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

IN THE MATTER OF THE PETITION	)	
OF PIVOTAL UTILITY HOLDINGS, INC.	)	**BPU DKT. NO. GR09030195**
D/B/A ELIZABETHTOWN GAS FOR	)	**OAL DKT. NO. PUC-03655-2009N**
APPROVAL OF INCREASED BASE TARIFF	)	
RATES AND CHARGES FOR GAS SERVICE	)	
AND OTHER TARIFF REVISIONS	)	

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE DIVISION OF RATE COUNSEL

PUBLIC VERSION - REDACTED

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IN THE MATTER OF THE PETITION OF PIVOTAL UTILITY HOLDINGS, INC. D/B/A ELIZABETHTOWN GAS FOR APPROVAL OF INCREASED BASE TARIFF RATES AND CHARGES FOR GAS SERVICE AND OTHER TARIFF REVISIONS
BPU Docket No. GR09030195
OAL DOCKET NO. PUC 03655-2009N
Direct Testimony of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes and my business address is 7 Sunset Road, Old Greenwich, Connecticut 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS TESTIMONY?

A. I was engaged by the New Jersey Department of the Public Advocate, Division of Rate Counsel ("Rate Counsel") to conduct a review and analysis and present testimony in the matter of the petition of Pivotal Utility Holdings Inc. d/b/a Elizabethtown Gas ("ETG" or "the Company") for increased base tariff rates and charges for gas service and other tariff revisions.

The purpose of this testimony is to present to the New Jersey Board of Public Utilities ("BPU" or "the Board") the appropriate rate base, pro forma operating income, revenue conversion factor and overall revenue requirement for RTG in this proceeding. In the determination of ETG's appropriate revenue requirement, I have relied on and incorporated the recommendations of the following Rate Counsel witnesses:

- Matthew Kahal, concerning the appropriate capital structure, capital cost rates and overall rate of return of ETG in this proceeding;
- David Peterson, concerning ETG's appropriate cash working capital requirement;
- Michael Majoros, concerning ETG's appropriate depreciation rates; and
- Richard Lelash, concerning the appropriate rate treatment of (1) the proposed New Jersey Call Center; (2) the proposed conservation program expenses; and (3) the environmental remediation related internal labor expenses.

In developing this testimony, I have reviewed and analyzed ETG's original March 10, 2009 filing and supporting testimonies and exhibits; ETG's June 19, 2009 6+6 update filing and supporting testimonies and exhibits; ETG's responses to initial and follow-up data requests submitted by Rate Counsel and BPU Staff; and other relevant documents and data, including prior Board Orders involving ETG.

III. CASE OVERVIEW AND SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE PROVIDE AN OVERVIEW OF THIS RATE CASE.

A. ETG's current base rates were set pursuant to the Board's Order in Docket No. GR02040245, dated November 22, 2002. Subsequent to that event, the Board authorized the acquisition of ETG by AGL Resources Inc. by Order issued November 17, 2004 in BPU Docket No. GM04070721. As a condition of this November 17, 2004 Order, ETG was required to implement a five-year base rate stay-out and to make a base rate filing no later than March of 2009 for rates to be effective in January 2010. The Company's base rate filing in the instant proceeding is being made in compliance with this November 17, 2004 BPU Order.

In its original filing dated March 10, 2009, the Company requested a base rate increase of $24,817,656, representing an increase of approximately 4.71% over the Company's pro forma revenues at current rates. This requested rate increase could be broken out by the following causative components:

- Carrying Cost of Increased Rate Base	$5.8 million
- Increased Depreciation Expense	9.1
- Increased Cost of Capital	4.0
- Increased Uncollectible Expenses	5.0
- Increased O&M Expenses	2.1
- Increased Margins from Customer Growth	(0.7)
- Other Items	(0.5)
Total	$24.8 million

In determining this original rate request, ETG used as the test period the 12-month period ended September 30, 2009, containing 3 months of actual data and 9 months of projected data.[1] The filing also included proposed post-test period adjustments for projected changes in rate base and capital structure and projected changes in most expenses through the end of calendar year 2009. In addition, the filing included projected changes in revenues and certain expenditures through February 28, 2010.

The original rate increase request includes proposed revisions in the Company's depreciation rates resulting in an increase in the Company's revenue requirement of approximately $3 million.

In addition to the proposed base rate increase, ETG is proposing various rate design changes. These rate design proposals include the elimination of declining block rates in the residential class and an increase in certain customer charges. The Company is also proposing a number of tariff changes that are designed to refine and simplify tariff administration, and make it more customer friendly. Furthermore, as part of its rate design proposals in this case, the Company is proposing the implementation of a new Efficiency and Usage Adjustment ("EUA") clause designed to allow the Company to recover its cost of service as customer usage declines as a result of conservation and other factors. Under the EUA, changes in actual use per customer for certain residential and commercial customer classes will be reconciled to the usage determinants underlying the Company's rates.

In addition to the changes in rates and tariffs just discussed, the Company seeks an accounting order from the Board enabling it to defer (1) certain transition costs that will be

[1] This original filing is referred to as the "3+9 filing."

incurred by ETG to relocate its call center to New Jersey; (2) potential future costs incurred to implement recommendations that may arise from its pending management audit; and (3) potential future costs that may be incurred to comply with New Jersey's Energy Master Plan.

Finally, the Company is requesting that the results of the Company's separate Utility Infrastructure Enhancement ("UIE") and Regional Greenhouse Gas Initiative ("RGGI") filings be incorporated in the rates to be established in this base rate case. On January 20, 2009, ETG filed with the Board a UIE proposal in Docket Nos. EO09010049 and GO09010053 in which ETG proposed several capital projects involving various gas distribution infrastructure-related work outside the scope of its projected normal 2009 capital budget. These projects are expected to be completed over the next two years at a projected cost of $60.4 million. On February 6, 2009, ETG made a filing in accordance with the Regional Greenhouse Gas Initiative legislation ("RGGI") in Docket Nos. GO09010056 and GO09010060 in which it proposed to implement a series of energy efficiency programs. ETG requests that the Board find a nexus between these two filings and this base rate case and incorporate the results of these separate processes into the Board's final order in this proceeding.

Q. HAS THE COMPANY UPDATED ITS ORIGINAL 3+9 FILING DATED MARCH 10, 2009?

A. Yes. On June 19, 2009, the Company updated its original 3+9 filing with its proposed 6+6 filing. This updated 6+6 filing, which was accompanied and supported by the supplemental testimonies and exhibits of 3 witnesses, not only updated the original 3+9 filing with an additional 3 months of actual data, but also incorporated a number of required filing revisions identified in the update and discovery processes. The June 19, 2009 6+6 update filing indicates a revised rate increase request of $17,362,668, which is $7,454,988 lower than the Company original 3+9 filing rate increase request of $24,617,656.

Q. WILL THE COMPANY FURTHER UPDATE ITS RATE CASE FILING FOR 9+3 AND 12+0 RESULTS?

A. It is my understanding that this is indeed the Company's intention. However, it took over 2 ½ months for the Company to update its 3+9 filing (containing actual results through December 31, 2008) with the 6+6 filing (containing actual results through March 31, 2009). Based on this experience, the Company's 9+3 filing (containing actual results through June 30, 2009) in all likelihood will not be available until the third week of September 2009 and the 12+0 filing (containing actual results for the entire test year) would not be available until sometime in March 2010.

The August 21, 2009 due date for this testimony necessarily required me to use the 6+6 update filing as the starting point of the revenue requirement presentations contained in this testimony and the attached Schedules RJH-1 through RJH-23. However, to the extent allowed by the procedural schedule of this case, the revenue requirement positions currently contained in this testimony should be updated to reflect 9+3 and 12+0 filing conditions after appropriate reviews.

Q. COULD YOU NOW SUMMARIZE YOUR REVENUE REQUIREMENT FINDINGS AND CONCLUSIONS IN THIS CASE?

A. Yes. I have reached the following revenue requirement findings and conclusions in this docket:

1. The appropriate rate base amounts to $400,013,729 which is $44,074,946 lower than ETG's proposed 6+6 updated rate base of $444,088,675. Schedules RJH-1, line 1 and RJH-3.

2. The appropriate forma operating income amounts to $37,863,796 which is $10,563,933 higher than ETG's proposed 6+6 updated pro forma operating income of $27,299,863. Schedules RJH-1, line 4 and RJH-9.

3. The appropriate overall rate of return on rate base, as recommended by Rate Counsel witness Matthew Kahal, is 7.52%, incorporating a recommended return on equity of 10.10%. This compares to ETG's proposed 6+6 updated overall rate of return on rate base of 8.41%, including a requested return on equity rate of 11.25%. Schedules RJH-1, line 2 and RJH-2.

4. The appropriate Revenue Conversion Factor to be used for ratemaking purposes in this case is 1.724055 as compared to ETG's proposed Revenue Conversion Factor of 1.727969. Schedule RJH-1, line 6.

5. The recommended ratemaking components outlined above indicate the need for a rate decrease of $13,434,861. This recommended rate decrease is $30,797,529 lower than ETG's proposed 6+6 updated rate increase of $17,362,668. Schedule RJH-1, lines 5-7.

6. The recommended rate decrease of $13,434,861 represents a decrease of 2.45% in ETG's pro forma test period operating revenues at current rates. This compares to ETG's proposed 6+6 updated rate increase percentage of 3.32%. Schedule RJH-1, line 8.

7. The Board should reject the Company's request for certain Accounting Orders to defer and eventually charge to the ratepayers (1) certain transition costs that are projected to be incurred by ETG to relocate its call center to New Jersey; (2) costs that may be incurred in the future to implement recommendations that may arise from its pending management audit; and (3) costs that may be incurred in the future to comply with New Jersey's Energy Master Plan.

IV. REVENUE REQUIREMENT ISSUES

A. RATE BASE

Q. PLEASE SUMMARIZE ETG'S PROPOSED PRO FORMA RATE BASE, THE METHOD EMPLOYED BY ETG TO DETERMINE ITS PRO FORMA RATE BASE, AND THE RECOMMENDED RATE BASE ADJUSTMENTS.

A. ETG's proposed 6 +6 updated rate base amounts to $444,088,675 and is shown by rate base component on Schedule RJH-3. All of ETG's proposed pro forma rate base balances except those for materials & supplies, gas stored underground and cash working capital represent fully projected balances as of the post-test period date of December 31, 2009. The proposed rate base balance for materials & supplies represents the actual 13-month average balance for the 12-month period ended March 31, 2009; the proposed rate base balance for gas stored underground represents the 13-month average balance for calendar 2009 based on 3 months actual and 9 months of projected data; and the claimed cash working capital requirement has been determined through a detailed lead/lag study approach.

I have not taken exception to the Company's proposed approach to reflect projected December 31, 2009 balances for all rate base components other than materials and supplies, gas stored underground and cash working capital; and I have accepted the Company's proposed projected December 31, 2009 rate base balances for customer advances/contributions, capital lease obligations and customer deposits – see Schedule

RJH-3, lines 5, 8 and 9. However, for reasons that will be discussed subsequently in this testimony, I have made certain adjustments to the Company's proposed December 31, 2009 balances for utility plant in service; accumulated depreciation; pension and Other Post Employment Benefits ("OPEB"); and accumulated deferred income taxes ("ADIT") – see Schedule RJH-3, lines 1, 2, 4, 6 and 7.

While I have accepted the Company's proposed 13-month average rate base balances for materials and supplies and gas stored underground, I have made an adjustment to the Company's proposed cash working capital requirement to reflect the recommendations made by Rate Counsel witness David Peterson – see Schedule RJH-3, line 10.

Finally, I have reflected one rate base component that ETG has failed to reflect. This concerns my recommended rate base deduction for consolidated income tax benefits – see Schedule RJH-3, line 11.

As summarized on Schedule RJH-3 and shown in more detail in subsequent RJH schedules, the previously described recommended rate base adjustments have the overall effect of reducing ETG's proposed 6+6 updated rate base by $44,074,946. Each of these recommended rate base adjustments will be discussed in detail below.

- **Utility Plant in Service**

Q. PLEASE EXPLAIN YOUR RECOMMENDED UTILITY PLANT IN SERVICE ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 1 AND SCHEDULE RJH-4.

