STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE WALTER J. BRASWELL

I/M/O THE PETITION OF	)	
PUBLIC SERVICE ELECTRIC AND	)	
GAS COMPANY FOR APPROVAL OF	)	
AN INCREASE IN ELECTRIC AND	)	
GAS RATES AND FOR CHANGES IN	)	
THE TARIFFS FOR ELECTRIC AND	)	
GAS SERVICE,	)	**BPU DOCKET No. GR09050422**
B.P.U. N.J. NO. 14 ELECTRIC AND	)	**OAL DOCKET No. PUC-7559-09**
B.P.U. N.J. NO. 14 GAS PURSUANT TO	)	
N.J.S.A. 48: 2-21 AND N.J.S.A. 48: 2-21.1	)	
AND FOR APPROVAL OF GAS	)	
WEATHER NORMALIZATION;	)	
A PENSION EXPENSE TRACKER AND	)	
FOR OTHER APPROPRIATE RELIEF	)	

DIRECT TESTIMONY OF ANDREA C. CRANE
ON BEHALF OF THE
NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE
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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 199 Ethan Allen Highway, Ridgefield, Connecticut 06877. (Mailing Address: PO Box 810, Georgetown, Connecticut 06829.)

Q. By whom are you employed and in what capacity?

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 300 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, West Virginia and the District of Columbia. These proceedings involved electric, gas, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony is included in Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On or about May 29, 2009, Public Service Electric and Gas Company ("PSE&G" or "Company") filed an Application with the State of New Jersey, Board of Public Utilities ("BPU" or "Board") seeking a rate increase of $133.72 million in its rates for retail electric service and of $96.92 million in its rates for natural gas service. The Company stated that its initial request would have resulted in an increase of approximately 1.93% in its annual electric base rate revenues and an increase of approximately 2.95% of its annual natural gas base rate revenues. However, it is only the Company's distribution revenues that are at issue in this base rate case. PSE&G's initial request would have resulted in an electric distribution revenue increase of approximately 10.99% and in a natural gas distribution revenue increase of approximately 13.41%.

The Company's case is based on a test year consisting of the twelve months ending December 31, 2009. As filed, PSE&G's revenue requirement reflected actual results for three months and projected results for the last nine months of the test year (3+9). PSE&G subsequently updated its filing to reflect six months of actual results and six months of projections (6+6 Update). In that update, the Company increased its electric rate increase request to $147.02 million and its gas rate increase request to $105.95 million. Accordingly, the Company is now seeking an electric distribution revenue increase of 12.07% and a natural gas distribution revenue increase of 15.09%.

In addition to its request for electric and natural gas distribution rate increases, PSE&G also requesting the establishment of a Weather Normalization Clause ("WNC") for its gas utility; a Pension Expense Tracker; and expansion of its Capital Adjustment Charge ("CAC") to include essentially all non-revenue producing plant additions between base rate cases.

The Columbia Group, Inc. was engaged by the New Jersey Department of the Public Advocate, Division of Rate Counsel ("Rate Counsel") to review the Company's Petition and to provide recommendations to the BPU regarding the Company's revenue requirement claims and its request for expansion of the CAC.

My testimony is based on the Company's 6+6 Update. PSE&G will provide an additional update incorporating twelve months of test year data (12+0 Update) prior to the hearings in this case. I will update my testimony, accordingly, based on the 12+0 Update during the hearing phase of this case. In developing my recommendations, I have relied on the cost of capital and capital structure testimony of Matthew I. Kahal, on the cash working capital and affiliated interest testimony of David Peterson, on the pension testimony of Mitchell Serota, on the customer service testimony of Dian Callaghan, and on the policy testimony of Richard W. LeLash.

Q. What are the most significant issues in this rate proceeding?

A. The most significant issues driving the rate increase request are the Company's claim for a cost of equity of 11.5%, the Company's request to roll into base rates projected Capital Infrastructure Investment Program expenditures through February 28, 2010, increases in depreciation relating to plant additions, and operating increases in payroll and benefit costs. In addition, the Company is requesting the establishment of several tracking mechanisms that would have a profound impact on how rates for PSE&G customers are determined between base rate cases. The Company's last electric base rate case was resolved with rates effective August 1, 2003. Its last natural gas base rate case was resolved with rates effective November 9, 2006.

III. SUMMARY OF CONCLUSIONS

Q. Have you been able to reach a final recommendation with regard to the Company's need for rate relief?

A. No, I have not. As discussed above, PSE&G has not yet provided actual results for the full twelve months of the test year. Therefore, the recommendations contained in this testimony are preliminary. My revenue requirement recommendation will be updated after the Company files its 12+0 Update and I have had the opportunity to review that data and to obtain any additional information necessary to complete my analysis.

Q. What are your preliminary conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing, including its 6+6 Update, and other documentation in this case, my conclusions are as follows:

1. The twelve months ending December 31, 2009 is a reasonable test year to use in this case to evaluate the reasonableness of the Company's claims.
2. Based on the testimony of Mr. Kahal, the Company has an overall cost of capital for its electric and gas operations of 8.08% (see Schedule ACC-2E and Schedule ACC-2G).[1]

[1] Schedules are designated "E" for electric and "G" for gas. Schedules ACC-1E and ACC-43E are summary schedules, ACC-2E is a cost of capital schedule, ACC-3E to ACC-13E are rate base schedules, and ACC-14E to AC-42E are income schedules. Schedules ACC-1G and ACC-39G, are summary schedules, ACC-2G is a cost of capital schedule, ACC-3G to ACC-12G are rate base schedules, and ACC-13G to AC-38G are income schedules.

3. PSE&G has pro forma test year, electric rate base of $3.285 billion (see Schedule ACC-3E).

4. The Company has pro forma electric operating income at present rates of $274.549 million (see Schedule ACC-14E).

5. PSE&G has a pro forma, electric revenue surplus of $15.439 million (see Schedule ACC-1E). This is in contrast to the Company's claimed electric revenue deficiency of $147.016 million.

6. PSE&G has pro forma test year, natural gas rate base of $2.164 billion (see Schedule ACC-3G).

7. The Company has pro forma natural gas operating income at present rates of $166.964 million (see Schedule ACC-13G).

8. PSE&G has a pro forma, natural gas revenue deficiency of $13.723 million (see Schedule ACC-1G). This is in contrast to the Company's claimed natural gas revenue deficiency of $105.948 million.

9. The BPU should deny the Company's request to expand the CAC to include other distribution plant between base rate case proceedings.

The recommendations contained in my testimony will be updated, as necessary, based on the Company's 12+0 Update.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the PSE&G is requesting in this case?

A. The Company utilized the following capital structure and cost of capital in its filing:

	Percent of Total	Cost Rate	Weighted Cost
Equity Capital	51.2%	11.5%%	5.89%
Preferred Stock	1.05%	5.03%	0.05%
Long-Term Debt	46.60%	6.21%	2.90%
Customer Deposits	1.15%	2.34%	0.03%
Total	100.00%		8.86%

In its 6+6 Update, the Company updated its proposed cost of capital from 8.86% to 8.81%, primarily as a result of a lower cost of long-term debt.

Q. What is the capital structure and overall cost of capital that Rate Counsel is recommending for PSE&G?

A. As shown on Schedule MIK-1 of Mr. Kahal's testimony, Rate Counsel is recommending an overall cost of capital for PSE&G of 8.08%, based on the following capital structure and cost rates:

	Percent of Total	Cost Rate	Weighted Cost
Equity Capital	49.73%	10.10%	5.02%
Preferred Stock	1.08%	5.03%	0.05%
Long-Term Debt	49.19%	6.11%	3.01%
Customer Deposits	—	—	—
Total	100.00%		8.08%

This is the overall cost of capital that I have used to determine the Company's pro forma required income, as shown on summary Schedule ACC-1E and summary Schedule ACC-1G, based on my recommended rate base. I then compared this required income to pro forma income at present rates to determine the Company's need for rate relief. As shown on Schedule ACC-1E and Schedule ACC-1G, my recommendations indicate that the Company currently has an electric revenue surplus of $15.439 million and a natural gas revenue deficiency of $13.723 million.

Q. Why has Rate Counsel removed customer deposits from the Company's capital structure, as shown above?

A. For ratemaking purposes, customer deposits can be reflected as part of a utility's capital structure, or customer deposits can be reflected as a rate base deduction with a corresponding adjustment to reflect interest on customer deposits above-the-line. As discussed in the Rate

Base section of my testimony, I am recommending that customer deposits be reflected as a reduction to rate base. Accordingly, Mr. Kahal has eliminated customer deposits from his capital structure recommendation.

V. RATE BASE ISSUES

A. Utility Plant-in-Service

Q. How did PSE&G determine its utility plant-in-service claims in this case?

A. The Company's claims for utility plant-in-service are based on its projected plant balances at December 31, 2009, the end of the test year. In addition, PSE&G included post test year electric and gas plant additions through February 28, 2010. Finally, the Company included its projected cumulative expenditures through February 28, 2010 relating to the Capital Infrastructure Investment Program.

Q. Are you recommending any adjustments to the Company's claim for utility plant-in-service?

A. Yes, I am recommending two adjustments. Specifically, I am recommending adjustments relating to a) the inclusion of post-test year plant in rate base and b) the Company's projected claim for plant transferred from the Capital Infrastructure Investment Program.

Q. Please quantify the post-test year plant additions that have been included in the Company's rate base claim.

A. PSE&G has included $54.4 million of post-test year electric plant additions and $22.3 million of post-test year gas plant additions in its rate base claim, as shown in Schedule MGK-11 R-1. In addition to reflecting plant additions through February 28, 2010, PSE&G has also incorporated two months of post-test year retirements in its claim. Thus, the Company has included $48.9 million of net post-test year electric additions and $18.5 million of net natural gas plant additions in its rate base claim. I am recommending that all post-test year plant additions, net of post-test year retirements, be eliminated from the Company's claim.

Q. What is the basis for this adjustment?

A. The Company's claim results in a mismatch among the components of the regulatory triad used to set rates in this case. For example, while the Company used projected plant-in-service balances at February 28, 2010 to determine its need for rate relief, its pro forma revenues at present rates are based on average test year customers. The Company's expense claim is a mixture of projected test year costs and certain costs that the Company has projected out well into 2011.

