P-12, p. 6, 11-14.

reserve (see formula in footnote below) and in that way they are accounted for in the accrual. *RA-12*, p. 7, l. 9-13.

The five-year average allowance for net salvage also gives the Company protection for net salvage recovery.[13] Because the net salvage allowance and the actual expense flow into the depreciation reserve (see formula in footnote below), the true-up inherent in the remaining life formula provides an added level of protection to the Company for net salvage recovery as well. *P-13*, p. 3, l. 16 to p. 4, l. 2.

Schedule 3 attached to Exhibit P-8RB is Public Service's calculation of the alleged shortfall in Mr. Majoros' proposal. In his rebuttal testimony, Mr. Majoros proved that this Schedule 3 uses invalid data and is incorrect and misleading. Public Service's Schedule 3 assumes retirements in the amount of $13,698,756 per year. Mr. Majoros' analysis shows that this assumption is much higher than the utility's actual retirements over the past five years. Those annual actual retirements range from $1,080,011 to $2,596,613, far less than the annual $13,698,756 that Public Service's witness assumed. *RA-13*, p. 5, l. 1-17. This Schedule 3 also assumes an annual negative net salvage cost of $17,123,445 for Mains, using Mr. Roff's proposed -125% net salvage ratio. *Id.*, p. 5, l. 18-21. Contrary to Mr. Roff's assumption, Mr. Majoros' analysis shows that the actual annual negative net salvage for the last five years ranges from

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[13]Although Public Service complained that this remaining life formula does not contain a variable for future net salvage, using the five-year average net salvage allowance in addition to the depreciation expense allowance provides full capital recovery. Using the five-year average net salvage allowance and then including a variable for future net salvage in the remaining life formula would improperly pass through a double recovery for net salvage costs. *RA-13*, p. 3, l. 7-15. Therefore, Public Service's complaint misses the point entirely and should be denied.

$1,927,738 to $3,245,293, also much less than Public Service's assumed annual amount of $17,123,445.

Mr. Majoros also made the following corrections to Public Service's Schedule 3.

> Although Mr. Roff calls column (8) the "Majoros Accrual", it is not the Majoros accrual. It is wrong for two reasons. First, Mr. Roff did not properly reflect the fact that the net salvage allowance approach is self-adjusting. If the Company were to actually incur removal costs at the levels assumed by Mr. Roff, the net salvage allowance would be adjusted to reflect this. Thus, assuming the validity of Mr. Roff's assumptions, $17,123,445 would be added to the Majoros accrual each year. Second, Mr. Roff's schedule includes an adjustment that has nothing to do with my recommendation to use a net salvage allowance rather than reflecting net salvage in the depreciation rate. Specifically, the "shortfall" shown on his schedule reflects his use of his 46-year remaining life, compared to my 60-year remaining life. Thus, the schedule exaggerates the differences between our two approaches. The Majoros accrual rate should be adjusted to 1.19 percent based on Mr. Roff's proposed 46-year remaining life to eliminate this distortion.
>
> Exhibit___(MJM-6) attached to this surrebuttal testimony corrects Mr. Roff's Schedule 3 to reflect the true Majoros accrual. It uses a 1.19 percent depreciation rate and adds a $17,123,445 net salvage allowance each year. The exhibit demonstrates that even using Mr. Roff's unreasonable assumptions, the Pennsylvania net salvage allowance method does <u>not</u> result in a shortfall. There is no shortfall. In fact, at the end the Majoros accruals yield virtually the same amount as Mr. Roff's, even based on his unreasonable assumptions. The Board should give no weight to the Roff's Schedule 3 nor to Mr. Roff's testimony.

RA-13, p. 6, l. 15 to p. 7, l. 9. Therefore, Mr. Majoros' recommendations do not create any capital recovery shortfall. He predicated his recommendations on reasonable lives and a normalized expense mechanism, both of which are trued-up with remaining-life depreciation. *Id.*, p. 7, l. 10-12. Mr. Majoros' corrections to Mr. Roff's Schedule 3 show that the five-year salvage allowance method used by Mr. Majoros yields full and reasonable capital recovery and that the Company's criticisms are entirely meretricious. *RA-13*, p. 5, l. 1 to p. 7, l. 12.

B. Public Service's Proposed Service Lives for Production and Storage Plant Are Not Factually Supported and Would Create Unjustified Depreciation Expense.

Public Service used the life span procedure to determine depreciation rates for its Production and Storage plant. However, the Company did not provide factual support for its proposed life spans. *RA-12*, p. 25, l. 26 to p. 27, l. 2. Mr. Majoros testified that the proposed life spans are much too short. *Id*., p. 24, l. 1-19. He relied on the NARUC Public Utility Depreciation Practices Manual (1996) as a source for what considerations and data are needed for these calculations. That Manual states that the final retirement date for the plant is the most important factor in determining a depreciation rate for life span property. The Manual specifies that the factors to be considered include economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressures, in order to develop an informed estimate of the final retirement date.[14] However, Public Service admitted that it had no specific detailed studies to support its estimated final retirement years. *RA-12*, p. 25, l. 26 to p. 26, l. 31. When asked to produce the basis for its retirement years, the Company could only produce a single page E-mail message describing its general approach without factual data or calculations to support it. *RA-12A, Exhibit MJM-5.* That is hardly the type of rigorous analysis that is needed.

[14] NARUC Manual, p. 146.

Mr. Majoros took an alternative approach that conservatively extended the service lives by ten years to more closely reflect what is likely to be the more accurate estimate. *RA-12*, p. 27, l. 11-28. The ten-year extension is based on Mr. Majoros' site visit to the plant in question and is further supported by his analysis of the account (311-LPG Equipment) in which the bulk of this plant is recorded. That analysis shows that the average service life of forty years that results from Mr. Majoros' 26 year remaining life estimate plus the 14.4 year average age of this investment compares conservatively to Mr. Roff's actuarial analyses of this account. Mr. Roff calculated a range of 43 to 77 years for this account, so that Mr. Majoros' approach appears at the lower, shorter end of that range, a reasonable result that demonstrates the fairness to both the utility and to the customers in his approach. *Id.*, p. 28, l. 5-7.

Moreover, this type of plant has been well maintained and Public Service acknowledges that it is critical to the gas utility operations, so there is no reason to expect that it will be retired from service as soon as Public Service's proposed retirement dates suggest. *Id.*, p. 28, l. 8-13. Also, Public Service did significant work to update the existing plant which extended their service lives (T406:L8 to T407:L7; T409:L10-23 and T411:L17-21) and could obviously do this again to keep operating these plants even longer since they are so critical to the utility's operation. T413:L13 to T414:L8. Mr. Majoros has proposed a conservative ten year extension for the service lives since the plant will likely continue in use long after that. *Id.*, p. 27, l. 3 to p. 28, l. 7. Mr. Cistaro's rebuttal testimony attempts to degrade the usefulness of these plants, but that contradicts the Company's admissions that this plant is critical to its operations and there is no reason to accept that they will be retired in the near future. *RA-13*, p. 13, l. 2-15; *P-2RB*, p. 9, l. 1 to p. 11, l. 18.