A. The Company's proposed overall plant in service balance includes a plant balance of $13,464,937 that has been allocated from the AGL Service Company ("AGSC") to ETG. As shown on Schedule RJH-4, this proposed AGSC-allocated plant balance has been derived by the Company by applying an overall blended ETG allocation factor of 13.51% to the total actual AGSC plant in service balance as of March 31, 2009. The blended ETG allocation factor of 13.51% represents the projected 2009 allocation rate used by the Company to allocate AGSC's budgeted 2009 costs to ETG. For reasons discussed in a subsequent section of this testimony,[2] I recommend that an overall blended ETG allocation factor of 13.10% be used to allocate AGSC costs to ETG for ratemaking purposes in this case. In addition, since all of the other rate base components proposed by the Company, and accepted by me, in this case reflect projected balances as of December 31, 2009, I have applied the ETG allocation factor of 13.10% to the projected AGSC plant balance as of December 31, 2009. Schedule RJH-4 shows that my recommended approach results in an AGSC-allocated plant in service balance of $12,633,301 which is $831,636 less than the Company's proposed AGSC-allocated plant balance of $13,464,937. This amount of $831,636 represents the recommended plant in service adjustment shown on Schedule RJH-3, line 1.

[2] Testimony section entitled "AGSC Cost Allocation Adjustment", p. 32.

- **Accumulated Depreciation Reserve**

Q. PLEASE EXPLAIN YOUR RECOMMENDED ACCUMULATED DEPRECIATION RESERVE ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 2 AND SCHE\DULE RJH-5.

A. The Company's proposed overall accumulated depreciation reserve balance includes a reserve balance of $7,823,998 that has been allocated from AGSC to ETG. As shown on Schedule RJH-5, similar to what the Company has proposed for its AGSC-allocated plant in service balance, this proposed AGSC-allocated reserve balance has been derived by applying an overall blended ETG allocation factor of 13.51% to the total actual AGSC accumulated depreciation reserve balance as of March 31, 2009 plus projected reserve additions through December 31, 2009. Similar to what I have recommended for the AGSC-allocated plant in service balance, I recommend that a blended ETG allocation factor of 13.10% be used for ratemaking purposes in this case. In addition, I have applied the ETG allocation factor of 13.10% to the revised projected AGSC depreciation reserve balance as of December 31, 2009 that was provided by the Company in its response to RCR-A-47.1. Schedule RJH-5 shows that my recommended approach results in an AGSC-allocated accumulated depreciation reserve balance of $8,651,106, which is $309,590 less than the Company's proposed AGSC-allocated depreciation reserve balance of $8,960,696. This amount of $309,590 represents the recommended accumulated depreciation reserve adjustment shown on Schedule RJH-3, line 2.

- **<u>Pension and Other Post Employment Benefits</u>**

Q. PLEASE DESCRIBE THE COMPONENTS OF THE COMPANY'S PROPOSED PENSION AND OPEB RATE BASE BALANCE SHOWN ON SCHEDULE RJH-3, LINE 4 AND SCHEDULE RJH-6.

A. As shown on Schedule RJH-6, the Company's proposed net pension/OPEB asset in rate base includes (1) the accrued pension liability; (2) the accrued OPEB liability; (3) the pension and OPEB Regulatory Asset resulting from the accelerated recognition of the pension and OPEB liabilities; and (4) the unamortized OPEB Transition Obligation. The accrued pension liability represents the cumulative difference between annual expensed pension costs in accordance with SFAS 87 that are collected in rates and the annual cash contributions to the pension trust fund. Similarly, the accrued OPEB liability represents the cumulative difference between annual expensed OPEB costs in accordance with SFAS 106 that are collected in rates and the annual cash contributions to the OPEB trust fund. The pension/OPEB Regulatory Assets were created by the accelerated recognition required by generally accepted accounting principles as a direct result of the acquisition of ETG by AGLR. In its November 17, 2004 Order approving the acquisition of ETG by AGLR (Docket No. GM04070721), the Board authorized the deferral of these Regulatory Assets and permitted ETG to seek recovery of the costs in this rate proceeding. Finally, the requested $2.28 million rate base component for the OPEB Transition Obligation represents the December 31, 2009 unamortized balance of the Regulatory Asset that was approved by the Board in Docket No. 97080563.

Q. DO YOU TAKE EXCEPTION TO ANY OF THESE PENSION/OPEB RATE BASE COMPONENTS?

A. As shown on Schedule RJH-6, based on my review of each of these pension/OPEB rate base balances, I have accepted the first three of these proposed rate base balances, i.e., the proposed December 31, 2009 balances of the accrued pension costs, accrued OPEB costs, and the Regulatory Asset for pension/OPEB due to the acquisition of ETG by AGLR. However, I recommend that the Company's proposal to include in rate base the unamortized balance for the OPEB Transition Obligation be rejected by the Board.

Q. PLEASE BRIEFLY DESCRIBE THE HISTORY OF THE UNAMORTIZED OPEB TRANSITION OBLIGATION BALANCE.

A. SFAS 106, which was first introduced in 1993, generally required employers to switch from "pay-as-you-go" to accrual accounting for their retiree health and other postretirement benefit plans ("OPEB"). Among other things, this mandated accounting change required all employers in the United States, including all NJ utilities, to book a very large one-time cost recognition referred to as the so-called Transition Obligation. It is my understanding that in 1997 and 1998, the Board conducted "limited issue" proceedings for the NJ utilities, including ETG, to address the ratemaking treatment of the financial consequences of the implementation of SFAS 106. In these limited issue OPEB proceedings, the Board, among other things, generally ruled that all NJ utilities would be allowed to book their Transition Obligations as deferred Regulatory Assets and amortize these Regulatory Assets over a 15-year period for ratemaking purposes. In ETG's limited issue OPEB proceeding, BPU Docket No. GR9708563, the Company was allowed to book its Transition Obligation balance at September 30, 1998, in the amount of $9,121,755, as a deferred Regulatory Asset. Since that time, the Company has amortized that balance over a 15-year amortization period, resulting in an annual OPEB amortization expense amount of $608,112. The unamortized deferred Transition Obligation Regulatory Asset balance as of December 31, 2009 amounts to $2,280,470. In this case, the Company is not only requesting rate recognition of the annual Transition Obligation amortization of $608,112, but is also requesting a return on the December 31, 2009 unamortized Transition Obligation balance of $2,280,470 by including that balance as a rate base component.[3]

Q. WHY DO YOU RECOMMEND THAT THE COMPANY'S PROPOSAL TO INCLUDE THE UNAMORTIZED TRANSITION OBLIGATION BALANCE IN RATE BASE BE REJECTED BY THE BOARD?

A. First, it should be recognized that the Transition Obligation is the result of an accounting change that does not affect a company's cash flow. It is therefore inappropriate to allow the Company to earn a return on a balance sheet item that never did, and never will, involve a cash outflow. Second, in Docket No. GR9708563, the Board never specifically allowed rate base inclusion of the unamortized Transition Obligation balance. When the Company was asked in RCR-151 to indicate where exactly in Docket No. GR9708563 the Board allowed rate base inclusion for the unamortized Transition Obligation balance for ratemaking purposes, the Company responded as follows:

Page 5 of the order states the following:

[3] See response to RCR-A-151.

> "The Board also **FINDS** that ETG's "transition obligation" at September 30, 1998, in the amount of $9,121,755, is reasonable, and should appropriately be recorded as a deferred regulatory asset on ETG's books."
>
> The excerpt acknowledges the existence of a regulatory asset, and the Company is seeking its treatment as a component of rate base in this proceeding.

Thus, the foregoing Board Order quote clearly does not state that the Company is allowed to include the unamortized Transition Obligation balance in rate base for a current return.

It should also be noted that the Company did not include its unamortized Transition Obligation in rate base in any of its prior base rate proceedings since Docket No. GR9708563.

Finally, based on my long-standing regulatory experience in rate proceedings in New Jersey, it is my understanding that no other utility in New Jersey is claiming its unamortized Transition Obligation balance in rate base for ratemaking purposes. In addition, I believe that the Board has never previously allowed such rate base treatment in any New Jersey rate proceedings.

- **ETG Accumulated Deferred Income Taxes**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED ETG ACCUMULATED DEFERRED INCOME TAX ("ADIT") BALANCE SHOWN ON SCHEDULE RJH-3, LINE 6 AND SCHEDULE RJH-7.

A. As previously discussed, I have recommended that the Company's proposed Pension and OPEB rate base balance be reduced by $2,280,470 to reflect the recommended removal of the unamortized OPEB Transition Obligation. Since the OPEB balance of $2,280,470 has an associated ADIT balance of $936,908 that is included in the Company's proposed ETG ADIT rate base balance, this ADIT should also be removed from rate base. As shown on Schedule RJH-3, line 6, this results in a recommended rate base increase of $936,908.

- **<u>AGSC-Allocated ADIT</u>**

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED AGSC-ALLOCATED ADIT BALANCE SHOWN ON SCHEDULE RJH-3, LINE 7 AND SCHEDULE RJH-8.

A. The Company has proposed to include in rate base proposed an ADIT balance of $1,479.650 that has been allocated from AGSC to ETG. As shown on Schedule RJH-8, similar to what the Company has proposed for its AGSC-allocated plant in service and depreciation reserve balances, this proposed AGSC-allocated ADIT balance has been derived by applying an overall blended ETG allocation factor of 13.51% to the total actual AGSC ADIT balance as of March 31, 2009. Similar to what I have recommended for the AGSC-allocated plant in service and depreciation reserve balances, I recommend that a blended ETG allocation factor of 13.10% be used for ratemaking purposes in this case. In addition, since all of the other rate base components proposed by the Company, and accepted by me, in this case reflect projected balances as of December 31, 2009, I have applied the ETG allocation factor of 13.10% to the projected AGSC ADIT balance as of

December 31, 2009. Schedule RJH-8 shows that my recommended approach results in an AGSC-allocated ADIT balance of $1,418,265, which is $61,385 less than the Company's proposed AGSC-allocated ADIT balance of $1,479,650. This amount of $61,385 represents the recommended AGSC-allocated ADIT adjustment shown on Schedule RJH-3, line 7.

- **Cash Working Capital**

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 10C.

A. The cash working capital adjustment shown on Schedule RJH-3, line 10c reflects my adoption of ETG's cash working capital requirement recommended by Rate Counsel witness David Peterson.

- **Consolidated Income Tax Benefits**

Q. HAS ETG REFLECTED ANY CONSOLIDATED INCOME TAX BENEFITS FOR RATEMAKING PURPOSES IN THIS CASE?

A. No. In this case, the Company has assumed that it pays income taxes on the so-called stand-alone basis. However, in reality, the Company does not calculate and pay income taxes on a stand-alone basis; rather it participates in consolidated income tax filings made by its parent company, AGLR. In fact, when considering the period 1991 – 2008, during the years 1991 up until the acquisition of ETG by AGLR in 2004, ETG participated in each of the annual consolidated income tax filings of its then-parent, NUI Corporation; and since the acquisition by AGLR in 2004, ETG has participated, and will continue to participate, in each of AGLR's annual consolidated income tax filings.

Q. WHY DOES A CONSOLIDATED INCOME TAX FILING GENERATE TAX SAVINGS?

A. The primary purpose of consolidated income tax filings is to minimize the federal income tax liabilities of the participating members. Certain members of the consolidated income tax filing generate tax losses. These tax losses are used to offset a portion of the taxable income generated by other affiliates, including ETG, to reduce income taxes payable for the entire consolidated entity. Without a consolidated tax filing, it could take several years under the IRS's carry-forward and carry-back restrictions, if ever, before the recurring loss companies would be able to fully realize tax savings. By filing a consolidated return, however, the consolidated entity as a whole is able to realize, in the current tax year, the tax benefits generated by the loss companies.

Q. SHOULD ETG'S RATEPAYERS SHARE IN THE TAX SAVINGS REALIZED FROM THE CONSOLIDATED INCOME TAX FILINGS?

A. Yes. ETG's ratepayers should only reimburse the Company for actual income taxes paid. If the tax savings from the consolidated income tax filings are not flowed through to the ETG ratepayers on an appropriate, proportionate basis, the ratepayers will pay rates that are higher than necessary to compensate ETG for its actual costs. I therefore recommend that an appropriate consolidated income tax benefit be calculated for ETG and reflected for ratemaking purposes in this case.

Q. DOES THE BOARD HAVE A RATE MAKING POLICY WITH REGARD TO THE RATE MAKING TREATMENT OF TAX BENEFITS TO BE ASSIGNED TO REGULATED UTILITIES UNDER ITS JURISDICTION AS A RESULT OF THESE UTILITIES' FILING OF CONSOLIDATED INCOME TAX RETURNS?