PSE&G chose the test year in this case and that test year ends at December 31, 2009. The use of plant additions that extend past the end of the test year is speculative and violates the principle that all components of the ratemaking equation should be matched at a point in time. Therefore, I recommend that the Company's attempt to include post-test year plant additions in rate base be denied.

Q. Has the BPU ever permitted the inclusion of post-test year plant in rate base?

A. Yes, I am aware that the New Jersey BPU has in the past permitted certain post-test year plant-in-service additions to be included in rate base. As stated in the Board's Decision on Motion for Determination of Test Year and Appropriate Time Period for Adjustments, Docket No. WR8504330, page 2:

> With regard to the second issue, that is, the appropriate time period and standard to apply to out-of-period adjustments, the standard that shall be applied and shall govern petitioner's filing and proofs is that which the Board has consistently applied, the "known and measurable" standard. Known and measurable changes to the test year must be (1) prudent and major in nature and consequence, (2) carefully quantified through proofs which (3) manifest convincingly reliable data. The Board recognizes that known and measurable changes to the test year, by definition, reflect future contingencies; but in order to prevail, petitioner must quantify such adjustments by reliable forecasting techniques reflected in the record.

It is clear that the Company has not met the criteria specified by the BPU for the inclusion of post-test year projects in rate base. PSE&G has not limited its post-test year plant-in-service claim to projects that are "major in nature and consequence." Furthermore, these post-test year additions have not been "carefully quantified through proofs which manifest convincingly reliable data." Instead, the Company failed to provide any quantitative support for its claim in its filing. Since the Company's post-test year plant-in-service claims do not meet the BPU's criteria for inclusion in rate base, and violate the regulatory matching principle, I recommend that the Board utilize the actual December 31, 2009 utility plant-in-service balances. I have used PSE&G projected test year-end balance for utility plant-in-service in developing my revenue requirement recommendation. This balance will be updated with actual data when the Company files its 12+0 Update. My adjustment is shown in Schedule ACC-4E and Schedule ACC-4G.

Q. Please describe the Company's rate base claim relating to Capital Infrastructure Investment Program expenditures.

A. PSE&G has included in rate base expenditures made to its Capital Infrastructure Investment Program ("CIIP") through February 28, 2010. This program was established in response to an Economic Stimulus initiative announced October 16, 2008 by Governor Corzine. In response, PSE&G filed its proposed Capital Infrastructure Investment Program on January 21, 2009. After extensive negotiations among various parties, the BPU approved a stipulation in that proceeding, memorialized in an Order dated April 28, 2009. That stipulation, executed on April 9, 2009 ("CIIP Stipulation") contained a cost recovery mechanism that permitted PSE&G to recover costs associated with the Capital Infrastructure Investment Program though a CAC surcharge mechanism that would be subject to periodic review and true-up. The CIIP Stipulation also provided that,

> ...during the Company's base rate case...the net capitalized amounts for the Qualifying Projects that are deemed to be reasonable and prudent, will be rolled into the Company's rate base and the associated revenue requirements will be recovered through base rates...Any Qualifying Project expenditures and CACs not included in base rates at the conclusion of the required base rate case will be included in the recalculation of CACs based on the methodology set forth in Appendix B. Six months prior to the anticipated completion of all of the Qualifying Projects, the base rate case referenced under paragraph 21 will be reopened for the sole purpose of considering base rate increases for electric and gas related to

the inclusion in rate base of the net amounts capitalized for the remaining Qualifying Projects. After all of the actual net amounts capitalized for all of the remaining Qualifying Projects are moved into rate base and base rate revenues are increased, the electric and gas CAC rates and tariffs will be recalculated to bring the balance to zero over a reasonable period of time and such rates and tariffs will terminate upon reaching a zero balance.[2]

The Company's original rate base claim included plant, accumulated depreciation, and deferred income taxes through February 28, 2010 for the Capital Infrastructure Investment Program based on the projected monthly expenditures reflected in the Stipulation. PSE&G's 6+6 Update reflects the impact of actual results through July 31, 2009. In its 6+6 Update, the Company reduced its projected electric Capital Infrastructure Investment Program expenditures at February 28, 2010 from $136.059 million to $109.182 million. Projected gas expenditures at February 28, 2010 associated with the Capital Infrastructure Investment Program were increased from $93.559 million to $99.152 million in the 6+6 Update.

Q. What is your recommendation with regard to the amount of Capital Infrastructure Investment Program plant that should be included in rate base?

A. Consistent with my recommendation relating to other utility plant-in-service, I am also recommending that Capital Infrastructure Investment Program plant be based on the actual December 31, 2009 balance, i.e., the end of the test year. However, based on actual results through July, which is the most recent information available, it appears that the Company is well behind its anticipated level of electric expenditures. Moreover, given the fact that this

2 *See*, *I/M/O the Petition of Public Service Electric and Gas Company For Approval of A Capital Economic Stimulus Infrastructure Investment Program and An Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and 48:2-21.1*, BPU Docket No. EO09010050, Order dated April 28, 2009, paragraph 22.

is a new program, we have very little history to utilize in attempting to evaluate the reasonableness of the Company's projected claim. Therefore, rather than utilizing the pro forma projected Capital Infrastructure Investment Program plant balance at December 31, 2009, I have only included actual expenditures through July 2009 in my revenue requirement calculation. This amount should be updated with actual results through December 31, 2009 when these results become available.

Q. Does the Company have a mechanism to recover costs associated with the Capital Infrastructure Investment Program that are not included in the base rates established as a result of this proceeding?

A. Yes. As noted, there is a CAC mechanism in place that allows the Company to recover costs associated with this program. This mechanism will continue until all of the infrastructure projects are complete and the associated costs rolled into base rates.[3] The CIIP Stipulation in BPU Docket No. EO09010050 contains a provision to reopen this base rate case to review any projects that are not rolled into base rates as a result of this case. Therefore, the Company will continue to recover costs for Capital Infrastructure Investment Program projects even if the BPU limits the projects that are transferred to base rates at this time. Given the uncertainty with regard to the level of actual expenditures to be made during 2009, as well as the fact that the Company has a mechanism to recover actual program

3 The Company is proposing that the CAC remain open indefinitely and be used to collect costs, between base rate cases, of all non-producing capital projects as well as certain other costs such as those associated with the proposed pension tracker.

expenditures, I have limited Capital Infrastructure Investment Program plant additions to actual additions through July 2009. I will update my recommendation accordingly through December 31, 2009, to the extent that actual program expenditures are reported by PSE&G and incorporate any adjustments recommended by other Rate Counsel consultants reviewing the technical and capital budgeting aspects of the Capital Infrastructure Investment Program projects. My adjustment is shown in Schedule ACC-5E and ACC-5G.

Q. As a general rule, should utility rates be established based on capital expenditures?

A. No, generally utility rates are based on plant that has been completed and placed into service, and not on capital expenditures. In fact, it is an important regulatory principle that plant included in rate base should be used and useful in the provision of utility service to existing customers. However, I have included expenditures, instead of completed and transferred plant-in-service, relating to the Capital Infrastructure Investment Program because the use of expenditures appears to be required per the Stipulation in the Capital Infrastructure Investment Program proceeding. The Capital Infrastructure Investment Program was an initiative in response to a specific state directive and was afforded unique ratemaking treatment that permits the Company to recover costs between base rate cases. Moreover, the program is subject to a true-up mechanism that is not generally used for plant additions. Therefore, my recommendation to reflect expenditures related to the Capital Infrastructure Investment Program in rate base should not be taken as support to deviate from sound ratemaking principles that require plant to be in-service prior to receiving rate base recognition.

B. Plant Held For Future Use

Q. Has the Company included any plant held for future use in rate base?

A. Yes, the Company has included $3.58 million of plant held for future use in its electric rate base claim. The Company has not included any plant held for future use in its natural gas rate base claim.

Q. What is plant held for future use?

A. Plant held for future use is plant that is not currently used in the provision of utility service to customers but which the Company claims has some potential to be used in the future to serve customers. One common example is land being held as a possible future site for a substation. The Company has included six substation sites in its electric rate base claim.

Q. Have you included plant held for future use in your revenue requirement recommendation?

A. No, I have not. This plant is, by definition, not used and useful in providing utility service to current customers. Moreover, this plant may never be used in the provision of utility service. The plant held for future use that is being claimed in rate base by PSE&G has been held for years and years without serving customers. As shown in the response to S-PP-2, the oldest parcel was acquired in 1973 and the most recent acquisition was made in 1991. Thus, this plant has been held by PSE&G for 18 to 35 years without providing utility service to New Jersey ratepayers. While the Company speculated in the response to S-PP-2 that one parcel could be used as soon as 2011, there is no certainty that any of this plant will ever be used to provide utility service. Accordingly, I am recommending that the Company's claim for the inclusion of plant held for future use in rate base be denied. My adjustment is shown in Schedule ACC-6E.

C. Accumulated Depreciation

Q. How did the Company develop its claim for accumulated depreciation?

A. The Company began with its projected electric and natural gas balances for accumulated depreciation at December 31, 2009. PSE&G then made adjustments to reflect additions to the depreciation reserve relating to a) additional depreciation through February 28, 2010, b) additional depreciation relating to the expenditures made pursuant to the Capital Infrastructure program, and c) one-half of its annualized depreciation expense adjustment.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending two adjustments. First, consistent with my recommendation to eliminate post-test year plant additions from the Company's rate base claim, I also recommend that post-test year additions to the depreciation reserve be eliminated. Second, consistent with my recommendation to limit Capital Infrastructure Investment Program expenditures to actual amounts through July 2009, I am recommending that the Company's depreciation reserve also be limited to reserve additions through that date. These recommendations will be updated based on the Company's 12+0 update as well as any updates to its Capital Infrastructure Investment Program reports.

Q. How did you quantify your first adjustment?

A. As shown on Schedule ACC-7E and ACC-6G, to quantify my first adjustment, I reduced the Company's reserve for depreciation by the difference between its projected claim at February 28, 2010 and its projected balance at December 31, 2009. This resulted in a depreciation reserve reduction of $18.983 million for the electric utility and of $12.493 million for the gas utility. Since these accumulated depreciation adjustments reduce the Company's reserve for depreciation, they have the effect of increasing the Company's rate base and therefore increasing its need for rate relief.