At the September 24, 2001 evidentiary hearing, Public Service attempted to support its short service lives by suggesting that competition for the retail natural gas supply function could shorten the service lives of these plants, but at the following hearing on September 25, Mr. Cistaro admitted under cross-examination by the Ratepayer Advocate that this is not the case:

> Q. I'll want to follow up on just a couple of issues that were raised by Mr. Camacho during yesterday's cross-examination of Mr. Roff, and that has to do with the impact of developing competition in the natural gas market on the Company's projection and storage facilities.
>
> Now, you mentioned interstate transportation and storage as a possible source of gas supply.
> Are you aware of any plans by Public Service to replace its production and storage facilities with interstate pipeline resources?
>
> A There are no plans at this particular time to replace those facilities.
>
> Q Are you aware of any plans to retire any of these facilities due to the impact of competition?
>
> A No, I believe my testimony is that when we look at these plants, we have to weigh them versus the availability of supplies on the coldest days of the year.
>
> The information that we have right now is that it is not available on the coldest days of the year, so we have no plans to retire them.
>
> Q Are you aware of any studies performed by the Company suggesting that any of these facilities are likely to be displaced as a result of competition?
>
> A I don't know of any studies regarding that particular issue.
>
> T:391:L11 to T:392:L10.

Mr. Cistaro also admitted that the Company has no studies on what to do with the plants in the hypothetical case that Public Service could obtain additional pipeline gas supply to substitute for these plants. T392:L11 to T393:L2. Further, Mr. Cistaro testified that if Public Service could displace these plants with pipeline gas, the plants could be sold or used elsewhere in the Company's system or some other alternatives might arise. T393:L20 to T394:L14. Therefore, the ALJ and the Board can ignore the Company's baseless suggestion that retail natural gas competition could justify the retirement years proposed for these plants. Public Service admits that the production plants operate effectively, safely and reliably (T404:L9-12), so there is no factual reason to believe they will be retired as near in the future as the Company alleges.

C. Public Service's Proposed Service Lives for Transmission and Distribution Plant Are Unjustifiably Short and Would Unreasonably Increase Revenue Requirements.

Public Service's methods for calculating service lives for Transmission and Distribution plant result in service lives for several accounts that are too short. Understated service lives cause excessive depreciation expense and unjustifiably increase revenue requirements. Mr. Majoros analyzed Public Service's calculations and performed geometric mean turnover analyses to test Public Service's service life proposals for the Transmission and Distribution plant. *RA-12*, p. 19, l. 19-23. A turnover analysis is based on the general theory that the time it takes the plant to "turn over" (i.e., the time it takes the retirements to exhaust a previous plant balance) is a measure of service life. *Id.*, p. 19, l. 18-21.

Mr. Majoros' analyses show in several areas that the Company has unreasonably proposed service lives that are too short. Mr. Majoros' geometric mean turnover analyses are included in the individual account sections of Exhibit MJM-2 in RA-12A. The table below shows the analysis results where Mr. Majoros differs from the Company's proposals and includes some, but not all, of the results from the more complete table in Mr. Majoros' direct testimony. *RA-12*, pp. 20-21. That table showed where Mr. Majoros' analyses agreed with some Public Service proposals as well as where he differed. The Ratepayer Advocate recommends that the ALJ and the Board adopt Mr. Majoros' proposals where they differ from those of Public Service.

Snavely King's T&D Life Analyses (Partial)

Acct. No.	Acct. Name	Life Analysis	Exh. MJM-2 Page Nos.
367.00	Transmission - Mains	Used same approach as Company, i.e., 75 R2 based on recommendation for 376 - Distribution Mains.	73-76
376.00	Distribution - Mains	All life indications are more than 60 and are getting longer. Roff uses 83 R2 to age the account. Broadest bands in turnover analysis support life in the range of 75 years. Use 75 R2.	84-92
380.00	Distribution - Services	Indications exceed 50 beginning with the 1988-90 band, then get longer. It is evident from examination of life indications chart that, beginning in 1990, a 55 year life is reasonable and conservative. Use 55 R1.5.	103-111
383.00 384.00	Distribution - Regulators & Regulator Installations	Most recent indications are extremely long, however prior to 1991 band, indications tended to support a life in 70-80 year range. Use 75.	119-126

Mr. Majoros' turnover analyses demonstrate that the Company's service life calculations for Distribution Mains and Services reach results that are much too short when compared to its previous experience. *RA-12*, p. 17, l. 3-15. Pages 86 to 88 of the Exhibit MJM-2 contained in RA-12A is the turnover analysis for account 376-Mains and pages 105 to 107 is the turnover analysis for account 380-Services. The analyses resulting from these calculations demonstrate that the Company's proposed service lives are much shorter than the most recent life indications. The geometric mean life estimate for Distribution Mains is 108 years while Public Service proposes only 60 years.[15] The geometric mean life estimate for Services is 87 years while Public Service proposes only 50 years.[16] From the above data, it is apparent that the Company is not only proposing a net salvage charge which is unreasonable and irrational, but is also proposing service lives that are too short. The Ratepayer Advocate recommends that the ALJ and the Board reject the unreasonable proposals made by Public Service and adopt the fully supported recommendations of our witness, Mr. Majoros.

D. Public Service's Improper Inclusion of Future Plant Additions When Calculating Depreciation Rates for Existing Plant in Service Should Be Rejected.

The ALJ and the Board should also reject Public Service's proposal to include future plant additions in the calculation of life span depreciation rates for Production and Storage plant. Future additions should not be included in life-span depreciation rate calculations. As stated by Mr. Majoros, costs for future additions are precluded from the depreciation determination by NARUC in its Depreciation Practices Manual which states that "interim additions are not considered in the depreciation base or rate until they occur." *RA-12,* p. 28, l. 17 to p. 29, l. 7. Conceptually and in actuality, future capital additions do not exist as of the depreciation study date, so they cannot have a remaining life at the study date. *Id.*, p. 29, l. 28-30. Also, including

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[15]*RA-12*, p. 17, l. 2-15 and *RA-13, Exhibit MJM-2,* p. 88.

[16]*RA-12*, p. 17, l. 2-15 and *RA-13, Exhibit MJM-2*, p. 107.

future additions in current rates violates normal ratemaking principles by charging current ratepayers for plant additions in the future that do not serve them now.[17] The Company's proposal for future additions creates an excessive depreciation expense, renders the resulting depreciation rate incorrect and should, accordingly, be rejected. *Id.*, p. 30, l. 5-7.

Public utility depreciation rates should be designed to recover from ratepayers the cost of existing net plant over the remaining life of existing plant. Including the future plant additions that have not even occurred reduces the remaining life relating to existing plant, unnecessarily increases revenue requirements, and charges current ratepayers for future plant additions that are not being used to serve them yet. *RA-12*, p. 29, l. 30 to p. 30, l. 4. Mr. Majoros calculated reasonable depreciation rates without the future plant additions included and his proposed depreciation rates should be adopted. *Id*., p. 30, l. 22 to p. 31, l. 1; Exhibit MJM-2, attached to *RA-12A*.

E. Public Service's Proposed Amortization Periods for General Plant Are Too Short When Compared to Historical Retirement Levels and Would Result in Overstated Amortization Expense.

Mr. Majoros also did a geometric mean analysis of Public Service's proposed revisions to the amortization periods for general plant. He compared the Company's revised amortization periods to the historical retirement levels and found that the number of years in most of the amortization periods was much shorter than would be indicated by the historical retirement levels.

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[17] This is not the case for future net salvage which, when calculated properly (not as the Company has done), can account for a future expense to dispose of *existing* plant that does serve customers now.