A. Yes. The Board has an established policy requiring that any tax savings allocable to a utility as a result of the filing of consolidated income tax returns be reflected as a rate base deduction in the utility's base rate filings. The BPU first established this policy in its Decision and Order ("D&O") in the Atlantic City Electric Company rate proceeding, BPU Docket No. ER90091090J. In this D&O, the Board also ruled that the calculation starting point for the consolidated income tax related rate base deduction must be July 1, 1990:

> ...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...This finding reflects a balancing of the interests to reflect the unique period of uncertainty during the period 1987-1991. We hereby reaffirm and emphasize that the Board's policy is to reflect an equitable and appropriate sharing of consolidated tax benefits for ratepayers in future rate proceedings....[4]

The Board reaffirmed its consolidated income tax policy in its D&O in the 1991 Jersey Central Power and Light Company ("JCP&L") base rate proceeding, BPU Docket No. ER91121820J, dated February 25, 1993. On pages 7 and 8 of its D&O in that docket the BPU stated:

[4] *I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for and Increase in Rates and Charges for Electric Service, Phase II,* BPU Docket No. ER90091090J, Order Adopting in Part and Modifying in Part the Initial Decision at 8 (Oct. 20, 1992).

> The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. Income from utility operations provide the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment.
>
> The issue, in this case, is not whether such an adjustment should be made, but, rather, what methodology should be used to make such an adjustment. In this area, the courts have held that the Board has the power and discretion to choose any approach which rationally determines a subsidiary utility's effective tax rate. <u>Toms River Water Company v. New Jersey Public Utilities Commissioners</u>, 158 <u>NJ Super</u> 57 (1978). Based on our review of the record in this case, the Board <u>REJECTS</u> the ALJ's recommendation to accept the income tax expense adjustment proposed by Petitioner and, instead, <u>ADOPTS</u> 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 <u>Atlantic</u> <u>Electric</u> decision (Docket No. ER90091090J). Moreover, in order to maintain consistency with the methodology applied in the <u>Atlantic</u> decision, we modify the Staff calculation and find that a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case. [5]

In addition, in a more recent 2002 JCP&L base rate case, Docket No. ER02080506, the Board ruled on page 45 of its Final Order:

> As a result of making a consolidated tax filing during the years 1991 – 1999, GPU, JCP&L's parent company during that time period as a whole paid less federal income taxes than it would have is each subsidiary filed separately, thus producing a tax savings. The law and

[5] *I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions,* BRC Docket No. ER91121820J, Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision at 7-8 (June 15, 1993).

> Board policy are well-settled that consolidated tax savings are to be shared with customers.

Finally, in the most recent Rockland Electric Company ("RECO") base rate case, Docket No. ER02100724, the Board again affirmed its consolidated income tax benefit policy. In this regard, the Board stated on page 64 of its Final D&O:

> The Board agrees with Staff that RECO's argument that it would be improper to consider data from the period prior to the date of the merger between O&R and Con-Ed (i.e, July 1999) is not valid. RECO's positive net income during the years 1991-1999 clearly produced tax savings for its parent company in those years, and RECO's customers should not be denied their share of these savings simply because of a subsequent merger of its parent with Con-ED.
>
> … the Board **HEREBY ADOPTS** the position of Staff that the $1,329 million rate base adjustment, calculated in accordance with well-settled Board policy, appropriately reflects consolidated tax savings achieved by RECO through offsetting tax losses of affiliates with RECO's positive taxable income. Further the Board **ORDERS** RECO to submit a consolidated tax adjustment in every future base rate case filing. The future consolidated tax adjustments are to be made utilizing the methodology that Staff utilized to calculate its $11.329 million adjustment as shown on Exhibit 4 of this order.

Q. HOW DID YOU DETERMINE THE APPROPRIATE CONSOLIDATED INCOME TAX ADJUSTMENT TO BE APPLIED TO ETG FOR RATE MAKING PURPOSES IN THIS CASE?

A. My recommended consolidated income tax benefit adjustment in this case has been determined based upon the calculation methodology that was approved by the Board in its Order in the previously discussed RECO base rate proceeding, BPU Docket No. ER02100724. The calculations were first made by the Company in its response to S-RREV-73. That response indicated a consolidated income tax benefit rate base deduction amount of approximately $14 million. However, in its response to RCR-A-160, the

Company corrected for a number of calculation errors that I had identified and also updated the calculations to include the actual 2008 consolidated income tax benefits. The response to RCR-A-160 indicated a revised consolidated income tax benefit rate base deduction amount of approximately $19,273,878. This latter rate base deduction amount was again revised by the Company in S-RREV 73, Third Revision, which indicates that the final revised rate base deduction balance should amount to $37,935,480.

Q. WHERE DID YOU REFLECT THIS RECOMMENDED CONSOLIDATED INCOME TAX BENEFIT AMOUNT?

A. This recommended consolidated income tax benefit balance is reflected as a rate base deduction on Schedule RJH-3, line 11.

B. <u>OPERATING INCOME</u>

Q. PLEASE SUMMARIZE ETG'S PROPOSED UPDATED PRO FORMA OPERATING INCOME, THE METHOD EMPLOYED BY ETG TO DETERMINE ITS PRO FORMA OPERATING INCOME, AND THE RECOMMENDED OPERATING INCOME ADJUSTMENTS.

A. ETG's proposed 6+6 updated net operating income amounts to $27,299,863, as shown on Schedule RJH-9, line 1. In deriving this pro forma income level, ETG projected its pro forma operating revenues based on projected billing determinants as of February 28 and a ten-year normal weather pattern. To be consistent with its proposal to reflect plant in service in rate base as of the post-test period date of December 31, 2009, ETG's proposed depreciation expenses were determined by applying its proposed new depreciation rates to its projected depreciable plant levels as of December 31, 2009. The proposed pro forma O&M expenses were determined by taking the unadjusted historic/projected O&M expenses in the 6+6 test period ended September 30, 2009 as the starting point and then adjusting these test period expenses for actual and projected expense changes during calendar year 2009 and the first two months of 2010. Generally, the same approach was used by ETG to determine its pro forma revenue taxes and other taxes. ETG's proposed pro forma income taxes were determined by taking the proposed pro forma net operating income before income taxes as the starting point, then deducting pro forma interest expenses through the "interest synchronization" method and applying the statutory SIT and FIT rates of 9.36% and 35%, respectively.

As summarized on Schedule RJH-9 and shown in detail on subsequent RJH schedules, I have recommended a large number of operating income adjustments with the combined effect of increasing ETG's proposed 6+6 updated pro forma after-tax operating income by a total amount of $10,563,933. Each of the recommended operating income adjustments will be discussed in detail below.

- **<u>Interest Synchronization Adjustment</u>**

Q. PLEASE EXPLAIN YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENT SHOWN ON SCHEDULE RJH-9, LINE 2 AND SCHEDULE RJH-10.

A. As shown on Schedule RJH-10, for purposes of calculating the pro forma interest expenses to be used as a tax-deductible expense for ratemaking purposes in this case, the Company has applied the weighted cost of debt component of its proposed overall rate of return to its proposed rate base. I have used the same calculation method and components as used by ETG to determine the recommended pro forma interest expenses to be used for ratemaking purposes in this case. The difference between my recommended pro forma interest expenses and ETG's proposed pro forma interest expenses is merely caused by the differences between ETG's proposed and Rate Counsel's recommended weighted cost of debt and rate base numbers. As shown on lines 3 - 5 of Schedule RJH-10, the recommended pro forma interest expenses are $1,085,220 lower than ETG's proposed pro forma interest expenses which, in turn, results in a recommended decrease of $445,852 in ETG's proposed 6+6 updated after-tax operating income.

- **Sales Adjustments**

Q. WHAT NORMALIZATION PERIOD HAS ETG USED IN THIS CASE TO WEATHER NORMALIZE ITS PRO FORMA POST-TEST PERIOD SALES?

A. In this case, ETG has proposed to weather normalize its pro forma post-test period sales based on the weather patterns in the 10-year period 1998 – 2008. The average heating degree days[6] ("HDD") for this 10-year period amount to 4,655 days. The Company has proposed this 10-year weather normalization approach because it believes that the average

[6] A heating degree day represents a measure of the cumulative difference between a base temperature (mostly 65 degrees F) and the actual mean temperature as reported by the National Oceanic and Atmospheric Administration ("NOAA") for each day during the period.

warmer weather experienced in the most recent 10 years is more indicative of what can be expected in the future.

Q. DO YOU AGREE WITH THE COMPANY THAT THE PRO FORMA POST-TEST PERIOD SALES SHOULD BE BASED ON A 10-YEAR WEATHER NORMALIZATION APPROACH?

A. No. Instead, I recommend that the pro forma post-test period sales in this case be weather normalized based on the traditional 30-year weather normalization approach.

Q. WHY DO YOU MAKE THIS RECOMMENDATION?

A. Traditionally, weather normalization adjustments have been based on the average weather patterns in the most recent 30-year period. In this regard, climate normals at the National Oceanic and Atmospheric Administration ("NOAA") have always been based upon 30-year historical periods that are re-computed at the completion of each decade; and the official HDD normals currently published by the NOAA continue to be based on a 30-year weather normalization period.[7] ETG's proposal to use a shorter 10-year weather normalization approach overlooks the volatility that can result from using such shorter periods. When a short period is used there are fewer data points included in the average. As a result, one single year that is far from the norm can have a significant impact on the results. This problem creates the possibility of shopping for the 10-year period that produces the best results. Thus, ETG's proposed 10-year weather normalization approach can result in greater volatility in determining an average number of HDDs. The use of an

[7] These facts were confirmed by the Company in its response to RCR-A-175.

updated "rolling" 30-year weather normalization approach should adequately reflect any trend of warmer winters with fewer HDDs while effectively limiting the type of volatility that can occur when shorter periods, like 10 years, are used.

Also, the fact that the 10-year period from 1998 – 2008 on average has been warmer than the average weather in the most recent 30-year period does not mean that the rate effective period of this case is going to be warmer than what the 30-year NOAA HDD average would indicate. For example, while the Company, through its 10-year weather normalization proposal is predicting 4,655 average annual HDDs, RCR-A-176.4 indicates that the most recent 12-month period ended May 2009 actually had 4,884 HDDs which is very close to the average HDDs of 4,900 experienced during the most recent 30-year period 1978 – 2008.[8]

Q. HAS THE BOARD EVER ENDORSED AND ACCEPTED A 10-YEAR WEATHER NORMALIZATION APPROACH IN ANY PREVIOUS GAS BASE RATE PROCEEDINGS IN NEW JERSEY?

A. I do not believe so. As confirmed in its response to RCR-A-174, ETG is also not aware of any gas base rate cases in which the Board has explicitly approved the use of a 10-year weather pattern.

Q. WHAT HAS BEEN ETG'S WEATHER NORMALIZATION POSITION IN ITS PRIOR RATE CASES?

[8] See RCR-A-74.1, page 1.

A. I understand that prior to ETG's last (2002) rate case, the Company always used 30-year normalized HDDs. In its 2002 base rate proceeding, the Company for the first time proposed using 10-year normalized HDDS and in settlement accepted rates based upon 20-year normalized HDDs.

Q. HOW WOULD ETG'S NET OPERATING MARGINS BE IMPACTED BY BASING THE PRO FORMA POST-TEST PERIOD SALES ON A 30-YEAR WEATHER NORMALIZATION APPROACH RATHER THAN THE COMPANY'S PROPOSED 10-YEAR NORMALIZATION PERIOD?

A. As shown on RCR-A-76.2, this would increase the Company's proposed post-test period net operating margins[9] of $134,555,832 by $4,981,104 to $139,536,936. After taking into account the associated state and federal income taxes at the composite tax rate of 41.084%, this net operating margin increase of $4,981,104 would increase the Company's proposed post-test period after tax operating income by $2,934,667.

Q. DO YOU RECOMMEND THAT ANOTHER ADJUSTMENT BE MADE TO THE COMPANY'S PROPOSED POST-TEST PERIOD SALES AND ASSOCIATED NET OPERATING MARGINS?

A. Yes. ETG has proposed to annualize its sales and associated net operating margins in this case based on billing determinants projected as of February 28, 2010. The Company has done so to match the fact that it has annualized certain payroll costs through February 28, 2010. Since the Company is projecting continuing sales declines over time, the

[9] Revenues net of associated cost of sales.

annualization of the Company's sales as of February 29, 2010 as compared to the annualization of the Company's sales at the end of the test period, September 30, 2009, has increased the Company's revenue requirement by approximately $1.5 million.[10] I do not agree with this proposed sales annualization approach. The revenue annualization approach traditionally used by the BPU is based on the matching of revenues with *rate base*. Since the Company has proposed, and I have accepted, the reflection of a projected rate base as of December 31, 2009, the Company should have annualized its sales based on projected billing determinants as of that same date, December 31, 2009. The Company has not done so and sales annualization data as of December 31, 2009 are not available at this time. Due to the current absence of these more appropriate sales annualization numbers, I have at this time reflected the Company's calculated annualized sales and associated net operating margins as of the end of the test year.