Q. How did you quantify your adjustment relating to the depreciation reserve associated with the Capital Infrastructure Investment Program?

A. My adjustment is based on the actual depreciation reserve balance at July 31, 2009. This is consistent with my recommendation to reflect actual expenditures through July 31, 2009. The depreciation reserve balance will be updated as the Company updates its report of actual expenditures. My adjustment, which decreases the electric reserve by $914,000 and decreases the gas reserve by $672,000, is shown in Schedule ACC-8E and ACC-7G.

Q. Do these adjustments incorporate the impact on the depreciation reserve of the annualized depreciation expense adjustment proposed by the Company?

A. Yes, they do. In calculating its reserve for depreciation, PSE&G has added one-half of its annualized depreciation expense adjustment to the reserve. The Company quantified this adjustment separately for the test year reserve addition and for the post-test year reserve addition. Therefore, the impact of the annualized depreciation expense adjustment is reflected in the Company's depreciation reserve claims at December 31, 2009 and February 28, 2010. Since my pro forma reserve for depreciation is based on the Company's claim at December 31, 2009, which incorporates the test year portion of its annualized depreciation expense adjustment, this expense adjustment is also reflected in my rate base recommendation.

D. <u>Cash Working Capital</u>

Q. What is cash working capital?

A. Cash working capital is the amount of cash that is required by a utility in order to meet cash outflows between the time that revenues are received from customers and the time that cash expenses must be paid. PSE&G filed a lead/lag study in support of its cash working capital claims in this case. The Company requested a cash working capital allowance of $279.809 million for its electric operations and of $157.666 million for its gas operations, based on the lead/lag study filed in its 6+6 Update. In addition to the cash working capital requirement associated with its lead/lag study, the Company also made cash working capital adjustments to reduce its claims based on a net assets and liabilities analysis associated with expenditures that are not reflected in its lead/lag study. In its 6+6 Update, this adjustment reduced the Company's cash working capital electric claim by $71.696 million and its natural gas claim by $87.359 million. Therefore, PSE&G is requesting a total cash working capital allowance of $208.113 million ($279,809 - $71,696) for its electric operations and of $70.307 million for its gas operations ($157,666 - $87,359) based on the 6+ 6 Update.

Q. Is Rate Counsel recommending any adjustments to the Company's cash working capital claim?

A. Yes, Rate Counsel witness David Peterson is recommending several adjustments to the Company's lead/lag study as discussed in the testimony of David Peterson. I have incorporated Mr. Peterson's recommended cash working capital adjustments in developing my pro forma rate base. Rate Counsel's cash working capital adjustment is shown in Schedule ACC-9E and Schedule ACC-8G. As noted by Mr. Peterson, the Company's cash working capital claim should be further updated to reflect the level of cash operating expenses approved by the Board in this proceeding.

E. Customer Deposits

Q. How are customer deposits treated for ratemaking purposes?

A. Customer deposits provide a source of funds for the utility. This source of funds can be reflected in two ways for ratemaking purposes. In this case, PSE&G has treated customer deposits as a source of capital and has included customer deposits, at a rate of 2.34%, as one of the components of its capital structure. More frequently, customer deposits are included as a source of non-investor supplied funds directly financing rate base and shown as a rate base deduction. The rationale for this ratemaking treatment is that rate base is limited to investment that is financed by investors. Since customers, not investors, provide customer deposits then any investment funded by customer deposits should be removed from rate base. This rate base method, however, also requires that the utility be permitted to recover an operating expense associated with the payment of interest on customer deposits.

Q. Which ratemaking treatment are you recommending be adopted by the BPU in this case?

A. I am recommending that customer deposits be reflected as a rate base reduction, with the associated interest expense moved "above-the-line." This method will ensure that ratepayers receive the full benefit of the customer deposits that they provide to the Company. As shown in the Company's filing, its total capitalization of $7.436 billion exceeds the combined electric and gas rate base claims of $6.181 billion by approximately 20%. Therefore, if customer deposits are included in PSE&G's capital structure, ratepayers will effectively only receive the benefits of 80% of this low-cost capital. As acknowledged in the response to RCR-A-220, retail utility ratepayers are responsible for providing 100% of the Company's customer deposits. Therefore, it is reasonable to ensure that all customer deposits provide benefit to ratepayers through a direct rate base deduction.

Q. How did you quantify your rate base deduction?

A. To quantify my adjustment, I utilized the Company's projected customer deposits at December 31, 2009, the end of the test year in this case. Since the Company does not separately track electric vs. gas customer deposits, I allocated total customer deposits between electric and gas operations based on each utility's respective share of test year revenue at present rates. I believe this is a reasonable allocation methodology since customer deposits are generally based on anticipated customer bills. My adjustment is shown in Schedule ACC-10E and Schedule ACC-9G.

Q. Do you have any further comments about your adjustment?

A. Yes. As shown in the response to RCR-A- 219, the Company's projection for customer deposits at December 31, 2009 appears to be low based on historic levels. For example, at March 31, 2009, the Company had total deposits of $87.208 million. Moreover, customer deposits had consistently increased each month during the prior two years. However, customer deposits declined significantly during the test year. In response to RCR-A-222, the Company explained that this decline was due to the fact that from March 31 to June 30, 2009 customer deposit activity was limited due to the implementation of the new customer information system ("CIS"). The Company noted that "[t]he process to pursue deposits on delinquent customers was reinstated in July, 2009." While customer deposits have increased since July 2009, they are still well below their March 31 level and are projected to remain low through December 31, 2009. Therefore, my recommendation to utilize the projected December 31, 2009 balance is conservative. The BPU may decide that it is more reasonable to utilize the March 31, 2009 balance, which may be more representative of future conditions. Nevertheless, to be consistent with my recommendation relating to using the end of the test year plant balances, I have also limited customer deposits to projected balances at December 31, 2009.

F. <u>Deferred Income Tax Reserve</u>

Q. Are you recommending any adjustments to the Company's claim for the deferred income tax reserve?

A. Yes, I am recommending two adjustments. These adjustments result from my recommendation to utilize projected balances at December 31, 2009 for utility plant-in-service and for Capital Infrastructure Investment Program expenditures. Consistent with those recommendations, I am also recommending that the BPU utilize the deferred income tax reserve balances at December 31, 2009 associated with PSE&G's utility plant-in-service.

At Schedule ACC-11E and Schedule ACC-10G, I have made adjustments to limit the deferred income tax reserve balances to projected balances at December 31, 2009.

I am also recommending that the deferred income tax reserves associated with the Capital Infrastructure Investment Program be limited to expenditures at December 31, 2009. However, as noted above, I believe that the Company's projections with regard to the Capital Infrastructure Investment Program are somewhat speculative. Therefore, I have reflected the July 2009 deferred tax reserve balance in my revenue requirement recommendation. This is consistent with the manner in which I have treated the plant-in-service and accumulated depreciation balances relating to the Capital Infrastructure Investment Program. These balances will be updated as the Company provides updates to its actual expenditures through December 31, 2009. My adjustments relating to the deferred income tax reserves associated with the Capital Infrastructure Investment Program are shown in Schedule ACC-12E and ACC-11G.

G. <u>Consolidated Income Taxes</u>

Q. Did PSE&G include a consolidated income tax adjustment in its filing?

A. No, it did not. PSE&G calculated its pro forma income tax expense on a "stand-alone" basis. The Company's filing ignores the fact that PSE&G does not file its federal income taxes on a stand-alone basis, but rather files as part of a consolidated income tax group. By filing a consolidated return, the tax loss benefits generated by one group member can be shared by the other consolidated group members, resulting in a reduction in the effective federal income tax rate. These tax savings should be flowed through to the benefit of New Jersey ratepayers. PSE&G has been a member of the Public Service Enterprise Group, Inc. consolidated income tax group since 1986.

Q. Why should these tax benefits be flowed through to the Company's ratepayers?

A. These tax benefits should be flowed through to ratepayers because these benefits reflect the actual taxes paid. Establishing a revenue requirement based on a stand-alone federal income tax methodology would overstate the Company's tax expense, result in a windfall to shareholders, and result in rates that are higher than necessary.

Q. Has this issue been addressed previously by the BPU?

A. Yes, The issue of consolidated income tax adjustments has been thoroughly reviewed by both the Board and the New Jersey courts, both of whom have found that a consolidated income tax adjustment is appropriate.[4] At pages 7-8 of its Decision in the 1991 Jersey Central Power and Light Company ("JCP&L") base rate case (BPU Docket No. ER91121820J), dated February 25, 1993, the BPU found that:

> 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 filing a consolidated tax return. Income from utility operations provides 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

4 I am not an attorney and therefore my comments are limited to the ratemaking implications of these findings. I am not testifying on any underlying legal issues associated with consolidated income tax adjustments.

an adjustment.

In the Board's Final Order, dated July 25, 2003, in the 2002 JCP&L base rate case, Docket No. ER02080506, page 45, it stated:

> 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 if each subsidiary filed separately, thus producing a tax savings. The law and Board policy are well-settled that consolidated tax savings are to be shared with customers.

Unregulated subsidiaries are free to manage their activities as they see fit. The reality is that Public Service Enterprise Group, Inc. has elected to file a consolidated income tax return for its subsidiaries, including PSE&G. Moreover, PSE&G has been a member of a consolidated income tax group since the Board first adopted consolidated income tax adjustments. Apparently the filing of a consolidated tax return still offers advantages to PSE&G and members of the consolidated income tax group. Because PSE&G has elected to file a consolidated tax return for its member companies, including PSE&G, I believe it is a settled matter that the tax savings should be shared with utility ratepayers.

Q. Did PSE&G comply with BPU policy regarding consolidated income taxes in its filing in this case?

A. No, the Company has not complied with accepted BPU policy and has instead requested rate recognition for federal income tax expense on a stand-alone basis.

Q. Do you believe that PSE&G has provided any new or compelling reason to justify a change in Board policy on the issue of consolidated tax savings?

A. No, I do not. I understand that the Company would prefer not to share tax benefits with its customers but they have not introduced any compelling new argument to support a departure from Board policy. In fact, the Company has not provided any testimony explaining why it did not include a consolidated income tax adjustment in its filing.