RA-12, p. 31, l. 19 to p. 32, l. 25. If adopted, the Company's proposals would result in unjustifiably high amortization expense by recovering the plant investment over fewer years than is proper. Many amortization periods bear no relationship at all to the historical levels, as seen on the chart in Mr. Majoros' direct testimony.

Comparison of Amortization
Periods in General Plant Functions

Description	Existing	Roff	Majoros
391.10 Office Furniture	29	20	20
391.20 Office Equipment	29	4	4
391.30 Office Computer Equipment	29	7	10
391.33 Office Personal Computer Equip	29	3	3
393.00 Stores Equipment	29	7	20
394.00 Tools, Shop & Garage Equip	29	7	15
395.00 Laboratory Equipment	29	5	15
397.00 Communications Equipment	29	10	15
398.00 Miscellaneous Equipment	29	7	20

Mr. Majoros proposes longer amortization periods based on historical studies of actual retirements. *Id*., p. 32, l. 8-32. For example, Public Service proposes a seven-year amortization period (based on its witness' judgment) for Office Computer Equipment which presumably includes main frames. Mr. Majoros proposes ten years based on the 9.6 year average age of what is actually in the Company's account. *RA-13,* p. 9, l. 14-19. It is much more reasonable for depreciation rates to reflect what is more likely to occur based on actual experience than to use Public Service's witness' judgment that contradicts the utility's actual experience. As can be seen from the above chart, even though Mr. Majoros' recommendations are shorter than recent life indications, they are still more reasonable when compared to Public Service's proposals.

Therefore, Mr. Majoros' recommendations can be seen as conservatively fair to the utility and to the customers.

POINT V

THE RATEPAYER ADVOCATE'S PROPOSED RATE DECREASE SHOULD BE ALLOCATED AS RECOMMENDED BY RATEPAYER ADVOCATE WITNESS BRIAN KALCIC.

A. The Ratepayer Advocate's Recommended Base Rate Decrease and Apportionment of Costs and Revenues Results in a More Equitable Rate Design than that of Public Service.

As discussed above, the Ratepayer Advocate believes that the Company's proposed rate increase is unjustified and that a base rate decrease is warranted. *RA-14,* p. 4. Moreover, the Ratepayer Advocate disagrees with the Company's proposed class revenue distribution and did not utilize its proposed apportionment to derive the Ratepayer Advocate's recommended decreases to individual rate classes. *Id.* The Ratepayer Advocate's rate design witness Brian Kalcic has proposed the following allocation of the recommended decrease:

<u>Firm Delivery Classes</u>	
Residential Service (RSG)	5.93%
General Service (GSG)	6.36%
Large Volume (LVG)	10.62%
Street Lighting (SLG)	3.61%
Subtotal	**6.77%**
<u>Interruptible/Cogeneration Classes</u>	
Transportation Service - Firm (TSG-F)	10.13%
Transportation Service - Non-Firm (TSG-NF)	0.00%
Cogeneration Interruptible/ Cogeneration Extended (CIG/CES)	0.00%
Subtotal	**6.46%**

Total % Decrease **5.75%** ***Sched. BK-2R.***

Public Service prepared a fully allocated cost of service study ("COSS") reflecting weather normalized costs and billing determinants for the 12 months ending June 30, 2001. *RA-14,* p. 3. The COSS was presented as a gas delivery business analysis only and is consistent with the Company's proposal to transfer its gas supply functions to an unregulated affiliate in Docket No. GM00080564. *Id*. Mr.Kalcic based his testimony on that analysis of the delivery portion of the Company's business and believes that the result of the Gas Contracts case would not alter his allocation of the non-gas costs. "To the extent that balancing and/or commodity costs are impacted by events in the Gas Contracts proceeding, such impacts would be separately identified and assigned directly to rate classes on a commodity and/or balancing therm basis." *Id.*, p. 4.

Public Service rate design witness Gerald Schirra's COSS is a two-stage process. In the first stage Mr. Schirra determined a cost-based revenue requirement for: a) the firm delivery classes (Rates RSG, GSG, LVS, SLG and TSG-F); and b) the Company's Competitive Appliance Service business. *Id*., p. 3. In the second stage he developed an adjusted cost-based revenue requirement for Rates RSG, GSG, LVG and SLG which reflected an offset to the base rate revenue requirement provided by the Company's Competitive Appliance Service activities. It is these second stage class revenue requirement levels that are used as a guide in the Company's rate design. *Id*.

In his Revised Testimony, Mr. Schirra set forth his allocation of costs and rate design. "Inherent in any cost of service study is the allocation to rate classes of many costs which by their very nature are difficult to relate precisely to cost causation. Experts will differ . . . on the best way in which many costs should be allocated among customer groups. The key is to determine which approach makes the most sense and then apply the end result with a reasoned, balanced view. . . ." *P-7*, p. 9, ll. 8-13. He furthers states that "any allocation method that deviates from the underlying cost causation principles should be avoided." *Id*., p. 10, l. 9.

The Company used its COSS results in its proposed rate design in a manner which recognized customer impacts. Public Service chose to move rate classes toward the cost of service levels shown in its cost study, limiting each class's increase in delivery rates to no less than one-half of the system average increase of 27.74% and no more than 1.5 times the system average increase. *RA-14*, p. 15. Furthermore, the Company determined that no class should receive an increase of more than 1.5 times the overall system average firm increase of 7.1% on a total revenue basis. Using this methodology, Public Service is generally proposing delivery rate increases ranging from 13.87% to 31.61%. *RA-15*, Sch. BK-1R. Schedule BK-1R in Mr. Kalcic's Supplemental Direct Testimony summarizes Public Service's proposed class revenue distribution, on both a total revenue and delivery revenue basis, at the Company's updated revenue request of $161.780 million. *RA-15*, Sch. BK-1R.

The Ratepayer Advocate agrees with the general methodology used by Mr. Schirra, *i.e.* moving rate classes toward their costs of service, but recognizing customer impact by limiting the level of each's rate change. *RA-14*, pp. 4, 15-16. However, since the Ratepayer Advocate believes that the Company's proposed rate increase is unjustified, the Ratepayer Advocate does not agree with the Company's proposed apportionment of the proposed increase. *Id.*

In his rate design Mr. Kalcic allocated the Ratepayer Advocate's proposed $20.371 million decrease in a two step process.[18] *Id.*, Sch. BK-2R. First, he allocated Mr. Henkes' recommended decrease plus offsets of $1.944 million, a total of $22.315 million, among Rates RSG, GSG, LVG and SLG, with certain restrictions. *Id*., Sch. BK-2R, l. 12. Specifically, Mr. Kalcic limited the decrease in delivery rates for any class to no more than 1.5 times the system average decrease in delivery revenues and no less than 0.5 times the system average. *RA-14*, p. 16.