Schedule RJH-11 shows that ETG's net operating margins based on the 30-year weather normalization approach, combined with sales annualization as of the end of the test year amount to $139,066,453. This currently recommended net margin amount is $4,510,621 higher than the Company's proposed net operating margins of $134,555,832 that is based on the 10-year weather normalization approach, combined with sales annualization as of February 28, 2010. This $4,510,621 increase in net operating margins, in turn, increases the Company's proposed after-tax operating income by $2,657,477.

[10] See 6+6 Schedule MJM-12.4-A, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustments 1-A and 2-A.

If the Company can provide the net operating margins based on the 30-year weather normalization approach, combined with sales annualization as of December 31, 2009, I would recommend that these net operating revenues be used for ratemaking purposes in this case rather than the net operating margins of $139,066,453 currently recommended on Schedule RJH-11.

- **AGSC Cost Allocation Adjustment**

Q. PLEASE DESCRIBE WHAT FACTOR WAS USED BY THE COMPANY TO ALLOCATE AGSC'S 2009 BUDGETED COSTS TO ETG FOR RATEMAKING PURPOSES IN THIS CASE.

A. In ETG's original March 10, 2009 filing, the Company used a projected overall blended rate of 13.40% to allocate AGSC's budgeted allocable 2009 costs to ETG. In this regard, the Company states in its response to RCR-A-146(d):

> Please note that 13.40% was the allocation rate used to allocate the AGSC costs to ETG for the 2009 budgeted costs.

This was also confirmed by Company witness Morley who stated on page 27 of his direct testimony:

> ETG was allocated 13.40% of the total AGSC budgeted costs for the 2009 budget which is comparable to the 2007 and 2008 percentage of 13.87% and 13.10%, respectively.

As confirmed in the Company's response to RCR-A-193, the blended allocation rate of 13.40% reflected in ETG's original March 10, 2009 filing changed to 13.51% in the June 19, 2009 6+6 update filing.

Q. WHAT WERE THE ACTUAL OVERALL BLENDED PERCENTAGE RATES AT WHICH AGSC'S TOTAL ALLOCABLE COSTS WERE ALLOCATED TO ETG IN EACH OF THE YEARS 2005 THROUGH 2008?

A. As confirmed by the Company in RCR-A-30.1, the actual percentages of costs allocated from AGSC to ETG in each of these years were as follows:

2005	17.42%
2006	14.23%
2007	13.87%
2006	13.10%

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE PREVIOUSLY DISCUSSED FACTS?

A. I conclude that the Company's proposal in this case to use a comparable projected blended allocation ratio of 13.51% for the allocation to ETG of AGSC's budgeted 2009 costs does not appear to be reasonable. History has shown that the actual percentage of total allocable AGSC costs allocated to ETG has consistently decreased from 17.42% in 2005 to 13.10% in the most recent actual 2008 allocation year and the Company has not provided any reasons why this downward trend should suddenly change to an upward trend on a projected basis for AGSC's 2009 cost allocation.

Q. WHAT IS YOUR RECOMMENDATION BASED UPON THE PREVIOUSLY DISCUSSED FINDINGS AND CONCLUSIONS?

A. I recommend that the most recent actual 2008 blended allocation rate of 13.10% be used to allocate AGSC's total allocable 2009 costs to ETG for ratemaking purposes in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED AFTER-TAX OPERATING INCOME IN THIS CASE?

A. I have calculated this impact on Schedule RJH-12. AGSC's total allocable 2009 costs included in the 6+6 update filing amounts to $150,938,453. Allocating this total cost amount to ETG at a ratio of 13.10% indicates an allocated ETG cost amount of $19,772,937. This recommended allocated ETG cost amount is $619,333 lower than the Company's proposed allocated ETG cost amount of $20,392,270 in the 6+6 update filing. This recommended expense reduction increases the Company's proposed after-tax operating income by $364,886.

- **<u>Incentive Compensation Expense Removal</u>**

Q. DOES THE COMPANY'S PROPOSED 6+6 UPDATED TEST PERIOD INCLUDE INCENTIVE COMPENSATION EXPENSES?

A. Yes. As summarized on Schedule RJH-13, the Company's proposed 6+6 updated test period O&M expenses include total ETG "direct"[11] incentive compensation expenses of $1,329,302, consisting of $1,237,893 for Annual Incentive Plan ("AIP") expenses, $72,722 for Long Term Incentive Plan ("LTIP") expenses, and $18,687 for stock awards. The test

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[11] ETG "direct" incentive compensation expense represents the expense that is associated with ETG's own employees as distinguished from AGSC-allocated incentive compensation expense which is the expense associated with AGSC employees that has been allocated to ETG.

period O&M expenses additionally include total AGSC-allocated incentive compensation expenses of $1,914,324, consisting of $1,886,106 for AIP and LTIP expenses and $28,218 for stock awards. In summary, the Company's proposed 6+6 updated test period O&M expenses include a total amount of $3,243,626 for incentive compensation expenses.

Q. WHAT ARE SOME OF THE KEY ELEMENTS OF THE AIP?

A. As described in the Company's response to RCR-A-80 **(Confidential)**,

[Begin confidential information: [redacted] **End Confidential information].**

Q. WHAT ARE SOME OF THE KEY ELEMENTS OF THE LTIP?

The response to RCR-A-80, page 2 of 6 **(Confidential)** provides the following summary of the nature and workings of the LTIP:

[Begin confidential information: [redacted] **End Confidential information].**

Q. HAVE ETG'S NON-UNION EMPLOYEES RECEIVED ANNUAL INCREASES IN THEIR "REGULAR" BASE COMPENSATION?

A. Yes. As shown in the response to RCR-A-88, during the most recent 4-year period 2005 – 2008, the average annual salary increases for ETG's non-union employees were 3.63% and in the current case, the Company has requested (and I have accepted) the annualized impact of an additional 3.5% increase for the non-union employees in 2009.

Q. BASED ON THE PREVIOUSLY DISCUSSED INFORMATION, WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE RATE TREATMENT FOR THE INCENTIVE COMPENSATION EXPENSES INCLUDED IN ETG'S PROPOSED TEST PERIOD O&M EXPENSES?

A. I recommend that ETG's proposed total incentive compensation O&M expenses of $3,243,626 be disallowed for rate making purposes in this case. The recommended disallowance of the "direct" ETG incentive compensation expenses of $1,329,302 is shown on lines 1 through 4 of Schedule RJH-13. The recommended disallowance of the AGSC-allocated incentive compensation expenses of $1,914,324 is shown on lines 5 through 7 of Schedule RJH-13. My recommendation increases the Company's proposed after-tax operating income in this case by $1,911,015, as shown on lines 8 through 10 of Schedule RJH-13.

Q. WHAT ARE THE REASONS FOR THIS RECOMMENDATION?

First, the criteria for determining the awards to be paid out under ETG's LTIP and AIP incentive compensation programs are, respectively, 100% and approximately 52% dependent on the achievement of financial performance measures that would increase AGLR's profitability and would enhance AGLR's shareholder value. Since the shareholders are the primary beneficiaries of such financial performance improvements, they should be made responsible for these discretionary incentive compensation costs. I would also note that incentive compensation that has as its objective to increase the shareholders wealth but is funded by the ratepayers is inconsistent with the requirement of the Regulatory Compact that the ratepayers should receive service at the lowest possible cost.

Second, the Company's proposed incentive compensation expenses of $3,243,626 are not known and certain. They are dependent on the achievement of certain goals and in determining its proposed pro forma incentive compensation awards, the Company has assumed that all of these goals will be achieved. However, if these goals are not reached, the incentive compensation could be substantially different from what the Company has assumed in this case. For example, I have previously discussed that if **[Begin confidential information:** [redacted]. **End confidential information].**

Third, ETG's employees are already well compensated without the consideration of the additional incentive compensation. Schedule RJH-14, line 5 shows that the average O&M payroll and employee benefits (w/o incentive compensation) per ETG employee is in excess of $103,000. Based on an assumed capitalization rate of approximately 8.25%,[12] the $103,000 total average compensation number per employee would be around $112,000. Furthermore, as previously discussed, the Company's employees that are eligible for incentive compensation have received average base salary increases in excess of 3.6% from 2005 through 2008 and an additional salary increase of 3.5% for 2009 has been recognized

[12] Derived from SRREV-5.1, page 1.

for ratemaking purposes in this case. Given these healthy overall base compensation and employee benefit numbers and reasonable base salary increases that have already been recognized in this case, I do not believe it reasonable and appropriate to saddle the ratepayers with an additional amount in excess of $3.2 million for bonus awards to be paid out under the Company's incentive compensation programs.

Fourth, the Company has not presented any evidence in this case showing the specific benefits that are accruing to the ratepayers as opposed to ETG's shareholders as a result of the LTIP and AIP incentive compensation plans for which these same ratepayers are asked to pay 100% of the costs. Neither has ETG presented any evidence in this case showing that there is any appreciable difference in the productivity level of ETG's and AGSC's employees as a direct result of the incentive compensation received by these employees.

Fifth, there is no incentive for management to control the level of the incentive compensation costs if 100% of these costs can be flowed through to the captive ratepayers. This would be particularly true given that the Company's management is the primary beneficiary of these incentive compensation plans.

Finally, I find the Company's request in this proposal for rate recovery of $3.2 million in bonus compensation on top of regular compensation particularly objectionable because this proposal is being made during the worst economic downturn since the Great Depression, where ratepayers are faced with job losses, plunging home values, and 410(k)s that have turned into 201(k)s. It is especially during these very difficult economic conditions that ratepayers need relief from these discretionary costs.

Q. DOES THE BOARD HAVE A STATED RATE MAKING POLICY WITH REGARD TO THE RATE TREATMENT OF INCENTIVE COMPENSATION?

A. Yes. In its Final Decision and Order in the Jersey Central Power & Light Company rate case, Docket No. 91121820J, the Board stated on page 4 of this Decision and Order:

> We are persuaded by the arguments of Staff and Rate Counsel that, at this time, the incentive compensation or "bonus" expenses should not be recovered from ratepayers. The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills or otherwise remaining profitable. These circumstances as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.[13]

As is noted before, this Board policy would be particularly applicable under the current economic circumstances.

Q. DID THE BOARD REITERATE THIS INCENTIVE COMPENSATION RATE MAKING POLICY IN A MORE RECENT LITIGATED BASE RATE CASE?

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[13] *I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions,* BRC Docket No. ER91121820J, Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision at 4 (June 15, 1993).

A. Yes. In the fully-litigated 2000 Middlesex Water Company base rate case, the BPU Staff stated on page 37 of its Initial Brief with regard to Middlesex's incentive compensation expenses:

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

While the ALJ in that case ruled that 50% of Middlesex's incentive compensation expenses could be recovered in rates, the Board overruled the ALJ and ordered that 100% of these incentive compensation expenses be removed from Middlesex's rates. [14]

Thus, my recommendation in the instant proceeding with regard to the Company's incentive compensation expenses is also consistent with well-established and long-standing Board ratemaking policy.

- **<u>ETG Vacancies</u>**

Q. IN DERIVING ITS PROPOSED PRO FORMA TEST PERIOD O&M PAYROLL EXPENSES OF $20,354,795, DID THE COMPANY ASSUME THAT THERE WILL BE NO EMPLOYEE POSITION VACANCIES IN THE TEST PERIOD AND DURING THE RATE EFFECTIVE PERIOD OF THIS CASE?

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[14] *I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Rates for Water Service and Other Tariff Changes,* BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part/ Initial Decision at 25-26 (June 6, 2001).

A. Yes. This was confirmed in the Company's response to RCR-A-87:

> … positions are considered vacant if the Company's budgeted FTEs[15] are higher than the actual FTEs in any given month. The Company assumed all budgeted positions filled (non vacancies) in the derivation of the annualized payroll expense of $20,354,795.

Q. WHAT WAS THE COMPANY'S ACTUAL VACANCY EXPERIENCE DURING THE MOST RECENT PERIOD FROM 2005 THROUGH THE FIRST HALF OF 2009?