Q. How does Public Service Enterprise Group, Inc. determine the actual amount of taxes paid by PSE&G to its parent each year?

A. The payment of taxes is discussed in the Tax Sharing Agreements that were provided in response to RCR-A-67. According to these agreements, PSE&G pays the amount of its stand-alone tax liability to Public Service Enterprise Group, Inc. It appears from the Tax Sharing Agreements that the Parent Company then pays any excess funds back to the members of the consolidated income tax group with tax losses, resulting in a contractual means to have the regulated and profitable subsidiaries subsidize unregulated and unprofitable ventures. These procedures transfer the excess amounts collected from ratepayers for income tax expense from the utility to the affiliate that generated the income tax loss, effectively resulting in a subsidization of the unregulated affiliate by New Jersey ratepayers. In contrast, the consolidated income tax adjustment adopted by the BPU partially compensates ratepayers for this subsidization, by crediting ratepayers with carrying costs on these funds.

The existence of Tax Sharing Agreements does not negate the validity of a consolidated income tax adjustment. The tax sharing agreements are not approved by the BPU and are nothing more than a contractual means to have the regulated and profitable subsidiaries subsidize unregulated ventures with ratepayer funds. According to the response to S-PREV-91, from 1993 to 2007, the cumulative amounts paid by PSE&G since 1991 exceeded the cumulative taxes paid to the IRS. This situation finally ended in 2008. However, even through 2008, almost 95% of all taxes paid to the Internal Revenue Service ("IRS") by Public Service Enterprise Group Incorporated were funded by the utility and its ratepayers.

Q Do consolidated income tax adjustments violate the normalization requirements of the IRS?

A. No, they do not. Prior to 1990, there was some question as to whether or not consolidated income tax adjustments violated the normalization provisions of the IRS. However, around that time, the IRS determined that such adjustments do not violate the normalization rules. The BPU subsequently adopted consolidated income tax adjustments for New Jersey utilities. The BPU should continue its practice of requiring a consolidated income tax adjustment for PSE&G in this case. My consolidated income tax adjustment for PSE&G is shown in Schedule ACC-13E and Schedule ACC-12G.

Q. How did you quantify your adjustment?

A. There are two methods of calculating consolidated income tax adjustments, the operating income method and the rate base method. With the rate base method, a utility's rate base is reduced by the accumulated tax benefits allocated to each entity that has positive taxable income. This method does not directly reduce the income tax expense included in a utility's revenue requirement, but rather provides for the treatment of these accumulated benefits as cost-free capital. This is the method adopted by the BPU.

The second method, the operating income or actual taxes paid method, provides for a direct reduction to pro forma income taxes to reflect the utility's allocable share of tax benefits resulting from tax losses of affiliates.

In RCR-A-217, I asked the Company to quantify the consolidated income tax benefit, based on the methodology approved by the Board in its Order in the base rate case proceeding involving Rockland Electric Company, BPU Docket No. ER02100724. It is my understanding that this is the last litigated case where the BPU addressed the methodology to be used for consolidated income tax adjustments. It is also the method that I used in testimony filed in the New Jersey Natural Gas Company and New Jersey-American Water Company base rate case proceedings. Unfortunately, the Company responded that it "has not done such a calculation." PSE&G did provide some underlying tax data in response to S-PREV-90 and I utilized that data to quantify my adjustment. Based on that response, I have quantified a rate base adjustment of the $326.972 million for the Company's electric utility and of $46.056 million for the Company's gas utility.

Q. How were consolidated income taxes calculated in the referenced proceeding involving Rockland Electric Company?

A. In that proceeding, the BPU ordered that the taxable income or loss for each company would be aggregated from 1991 to the most recent data available. For each year, the taxable income or loss for the group of companies that had an aggregated (1991-present) taxable loss was then multiplied by that year's annual federal income tax rate, in order to determine the annual income or loss for the year. Since this portion of the calculation was limited to companies that had aggregated losses over the period, the result was a taxable loss for most (but not all) of the years in question. The annual tax benefit for those companies that had aggregated net losses was then itself aggregated from 1991 to the present. Adjustments were then made for any alternative minimum tax ("AMT") payments made by the group. The resulting aggregated tax benefit, net of AMT, was then allocated among all the companies that had a 1991-present aggregated positive taxable income, based on each entity's share of the aggregated positive taxable income. This resulted in an allocation of 56.01% to PSE&G's electric operations and of 7.89% to PSE&G's gas operations.

Q. Do you have any comment regarding the magnitude of these consolidated income tax adjustments?

A While these adjustments are quite large, the magnitude is not unexpected, given the cumulative rate base methodology that has been adopted by the BPU. I note that the consolidated income tax adjustment results in a revenue requirement adjustment of approximately $45.0 million for electric operations and of $6.4 million for gas operations, still well below PSE&G's federal income tax claims in this case of $104.489 million for electric operations and of $77.644 for gas operations.

Q. Please comment on the contention raised by some New Jersey utilities that consolidated income tax adjustments represent the confiscation of a valuable shareholder asset.

A. This argument ignores the fact that the operating losses have value only because they can be used to offset positive taxable income of other group members. Thus, it is the positive taxable income of PSE&G, and other consolidated group members, that give the operating losses their value and result in the consolidated income tax savings. The consolidated income tax adjustment does not attempt to transfer to ratepayers the tax benefit of any unregulated entity, it simply recognizes that the filing of a consolidated tax return results in a collective benefit to all members of the consolidated income tax group, and that a portion of that benefit should be allocated to PSE&G and its ratepayers.

Once the parent company decided that a consolidated income tax return would be filed, all members of the consolidated group became individually responsible for the entire annual tax liability. Therefore, it is entirely reasonable for the Board to recognize that the consolidated income tax group results in a lower effective tax rate for PSE&G.

If, on the other hand, the parent company wanted to retain the independence of each entity for income tax purposes, it should not have elected to file a consolidated income tax return. In that case, each entity would individually retain the benefit of any tax losses. Moreover, in that case, each entity would only be responsible to the IRS for the taxes resulting from its own individual financial results.

It is ultimately the utility's ratepayers that are the source of the tax payments made by PSE&G to its parent company. Therefore, any payments made to the tax loss companies is funded, at least in part, by ratepayers. The fact that these funds may be funneled through the parent company does not change the fact that ratepayers are the ultimate source of the funds provided by PSE&G. Consolidated income tax adjustments recognize that cost-free capital is provided by ratepayers, because they provide the utility income that generates the tax benefits. This point is addressed in the 1993 JCP&L decision quoted above. It should be apparent that requiring ratepayers to pay a statutory federal tax rate that exceeds the actual taxes paid, provides a cost-free source of capital to the Company, and ultimately to the consolidated group. It is undisputed that a consolidated tax filing for the group members results in an overall tax expense that is less than the sum of the tax expenses resulting from the application of a statutory tax rate.

Q. Prior to allocating any income tax benefit to the utility, should the benefits resulting from consolidated income tax filings be allocated first, to the extent possible, to unregulated entities?

A. No. This argument is a variation of the theme that unregulated losses could be consumed by earnings from unregulated entities. This issue was raised and addressed in the July 25, 2003 JCP&L Order discussed previously. The Board states at page 46 of that Order: "The Board believes that Staff correctly points out that allocating all of the savings to the unregulated affiliates, as proposed by JCP&L in this proceeding, would be as arbitrary and unfair as it would be to allocate the entire savings to the regulated companies." The Order continues at page 47 :

> The consolidated tax savings in question could not be achieved without the income of the affiliates with positive income and it would not be equitable to say that it was achieved by using the positive income of some companies but not others. Therefore, the tax savings should be allocated to each of the affiliates with positive income by their percentage share of positive income regardless of whether or not they are regulated or unregulated.

Q. Do you agree with the argument raised by some New Jersey utilities that if a rate base offset of the consolidated income tax adjustment is allowed, then it must be adjusted to reduce the operating losses of affiliates that incurred losses due to expenses that were disallowed for ratemaking purposes?

A. No I do not. This statement is based on the mistaken premise that consolidated income tax adjustments are an attempt to incorporate certain non-utility financial transactions into the ratemaking process. However, consolidated tax adjustments do not attempt to impute non-regulated transactions to a utility's revenue requirement. Such adjustments simply recognize the benefits accruing to each group member as a result of participating in a consolidated return. Moreover, it is abundantly clear from the Board Orders that consolidated income tax adjustments do not distinguish between losses generated by regulated or unregulated entities.

The overriding fact is that the net operating losses of members of a consolidated tax group are of little value without the income generated by the positive taxable income of other group members. In the case of PSE&G, that taxable income is provided by ratepayers and it is well accepted that New Jersey ratepayers will share in any benefits generated by a consolidated tax filing. PSE&G's parent company could have chosen to file stand-alone returns, thereby retaining any benefits associated with net operating losses for the companies giving rise to those losses. It chose not to do so. Therefore it is appropriate to continue to calculate the consolidated income tax adjustment in accordance with Board precedent.

There is no benefit to allocate to shareholders that does not arise, at least in part, from ratepayer-supplied utility income. There is no tax benefit without income to offset losses and that income is provided primarily by regulated utility income. Moreover, the methodology adopted in New Jersey, i.e., calculating a rate base offset for the cost-free capital provided by the consolidated income tax filing, means that ratepayers are only benefiting by earning a carrying charge on the excess taxes reflected in rates. Even under the BPU-approved methodology, ratepayers are not compensated for the actual excess of income taxes that they pay in rates relative to the Company's allocated share of the actual taxes paid. Moreover, New Jersey ratepayers do not benefit from costs incurred by the parent company or unregulated affiliates that would otherwise have been disallowed if incurred by the utility. Instead, New Jersey ratepayers are benefiting only from the recognition that the Company's allocated share of the federal income liability is less than the amount collected in rates. Hence a rate base adjustment can be viewed as the ratepayers "loaning" the Company a sum equal to the difference between the statutory tax expense and the lower taxes actually paid by PSE&G in its consolidated tax return. The interest rate applied to this loan is the Company's allowed return on rate base. It really does not matter what the nature or source of the net operating losses are, only what the impact is on the effective tax rate. In this case, the Company simply does not have the tax expense that they have included in rates and ratepayers are entitled to a rate base credit to reflect that fact. Likewise it is not material to the consolidated income tax adjustment whether or not the tax benefit arose from a disallowed cost or was simply incurred by a non-regulated entity pursuing any other line of business. In New Jersey, it is well-established policy that a tax benefit arising from the filing of a consolidated income tax filing is to be shared with ratepayers.