In his rate design, Mr. Kalcic proposed to move TSG-F and CIG margins from the LGAC to the Margin Adjustment Clause ("MAC") (discussed in SectionV.C. below). Consequently, in the second step of his methodology Mr. Kalcic allocated $16.128 million in TSG-F and CIG margins to the firm delivery classes on a per therm basis. *RA-15*, p. 2, Sch. BK-2R, l. 14. When combined, Mr. Kalcic's rate design steps produce appropriate class revenue adjustments, i.e., ones that are consistent with the Company's cost of service results and reflective of customer impact considerations.[19] As shown in Schedule BK-2R and set forth above, Mr .Kalcic has recommended

[18]As discussed in Section II.C. of this brief, the Ratepayer Advocate's revenue requirement recommendation has been revised to reflect the addition of transportation and inventory injection costs to the Ratepayer Advocate's proposed valuation of the Company's pro forma gas inventory balance. This revision has the effect of changing the Ratepayer Advocate's recommended rate decrease from $20.371 million to $14.485 million. Sch. RJH-1R, updated 10/29/01, l. 7. The revision is easily accommodated in Step 1 of Mr. Kalcic's rate design using the class decrease parameters noted above and would be fully reflected therein. Step 2 of Mr. Kalcic's rate design addresses only the apportionment of MAC margins and would not be affected by the change.

[19]As noted in Mr. Kalcic's testimony, Mr. Kalcic disagreed with one aspect of the Company's allocation methodology. The Company combined its existing TSG-NF with the ISG class, which currently pays higher rates than the TSG-NF class. The Company applied a 14.1% increase to the current TSG-NF class on a stand-alone basis and applied the result to the combined class, resulting in a rate *decrease* for the ISG class at the expense of other customer

rate decreases ranging from 3.6% for Street Lighting to 10.62% for the LVG class. Residential rates (RSG class) would decrease by 5.9%. T539:L14-20; *RA-15,* Sch. BK-2R.

Schedule BK-3R in Mr. Kalcic's Supplemental Direct Testimony shows his recommended rate design and proof of revenue which corresponds to the revenue distribution shown in Schedule BK-2R. *RA-15.* The schedule follows the general format of Schedule GWS-16. All customers are assumed to take BGSS commodity service with the commodity prices shown in Schedule GWS-16. Billing determinant adjustments corresponding to Mr. Henkes' pro forma present revenue adjustment of $0.82 million were also incorporated.[20] *RA-15*, p. 2; Sch. RJH-11R, l. 1. The Societal Benefits Charge ("SBC") and MAC values shown in Sch. BK-3 were derived by moving certain expenses and revenues: Mr. Kalcic removed all uncollectible expense from the calculation of the SBC. *RA-14*, p. 18, Sch. BK-3R, l. 1, col. 7. Additionally, he adjusted the Margin Adjustment Clause ("MAC") by removing net revenues from Rates TSG-F, TSG-NF and CIG from the LGAC and, along with TSG-NF margins, returning them to customers through the MAC on a per therm basis. *RA-14*, p. 18.

Schedule BK-4R is a summary of present and recommended delivery charges for Rate RSG customers. *RA-15*, p. 3.

B. Public Service Should Not Be Permitted to Recover All of its Uncollectible Expenses on an

classes. Mr. Kalcic has avoided this result by applying his recommended methodology to the combined TSG-NF and ISG classes.

[20]The $0.82 million adjustment is based upon Mr. Henkes' determination that the Company will earn an additional $0.82 million in revenues than was reflected in the Company's 12 + 0 filing. Sch. RJH-11R, l. 1.

Automatic Pass-through Basis Through the SBC. It Should Be Required to Identify and Quantify Those Uncollectible Expenses Related to Board-approved Social Programs as Mandated by EDECA.

The Company is proposing to remove all costs associated with uncollectibles from base rates and to recover them in the Societal Benefit Charge ("SBC"). *P-7*, p. 40. Mr. Schirra argues that this approach would ensure that the Company would recover only the actual cost of uncollectibles and that any reduction in uncollectible expense associated with the expansion of low income assistance programs (through the Universal Service Fund), would be passed through to ratepayers. *Id*. However, Public Service is actually requesting an automatic pass-through of 100% of its uncollectible expenses, without bearing any risk of lost revenues. In cross-examination Mr. Schirra admitted that the Company would fully recover all costs related to uncollectibles:

Q That means they would be collected from all customers; is that correct?

A That is correct.

Q Therefore, Public Service would bear absolutely no risk for any of these uncollectible charges; is that correct?

A We would fully recover the cost, if that fits within your definition of not bearing risk.

T451:L14-21.

Consistent with the mandate of EDECA, any SBC recovery of uncollectibles should be limited to those associated with Board-approved social programs.

The Electric Discount and Energy Competition Act ("EDECA" or the "Act") defines the "societal benefits charge" as "a charge imposed by an electric[*sic*] public utility, at a level determined by the board, pursuant to and in accordance with, section 12 of this act...." *N.J.S.A. 48:3-51*. Section 12 identifies those costs which can be collected through the SBC:

(1) The costs for social programs for which rate recovery was approved by the board prior to April 30, 1997;

(2) Nuclear plant decommissioning costs;

(3) The costs of demand side management programs that were approved by the board prior to April 30, 1997;

(4) Manufactured gas plant remediation costs; and

(5) The costs of consumer education, as determined by the board.....

N.J.S.A. 48:3-60(a).

Thus EDECA permits the recovery of uncollectibles through the SBC only to the extent they are the result of Board-approved social programs.

Public Service has been unable to identify in its SBC the level of the Company's uncollectibles that are the result of Board-approved social programs which EDECA permits. In cross-examination Mr. Schirra acknowledged that some of the uncollectible amounts were not related to Board-approved social programs; however, he was unable either to identify specific social programs or to quantify the uncollectibles which could be credited to those programs. Mr. Schirra admitted that in the following colloquy with Counsel for the Ratepayer Advocate:

Q Is any of that amount unrelated . . . to Board approved social programs, to your knowledge?

A The uncollectible expense is related to all of the Company's uncollectibles. The nexus to social programs is a matter of interpretation. Some or all of

> that may be related to social programs. If you look at the line it is called social programs, uncollectibles expense, it is not saying one is necessarily one hundred percent included in the other.
>
> Q Do you have any way of determining how much of that amount is related to the social programs versus other uncollectible amounts?
>
> A I don't think that a clear understanding or definition of what exactly is a social program, that's a broad term that is used in many cases in recent years.
>
> T450:L13-T451:L11.

In the absence of any information regarding how much, if any, of Public Service's test-year uncollectible expense is associated with Board-approved social programs, Public Service should not be permitted to recover any uncollectible expense through the SBC. *RA-14*, pp. 7-8.

This is not the first time that Public Service has tried to move uncollectible expenses into the SBC. In the Company's Service Unbundling Proceeding, Docket Nos. GX9903121 and GO99030124, the Board specifically rejected that provision of the Company's proposed Unbundling Stipulation which permitted the Company to collect one half of its actual 1998 uncollectibles in the SBC. *Final Decision and Order* dated July 31, 2000.The Order stated:

> **2) Recovery of uncollectible expense -** The RPA has argued against automatic recovery of all uncollectibles through the SBC, asserting that the Act explicitly limits recovery through the SBC of uncollectibles attributable to Board-approved social programs. N.J.S.A. 48:3-50. Based on our review of the record and requirements of the Act, we **<u>HEREBY MODIFY</u>** paragraph 3(a) to delete the provision which would include an initial uncollectibles expense of one half of the Company's actual 1998 uncollectibles expense of $15.694 million. Recovery of uncollectible expenses should remain in base rates; none should be transferred to the SBC at this time.
>
> *Id.*, p. 17.

Given the Board's prior rejection of moving uncollectibles into the SBC and the Company's continuing inability to identify those uncollectibles related to social benefit programs which Section 12 permits to be collected in the SBC, all of Public Service's uncollectible costs should remain in base rates.