A. As derived from the responses to RCR-A-85 and RCR-A-185, the Company has experienced the following average annual vacancy positions from 2005 through June 2009:

2005	25
2006	21
2007	6
2008	3
2009 – 6 mos.	9

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE PREVIOUSLY DISCUSSED FACTS?

A. I recommend that, in the determination of the appropriate payroll and employee benefit expenses for ratemaking purposes in this case, a reasonably representative level of vacant ETG employee positions be reflected. Based on the vacancy data in the foregoing table, I recommend that this representative vacancy level be set at 6 employee positions.

Q. WHAT ARE THE REASONS FOR THIS RECOMMENDATION?

[15] FTE stands for Full-Time Equivalent employees.

A. History has proven that ETG will always have unfilled budgeted positions due to normal turnover, retirements and terminations. There will always be differences between the numbers of authorized and actual employees during any time in any particular year. To assume, as ETG has done, that there will be zero vacancies during the test period is unrealistic and inappropriate. For those reasons, it is appropriate to reflect an employee vacancy level that would be representative of what can reasonably expected during the rate effective period of this case. As I stated before, I have determined this appropriate ETG employee vacancy level to be 6 vacancies.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED AFTER-TAX OPERATING INCOME IN THIS CASE?

A. Since vacant employee positions do not create a revenue requirement for ETG, the costs associated with the 6 recommended position vacancies must be removed from the Company's proposed pro forma test period O&M payroll and employee benefit expenses. On Schedule RJH-14, I have calculated that the O&M payroll and employee benefit expenses (excluding of incentive compensation) associated with 6 employee position vacancies amount to $618,877. The removal of this expense amount increases the Company's proposed after-tax operating income by $364,618.

- **<u>AGSC Vacancies</u>**

Q. IN DERIVING ITS PROPOSED PRO FORMA TEST PERIOD COST AMOUNT ALLOCATED FROM AGSC TO ETG, DID THE COMPANY ASSUME THAT

THERE WILL BE NO EMPLOYEE POSITION VACANCIES IN THE TEST PERIOD AND DURING THE RATE EFFECTIVE PERIOD OF THIS CASE?

A. In its original March 10, 2009 filing, in which the AGSC costs allocated to ETG were based on the 0+12 AGSC 2009 budget, the Company did indeed assume this, as confirmed in its response to RCR-A-94:

> … positions are considered vacant if the Company's budgeted FTEs are higher than the actual FTEs in any given month. The Company assumed all budgeted positions filled (non vacancies) in the derivation of the annualized payroll expense of $62,901,980.

In the Company's 6+6 update filing, in which the AGSC costs allocated to ETG were based on the 3+9 AGSC 2009 budget, the actual payroll costs associated with the first 3 months of 2009 reflected the actual vacant positions during that period, but the budgeted payroll costs for the remaining 9 months of 2009 assumed no vacancies.

Q. WHAT WAS AGSC'S ACTUAL VACANCY EXPERIENCE DURING THE MOST RECENT PERIOD FROM 2005 THROUGH THE FIRST HALF OF 2009?

A. As derived from the responses to RCR-A-92 and RCR-A-194, AGSC has experienced the following average annual vacancy positions from 2005 through June 2009:

2005	117
2006	87
2007	35
2008	28
2009 – 6 mos.	21

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE PREVIOUSLY DISCUSSED FACTS?

A. I recommend that, in the determination of the appropriate AGSC-allocated payroll and employee benefit expense for ratemaking purposes in this case, a reasonably representative level of vacant AGSC employee positions be reflected. Based on the vacancy data in the foregoing table, I recommend that this representative vacancy level be set at 20 AGSC employee positions.

Q. WHAT ARE THE REASONS FOR THIS RECOMMENDATION?

A. History has proven that AGSC will always have unfilled budgeted positions due to normal turnover, retirements and terminations. There will always be differences between the numbers of authorized and actual employees during any time in any particular year. To assume, as the Company has done, that there will be zero vacancies during the test period is unrealistic and inappropriate. For those reasons, it is appropriate to reflect an employee vacancy level that would be representative of what can reasonably expected during the rate effective period of this case. As I stated before, I have determined this appropriate AGSC employee vacancy level to be 20 vacancies.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED AFTER-TAX OPERATING INCOME IN THIS CASE?

A. Since vacant employee positions do not create a revenue requirement, the costs associated with the 20 recommended AGSC position vacancies must be removed from the Company's proposed pro forma test period AGSC-allocated O&M payroll and employee benefit expenses. On Schedule RJH-15, I have calculated that the annual AGSC-allocated O&M payroll and employee benefit expenses (excluding of incentive compensation) associated with 20 employee position vacancies amount to $235,237. I then applied a factor of 9/12th to this latter expense amount to reflect the fact that the vacancy adjustment should only be applied for the last 9 months of AGSC's updated 3+9 2009 budget. The removal of the resulting expense amount of $176,428 increases the Company's proposed after-tax operating income by $103,944.

- **<u>Officers Benefit Expense Adjustments</u>**

Q. HAVE YOU RECOMMENDED THAT THE EXPENSES FOR CERTAIN EMPLOYEE BENEFITS THAT ARE ONLY AWARDED TO THE COMPANY'S TOP OFFICERS BE REMOVED FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes. These recommended expense removals are shown on Schedule RJH-16. They concern Non-Qualified Excess Benefit Plan expenses; AGSC Financial Planning Services Plan expenses; and ETG's Supplemental Executive Retirement Plan ("SERP") expenses.

Q. PLEASE DESCRIBE THE PURPOSE AND RECIPIENTS OF THE NON-QUALIFIED EXCESS BENEFIT PLAN.

A. As described in the response to RCR-A-146 **(Confidential)**:

[Begin confidential information: [redacted]

[redacted]. **End confidential information].** Thus, this Excess Benefit Plan provides the Company's highest compensated employees with additional retirement benefits over and above those employees' "regular" retirement benefits received under AGL's Pension Plan.

Q. PLEASE DESCRIBE THE PURPOSE AND RECIPIENTS OF THE AGSC FINANCIAL PLANNING SERVICES PLAN.

A. The response to RCR-A-147 **(Confidential)** states in this regard:

> **[Begin confidential information:** [redacted]

[redacted] **End confidential information].**

Q. PLEASE DESCRIBE THE PURPOSE AND RECIPIENTS OF THE ETG SERP PLAN.

A. The response to RCR-A-104 states in this regard:

> Participants in the SERP plan are specific officers of the Company selected by the Board of Directors. Per the plan document, the purpose of the SERP plan is to provide those specific participants and their beneficiaries with an

> additional retirement and/or death benefit in addition to the benefit(s) they would receive from the Company's qualified plan and its Code Section 415 excess plan. As of January 1, 2008, participation in the Plan consisted of 22 retirees receiving benefits and 4 vested deferred participants with benefits payable to them in the future. No active participants were accruing benefits under this Plan as of January 1, 2008.

Thus, similar to the previously described Excess Benefit Plan, the SERP plan provides the Company's highest compensated employees with additional retirement benefits over and above those employees' "regular" retirement benefits received under AGL's Pension Plan.

Q. WHY DO YOU RECOMMEND THAT THE EXPENSES ASSOCIATED WITH THESE THREE PLANS BE REMOVED FOR RATEMAKING PURPOSES IN THIS CASE?

A. The short answer is that I do not believe that the ratepayers should be required to fund these types of top officers compensation perks. The ratepayers are already 100% responsible for funding the "regular" retirement benefits of the Company's employees. It would be unreasonable to further burden the ratepayers with the costs of providing the Company's highest compensated employees with additional retirement benefits that are over and above the "regular" retirement benefits they are already receiving. I also believe it is unreasonable to force the captive ratepayers to pay for the personal tax preparation, financial planning, and estate planning of AGLR's Chairman and Executive Vice Presidents. This should be particularly true given that the ratepayers are currently already being buffeted from all sides with job losses and other consequences of today's severe economic downturn. In summary, if the Company wishes to provide its top officers with these additional compensation perks, the expenses associated with these perks should be picked up by the Company's shareholders, not the captive ratepayers.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED AFTER-TAX OPERATING INCOME IN THIS CASE?

A. As shown on Schedule RJH-16, my total recommended expense removal amounts to $258,285. This expense removal increases the Company's proposed after-tax operating income by $152,171.

- **Uncollectible Expense Adjustment**

Q. WHAT IS THE COMPANY'S PROPOSED POSITION IN THIS CASE WITH REGARD TO ITS UNCOLLECTIBLE RATIO AND THE ASSOCIATED UNCOLLECTIBLE EXPENSES?

A. The Company's actual uncollectible ratio[16] for 2008 was approximately 1.75%. The Company is of the opinion that this actual 2008 bad debt rate is "likely to reflect the Company's actual bad debt expense during both the test-year and the period in which the rates established in this proceeding will be in effect."[17] Based on this position, the Company calculated its proposed uncollectible expenses in this case by applying the uncollectible ratio of 1.75% to its 6+6 updated pro forma operating revenues. As shown on Schedule RJH-17, this resulted in the Company's proposed 6+6 updated uncollectible expense of $9,165,651.

[16] Net write-off to revenue ratio.
[17] Morley supplemental testimony, page 6, lines 3 – 7.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED POSITION IN THIS CASE WITH REGARD TO THE UNCOLLECTIBLE RATIO TO BE USED FOR RATEMAKING PURPOSES IN THIS CASE?

A. No. The Company's actual uncollectible ratios from 2004 through April 2009 and the Company's 2009 budgeted uncollectible ratio have been as follows:

2004	0.86%
2005	0.71
2006	0.84
2007	0.87
2008	1.75
12-mos 4/30/09	1.68
2009 budget	1.55

This table shows that the Company has picked the highest uncollectible ratio (1.75%) experienced in the recent past as the representative ratio for the rate effective period of this case, which may the next 5 years based upon the Company's proposal to amortize the current rate case expenses over 5 years. I do not believe this represent a reasonable approach to use for ratemaking purposes in this case. The 2008 1.75% uncollectible ratio is obviously a result of the severe recession started in that year. However, to assume that this very high ratio will continue to be experienced in the rate effective period of this case (which may be the next 5 years), in my opinion, is unreasonable. In this regard, the actual uncollectible ratio of 1.68% for the 12-month period ended April 30, 2009 is already showing a small decrease from the 2008 ratio of 1.75%. Furthermore, the Company's own approved 2009 operating budget calls for an uncollectible ratio of 1.55% in 2009.

In summary, I do not believe it is reasonable to assume that the 2008 recession-influenced high ratio of 1.75% will continue to be at that high level on average during the rate effective period of this case. Rather, I believe it is more likely that the Company's near-future uncollectible ratio will average at a level lower than 1.75% as the current economic conditions gradually improve. Based on the previously discussed facts, I therefore recommend that an uncollectible ratio of 1.55% should be used for ratemaking purposes in this case.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED AFTER-TAX OPERATING INCOME?

A. The pro forma operating revenues that I am recommending in this case, based on a 30-year weather normalization and annualized as of September 30, 2009, amount to $547,611,307. Applying the recommended uncollectible ratio of 1.55% to this revenue level indicates recommended uncollectible expenses of $8,487,975. The calculations and source references underlying this recommended uncollectible expense level are shown on Schedule RJH-17. This recommended uncollectible expense is $677,676 lower than ETG's proposed uncollectible expense of $9,165,651 which, in turn, increases the Company's proposed after-tax operating income by $399,259.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THIS ISSUE?

A. Yes. My recommended lower uncollectible ratio of 1.55% will also impact the Revenue Conversion Factor to be used for ratemaking purposes in this case. This will be addressed in more detail later in this testimony.

- **<u>Conservation Program Expense Removal</u>**

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL AND YOUR RECOMMENDED POSITION WITH REGARD TO THE PROPOSED CONSERVATION PROGRAM EXPENSES.

A. As shown on Schedule RJH-18, the Company has proposed base rate treatment for conservation program expenses totaling $940,000. Based on the recommendations contained in the testimony of Richard Lelash, I have removed these expenses from base rate consideration. This recommended base rate expense removal increases the Company's proposed after-tax operating income by $553,810.

- **<u>New Jersey Call Center Expense Adjustment</u>**

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL WITH REGARD TO THE PROPOSED NEW JERSEY CALL CENTER.

A. As shown on Schedule RJH-19, the Company has proposed total New Jersey Call Center (NJCC) expenses of $4,503,642 in this case. This proposed total expense amount consists of two components: (1) annual recurring payroll and non-payroll expenses of $4,355,565; and (2) non-recurring net transition costs of $740,386 which the Company proposes to defer and amortize over a 5-year period for an annual amortization expense of $148,077.