Q. Did the Company recently provide updated tax data with regard to the test year?

A. Yes, it did. PSE&G provided updated tax data for 2009 as my testimony was being finalized. I have not had an opportunity to fully examine the updated tax data or to ask additional discovery on this update. Therefore, while I have incorporated this updated 2009 data in my consolidated income tax adjustment, additional adjustments may be necessary based on a more complete review of the 2009 data. In addition, I would expect the 2009 data to be revised further once the Company files its 12+0 Update.

H. Summary of Rate Base Issues

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's electric rate base from $3.843 billion, as reflected in the 6+6 Update, to $3.285 billion, as summarized on Schedule ACC-1E. My recommended adjustments reduce the Company's natural gas rate base from $2.338 billion, as reflected in the 6+6 Update, to $2.164 million, as shown on Schedule ACC-1G.

VI. OPERATING INCOME ISSUES

A. Pro Forma Revenues

Q. Are you recommending any adjustments to the Company's pro forma revenue claim?

A. Yes, I am recommending two adjustments to the Company's pro forma revenue claim. Specifically, I am recommending that sales be weather normalized based on 30-year normal weather data and that revenues be annualized based on customer growth during the test year.

Q. How did the Company determine its weather normalization adjustment in this case?

A. The Company utilized a twenty-year time period to determine its original test year revenue forecast. In its 6+6 Update, the Company made an adjustment to normalize actual sales through June 30, 2009, based on comparing actual weather during the first six months of 2009 to the 20-year normal.

Q Do you agree with the use of twenty years to weather normalize sales?

A. No, I do not. I recommend that the BPU utilize a thirty-year standard for normal weather. PSE&G filed its last electric and gas base rate cases using a thirty-year normalization.

Q. Why do you believe that 30-year data is more appropriate to utilize in developing the Company's weather normalization adjustment than the twenty-year period recommended by the Company?

A. The thirty-year normal has been established by National Oceanic and Atmospheric

Association ("NOAA"), the government organization charged with establishing and recording the climatic conditions of the United States. The thirty-year standard is the objective standard, established by the government body responsible for determining normal weather conditions. Moreover, the thirty-year standard is the international standard adopted by the United Nation's World Meteorological Organization ("WMO"). The thirty-year normal is used for a wide range of applications and it has served as the standard in utility regulation for some time.

Q. Do you believe that the use of a NOAA standard is preferable to having regulatory commissions set their own standards?

A. Yes, I do. It should not be the role of each regulatory commission to determine "normal" weather. Rather, that determination should be made by the governmental agency and other international bodies with expertise and responsibility for tracking, analyzing, and reporting weather statistics. In the United States, that agency is NOAA, which has determined that normal weather should be defined as the arithmetic mean computed over a thirty-year period of time. NOAA has further defined the appropriate time period over which to calculate normal weather as three consecutive decades.

Q. Why are longer time periods preferable to shorter ones for weather normalization data?

A. There are a few reasons. First, longer time periods tend to average out weather and temperature extremes much better than shorter periods. Obviously, one particularly cold or warm winter with many or few heating/cooling degree days has a much greater effect upon a twenty-year average than it does upon a thirty-year average. In fact, a single data point has a 5% impact on a twenty-year average, but only a 3.3% impact on a thirty-year average. Therefore, the effect of a single data point is 50% greater with a twenty-year average than with a thirty-year average.

Second, a shorter time period may fail to include extreme weather in computing average degree days. It is normal and customary to have a very cold or a very warm winter every so often, and the data base should include these extremes.

Q. Why is it important to have good standard weather data?

A. Utility rates are based upon normal operating conditions. If revenues are based on an accurate, consistent and widely-accepted standard for normalizing weather, in some years the Company's revenues will be less than normal, in some years the Company's revenues will be greater than normal, but over time, the Company's revenues will reflect normal weather and the Company will receive the opportunity to earn its fair rate of return. In addition, the use of an accepted objective standard, such as the thirty-year NOAA standard, ensures consistency from case to case.

Q. Are there other factors that lead you to favor the thirty-year NOAA standard over the twenty years of data recommended by the Company?

A. Yes. Among other things, the NOAA standard has a long history of use and acceptance. The use of the NOAA thirty years as "normal" is based upon an international agreement and is commonly used to reflect normal weather conditions in a variety of industries and applications.

Q. Is there a statistical reason why a thirty-year normal should be used?

A. Yes, there is. The use of thirty data points has its basis in the central limit theorem, which states that if the sample size has at least thirty data points, then the distribution of sample means is normal, resulting in a normal distribution centered around the mean with a standard deviation that decreases as the sample size increases. Essentially, the population sample of at least thirty data points will result in a bell-shaped curve.

Q. Is NOAA examining the possibility of making any changes to the manner in which it determines normal weather?

A. Yes, it is. NOAA has initiated an investigation to address 1) assuring the availability of up-to-date climate normals, and 2) assuring the representativeness of a thirty-year average normal given a changing climate state. This process was initiated in May 2007.

The first issue involves the frequency with which NOAA thirty-year normals are updated. In the past, the official NOAA weather normal was based on data during three consecutive decades. Thus, this data was essentially updated only once every ten years. Now that technology has advanced, NOAA is exploring whether it might be reasonable to update the NOAA thirty-year normal weather data more frequently. At least part of the rationale for using three consecutive decades of data was the difficulty of updating this data more frequently. Technology has advanced considerably over the past few years, to the point where it is now relatively easy to calculate a new thirty-year normal each year. I understand that NOAA may make available more frequent updates to the thirty-year normal as a result of its current investigation. I have no objection to the use of the most recent thirty years of data to calculate normal weather.

The second issue is whether a basic change from the thirty-year normal should be adopted. NOAA has not made any move in this direction at this time. While NOAA has acknowledged that the issue of climate change has been raised by utilities in regulatory proceedings, and while NOAA is exploring the impact of such climate change on the calculation of normal weather, there is no indication that NOAA plans to terminate the use of thirty years as the time period over which to calculate normal weather.

Q. If NOAA changed the methodology used to determine normal weather, and instead adopted some other time period over which to calculate normal weather, would your recommendation change?

A. Yes, it would. As noted above, there are statistical reasons for adopting a time frame of at least thirty years to determine normal weather. However, if NOAA adopted a different standard, then I would recommend a change in the time period used by regulatory commissions, including the BPU, to determine normal weather for ratemaking purposes. The important point is that an independent government body with expertise should be selecting the time period used to define normal weather. This issue should not be determined on the basis of arguments made in rate cases by parties who have their own motives for suggesting various time periods.

Since NOAA is the governmental organization charged with determining the appropriate time period for determining normal weather, the BPU should not take any actions that would be contrary to the NOAA standard at this time. If the BPU is inclined to adopt a time period of less than thirty years for determining normal weather, it should wait for the results of the NOAA investigation before adopting a method that is inconsistent with the current NOAA standard. Accordingly, the BPU should at least wait for the completion of the current NOAA investigation so that the results of the investigation can be considered by the Board.

Q. Is the purpose of a weather normalization adjustment to predict future weather, as has sometimes been suggested?

A. No, it is not. The purpose of a weather normalization adjustment is not to forecast or predict weather for a particular year. Regulatory commissions are regulators, not weather forecasters. The purpose of a weather normalization adjustment is instead to determine what customer usage would be, assuming "normal" weather. Thus, finding that the use of a twenty-year normal is a better predictor of the weather does not provide any meaningful information about normal weather on which utility rates should be based.

The regulator is attempting to determine, on a prospective basis, what a "normal" period of operating results will be. One of the components of this determination is normal weather. The regulator is not trying to predict weather, or to make a company indifferent to weather, but rather to set rates prospectively that are normalized for weather. In some years a utility will have colder than normal weather and in some years it will have warmer than normal weather. But over time, these variations constitute normal weather.

Q. Why is it important to have a consistent standard determined by an independent objective organization like NOAA?

A. The thirty-year period for determining what constitutes normal weather was not defined by PSE&G, Staff, or Rate Counsel. Rather, it was defined by the United States Government organization that is responsible for defining normal weather, i.e., NOAA. Once the BPU deviates from this objective standard, then all parties will have an incentive to promote the time period that results in the best result for their particular constituency in each particular case. Deviating from the objective standard as determined by NOAA will open the door to arguments in every case about how long a period of time should determine what constitutes normal weather.

Q. Isn't it possible that weather patterns do change over time?

A. Yes, it is. However, permanent changes in weather patterns are likely to take place over a long period of time. NOAA has determined that data from a period of thirty years satisfactorily represents normal weather. To the extent weather patterns do exhibit a permanent change over time, such changes will be reflected in the thirty-year NOAA data. Moreover, the BPU should not confuse the determination of "normal" weather with the issue of how customers will react to variations from normal weather. The fact that energy prices have risen, that there is better communication with customers, and that energy efficiency incentives are offered have no impact on the weather, or on the definition of normal weather. Rather, these factors impact how customers may respond to deviations from normal weather. Weather is based on climatological patterns and customers have virtually no impact on these weather patterns, at least not over the thirty-year period that is defined as constituting normal weather.

However, the BPU should be mindful of the difference between changes in weather patterns over time and changes in usage patterns over time. The two are not the same. While NOAA uses a thirty-year period to determine normal degree days, NOAA is not involved in forecasting how energy sales are likely to be impacted due to variations in degree days. For example, assume that the thirty-year normal results in 3,000 heating degree days for the BPU service territory. A separate but related question is how customer usage changes with changes in degree days. Due to conservation efforts, more efficient appliances and furnaces, and other factors, it is entirely possible that the impact of variations in degree days is different in 2009 than it was in 1968. My recommendation that the BPU continue to utilize a thirty-year standard does not prevent the utility or other parties from presenting arguments regarding the *impact* of weather variations on energy usage. By continuing to utilize a thirty-year weather standard, the BPU is not precluding any party from providing evidence demonstrating the impact of various weather changes on electricity or natural gas usage in a utility base rate case.