C. Public Service's Proposed Margin Adjustment Clause Should Include Delivery-Related Margins Currently Included in the Company's LGAC.

Public Service proposes to establish a Margin Adjustment Clause ("MAC"), a deferred accounting mechanism which would track delivery-related revenue margins from the TSG-NF class. Rate TSG-NF is an interruptible transportation service available to customers with installed alternate fuel capability using a minimum of 150 therms per hour. Pursuant to the Board's Order in the Company's Gas Unbundling proceeding, all firm delivery ("FT") rate schedules currently receive a fixed credit for TSG-NF margins in their base delivery rates. *RA-14*, p. 9. Public Service proposes to change this treatment, using the new MAC mechanism to credit the TSG-NF net revenues to firm delivery customers (Rate Schedules RSG, GSG, LVG, SLG and TSG-F). *Id.* In addition, all net revenues credited through the MAC would be subject to deferred accounting treatment wherein the MAC would be reset annually to reflect forecasted TSG-NF revenues and to amortize over- or under-recovered balances. *P-7*, p. 44; *RA-14*, p. 9.

The Ratepayer Advocate does not oppose moving TSG-NF margins from base delivery rates to the MAC provided that the proposal is modified to reflect symmetrical treatment of revenues from customers switching to and from TSG-NF service. Additionally the Ratepayer Advocate would extend the MAC mechanism to include the delivery-related margins of two other classes–TSG-F and CIG.

Although the Ratepayer Advocate supports the transfer of TSG-NF margins to the MAC, the treatment of TSG-NF margins should be symmetrical. First, the Company proposes to retain the net revenues of any customer formerly served under Rate LVG who switches to TSG-NF after the effective date of new rates resulting from this proceeding. *RA-14.* p.10. Second, it proposes to retain a portion of the revenues associated with any new TSG-NF customer whose service begins on or after the end of the test year. The retained margin amount would equal 20% of the cost of new facilities required to serve such customers, net of any direct customer contribution toward those costs. *RA-14,* p. 10.

The Ratepayer Advocate does not object to the Company's proposal to retain 100% of net revenues of an LVG customer who switches to TSG-NF after the effective date of new rates so long as that treatment is reciprocal. Specifically, the Ratepayer Advocate recommends that the net revenues of TSG-NF customers switching back to firm LVG service following the effective date of new rates in this proceeding remain in the MAC rather than flow to the Company's bottom line. *RA-14*, p. 14. To be equitable to both Public Service and its ratepayers, customer switching after the effective date of new rates in this proceeding should receive symmetrical treatment regarding margin retention. *Id.*

The Company does not object to the Ratepayer Advocate's proposal for symmetrical treatment. In cross-examination Mr. Schirra stated, "I have no objection to Mr. Kalcic's recommendation. I have not opposed that in my rebuttal." T484:L22-24. Given this modification of the Company's position, Mr. Kalcic's recommendation should be approved.

The Ratepayer Advocate also recommends that margins related to the TSG-F and CIG tariffs be transferred from the LGAC to the MAC. Currently, net revenues associated with larger firm transportation ("TSG-F") and cogeneration ("CIG") customers are returned to ratepayers through the LGAC via an offset to the Company's Non-Gulf Coast cost of gas. *RA-14,* p. 11.

Mr. Kalcic has testified to three reasons that these LGAC margins should be incorporated into the proposed MAC. First, the LGAC is not an appropriate mechanism to return margins from transportation tariffs to firm delivery customers since the LGAC applies only to customers who purchase commodity gas from Public Service. *RA-14*, p. 12. Those customers who receive firm delivery service only would be excluded from this benefit. Plant and expenses associated with providing service to firm transportation and cogeneration customers are included in the revenue requirement used to develop firm delivery rates. Consequently, it is appropriate that the base rate margins obtained from these customers be used to offset the base rates of firm delivery customers, not the Non-Gulf Coast cost component of BGSS. *Id*., p. 13.

Second, it is not appropriate to use base rate margins to credit commodity costs. *Id*. That treatment only distorts the effect of commodity prices and is particularly inappropriate during the transition to a competitive commodity market. *Id*. Third, consolidating all delivery-related margins within the proposed MAC would standardize the treatment of all delivery-related margins and assist with clarifying the accounting treatment of such margins in the Company's tariff. *Id*.

The shift of these margins from the LGAC to the MAC would result in a greater Non-Gulf Coast cost of gas component in the Company's BGSS rate, thus resulting in higher shopping credits for those customers who purchase gas from a TPS. *Id*. By properly allocating delivery-related margins to the delivery portion of rates, there will be an incentive for customers to migrate to third party suppliers, which has been the goal of EDECA and related Board Orders.

Mr. Wohlfarth argues that this base rate case is not the forum to pursue this issue because it has been examined in other proceedings. *Id*., p. 3. On the contrary, a base rate case is the most appropriate venue to examine all aspects of a utility's operations. Public Service's last base rate case was almost ten years ago. Many changes in the utility industry have occurred since that case, not the least of which are EDECA and the various unbundling proceedings. During this period issues were addressed by the Board almost on a stand-alone basis. It is only in this base rate case that all aspects of the Company's operations, costs, revenues and methodologies can be addressed, allocations revised and applied proportionately, and rates designed to collect appropriate revenues from each class.

Moreover, it should be noted that Public Service itself is proposing to consolidate Rate ISG with Rate TSG-NF. *P-7 R-1*, p. 13. As a result, ISG margins, which currently reside in the LGAC, would be transferred from the LGAC to the MAC since *all* TSG-NF margins would be included in the MAC.[21] *RA-16*, p. 5. If ISG margins can be transferred from the LGAC to the MAC *in this proceeding* under the Company's own proposal, there is no reason TSG-F and CIG margins should not receive the same treatment. Based on the above discussion, the Board should review the issue of the TSG-F and CIG margins, and should order that they be moved into the MAC as an appropriate allocation based on cost causation.

Mr. Wohlfarth stated in his testimony that "when BGSS customers switch to TPS supply, the obligations to pay demand charges remain with the remaining BGSS customers and therefore, any credits derived from the use of the upstream capacity by interruptible customers, must also remain with the remaining BGSS customers. *P-11*, p. 4. Contrary to Mr. Wohlfarth's contention, Mr. Kalcic explains that the TSG-F and CIG margins in question are delivery-related – i.e,. they represent the net revenue earned by the company from delivering gas to TSG-F and CIG customers through its distribution system, not from the use of upstream pipeline capacity. Since all the Company's allowed rate base and expenses are included in the revenue requirement used to

[21] Sch. BK-2R, l. 13 includes the ISG margins which would be transferred to the MAC under the Company's proposal.

develop firm delivery rates, and there is currently no direct credit to firm delivery rates stemming from the use of delivery system resources by TSG-F and CIG customers, all TSG-F and CIG margins should be credited via the MAC. *Id*., p. 4.

Finally, while TSG-F and CIG margins "belong" to firm delivery customers, the margins are currently credited to only a portion of those customers–those firm delivery customers who also purchase commodity from Public Service. *Id.*, p. 5. The Ratepayer Advocate submits that it is the current LGAC treatment of these margins that is "artificial," not Mr. Kalcic's proposal to transfer these margins to the MAC.