Q. DO YOU RECOMMEND THAT ADJUSTMENTS BE MADE TO THE COMPANY'S PROPOSED NEW JERSEY CALL CENTER EXPENSES?

A. Yes. First, I recommend that the incentive compensation portion of the annual recurring payroll costs be removed for ratemaking purposes in this case. I am making this recommendation for the same reasons as previously discussed in this testimony.[18] As shown on Schedule RJH-19, line 1, this recommendation reduces the Company's proposed NJCC annual payroll expenses by $260,000.

Second, I have reflected the recommendation made by Rate Counsel witness Richard Lelash to remove the net transition cost amortization expense of $148,077.

Third, I have reflected the additional recommendation made by Mr. Lelash to impose a $1 million penalty as a result of current deficiencies in the Company's service performance relative to accepted industry standards.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED POSITION WITH REGARD TO THIS ISSUE ON THE COMPANY'S PRO FORMA AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-19, my recommended position with regard to this issue reduces the Company's proposed New Jersey Call Center expenses by $1,408,077 and this recommended expense reduction, in turn, increases the Company's proposed pro forma after-tax operating income by $829,583.

[18] In the testimony section entitled "Incentive Compensation Expense Removal."

- **Environmental Remediation Labor Expense Adjustment**

Q. PLEASE EXPLAIN THE ENVIRONMENTAL LABOR EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-9, LINE 12 AND SCHEDULE RJH-20.

A. In this case, the Company has proposed base rate recovery for the internal labor costs associated with the Company's environmental remediation program which are currently being recovered through the Remediation Adjustment Clause ("RAC"). Rate Counsel witness Lelash, on the other hand, has recommended that such environmental remediation labor expenses continue to be recovered through the RAC. The adoption of Mr. Lelash's recommendation requires that the environmental remediation labor expenses that are embedded in the Company's proposed pro forma base rate payroll expenses be removed so as not to double-recover these labor expenses in both the Company's RAC and base rates. The Company has indicated that the environmental remediation labor expenses included in its proposed pro forma O&M payroll amount to approximately $65,000. The recommended removal of this $65,000 expense increases the Company's proposed after-tax operating income by $38,295.

- **PRP Regulatory Asset Amortization Adjustment**

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED DECEMBER 31, 2009 REGULATORY ASSET BALANCE ASSOCIATED WITH THE PIPELINE

REPLACEMENT PROGRAM ("PRP") THAT WAS THE SUBJECT OF THE STIPULATION IN BPU DOCKET NO. GR05040371?

A. Yes. The Company has calculated an estimated December 31, 2009 Regulatory Asset balance of $1,423,056 for the PRP. I have conducted a review to determine whether this proposed Regulatory Asset balance has been appropriately calculated in accordance with the stipulation provisions regarding this PRP issue in the BPU's Order in Docket No. GR05040371. Based on this review, I have concluded that the Company's calculated December 31, 2009 PRP Regulatory Asset balance of $1,423,056 has been calculated properly.

Q. IS THERE STILL AN ISSUE WITH THE RATEMAKING TREATMENT PROPOSED BY ETG FOR THIS REGULATORY ASSET?

A. Yes. While the Company was allowed by the Board in Docket No. GR05040371 to amortize the Regulatory Asset balance as an expense in the instant rate proceeding, I do not agree with the Company's proposed 3-year amortization period. Rather, I believe that a longer amortization period, like 5 years, would be more appropriate to reflect for ratemaking purposes in this case. This 5-year amortization period is consistent with the 5-year amortization period proposed by the Company, and accepted by me, for ETG's current rate case expenses.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S AFTER-TAX OPERATING INCOME IN THIS CASE?

A. As shown on Schedule RJH-9, line 13 and Schedule RJH-21, my recommendation increases ETG's after-tax operating income by $111,788.

- **Miscellaneous Expense Adjustments**

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENTS SHOWN ON SCHEDULE RJH-22.

A. On Schedule RJH-21, line 1, I have removed the Counsel for Responsible Energy ("CRE") expenses that were allocated from AGSC to ETG. RCR-A-127.1 describes CRE and its purpose and activities as follows:

> (CRE) is an industry coalition created to develop and execute a multi-year nationwide customer education campaign. Our industry has a compelling story and now is the time to tell it! It would be difficult – and expensive – for any company to develop such a campaign on its own. We must come together as a unified voice for the industry to achieve even greater success in today's challenging market. In doing so, we also establish a flexible framework to support future industry-wide marketing and education initiatives.

RCR-A-127.1 also lists some of the specific accomplishments of the CRE, including, among other things:

- Conducting market research in 8 states
- Selecting international marketing agency
- Creating natural gas industry brand positioning, logo and tagline
- Supporting local execution of marketing initiatives consistent with national campaign
- Conducting National PR campaign

The foregoing information clearly shows that the main purpose of the CRE is the promotion and marketing of natural gas as an energy source. It is Board policy that expenses associated with promotional, institutional and public relations activities be excluded for ratemaking purposes.[19] Thus, I have removed these AGSC-allocated CRE expenses in accordance with this well-established and long-standing Board ratemaking policy.

On Schedule RJH-22, line 2, I have removed certain additional non-jurisdictional NJUA dues which the Company has acknowledged in its response to RCR-A-190 should be treated below-the-line.

Q, WHAT IS THE IMPACT OF YOUR RECOMMENDED MISCELLANEOUS EXPENSE ADJUSTMENTS ON THE COMPANY'S PROPOSED PRO FORMA AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-22, my recommended miscellaneous expense adjustments increase the Company's proposed pro forma after-tax operating income by $30,541.

- <u>Depreciation Expense Adjustment</u>

Q. PLEASE EXPLAIN ETG'S PROPOSED AND YOUR RECOMMENDED ANNUALIZED DEPRECIATION EXPENSE LEVELS.

A. In determining its proposed annualized depreciation expenses for ETG plant, the Company applied the proposed depreciation rates from Dr. Kateregga's new depreciation study to the projected December 31, 2009 depreciable ETG plant balances. This resulted in proposed annualized ETG plant depreciation expenses of $21,606,779. Next, the Company added

[19] See BPU's Final Decision and Order, page 9 in JCP&L's base rate proceeding, BRC Docket No. ER91121820J.

$1,515,597 for AGSC-allocated depreciation expenses and $19,549 for the amortization of leased vehicle. Thus, as shown on Schedule RJH-22, the Company's proposed total annualized depreciation expenses amounts to $23,141,925.

My recommended annualized depreciation expenses for ETG plant were determined using the same calculation methodology as used by ETG, except that they are based on the depreciation rates recommended by Rate Counsel witness Michael Majoros. The so-determined recommended ETG plant depreciation expense amount of $16,413,977 is shown on Schedule RJH-22, line 1. I have also corrected the Company's proposed AGSC-allocated depreciation expense from $1,515,597 to $1,251,126. This required correction, which is shown on line 2, was conceded by the Company in its response to RCR-A-148. I have taken no exception to the Company's proposed leased vehicle amortization expense of $19,549. As shown on lines 4 – 6 of Schedule RJH-22, the resulting total recommended annualized depreciation expenses of $17,684,652 are $5,457,273 less than the Company's proposed total annualized depreciation expenses which, in turn, results in a recommended increase in after-tax operating income of $3,215,207.

- **Accounting Orders**

Q. PLEASE PROVIDE YOUR UNDERSTANDING OF THE COMPANY'S REQUEST FOR ACCOUNTING ORDERS FROM THE BOARD IN THIS CASE FOR VARIOUS COSTS ETG MAY POTENTIALLY INCUR IN THE FUTURE.

A. In this case the Company is seeking accounting orders from the Board that would allow

ETG to defer and charge to the ratepayers in its next base rate filing costs that may be incurred to implement recommendations that may arise from the pending management audit, as well as future costs that may be incurred to comply with New Jersey's Energy Master Plan ("EMP").

Q. DO YOU AGREE WITH THIS REQUEST?

A. No. If costs associated with recommendations from the current management audit and New Jersey EMP become known and measurable prior to the close of record in this case, it would be reasonable to provide for appropriate base rate recovery in this case. It is another matter, however, to allow cost deferral and future base rate recovery for costs that may potentially be incurred in the future and are not known and measurable by the time the record in this case closes. Allowing future rate recognition for such unknown costs represents inappropriate single-issue ratemaking which should be rejected by the Board as it would inappropriately consider the revenue requirement impact of cost changes in two selective areas without regulatory scrutiny of *all* of the Company's revenue requirement components at the same time.

C. REVENUE CONVERSION FACTOR

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN THE COMPANY'S PROPOSED AND YOUR RECOMMENDED REVENUE CONVERSION FACTORS SHOWN ON SCHEDULE RJH-1, LINE 6.

A. As shown under footnote (2) of Schedule RJH-1, the difference between my recommended and the Company's proposed revenue conversion factors is caused by the difference in uncollectible ratios included in the conversion factor calculation.

Q. MR. HENKES, DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SCHEDULES

RJH-1 THROUGH RJH-23

Test Year: 9/30/09
BPU Docket No. GR09030195

Sch. RJH-1

ELIZABETHTOWN GAS COMPANY
REVENUE REQUIREMENT

	ETG 6+6 (1)	Adjustments	RC	
1. Rate Base	$ 444,088,675	$ (44,074,946)	$ 400,013,729	RJH-3
2. Rate of Return	8.41%		7.52%	RJH-2
3. Required Operating Income	37,347,858		30,071,200	
4. Pro Forma Operating Income	27,299,863	10,563,933	37,863,796	RJH-9
5. Operating Income Deficiency	10,047,995		(7,792,596)	
6. Revenue Conversion Factor	1.727969		1.724055	(2)
7. Revenue Deficiency	$ 17,362,668	$ (30,797,529)	$ (13,434,861)	
8. Rate Increase	3.32% (3)		-2.45%	(4)

(1) 6+6 Schedule MJM-1-A

(2)

	ETG 6+6	RC
Revenues	100.000000	100.000000
Less: Uncollectibles	1.773000	1.550000
	98.227000	98.450000
Less: State Income Taxes @9.36%	9.194047	9.214920
	89.032953	89.235080
Less: Federal Income Taxes @35%	31.161533	31.232278
	57.871419	58.002802
Revenue Conversion Factor	1.727969	1.724055

(3) Revenue deficiency on RJH-1, line 7 divided by pro forma adjusted operating revenues of $522,848,085 (6+6 Schedule MJM-3-A)

(4) Revenue deficiency on RJH-1, line 7 divided by pro forma adjusted operating revenues of $547,611,307 (RCR-A-76.2)

ELIZABETHTOWN GAS COMPANY
RATE OF RETURN

ETG 6+6	Ratios	Cost Rate	Weighted Cost
	(1)	(1)	(1)
Long Term Debt	42.33%	6.15%	2.60%
Short Term Debt	7.97%	2.74%	0.22%
Common Equity	49.70%	11.25%	5.59%
Total	100.00%		8.41%

RATE COUNSEL	Ratios	Cost Rate	Weighted Cost
	(2)	(2)	(2)
Long Term Debt	45.91%	6.02%	2.76%
Short Term Debt	7.97%	1.20%	0.10%
Common Equity	46.12%	10.10%	4.66%
Total	100.00%		7.52%

(1) 6+6 Schedule MJM-6-A, page 1 of 2
(2) Testimony of Matthew I. Kahal

ELIZABETHTOWN GAS COMPANY
RATE BASE

	ETG 6+6 (1)	Adjustments	RC	
1. Utility Plant in Service	$ 763,846,684	$ (831,636)	$ 763,015,048	RJH-4
2, Accumulated Depreciation	(287,647,772)	309,590	(287,338,182)	RJH-5
3. Net Utility Plant	476,198,912	(522,046)	475,676,866	
4. Pension and OPEB	8,731,526	(2,280,470)	6,451,056	RJH-6
5. Customer Advances/Contributions	(519,001)		(519,001)	
6. ETG ADIT	(86,896,545)	936,908	(85,959,637)	RJH-7
7. AGSC-Allocated ADIT	(1,479,650)	61,385	(1,418,265)	RJH-8
8. Capital Lease Obligations	(69,430)		(69,430)	
9. Customer Deposits	(9,429,937)		(9,429,937)	
10. Working Capital:				
a. Materials & Supplies	433,873		433,873	
b. Gas Stored Underground	40,403,680		40,403,680	
c. Cash Working Capital	16,715,246	(4,335,242)	12,380,004	(2)
d. Total Working Capital	57,552,799	(4,335,242)	53,217,557	
11. Consolidated Income Tax Benefits	-	(37,935,480)	(37,935,480)	(3)
12. TOTAL NET RATE BASE	$ 444,088,675	$ (44,074,945)	$ 400,013,729	