Q. How did you quantify your adjustment?

A. In response to RCR-A-138, the Company quantified the impact on pro forma sales if a thirty-year normal had been utilized for the first six month of 2009. I have used this data request as the basis for my adjustment.[5] I have priced out the change in units, by rate class, to determine the impact on the Company's weather normalization adjustment if a thirty-year period had been used. My adjustment is shown in Schedule ACC-15E and ACC-14G.

Since the Company's weather normalization adjustment only addressed the first six months of 2009, the underlying 2009 forecast for July to December 2009 still reflects a twenty-year normal. When the Company provides its 12+0 Update, it should also update the response to RCR-A-138 and quantify the impact on the 12+ 0 Test Year results if a thirty-year period is used to normalize weather.

5 It should be noted that the response to RCR-A-138 (Update) had an error in that the heating degree days used to normalize electric sales for the RS class were the same under both the twenty and thirty-year scenarios. The Company subsequently provided Rate Counsel with a corrected schedule. In addition, the Company has not yet provided the impact of the thirty-year normal on its demand adjustment. Therefore, my recommendation will be further updated to reflect the demand impact once this impact is provided by PSE&G.

Q. If the BPU approves the Company's request to establish a Weather Normalization Clause ("WNC") for its natural gas operations, what period of time should be used to define normal weather as reflected in the clause?

A. If the BPU approves the Company's request to establish a WNC, it is important that the period of time used to define normal weather in the clause be consistent with the weather normalization methodology used to establish base rates. Otherwise, there will be a mismatch between the underlying base rates and the future rates reflected in the WNC. Accordingly, if the BPU accepts my recommendation to establish base rates using a thirty-year period to define normal weather, it should also use a thirty-year period when calculating future WNC rates. It should be noted that I am not making any recommendation regarding whether the BPU should approve the Company's request to establish a WNC. This issue is being addressed on behalf of Rate Counsel by witness Richard LeLash.

Q. What is the second revenue adjustment that you are recommending in this case?

A. The Company's pro forma revenue claim is based on six months of actual customer counts and six months of projected customers. PSE&G did not make any adjustment to annualize its pro forma revenue to reflect customer growth during the test year.

Q. Do you believe that such an adjustment is necessary?

A. Yes, I do. Annualization adjustments are frequently made to reflect the fact that customers typically increase from year to year. This is especially true of residential customers. In its response to RCR-A-221, the Company provided information regarding the number of customers, by customer class, for each of the past sixty months. As shown in this response, while the number of customers has fluctuated from month-to-month, the overall trend has been an increase in the number of customers.

	Growth 9/08 - 9/09	Annual Average Growth 9/04-9/09
Electric:		
RS	2.19%	1.10%
GLP	3.40%	1.63%
LPL	27.73%	8.14%
Gas:		
RGS	4.23%	1.66%
GSG	8.17%	2.35%
LVG	15.19%%	3.44%

As demonstrated above, while customers have fluctuated from month-to-month, there has been a fairly consistent growth in the number of customers if one examines year-over-year growth rates. This data also demonstrates that the annual increases in the number of residential and general service natural gas customers has been greater than the increase in residential and general service electric customers. But the data clearly shows an upward trend in customers that is not reflected in the Company's revenue requirement.

Q How did you quantify your adjustment?

A. As stated, the number of customers generally fluctuates each month, both up and down, due to seasonality in the Company's service territory. Therefore, it would not be appropriate to utilize the actual number of customers at the end of the test year to annualize sales. Instead, I based my recommendation on the annual growth in customers from year-to-year, as shown above.

With regard to electric sales, I am recommending a 0.5% increase to reflect customer increases in the residential and general service rate classes. Theoretically, the Company's test year revenues reflect, on average, only one-half of the growth in customers that was experienced during the test year. Based on September data, this would suggest that an adjustment of up to 1.10% for residential customers (2.19% / 2) and of up to 1.7% for general service customers (3.40% / 2) would be appropriate. However, I also recognize that the September 2008 to September 2009 growth rates have been about double what the average growth has been over the past four years. Therefore, to be conservative, I have included a 0.5% increase in my revenue requirement recommendation. I will review the reasonableness of this recommendation once the Company provides actual test year results for the full year. I limited my electric adjustment to residential and general service customers. Since LPL customers have a much greater variation in usage, it is difficult to quantify the impact on sales that the addition or loss of a particular number of LPL customers will have. For that reason, I excluded LPL customers from my adjustment. My adjustment is shown in Schedule ACC-16E.

With regard to gas sales, I am recommending a 1.0% increase to reflect customer increases in the residential and general service rate classes. Based on September data, an adjustment of up to 2.11% for residential customers (4.23% / 2) and of up to 4.08% for general service customers (8.17% / 2) could be appropriate. Once again, however, the September 2008 to September 2009 growth rates have been significantly larger than the multi-year average. Therefore, I have only included a 1.0% increase in my revenue requirement recommendation for gas customers. I limited my natural gas adjustment to residential and general service customers for the same reasons discussed above. My adjustment is shown in Schedule ACC-15G. My recommendation will be further reviewed, and refined if necessary, based on the Company's 12+0 Update.

B. <u>Salary and Wage Expense</u>

Q. How did the Company develop its salary and wage expense claim in this case?

A. The Company states that its salary and wage claim is based on payroll increases through February 28, 2011, fourteen months past the end of the test year in this case. As shown in the Workpaper to its 6+6 Update, PSE&G made two adjustments to its projected test year payroll costs. First, the Company increased test year costs to reflect anticipated 2010 increases. This included a 3.25% increase for union employees at May 1, 2010 and 2% increases for Management, Administrative, Secretarial, and Technical ("MAST") and Service Company employees anticipated in April 2010. PSE&G then made an additional adjustment to reflect two months of 2011 costs, assuming further increases in 2011 of 3.25% increase for union employees and of another 2.0% for MAST employees.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending that the Company's 2011 payroll adjustment be eliminated. First, the Company's claim appears to be based on annualized costs through February 28, 2011, more than fourteen months past the end of the test year. The inclusion of these payroll increases reaches too far beyond the end of the test year selected by PSE&G in this case and should be rejected. Rates are set based on a regulatory triad that synchronizes rate base, revenues and expenses at a point in time. The Company's proposal to include these pro forma labor costs violates the principle that all elements of the Company's revenue requirement should be matched at a point in time.

However, the Company's claim is even more egregious than it initially appears. The Company stated that its intent was to reflect costs through February 28, 2011, or during the first year that new rates would be in effect, assuming an effective date for new rates of March 1, 2010. Given the procedural schedule in this case, it is unlikely that new rates will actually be in place by March 1, 2010. More importantly, the 2011 increases reflected in the Company's filing will not be in place by February 28, 2011. By including two months of the 2011 increase in its claim, the Company is inferring that the 2011 increases will take place on January 1, 2011. However, as stated in the response to RCR-A-8, MAST increases take place in January and March, and union increases take place in May. Therefore, the vast majority of the 2011 increases included in the Company's claim will not even occur until May 1, 2011.

Q. What do you recommend?

A. In order to preserve the regulatory triad, I have excluded the Company's 2011 salary and wage increases from my revenue requirement recommendation. These increases extend too far beyond the end of the test year to be included in rates established in this case. My adjustment is shown in Schedule ACC-17E and Schedule ACC-16G.

C. Incentive Compensation Program Expense

Q. Please describe the Company's incentive compensation programs.

A. The Company has included costs for three incentive compensation plans in its revenue requirement claim. First, PSE&G has included costs of approximately $2.1 million (total electric and gas allocation) for costs of the Management Incentive Compensation Plan ("MICP"). The purpose of this plan is to "foster attainment of the financial and operating objectives of the Company and its Participating Affiliates, which are important to customers and stockholders by providing incentives to certain key officers and executive-level employees who contribute to attainment of these objectives." The MICP is based on four performance criteria: corporate, financial, business unit scorecard, and individual. The corporate and financial goals appear to be much more heavily weighted than either the business unit or individual goals, although specific weightings can vary from year-to-year.

Second, PSE&G had included approximately $14.3 million (total electric and gas allocation) for the Performance Incentive Plan ("PIP"), which is available to salaried employees. The PIP is similar to the MICP, although it does not appear to be weighted as heavily toward corporate and financial criteria as MICP.

Third, the Company has included costs of approximately $9.6 million (total electric and gas allocation) relating to the Long-Term Incentive Plan ("LTIP"), which is a stock award and option plan available to select executive employees. Among the primary goals of the LTIP is to "align Participants' interests with those of the Company's shareholders and thereby promote the long-term financial interest of the Company and its Subsidiaries, including the growth in value of the Company's equity and enhancement of long-term shareholder return." Awards are made at the discretion of the Organization and Compensation Committee of the Board of Directors.

Q. Do you believe that the incentive compensation program costs should be passed through to ratepayers?

A. No, I do not. I have several concerns about these types of programs, most of which are based, at least in part, on a utility's ability to achieve certain earnings goals. First, it should be noted that 45% of the overall cost of these plans involves incentive compensation awards for a small group of officers and executives. In addition to these awards, the Company's revenue requirement claim also includes approximately $2.1 million for base salaries for officers. I am not recommending any disallowance relating to the test year cost for officer and executive salaries. Thus, my revenue requirement recommendation already reflects a generous allowance for officers. If the Company wants to further reward officers and executives it can do so, but these additional costs should be borne by shareholders, not ratepayers.

I also have concerns regarding incentive compensation costs for other salaried employees. Providing employees with a direct financial interest in the profitability of the Company is an objective that would benefit shareholders, but it does not benefit ratepayers. Incentive compensation awards that are based on earnings criteria violate the principle that a utility should provide safe and reliable utility service at the lowest possible cost. This is because these plans require ratepayers to pay higher compensation costs as a consequence of high corporate earnings, a spiral that does not directly benefit ratepayers, but does benefit shareholders, as well as the management responsible for establishing such programs and to whom much of the incentive compensation is granted.

Incentive compensation plans tied to corporate performance result in greater enrichment of company personnel as a company's earnings reach or exceed targets that are predetermined by management. It should be noted that it is the job of regulators, not the shareholders or company management, to determine what constitutes a just and reasonable rate of return award to shareholders in a regulated environment. Regulators make such a determination by establishing a reasonable rate of return award on rate base in a base rate case proceeding.