D. The Board Should Reject Public Service's Proposal for Two-Way Interest on MAC Deferrals.

The Company is also proposing that the MAC be subject to deferred accounting treatment, and that two-way interest be calculated on the deferred amounts. *P-7*, pp. 11, 13. The margins from Rates TSG-F and CIG, currently in the LGAC, receive one-way interest on over-recoveries only. *Id*., p. 13. Although other adjustment mechanisms permit two-way interest, the components of the MAC should result in different treatment. As noted above, the Company's Gas Unbundling Proceeding removed TSG-NF margins from the LGAC and established a fixed distribution credit. *Id.,* p. 14. Until that time, TSG-NG margins were credited to the LGAC like the TSG-F and CIG margins. *Id.* However, since TSG-NF margins were not subject to reconciliation in the Unbundling case, the Board Order in BPU Docket Nos. GX99030121 and GO99030124 does not control with respect to the interest treatment of former LGAC margins. Consequently, all MAC balances be subject to one-way interest treatment.

POINT VI

THE BOARD SHOULD REJECT PUBLIC SERVICE'S OTHER PROPOSED TARIFF CHANGES AS ANTI-COMPETITIVE AND UNDULY BURDENSOME TO CUSTOMERS

A. The Board Should Reject Public Service's Proposed One-Year Term for Residential Customers Returning from Third Party Service as Anti-Competitive and Unnecessary.

Public Service is proposing to establish a minimum one year term of service for residential customers who return to the Company's system for commodity service. *P-7*, pp. 62, 75. Mr. Schirra stated two arguments in support of this position: 1) the minimum term is needed for the Company's BGSS supplier to arrange for/manage firm pipeline and storage capacity to service returning customers; and 2) the minimum term is needed to prevent "gaming," that is, a situation where a residential customer returns to BGSS supply for just the winter months when the levelized BGSS price would be expected to be below actual cost, only to leave the system when the BGSS price moves above actual cost. *P-7*, p. 75. Mr. Schirra notes that such gaming would not impact the Company directly, but rather would shift supply costs from shopping to non-shopping delivery customers. *Id.*, p. 75, *RA-14*, p. 5. The only exception to the one-year term would be a one-month grace period for customers who switch from one TPS to another. *Id*.

The Ratepayer Advocate opposes the one-year minimum term for several reasons. First, the one-year minimum is a roadblock to customer choice and delays the development of a vibrant competitive market. *RA-14*, p. 6. Residential customers who return to BGSS service should be able to return to TPS service upon giving required notice. *Id*. Second, regarding the need to purchase firm pipeline and storage capacity to serve returning customers, the Company has presented no analysis quantifying the amount of new upstream pipeline capacity and/or storage that might be needed to serve returning residential customers. *Id.,* p. 5. As Mr. Kalcic noted, the Company "simply seems to posit a worst case scenario, where significant new pipeline capacity is required to serve returning customers .... There may be little or no impact on system capacity requirements from returning customers." *Id.,* pp. 5-6.

Indeed, last winter's "reverse migration" of commodity customers back to the Public Service system bears out Mr. Kalcic's statement. Of the 48,000 dekatherms per day needed for returning customers, only 230 dekatherms per day were needed for returning residential customers. T439:L13; TR 430. These figures demonstrate how minimal is the effect that returning residential customers currently have on Public Service's system, and would have, even if more customers migrate to TPS service and then return. *RA-16,* p.6. This is particularly true if Public Service were to assign capacity and/or storage to TPSs and that capacity and/or storage could be recalled to serve returning customers. *Id.,* p. 6, n.2.

Mr. Kalcic also disputes the Company's allegation regarding the possibility of "gaming" the system on the ground that, given the relatively small usage of a typical residential customer, it is unclear whether a significant amount of gaming by residential customers is even likely. *Id*., p. 6. Nor is it clear that residential customers are sufficiently sophisticated enough to "game the system". The Company's "solution" to a purely speculative occurrence would have a detrimental effect on the development of a competitive market for gas supply because it would remove potential customers from the marketplace for lengthy periods, thereby placing an unnecessary barrier in the path of competition. *Id***.** There is no evidence of gaming by residential customers at this time; the Company's argument is purely speculative. The Ratepayer Advocate submits that it is inappropriate to devise a solution to a hypothetical problem of residential seasonal switching before there is evidence that the problem even exists. *RA-16*, p. 6. If such a problem should develop in the future, the Board can address the issue at that time.

Moreover, to the extent that seasonal switching is related to "turnbacks"—that is, TPSs exiting the market and breaching contracts with customers, the issue should be addressed in the Board's regulation of TPSs, not in this base rate case. *Id.* In cross-examination Mr. Wohlfarth addressed the issue of TPSs turning customers back to Public Service for commodity service:

> Q If these customers are on one year contracts or possibly longer why are so many customers returning prior to that time?
>
> A ....[L]ast winter the unique situations surrounding the very volatile gas price I think caused either the customer on the one hand or the third-party supplier on the other to, I use the term, turn back the customer to our sales office.
>
> Q Why would the supplier turn back its customers to the Company?
>
> A. The price in the contract that includes most likely in many cases a fixed price which includes the commodity price and what we call a basis price, the price between the transportation component of moving gas from the Gulf Coast to New Jersey was such that third-party suppliers were in a difficult situation.
>
> They were trying to renew or renegotiate that basis going forward and the Company's price imbedded [*sic*] in its LGAC rate was considerably less.
>
> Q Would that mean that the third-party supplyer [sic] was leaving the market all together [*sic*] under those circumstances?
>
> A No, not all together [*sic*].
> I think certain third-party suppliers weren't able to manage the situation. . . .
>
> T430:L23-T432:L9.

The issue of turnbacks appears to be primarily a problem of TPS activity rather than customers returning voluntarily. *Id.* It is also primarily a problem relating to commercial and industrial customers. T429:l13. The Company should address this problem with its marketers and commercial and industrial customers and should not impose anti-competitive restrictions on the residential class, which has not played a significant role in this situation. Moreover, the Company has an ideal forum in which to address the problem-- the pending petition *I/M/O Energy Master Plan Phase II Proceeding To Investigate the Future Structure of the Electric Power Industry - Third Party Supplier Agreements,* Docket Nos. EX94120585Y, EO97070457, EO97070460, EO97070463 and EO97070466, currently before the Board. Returning residential customers have not created problems either with gaming or with turnbacks. Given the anti-competitive nature of the Company's proposal, the Ratepayer Advocate recommends that the Board reject the Company's one-year minimum term proposal. *Id.*

B. Since Third Party Supplier Security Requirements Are the Subject of Proceedings Currently Before the Board, it Is Inappropriate to Increase TPS Security Charges in this Proceeding.

The Company is proposing to increase TPS security requirements from $70 to $140 times the TPS's Daily Requirements (expressed in dekatherms). *P-7*, p. 46. It further proposes to increase the charge for non-Critical Period under deliveries from $10 per dekatherm to two times the actual daily price of gas. *Id.* Mr. Schirra states in his direct testimony that these increases are necessary because current gas costs are significantly higher than the prices existing when the current security deposit provisions were implemented. *RA-14*, p. 8.