(1) 6+6 Schedule MJM-5-A
(2) Testimony of David E. Peterson
(3) S-RREV-73.2 Third Revision, page 4 of 4

ELIZABETHTOWN GAS COMPANY
AGSC-ALLOCATED PLANT IN SERVICE

	ETG 6+6 (1)	Adjustments	RC	
1. AGSC Plant in Service	$ 99,664,075		$ 96,437,412	(2)
2. Composite ETG Allocation Rate	13.51%		13.10%	(3)
3. AGSC Plant Allocated to ETG Rate Base	$ 13,464,937	$ (831,636)	$ 12,633,301	

(1) 6+6 Schedule MJM-12.5-A, Schedule 2, page 3 of 3, Workpaper supporting Schedule MJM 5. Plant balance is actual balance as of 3/31/09
(2) Projected AGSC plant balance as of 12/31/09 - per RCR-A-47.1
(3) Most recent actual ETG allocation rate for calendar year 2008 - see RCR-A-30.1

ELIZABETHTOWN GAS COMPANY
AGSC-ALLOCATED DEPRECIATION RESERVE

	ETG 6+6 (1)	Adjustments	RC	
1. AGSC Depreciation Reserve	$ 57,911,264		$ 57,361,894	(2)
2. Composite ETG Allocation Rate	13.51%		13.10%	(3)
3. AGSC Plant Allocated to ETG Rate Base	$ 7,823,998	$ (309,590)	$ 7,514,408	
4. AGSC Post-TY Reserve Additions	1,136,698		1,136,698	
5. AGSC Depreciation Reserve Allocated to ETG Rate Base	$ 8,960,696	$ (309,590)	$ 8,651,106	

(1) 6+6 Schedule MJM-12.5-A, Schedule 2, page 3 of 3, Workpaper supporting Schedule MJM 5. Reserve balance is actual balance balance as of 3/31/09 plus projected reserve additions through 12/31/09
(2) Projected AGSC reserve balance as of 12/31/09 - per RCR-A-47.1
(3) Most recent actual ETG allocation rate for calendar year 2008 - see RCR-A-30.1

ELIZABETHTOWN GAS COMPANY
PENSION AND OPEB RATE BASE BALANCE

	ETG 6+6 (1)	Adjustments	RC
1. Accrued Pension Costs	$ (11,692,070)		$ (11,692,070)
2. Accrued Other Postretirement Benefits	(612,492)		(612,492)
3. Regulatory Asset for Pension and OPEB Due to Acquisition	18,755,618		18,755,618
4. Unamortized OPEB Transition Obligation	2,280,470	(2,280,470)	-
5. Total Pension and OPEB Rate Base Balance	$ 8,731,526	$ (2,280,470)	$ 6,451,056

(1) 6+6 Schedule MJM-5.2-A

ELIZABETHTOWN GAS COMPANY
ETG ACCUMULATED DEFERRED INCOME TAXES

1.	ETG ADIT Proposed by Company	$ 86,896,545	(1)
2.	Less: ADIT Associated with Rate Counsel's Recommended Adjustment for the Pension/OPEB Rate Base Balance	(936,908)	(2)
3.	ETG ADIT Recommended by Rate Counsel	$ 85,959,637	

(1) 6+6 Schedule MJM-5-A, line 6
(2) Composite income tax rate of 41.084% x pension/OPEB adjustment of ($2,280,470) on RJH-3, line 4

ELIZABETHTOWN GAS COMPANY
AGSC-ALLOCATED ACCUMULATED DEFERRED INCOME TAXES

	ETG 6+6 (1)	Adjustments	RC	
1. AGSC Total Accumulated Deferred Income Taxes	$ 10,951,996		$ 10,826,453	(2)
2. Composite ETG Allocation Rate	13.51%		13.10%	(3)
3. AGSC ADIT Allocated to ETG Rate Base	$ 1,479,650	$ (61,385)	$ 1,418,265	

(1) 6+6 Schedule MJM-12.5-A, Schedule 2, page 3 of 3, Workpaper supporting Schedule MJM 5. ADIT balance is actual balance as of 3/31/09
(2) Projected AGSC ADIT balance as of 12/31/09 - per RCR-A-47.1
(3) Most recent actual ETG allocation rate for calendar year 2008 - see RCR-A-30.1

Test Year: 9/30/09
BPU Docket No. GR09030195

Sch. RJH-9

ELIZABETHTOWN GAS COMPANY
PRO FORMA OPERATING INCOME

	6+6 Basis	
1. Pro Forma Operating Income Proposed by ETG:	$ 27,299,863	(1)
RATE COUNSEL ADJUSTMENTS:		
2. Interest Synchronization Adjustment	(445,852)	RJH-10
3. Sales Adjustments	2,934,667	RJH-11
4. AGSC Cost Allocation Adjustment	364,886	RJH-12
5. Remove All Incentive Compensation	1,911,015	RJH-13
6. Reflect Representative ETG Vacancy Level	364,618	RJH-14
7. Reflect Representative AGSC Vacancy Level	103,944	RJH-15
8. Officers Benefit Expense Adjustments	152,171	RJH-16
9. Uncollectible Expense Adjustment	399,259	RJH-17
10. Remove Conservation Program Expenses	553,810	RJH-18
11. NJ Call Center Expense Adjustment	829,583	RJH-19
12. Environmental Remediation Labor Expense Adjustment	38,295	RJH-20
13. PRP Regulatory Asset Amortization Adjustment	111,788	RJH-21
14. Miscellaneous Expense Adjustments	30,541	RJH-22
15. Depreciation Expense Adjustment	3,215,207	RJH-23
16. Total Rate Counsel Adjustments	10,563,933	
17. Pro Forma Operating Income Recommended by Rate Counsel	$ 37,863,796	

(1) 6+6 Schedule MJM-3-A

ELIZABETHTOWN GAS COMPANY
INTEREST SYNCHRONIZATION

	ETG 6+6 (1)	Adjustments	RC	
1. Rate Base	$ 444,088,675		$ 400,013,729	RJH-3
2. Weighted Cost of Debt	2.82%		2.86%	RJH-2
3. Synchronized Interest Expense	$ 12,523,301	(1,085,220)	$ 11,438,081	
4. Composite SIT and FIT Rate		41.084%		
5. Impact on Net Operating Income		$ (445,852)		

(1) 6+6 Schedule MJM-12-A, Workpapers Supporting Adjustment 7(a)

ELIZABETHTOWN GAS COMPANY
SALES ADJUSTMENTS

1.	Net Operating Margins Based on 30-Year Normal Weather, Annualized as of End of Test Year (Recommended by RC)	$ 139,536,936	(1)
2.	Net Operating Margins Based on 10-Year Normal Weather, Anualized as of 2/28/10 (Proposed by ETG)	134,555,832	(2)
3.	Recommended Net Operating Margin Increase	4,981,104	
4.	Income Taxes @ Composite Rate of 41.084%	2,046,437	
5.	Recommended Increase in After-Tax Operating Income	$ 2,934,667	

(1) RCR-A-76.2
(2) 6+6 Schedule MJM-12.4-A, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustments 1-A and 2-A

ELIZABETHTOWN GAS COMPANY
AGSC COST ALLOCATION ADJUSTMENT

1.	AGSC Total Allocable Costs in 3+9 2009 AGSC Budget	$ 150,938,453	(1)
2.	Composite % of AGSC Total Allocable Costs Allocated to ETG	13.10%	(2)
3.	Recommended AGSC Cost Allocated to ETG	19,772,937	
4.	Company-Proposed AGSC Cost Allocated to ETG	20,392,270	(3)
5.	Recommended Cost Reduction Adjustment	(619,333)	
6.	Income Taxes @ Composite Rate of 41.084%	(254,447)	
7.	Recommended Increase in After-Tax Operating Income	$ 364,886	

(1) 6+6 Schedule MJM-12.3-A, MJM Schedule 2, 2009 Budget - 3+9- AGL Services Company, page 5 of 6
(2) Most recent actual ETG allocation rate for calendar year 2008 - see RCR-A-30.1
(3) 6+6 Schedule MJM-12.4-A, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustments 3(k), 4(b) and 5(a)

Test Year: 9/30/09
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Sch. RJH-13

ELIZABETHTOWN GAS COMPANY
INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

	ETG 6+6	Adjustments	RC	
ETG "Direct" Incentive Compensation				
1. AIP Awards	$ 1,237,893	$ (1,237,893)	$ -	(1)
2. LTI Awards	72,722	(72,722)	-	(1)
3. Stock Awards	18,687	(18,687)	-	(1)
4. Total ETG "Direct" Incentive Compensation	$ 1,329,302	$ (1,329,302)	$ -	
AGSC Incentive Compensation Allocated to ETG				
5. AIP/LTI/Stk Awards	$ 1,886,106		$ -	(2)
6. Stock Awards	28,218		-	(2)
7. Total AGSC-Allocated Incentive Compensation	$ 1,914,324	$ (1,914,324)	$ -	
8. Total Adjustment (O&M Expense)		$ (3,243,626)		
9. Income Taxes @ Composite Rate of 41.084%		(1,332,611)		
10. Recommended Increase in After-Tax Operating Income		$ 1,911,015		

(1) RCR-A-181.1. AIP awards of $1,508,615 are pre-capitalization and have been reduced by $270,722 for the capitalized cost portion
(2) RCR-A-181.2. AIP/LTI/Stk Awards of $2,103,510 are pre-capitalization and have been reduced by $189,185 for the capitalized AIP cost portion

ELIZABETHTOWN GAS COMPANY
ETG VACANCY ADJUSTMENT

1.	Pro Forma Proposed O&M Payroll	$ 20,354,795	(1)
2.	Budgeted Number of Employees on Which Payroll in Line 1 is Based (Assumes No Vacancies)	267	(2)
3.	Average O&M Payroll per Employee	76,235	
4.	Average O&M Employee Benefits (Excluding Incentive Compensation) per Employee @ 35.3% of Line 3	26,911	(3)
5.	Total O&M Payroll and Employee Benefits per Employee	103,146	
6.	Recommended Representative Employee Vacancy Level	6	(4)
7	Total O&M Expense Reduction due to Vacancies	618,877	
8.	Income Taxes @ Composite Rate of 41.084%	254,260	
9.	Recommended Increase in After-Tax Operating Income	$ 364,618	

(1) 6+6 Schedule MJM-12.4-A, Workpaper supporting 6+6 Schedule MJM-4-A, Adjustment 3(A)
(2) RCR-A-85.2 and response to RCR-A-87
(3) RCR-A-182.1
(4) Per response to RCR-A-85:

	Average Actual Vacancies
2005	25
2006	21
2007	6
2008	3
2009 - 6 months through June	8
Recommended for use in this case	6

Test Year: 9/30/09
BPU Docket No. GR09030195

Sch. RJH-15

ELIZABETHTOWN GAS COMPANY
AGSC VACANCY ADJUSTMENT

1.	AGSC O&M Payroll Allocated to ETG	$ 7,701,104	(1)
2.	Actual/Budgeted Number of Employees on Which Payroll in Line 1 is Based	795	(2)
3.	Average O&M Payroll per Employee	9,687	
4.	Average O&M Employee Benefits (Excluding Incentive Compensation) per Employee @ 21.42% of Line 3	2,075	(3)
5.	Total O&M Payroll and Employee Benefits per Employee	11,762	
6.	Recommended Representative Vacancy Level	20	(4)
7.	Annualized O&M Expense Reduction due to Vacancies	235,237	
8.	Factor to Reflect Vacancy Adjustment for Only 9 Months	9/12	
9.	Recommended O&M Exp Reduction due to Vacancies	176,428	
10.	Income Taxes @ Composite Rate of 41.084%	72,484	
11.	Recommended Increase in After-Tax Operating Income	$ 103,944	

(1) Response to RCR-A-196, adjusted for use of composite ETG allocation rate of 13.10%

(2) Per RCR-A-92.2 and RCR-A-194.1, p.9 of 9:

	# of Employees
Jan 2009 - Actual (reflects vacancies)	781
Feb 2009 - Actual (reflects vacancies)	782
Mar 2009 - Actual (reflect vacancies)	778
Apr 2009 - Budget (assumes no vacancies)	798
May 2009 - Budget (assumes no vacancies)	799
Jun 2009 - Budget (assumes no vacancies)	799
Jul 2009 - Budget (assumes no vacancies)	800
Aug 2009 - Budget (assumes no vacancies)	800
Sep 2009 - Budget (assumes no vacancies)	800
Oct 2009 - Budget (assumes no vacancies)	800
Nov 2009 - Budget (assumes no vacancies)	800
Dec 2009 - Budget (assumes no vacancies)	800
Average	795