Allowing a utility to charge for additional return that is then distributed to employees as part of a devised plan to divide extraordinary profits violates all sense of fairness to the ratepayers of the regulated entity. It is certain to result in burdensome and unwarranted rates to its ratepayers, and also violates the principles of sound utility regulation, particularly with regard to the requirement for "just and reasonable" utility rates.

Q. What would be the appropriate response by the BPU if the earnings of PSE&G were in excess of its authorized rate of return?

A. If the BPU determined that these excess earnings were expected to continue, the appropriate response would be to initiate a rate investigation, and, if appropriate, to reduce the utility's rates.

Q. Are PSE&G employees being well compensated separate and apart from these employee incentive plans?

A. Yes, they are. As shown in the response to RCR-A-8, MAST employees have consistently been awarded annual payroll increases from 3.0% to 4.0%. Thus, there is no indication that the employees of PSE&G are underpaid or that the Company would have difficulty attracting qualified employees in the absence of these programs.

Q. What do you recommend?

A. I recommend that the BPU deny the Company's request for recovery of incentive compensation costs. Approximately 45% of these costs relate to incentive awards for a small number of officers and executives. Moreover, employees are consistently receiving payroll increases that are clearly reasonable relative to market conditions. If the Company wants to reward officers and salaried employees based, in whole or in part, on financial results then shareholders should be willing to absorb these costs. This recommendation will require the Board of Directors to establish incentive compensation plans that shareholders are willing to finance. As long as ratepayers are required to pay the costs of these incentive plans, then there is no incentive for management to control these costs. This is especially true since the officers and executives of the Company are primary beneficiaries of such plans. Therefore, I recommend that the Company's claim for incentive compensation costs be denied. My adjustment is shown in Schedule ACC-18E and Schedule ACC-17G.

Q. Has the BPU previously addressed this issue?

A. Yes. Rate Counsel has informed me that the Board has a policy of disallowing incentive compensation costs when the performance triggers and benchmarks are tied to financial performance objectives. In the 2000 Middlesex Water Company base rate case, Board Staff argued in its Initial Brief that,

> 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.[6]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be

6 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Staff Initial Brief, page 37.

permitted to recover 50% of its incentive compensation costs in rates. However, the BPU rejected the ALJ's recommendation and instead ordered that 100% of these costs be disallowed.[7]

In an earlier decision, the BPU found that including employee incentives in utility rates is especially troublesome during difficult economic times, finding that,

> 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 and 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.[8]

It is indisputable that ratepayers are once again facing very difficult economic conditions, with increasing costs, widespread housing foreclosures, and a general economic downturn. Thus, the BPU's reasoning for disallowing these costs is just as relevant today as it was in 1993. The BPU's findings on this issue therefore support my recommendation that all such costs be excluded from the Company's revenue requirement.

D. <u>Severance Expense</u>

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

8 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).

Q. Please describe the Company's claim for severance costs.

A. The Company's initial claim included severance costs of $81,088 (total electric and gas allocation). This claim appeared reasonable relative to historic levels, as shown below:

	Electric	Gas	Total
2006	$16,804	$16,765	$33,570
2007	$250,317	$210,640	$460,957
2008	$95,073	$63,482	$158,554
Test Year	$45,144	$35,943	$81,088

However, in its 6+6 Update, the Company increased its claim from $81,088 to $1,031,164.

Q. Has the Company explained the reason for this significant increase?

A. No, I am not aware of any explanation for the increase to the Company's claim for severance costs. However, based on its update to the response to RCR-A-14, it is clear that that this claim is being driven by severance costs incurred by the Service Company and not directly by the utility.

Q. What do you recommend?

A. The 6+6 Update reflects costs that are well beyond the range of reasonableness given historic levels. Moreover, as demonstrated above, severance costs can vary from year-to-year. Accordingly, I am recommending that the BPU utilize a three-year average of severance costs to determine a normalize level of costs for this proceeding. My adjustment, which is shown in Schedule ACC-19E and ACC-18G, results in pro forma severance costs of $120,287 for the electric utility and of $96,477 for the gas utility, based on the three-year average cost.[9]

E. Payroll Tax Expense

Q. Have you also made an adjustment to the Company's payroll tax expense claim?

A. Yes, I have made an adjustment to eliminate the payroll taxes associated with my recommended adjustments relating to salary and wage costs, incentive compensation costs, and severance costs. To quantify my payroll tax adjustment, I utilized the statutory social security and medicare tax rate of 7.65%. My adjustment is shown in Schedule ACC-20E and Schedule ACC-19G.

F. Pension Expense

Q. How did PSE&G determine its pension claim in this case?

A. The Company's claim includes projected pension costs based on acturially-determined costs pursuant to Statements of Financial Accounting Standards ("SFAS") 87. The Company's claim is based on 10 months of projected 2010 costs and 2 months of projected 2011 costs. PSE&G has included pension costs for Service Company employees as well as pension costs for utility employees. The Company has allocated 51% of the Service Company to utility operations. PSE&G assumed that 58% of its costs would be expensed, and that the resulting pension expenses would be allocated 51% to gas operations and 43% to electric operations. These are the same assumptions used for the Company's salary and wage claims.

9 The Company's initial response to RCR-A-14 included a small amount of capital costs. These costs were eliminated in the updated response. I have based my adjustment on the updated response, which only reflects O&M costs.

Rate Counsel's recommended pension and Other Post Employment Benefit ("OPEB") claims are being addressed by Rate Counsel witness Mitchell I Serota.[10]

Mr. Serota recommends a reduction to the Company's claimed total company pension cost of $37.2 million. At Schedule ACC-21E and Schedule ACC-20G, I have incorporated Mr. Serota's recommendation into my recommended revenue requirement, using the allocations discussed above. It is my understanding that Mr. Serota is not recommending any adjustment to the Company's OPEB claim.

G. <u>Supplemental Executive Retirement Program ("SERP") Expense</u>

Q. What are SERP costs?

A. These costs relate to supplemental retirement benefits for key executives that are in addition to the normal retirement programs provided by the Company. These programs generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans.

In response to RCR-A-24, the Company identified three SERP components. First, a Limited Supplemental Benefits Plan, that provides "supplemental death and retirement benefits to a select group of management or highly compensated employees...." Second, a Retirement Income Reinstatement Plan, that takes into account compensation in excess of the IRS qualified limit of $245,000. Third, the Mid Career Hire Supplemental Retirement Income Plan, which provides additional service credit to key employees.

10 The Company is also requesting the establishment of a pension expense tracker. This issue is being addressed in the testimony of Rate Counsel witness Robert Henkes.

Q. What are the test year SERP costs that the Company has included in its claim?

A. As shown in the response to RCR-PT-4, the Company is projecting total company SERP costs of $9.153 million in 2010 and of $8.987 million in 2011. While the utility's share of these costs is only approximately $760,000, more than half of the total costs are Service Company costs, a portion of which would be reallocated to PSE&G. Based on the allocations discussed above, I calculate that the Company's electric and gas expense claims includes approximately $1.8 million in SERP costs.

Q. Do you believe that these costs should be included in utility rates?

A. No, I do not. As noted above, the officers of the Company are already well compensated. Moreover, employees that receive SERP benefit are also included in the normal retirement plans of the Company, so ratepayers are already paying retirement costs for these employees. If PSE&G wants to provide further retirement benefits to select employees, then shareholders, not ratepayers, should fund these excess benefits. Therefore, I recommend that the Company's claim for SERP costs be disallowed. My adjustment is shown in Schedule ACC-22E and ACC-21G.

H. <u>Rate Case Expense</u>

Q. How did the Company develop its rate case cost claim?

A. PSE&G is requesting recovery of rate case costs of $1.5 million, as shown in the response to RCR-A-179. The Company's claim includes legal costs of $405,000, consultant fees of $915,000, and other miscellaneous costs of $180,000. The Company did not propose any amortization period for these costs. Therefore, PSE&G is proposing to include an annual amount of $1.5 million in its utility rates indefinitely. Moreover, the Company has not proposed any sharing of rate case costs between ratepayers and shareholders.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending two adjustments. First, I am recommending that the BPU adopt a three-year amortization period for rate case costs. PSE&G's last gas base rate case had rates effective November 9, 2006 and its last electric base rate case had rates effective August 1, 2003. By the time that rates are approved in this case, approximately 3 ½ years will have passed since the last gas case and almost 7 years since the last electric case. Therefore, I am recommending that rates in this case be amortized over a period of no less than three years. This recommendation appears reasonable in light of the Company's recent history with regard to base rate filings. At Schedule ACC-23E and Schedule ACC-22G, I have made adjustments to reflect a three-year amortization of rate case costs. To quantify my adjustments, I allocated the Company's claim equally between electric and gas operations.

Q. What is your second recommended adjustment to rate case costs?

A. The BPU has a well-established policy of requiring a 50/50 sharing of rate case costs between ratepayers and shareholders. This policy recognizes that shareholders benefit from rate case filings and therefore shareholders should fund a portion of these costs. PSE&G did not reflect any such sharing in its claim for rate case costs. Instead, the Company has included 100% of these costs in its revenue requirement. Accordingly, at Schedule ACC-23E and ACC-22G, I have also made an adjustment to reflect a 50/50 sharing of rate case costs between ratepayers and shareholders, consistent with BPU policy.

Q. Do you have any additional comments about the Company's claim for rate case costs?

A. Yes, I do. In response to RCR-A-50, the Company refused to provide copies of its contracts for consulting services associated with this base rate case. Therefore, we do not have any underlying support for the legal and consulting costs included in the Company's claim. Without this support, it is impossible to determine if the Company's claim for rate case support services is reasonable, since we do not have any description of the services being provided or of the applicable hourly rates. In response to RCR-A-51, the Company stated that it did not issue any Requests for Proposal for rate case services. Therefore, it does not appear that the Company used a competitive process to select these firms. PSE&G is requesting recovery of over $1.32 million in legal and consulting costs for which no supporting documentation has been provided. Accordingly, the BPU may conclude that none of these costs have been justified and eliminate all legal and consulting costs from the Company's rate case expense claim unless PSE&G provides additional material to justify these costs.