One of the risks associated with increasing security requirements is that alternate suppliers may pull out of the marketplace, thereby slowing the transition to a competitive market. *Id.* There is little enough marketer interest in the New Jersey residential market as it is; entry into this market should not be made more difficult out of an excess of caution. While it may be appropriate to adjust TPS security requirements from original levels, the Board must insure that any adjustment is cost justified and not anti-competitive. *Id., RA*-16, p. 7. The Board is currently addressing this subject in *I/M/O Energy Master Plan Phase II Proceeding To Investigate the Future Structure of the Electric Power Industry - Third Party Supplier Agreements,* Docket Nos. EX94120585Y, EO97070457, EO97070460, EO97070463 and EO97070466. Those proceedings have defined the issues and the various interests. *RA-14*, p. 8. The Board should therefore determine TPS security requirements in the context of the record established in the above-cited proceedings and should not decide the issue in this case. *Id.*

C. Public Service Should Not Be Permitted to Offer New Optional Metering Services until Competing Suppliers are also Provided with the Opportunity to Offer Metering Services.

Public Service has proposed to offer new metering services to customers. *P-1,* Sch. 2, Sec. 8.5.1 & 8.5.2, Proposed Standard Terms and Conditions. These services include new charges for certain optional metering services, such as the availability of Gas Data Pulse information and Interval Gas Meters. Pursuant to the proposed tariff all new services would reflect both initial set-up charges and on-going monthly charges, the exact amounts varying with the type of service and/or equipment requested by the customer. *P-7,* p. 84, *RA-14*, p. 19.

The Board should deny the Company's request to implement these optional metering services at this time. *RA*-16, p. 1. These services should be viewed in light of the legislative mandate in EDECA, which requires that electric and gas customers be given the opportunity to choose a supplier for some or all customer account services("CAS") not later than one year after the starting date of retail competition. *Id.*, p. 2. The CAS proceedings included review of the safety, reliability and economic benefit of new metering services which might become available to consumers. *Id.* Metering is included in the definition of CAS and is a potentially competitive service to be addressed in the context of the CAS Working Group, or, if issues remain unresolved, in litigation. *Id*., p. 2; *RA-14,* p. 20. Pursuant to the Stipulation and Order in the Board's generic CAS proceedings, Docket No. EX9909676, the Board is to issue an Order resolving all outstanding issues no later than January 1, 2003 for implementation no later than August 1, 2003. The actual availability date of these services could be much earlier. Until the unbundling of competitive account services is complete, it would be anti-competitive to allow one company, Public Service, to implement new metering services and/ or options. *RA.-14,* p. 21. Allowing the Company to offer such optional services now will give Public Service an unfair "head start" in the race to supply customers with a competitive metering service. *Id*., *RA-16,* p. 2.

D. The Board Should Reject Public Service's Proposal to Increase Its Reconnection Charge by 275% as the Proposal is Excessive, Burdensome to Low-Income Customers and Counterproductive.

Public Service is proposing to increase its reconnection charge for customers whose service has been disconnected from $20 to $75, a 275% increase. *P-7,* p. 86. The Ratepayer Advocate believes that this charge is excessive, unduly burdensome to low-income customers and counterproductive.

The recently approved interim Universal Service Fund will not alleviate the burden such a large reconnection fee would place on low-income customers whose service is disconnected for non-payment. *IMO Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act,* BPU Docket No. EX00020091(Oral Decision issued October 25, 2001**,** Order pending). As the Editorial Board of the Star Ledger recently noted**,** "the need [for a universal service fund] among low-income families, whose wages stagnated even during the 1990s boom, is clear and will undoubtedly continue. An assistance program might even save the utilities the expense of trying to collect money from families that simply cannot pay." *Editorial, Star Ledger,* October 29, 2001. The fund may prevent some disconnections; however, it will not prevent all shut-offs for non-payment. The Company's proposed 275% increase will create an additional financial hurdle for low-income customers to jump; many of them may not be able to do so.

Ratepayer Advocate witnesses Brian Kalcic and Roger Colton both strongly oppose the proposed increase. Mr. Kalcic testified that a 275% increase in reconnection fees cannot be economically justified. *RA-14*, p. 22. Further, both witnesses have noted that the Company's proposed increase would have a disproportionate effect on low-income customers who are unable to afford it. *Id*. *RA-40*, p. 50.

As Mr. Colton explained during cross-examination, even if the reconnection fee is not *directed* at low-income households, they are disproportionately the number of people who are disconnected in the first place. T1094:L21. Low-income customers have service terminated at a rate four times higher than their non-low-income counterparts. *Id*. The proposed reconnection fees will tend to increase bills that are unaffordable to begin with and will make it less likely that low-income customers will be able to retain service. *Id*. It is noteworthy that the Editorial Board of the Star-Ledger addressed the issue of low-income customers' inability to pay in an editorial supporting the newly-approved Universal Service Fund. If a high fee is imposed on a customer with a limited ability to pay, that household 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. *Id*. If that household does return to the system, it is likely that it will continue to have payment trouble. This further harms the household and results in further lost revenues. Again the Company's other ratepayers will pay more than their fair share of embedded costs. T1985:L3. Imposing a $75 reconnection fee on low-income customers is counterproductive at best. T1095:L14.

Further, low-income customers pay more than their fair share of the costs of the Company's distribution system. Mr. Colton testified that since gas rates are almost universally based upon averaged costs, low-income residential customers pay more than their fair share of costs. *RA-39,* p. 49. As a class, low-income consumers disproportionately tend to live in older homes, in older neighborhoods, and in urban areas. *Id.* The distribution system serving these customers is comparatively old, has a lower original cost, and has been depreciated over the years. *Id.* Because the cost of the utility distribution system and revenue requirements therefor are averaged, low income customers living in older homes in urban areas pay more than their allocable share of costs; they also pay a share of the costs attributable to higher income customers living in newer homes. *Id.* Thus, as a result of averaging, those customers who are least able to pay their own bills are contributing to the payment of more affluent customers living in more expensive homes in newer neighborhoods. *Id.*

Public Service is unforgiving in its policies and charges to customers who cannot afford to pay their utility bills; however, the Company offers discounts to large customers. *IMO Application of Camden Cogen LP and Cogen Technology and Public Service Electric & Gas for Approval of Amendment and Restructuring of Power Purchase and Interconnection Agreements* *and Gas Service Agreements Currently Existing between Camden, Bayonne and Public Service*, Docket No. EM 01050327; *IMO Application of Newark Bay Cogeneration and Public Service for Approval of Amendment and Restructuring of Power Purchase and Interconnection Agreement and Gas Service Agreements Currently Existing between Newark Bay and Public Service*, Docket No. EE00040245.

Finally, the Company's purported cost-justification for the proposed increase is inadequate. Mr. Schirra states in his testimony that the proposed reconnection charge is appropriate as it is based on a specific cost analysis. *P-7 RB,* p. 7. He attempts to justify the 275% increase by stating that the increased charge will only be payable by those customers who cause the Company to incur the costs for which the charge is imposed – those whose service must be reconnected after having been disconnected due to non-payment. *Id.* However, Schedule GWS-18 R-1, l. 14 shows that the estimated cost to the Company, including overhead, for each shut-off for non-payment ("SONP") is $69.69. *P-7,* p. 86. The proposed $75 reconnection charge is therefore above total cost. Moreover, the cost per SONP based solely on direct costs (excluding indirect overheads) is $55.78. Sch. GWS-18 R-1, l. 15. This net cost is a more accurate measure of the Company's out-of pocket costs than the all-inclusive amount of $69.69. *RA-16,* p. 3. Using net cost as a measure, the proposed $75 reconnection charge is 34.5% too high. *Id.*

The Ratepayer Advocate recommends, particularly in light of its recommended base rate decrease, that the current reconnection charge remain unchanged. *RA-14*, p. 22. While this approach will not move the reconnection charge toward the Company's claimed cost benchmark, any unrecovered reconnection costs would be recouped in the recommended base rates. *Id.* Further, as Mr. Colton testified, implementation of a Universal Service Program as contemplated in EDECA should reduce the number of customer shut-offs. *Id.* Thus, to the extent that the Company's USF programs are appropriately structured and expanded in the future, the number of SONPs may be expected to decline from test year levels. *Id.*

CONCLUSION

For all the foregoing reasons, as well as those set forth in the testimony of the Ratepayer Advocate's witnesses, the Ratepayer Advocate respectfully requests that the following recommendations should be adopted:

Rate of Return

- Reject the return on equity figure proposed by Public Service and adopt return on equity figure of 9.85% recommended by the Ratepayer Advocate, resulting in an overall rate of return of 8.22%. *RA-7*; *RA-8; RA-9*; and *RA-1*, Sch. RJH-2R.