(3) RCR-A-183.1

(4) Per responses to RCR-A-92 and RCR-A-194:

	Average Actual Vacancies
2005	117
2006	87
2007	35
2008	28
2009 - 6 months through June	21
Recommended for use in this case	20

ELIZABETHTOWN GAS COMPANY
OFFICERS BENEFIT EXPENSE ADJUSTMENTS

1. Remove Non-Qualified Excess Benefit Plan Expenses			
a. ETG "Direct"	$	(6,274)	(1)
b. AGSC Allocated to ETG		(148,671)	(1)
c. Total Expense Removal		(154,945)	
2. Remove AGSC Financial Planning Plan Expenses Allocated to ETG		(12,941)	(2)
3. Remove ETG Supplemental Executive Retirement Plan (SERP) Expenses		(90,399)	(3)
4. Total Recommended Expense Removal		(258,285)	
5. Income Taxes @ Composite Rate of 41.084%		(106,114)	
6. Recommended Increase in After-Tax Operating Income	$	152,171	

(1) RCR-A-146.1
(2) Response to RCR-A-147(d)
(3) Response to RCR-A-104(a)

ELIZABETHTOWN GAS COMPANY
UNCOLLECTIBE EXPENSE ADJUSTMENT

	ETG 6+6 (1)	Adjustments	RC	
1. Pro Forma Operating Revenues	$ 522,714,216		$ 547,611,307	(2)
2. Uncollectible Ratio	1.7535%		1.5500%	(3)
3. Pro Forma Uncollectible Expense	$ 9,165,651	(677,676)	$ 8,487,975	
4. Income Taxes @ Composite Rate of 41.084%		(278,416)		
5. Recommended Increase in After-Tax Operating Income		$ 399,259		

(1) 6+6 Schedule MJM-12.4, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustment 3(d)
(2) RCR-A-76.2

(3) Per responses to RCR-A-142 and 173:

	Net Write-Off to Revenue Ratio
2004	0.86%
2005	0.71%
2006	0.84%
2007	0.87%
2008	1.75%
12-mos. ended 4/09	1.68%
2009 Budget	1.55%
Recommended Ratio	1.55%

Test Year: 9/30/09
BPU Docket No. GR09030195

Sch. RJH-18

ELIZABETHTOWN GAS COMPANY
CONSERVATION PROGRAM EXPENSE ADJUSTMENT

	ETG 6+6 (1)	Adjustments	RC (2)
1. Outreach	$400,000		$ -
2. Maintenance	76,800		-
3. Admin Project Manager	100,000		-
4. Addition of Four Energy Efficiency Auditors	363,200		-
5. Total Conservation Program Expenses	$ 940,000	$ (940,000)	$ -
6. Income Taxes @ Composite Rate of 41.084%		(386,190)	
7. Recommended Increase in After-Tax Operating Income		$ 553,810	

(1) 6+6 Schedule MJM-12.4, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustment 3(l)
(2) Testimony of Richard Lelash

ELIZABETHTOWN GAS COMPANY
NEW JERSEY CALL CENTER EXPENSE ADJUSTMENT

	ETG 6+6 (1)	Adjustments		RC	
1. Payroll Costs	$ 4,129,530	$ (260,000)	(2)	$ 3,869,530	
2. Non-Payroll Costs	226,035			226,035	
3. Sub-Total	4,355,565	(260,000)		4,095,565	
4. Non-Recurring Transition Costs	899,386			-	(3)
5. Job Creation Tax Rebates	(159,000)			-	(3)
6. Net Transition Costs	740,386			-	
7. Amortization Period (Yrs)	5				
8. Transition Cost Amortization	148,077	(148,077)		-	
9. Service Performance Penalty	-	(1,000,000)		(1,000,000)	(3)
10. Total NJ Call Center Expenses [L3 + L8 + L9]	$ 4,503,642	$ (1,408,077)		$ 3,095,565	
10. Income Taxes @ Composite Rate of 41.084%		(578,494)			
11. Recommended Increase in After-Tax Operating Income		$ 829,583			

(1) 6+6 Schedule MJM-12.4, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustment 3(e)
(2) Removal of incentive compensation - per response to RCR-A-170
(3) Testimony of Richard Lelash

ELIZABETHTOWN GAS COMPANY
REMOVAL OF INTERNAL LABOR EXPENSE FOR ENVIRONMENTAL REMEDIATION

1. Payroll O&M Expenses Associated with Environmental Remediation	$	65,000	(1)
2. Income Taxes @ Composite Rate of 41.084%		26,705	
3. Recommended Increase in After-Tax Operating Income	$	38,295	

(1) Reponses to RCR-A-136 and S-RREV-83

Test Year: 9/30/09
BPU Docket No. GR09030195

Sch. RJH-21

ELIZABETHTOWN GAS COMPANY
PRP REGULATORY ASSET AMORTIZATION ADJUSTMENT

	ETG 6+6 (1)	Adjustments	RC
1. PRP Regulatory Asset Balance at 12/31/09	$ 1,423,056		$ 1,423,056
2. Amortization Period (Yrs)	3		5
3. Annual Amortization	$ 474,352	$ (189,741)	$ 284,611
4. Income Taxes @ Composite Rate of 41.084%		(77,953)	
5. Recommended Increase in After-Tax Operating Income		$ 111,788	

(1) 6+6 Schedule MJM-12.4-A, Workpapers Supporting 6+6 Schedule MJM-4-A, Adjustment 3(m)

ELIZABETHTOWN GAS COMPANY
MISCELLANEOUS EXPENSE ADJUSTMENTS

1.	Remove Council for Responsible Energy Expenses Allocated from AGSC to ETG	$ (49,712)	(1)
2.	Remove Additional Non-Jurisdictional NJUA Dues	(2,126)	(2)
3.	Total Miscellaneous Expense Adjustments	(51,838)	
4.	Income Taxes @ Composite Rate of 41.084%	(21,297)	
5.	Recommended Increase in After-Tax Operating Income	$ 30,541	

(1) 3+9 2009 AGSC budget account 660014: $379,478 x ETG allocation factor of 13.10% = $49,712
(2) Response to RCR-A-190

ELIZABETHTOWN GAS COMPANY
DEPRECIATION EXPENSE ADJUSTMENT

	ETG 6+6 (1)	Adjustments	RC	
1. ETG Depreciation	$ 21,606,779	$ (5,192,802)	$ 16,413,977	(2)
2. AGSC-Allocated Depreciation	1,515,597	$ (264,471)	1,251,126	(3)
3. Amortization of Leased Vehicles	19,549		19,549	
4. Total Depreciation Expense	$ 23,141,925	(5,457,273)	$ 17,684,652	
5. Income Taxes @ Composite Rate of 41.084%		(2,242,066)		
6. Recommended Increase in After-Tax Operating Income		$ 3,215,207		

(1) 6+6 Schedule MJM-12.4-A, Supporting Schedule MJM-4, Adjustment 4(a)
(2) Testimony of Michael Majoros: ETG depreciation of $18,007,978 less COR Reg Liab amortization of $1,594,001
(3) Response to RCR-A-148

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company Report Re. PROMOD and Its Use in	Docket 85-26	10/1986

Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001
Chesapeake Gas Company	Docket No. 01-307	12/2001

Gas Base Rate Proceeding*		
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006
United Water Delaware Water Base Rate Proceeding*	Docket No. 09-60	06/2009

<u>DISTRICT OF COLUMBIA</u>

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996

Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005
Georgia Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 25060-U	10/2007

FERC

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

KENTUCKY

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997

Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004

Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005
Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006
Duke Energy Kentucky Electric Base Rate Proceeding*	Case No. 2006-00172	09/2006
Atmos Energy Corporation Gas Show Cause Proceeding*	Case No. 2005-00057	09/2006
Inter County Electric Cooperative Electric Base Rate Proceeding	Case No. 2006-00415	04/2007
Atmos Energy Corporation Gas Base Rate Proceeding*	Case No. 2006-00464	04/2007
Columbia Gas of Kentucky Gas Base Rate Proceeding*	Case No. 2007-00008	06/2007
Delta Natural Gas Company Gas Base Rate Proceeding – Alternative Rate Mechanism*	Case No. 2007-00089	08/2007
Nolin Rural Electric Cooperative Corporation Electric Rate Proceeding	Case No. 2006-00466	09/2007
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2006-00022	10/2007

Jasckson Energy Cooperative Electric Base Rate Proceeding	Case No. 2007-00333	03/2008
Jackson Purchase Energy Corporation Electric Base Rate Proceeding	Case No. 2007-00116	04/2008
Blue Grass Energy Cooperative Electric Base Rate Proceeding	Case No. 2008-00011	7/2008
Louisville Gas & Electric Company Electric and Gas Base Rate Proceedings*	Case No. 2008-00252	10/2008
Kentucky Utilities Company Electric Base Rate Proceeding*	Case No. 2008-00251	10/2008
Owen Electric Cooperative Corporation Electric Base Rate Proceeding	Case No. 2008-00154	12/2008
Kenergy Corporation Electric Base Rate Proceeding	Case No. 2008-00323	12/2008
Kentucky-American Water Company Water Base Rate Proceeding*	Case No. 2008-00427	04/2009
Grayson Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2008-00254	04/2009
Farmers Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2008-00030	04/2009
Big Sandy Electric Cooperative Electric Base Rate Proceeding	Case No. 2008-oo401	04/2009

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982

Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989

Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company	Docket ER 94070293	11/1994

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Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and	Docket Nos. ES96039158	

Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	& ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997
South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998

Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company Gas Cost Adjustment Clause Proceeding DSM Adjustment Clause Proceeding	 Docket No.GR99070509 Docket No. GR99070510	 03/2000 03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000

United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
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Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000
Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
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Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
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Pennsgrove Water Company — Docket No. WR00120939 — 07/2001
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Public Service Electric & Gas Company — Docket No. GR01050328 — 08/2001
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Public Service Electric & Gas Company — Docket No. GR01050328 — 09/2001
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New Jersey American Water Company — Docket No. WF01050337 — 12/2001
Financing Proceeding

Consumers New Jersey Water Company — Docket No. WF01080523 — 01/2002
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Consumers New Jersey Water Company — Docket No. WR02030133 — 07/2002
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New Jersey American Water Company — Docket No. WM01120833 — 07/2002
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Borough of Haledon – Water Department — Docket No. WR01080532 — 07/2002
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United Water Lambertville — Docket No. WM02080520 — 11/2002
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United Water Vernon Hills & Hampton — Docket No. WE02080528 — 11/2002
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United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Minimum Pension Liability Proceeding	Docket No. EO02110853	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
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Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003
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Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
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Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
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New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004
United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004
Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005
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Public Service Electric & Gas Company* Merger of PSEG and Exelon Corporation Surrebuttal Testimony	Docket No. EM05020106	12/2005
Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005
Rockland Electric Company Competitive Services Audit	Docket No. EA02020098	12/2005
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Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755	01/2006
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Pinelands Water Company Water Base Rate Proceeding*	Docket No. WR05080681	03/2006
Pinelands Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR05080680	03/2006
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Public Service Electric & Gas Company Gas Base Rate Proceeding*	Docket No. GR05100845	07/2006
New Jersey American Company Consolidated Water Base Rate Proceeding,* New Jersey American Water Company, Elizabethtown Water Company, and Mount Holly Water Company	Docket No. WR06030257	10/2006
Roxiticus Water Company Water Base Rate Proceeding	Docket No. WR06120884	04/2007
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United Water Company of New Jersey Water Base Rate Proceeding*	Docket No. WR07020135	09/2007
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR07040275	09/2007
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Atlantic City Sewerage Company Base Rate and Purchased Sewerage Treatment Clause Proceedings	Docket No. WR07110866	04/2008
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Aqua New Jersey Water Company Water Base Rate Proceeding	Docket No. WR07120955	06/2008
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Pinelands Water Company Water Base Rate Proceeding	Docket No. WR08040282	12/2008
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United Water Arlington Hills Sewerage Company Wastewater Base Rate Proceeding	Docket No. WR08100929	04/2009
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Middlesex Water Company Purchased Water Adjustment Clause	Docket No. WR09010036	05/2009
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Lawrenceville Water Company Change of Control Proceeding	Docket No. WM08110984	06/2009
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Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
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Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

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