Rate Base

- Adopt the rate base adjustments recommended by the Ratepayer Advocate which total $145,243,000, resulting in a pro-forma rate base for the Company of $1,820,245,000. *RA-1*, Sch. RJH-3R (rev. 10/29/01), *RA-2*; and *RA-3*. (Appendix B).

Revenue and Expenses

- Adopt the increase in pro-forma operating income of $158,157,000 recommended by the Ratepayer Advocate, which reflects adjustments amounting to a net $102,238,000 increase over the Company's proposed operating income of $55,919,000. *RA-1*, Sch. RJH-1R, RJH-4R (rev. 10/29/01); *RA-2;* and *RA-3*. (Appendix B).

- Adopt the customer revenue annualized adjustment recommended by the Ratepayer Advocate, which increases the Company's test year revenue margins by $819,000 and its proposed pro-forma test year operating income by $484,000. *RA-1*, Sch. RJH-11R.

- Adopt the Ratepayer Advocate's recommended labor-related operating income adjustments (increases) of $3,159,000 and $3,903,000, reflecting the use of a 5-year average O&M ratio and a 9 month test year cut-off on pro-forma labor expenses, respectively. *RA-1*, Sch. RJH-12R, RJH-13R.

- Reject the Company's proposal to include $6.35 million in executive incentive compensation expense as well as $20,000 in test year LTIP administrative and brokerage fees in its pro-forma test year expenses, resulting in an adjustment (increase) of $3.756 million to pro-forma operating income. *RA-1*, Sch. RJH-14R.

- Adopt the Ratepayer Advocate's proposal to include on actual test year FASB 106 expenses, amounting to $19.2 million, and requiring an upward adjustment to pro-forma operating income of $1.138. million. *RA-1*, Sch. RJH-15R.

- Since the Board has not yet ruled on the Company's petition to transfer of its gas supply, storage, and capacity contracts to an unregulated affiliate, adopt the Ratepayer Advocate's recommended adjustment of $22.999 million, reversing the entry made by the Company to reduce its test year operating income to reflect the proposed transfer. *RA-1*, Sch. RJH-4R (rev. 10/29/01). (Appendix B).

- Adopt the Ratepayer Advocate's recommended adjustment for regulatory commission expenses amounting to an increase in pro-forma operating income of $488,000. *RA-1*, Sch. 16R.

- Adopt the Ratepayer Advocate's recommended adjustments (increases) to pro-forma operating income for Research and Development, Deferred Marketing Amortization, and Expired Amortizations, amounting to $529,000, $522,000, and $174,000, respectively. *RA-1*, Sch. RJH-17R, RJH-18R, and RJH-19R.

- Adopt the Ratepayer Advocate's recommended adjustment for charitable contributions, amounting to $1,523,000.

- Adopt the Ratepayer Advocate's recommended adjustments (increases) to pro-forma operating income for property insurance amounting to $157,000 and other miscellaneous adjustments totaling $301,000. *RA-1*, Sch. RJH-21R, RJH-22R.

- Adopt the Ratepayer Advocate's recommended adjustment for depreciation expense, resulting in an increase in test year operating income of $61,267,000. *RA-1*, Sch. RJH-23R.

- Adopt the Ratepayer Advocate's recommended adjustment for interest synchronization, amounting to an increase in the Company's pro-forma test year operating income of $2,460,000. *RA-1*, RJH-25R (rev. 10/29/01). (Appendix B).

Depreciation

- Reject Public Service's proposal for a 62% increase in its annual depreciation allowance as unreasonable and excessive and adopt the Ratepayer Advocate's proposals for a 41% decrease, resulting in an adjustment (increase) to pro-forma operating of $61.267 million. *RA-1*, Sch. RJH-23R. Public Service proposes a annual depreciation expenses of $129, 059,269 whereas the Ratepayer Advocate proposes an annual depreciation expense amount of $82,300,003. *RA-12*, p. 3; *RA-12A*; and *RA-13.*

- Adopt the five-year average annual net salvage expense approach.

- Adopt the Ratepayer Advocate's service life proposals for Transmission and Distribution accounts

- Adopt the Ratepayer Advocate's service life proposals for Production and Storage plant and deny the inclusion of future interim additions.

- Adopt the Ratepayer Advocate's amortization periods for General Plant accounts.

Cost of Service and Rate Design

- Approve the use of the Ratepayer Advocate's recommended rate design to implement its recommended revenue decrease which *inter alia* limits the decrease to any one class to no more than 1.5 times the system average decrease in delivery revenues and no less than 0.5 times the system average. *RA-14*, p. 6; *RA-15*, Sch. BK-2R; *RA-15*; and *RA-16*.

- Adopt the Ratepayer Advocate's recommendation that all uncollectible amounts should remain in base rates and not passed through the SBC to customers, because the costs related to Board-approved social programs have neither been identified nor quantified, as required by the EDECA.

- Condition the approval of the Company's proposal to include TSG-NF margins in the MAC on the requirement that all net revenues from the TSG-F and CIG classes, which are delivery-related margins, are also included in the MAC. *RA-14*, p. 14.

- Permit the Company to retain 100% of net revenues of LVG customers who switch to TSG-NF after the effective date of new rates from this proceeding only if the net revenues of TSG-NF customers who switch to LVG after the effective of new rates remain in the MAC. *RA-14*, p.14.

- Reject the Company's proposal for two-way interest on the MAC deferral. All MAC balances should be subject to one-way interest treatment.

- Reject the Company's proposed one-year term for residential customers returning from third party service as anti-competitive and unnecessary. *RA-14*, pp. 5-6.

- Reject the Company's proposal to increase TPS security charges in this proceeding since third party supplier security requirements are the subject of other proceedings currently before the Board. *RA-14*, p. 8.

- Reject the Company's proposal to offer new optional metering services until competing suppliers also have the opportunity to offer metering services. *RA-14*, pp. 19-21.

- Reject the Company's proposal to increase its reconnection fee from $20 to $75, an increase of 275%, because the proposal is excessive, burdensome to low-income customers, and counterproductive. *RA-14*, p. 22; and *RA-16*, p. 3.

Adoption of the Ratepayer Advocate's recommendations would result in an overall rate reduction amounting to $14.485 million. *RA-1*, Sch. RJH-1R (rev. 10/29/01) (Appendix B).

Respectfully submitted,

BLOSSOM A. PERETZ, ESQ.
RATEPAYER ADVOCATE

By:______________________________
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DATED: November 1, 2001