I. Injuries and Damages Expense

Q. How much did the Company include in its claim for injuries and damages expenses?

A. The Company included approximately $12.0 million of injuries and damages expenses in its electric claim and approximately $9.7 million in its natural gas claim.

Q. Are you recommending any adjustment to the Company's claim?

A. I am not recommending any adjustment to its gas claim, but I am recommending an adjustment to its electric claim for injuries and damages. The Company's test year electric claim is significantly higher than the annualized cost based on the first six months of the test year. As shown in the Company's workpapers, actual costs for the first six months of 2009 were $4,751,506 for the electric utility. Therefore, it appears that the Company's test year claim is overstated. At Schedule ACC-24E, I have made an adjustment to reduce this claim by $2.5 million. My recommendation reflects a test year injuries and damages cost for electric operations of $9.5 million, which is based on annualizing costs through June 2009. My recommendation will be further updated, as necessary, once the Company provides its 12+0 Update. I am not recommending any adjustment at this time to the Company's injuries and damages claim for its natural gas operations because the test year projection appears reasonable given actual results for the first six months of 2009.

J. Customer Information System Amortization Expense

Q. Please describe the Company's claim for recovery of deferred customer information system ("CIS") costs.

A. In its filing, PSE&G is requesting recovery of deferred costs associated with implementation of the new CIS. The CIS was placed into service in April 2009 and the capital costs of the system are included in PSE&G utility plant-in-service claim. In addition to the capital costs of the system, PSE&G is also requesting recovery of $32.03 million of deferred operating and maintenance costs. These are primarily non-recurring costs associated with the training of customer service representatives. The Company is proposing to amortize these costs over a ten-year period. Moreover, PSE&G has included carrying costs during the amortization period in its claim. The Company is proposing to recover a levelized cost of $4.6 million (total electric and gas) associated with these deferred costs each year during the proposed ten-year amortization period.

Q. Is it appropriate to include these deferred costs in the Company's prospective rates?

A. No, it is not. The Company's claim constitutes retroactive ratemaking and should be denied by the BPU. If a utility wants to defer a cost for ratemaking purposes, it has an obligation to seek a deferred accounting order from the regulatory authority. Most accounting orders issued by regulatory agencies permit a utility to seek future rate recovery of a previously-incurred cost, although accounting orders generally do not guarantee such recovery. In any case, PSE&G did not receive BPU authorization to defer these costs prior to filing this base rate case. Therefore, allowing these past costs to be recovered would violate the prohibition against retroactive ratemaking.

The prohibition against retroactive ratemaking is a well-established regulatory principle. A company cannot unilaterally decide to defer costs and expect recovery in a future rate case. If the Company believed that the CIS expenses would have a material impact on its financial integrity, then it had an obligation to seek authorization for deferral from the Board. No such authorization was sought and recovery of these past costs should be denied. Moreover, there is no indication that the Company's financial integrity would suffer if PSE&G is denied recovery of the past costs. My adjustment is shown in Schedule ACC-25E and ACC-23G.

Q. Do you have any other comments regarding the Company's CIS implementation?

A. Yes, I do. The implementation of the CIS is addressed more fully in the testimony of Rate Counsel witness Dian P. Callaghan.[11] In her testimony, Ms. Callaghan addresses several customer call center performance standards that are not currently being met, including the number of calls answered within 30 seconds (known as "ASA"), the abandoned call percentage ("ACP"), and the average speed of answering a call. Ms. Callaghan states that PSE&G is experiencing problems with billing and meter reading due to the implementation of the CIS. She also notes that customer complaints to the Board have increased significantly.

11 The CIS system is referred to as the Customer Care System ("CCS") or iPower in Ms. Callaghan's testimony.

PSE&G has undoubtedly had, and continues to have, problems with implementation of the CIS, lending further support for my adjustment to disallow the Company's claimed deferral. In addition to the CIS deferral, there may be other costs in the Company's test year that were not deferred, but that do not reflect a normalized level of prospective costs due to the CIS. For example, in the response to RCR-CI-30, PSE&G stated that it hired 30 additional call center representatives in the summer and that it plans to hire another 50 during October and November to "return the ASA to pre implementation levels." According to the Company's response to DCA-12, the 50 new employees are not reflected in the current business plan and therefore these costs would not be reflected in the recent 6+6 Update.

Given the problems that customers have experienced as a result of the CIS, the Board should ensure that ratepayers do not pay for additional personnel or other costs that PSE&G will incur during the test year to correct ongoing problems with the CIS. While ratepayers should pay for normal ongoing costs associated with the new system, all non-recurring costs should be removed from the test year. Therefore, when the Company provides its 12+0 u20pdate, it should identify all test year costs that were incurred in response to problems associated with implementation of the CIS, including the additional personnel costs discussed in the data requests referenced above.

K. Management/Affiliated Standards Audit Expenses

Q. Please describe the Company's claim for recovery of Board-mandated audit costs.

A. In its revenue requirement claim, PSE&G included a test year adjustment relating to a Management/Affiliated Standards audit being conducted by the BPU. As discussed on page 36 of Mr. Kahrer's testimony, "Affiliate standards audits are to take place approximately every three years. Management audits are conducted every five years. At this time, the BPU is beginning a combined Management and Affiliated Standards audit of PSE&G."

The Company is estimating total costs of $3.361 million for the audit. It has allocated 55% of the audit costs to electric operations and 45% to gas operations. The Company is proposing to amortize these costs over four years.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending an adjustment to reduce the Company's claim from $3.361 million to $2.1 million. $2.1 million is the amount of the 2009 Plan cost as shown in the Company's workpaper to Schedule MGK-37. This amount appears reasonable, given the fact that the BPU awarded the auditing contract to Overland Consulting at a total cost of just under $1.2 million. Thus, my recommendation of $2.1 million includes over $900,000 in other auditing-related costs. While the Company is likely to incur additional costs over and above the BPU auditing contract costs, most of these costs relate to personnel and therefore the applicable salary and wage costs for these employees should already be reflected in the test year costs. Accordingly, I believe that my allowance of $900,000 is appropriate. Through June 2009, PSE&G incurred costs of approximately $300,000 on a total company basis for the combined Management/Affiliate Standards Audit.

Q. How did you quantify your adjustment?

A. As stated, I based my adjustment on the Company's projected test year cost as shown in its 6+6 Update, but I have excluded its requested post-test year adjustment. In addition, I have accepted the Company's allocation between the electric and gas utilities. Therefore, I have allocated $1.155 million of my recommended pro forma cost of $2.1 million to electric and $945,000 to gas. In addition, I have accepted the use of a four-year amortization period. As shown in Schedule ACC-26E and ACC-24G, my recommendation results in an annual expense reduction of $174,000 for the electric utility and of $142,000 the gas utility.

L. Vegetative Management Expense

Q. What are vegetative management costs?

A. Vegetative management costs are costs incurred by the electric utility relating to tree trimming and other activities with the goal of preventing vegetative interference with electric lines. A reasonable vegetative management program is necessary in order to provide safe and reliable service and minimize outages relating to natural causes.

Q. What did the Company include in its claim for vegetative management expenses?

A. According to the response to RCR-A-46, the Company included test year operating costs of

$21,675,000 and capital costs of $469,000.[12]

Q. Has does the Company's claim compare with historic expense levels?

A. The Company's claim is high relative to historic costs, as shown below:

Year	Vegetative Management Operating Costs ($000)
2009	$21,675
2008	$13,260
2007	$18,561
2006	$23,528
2005	$15,290
2004	$12,754
3 Year Average	$18,450
5 Year Average	$16,679

Moreover, this chart also indicates that these costs can fluctuate significantly from year-to-year.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I given the fact that the Company's 2009 Plan costs are so high relative to historic levels, and given the fluctuations that occur in annual vegetative management costs, I am recommending that a three-year average of these costs be included in the Company's revenue requirement in this case. The use of a three-year average will mitigate the impact of annual

12 It should be noted that the Company did not update this response to reflect its 6+6 Update.

fluctuations and appears more reasonable than the 2009 Plan costs included in the Company's filing. My recommendation is shown in Schedule ACC-27E.

M. Insurance Expense

Q. How did the Company determine its claim for insurance costs?

A. The Company's claim is based on 10 months of its projected 2010 costs and 2 months of its projected 2011 costs. Moreover, its projected 2010 costs reflect increases of 11.5% for electric and of 13.3% for gas over its current test year projection. Its projected 2011 costs are based on an increase of 10% over the Company's projected 2010 costs. These projected increases are especially troubling when one considers the fact that even the Company's test year projection appears high. With regard to electric operations, PSE&G is projecting an increase of over 25% in its insurance costs for the last six months of 2009 relative to actual costs incurred in January-June. Its projected insurance expense for its gas operation from July-December 2009 is almost 24% higher than its actual costs for the first six months of the test year.

Q. How should insurance costs be determined?

A. Insurance costs should be determined based on annualizing premiums at the end of the test year. The use of speculative 2010 and 2011 increases should be rejected. Accordingly, I am recommending that the BPU reject the Company's insurance cost claims in this case.

Q. How did you quantify your adjustment?

A. To quantify my adjustment, I have included the Company's current test year claim in my revenue requirement recommendation. While the Company's test year claim still appears overstated based on actual results to date, there may be cost increases during the last six months that should be annualized for ratemaking purposes. Therefore, I believe that the Company's test year projection may represent a reasonable allowance for ratemaking purposes and therefore I have included this amount in my revenue requirement. I will reevaluate my recommendation when the Company provides updated results for the entire test year. My recommendation is shown in Schedule ACC-28E and Schedule ACC-25G.

N. Postage Expense

Q. How did the Company determine its postage expense claim?

A. Similar to the way it calculated insurance costs, the Company's claim for postage costs is based on 10 months of its projected 2010 costs and 2 months of its projected 2011 costs. In this case, its projected 2010 costs reflect increases of 2.8% over its current test year projection while its projected 2012 costs are based on an increase of 8% over the Company's projected 2010 costs. PSE&G allocates its projected postage costs 55% to electric and 45% to gas.

One significant difference between the Company's insurance cost projections and its postage cost projections is that the postage costs projected for the later half of 2009 appear low relative to actual results for the first six months of 2009. During the first half of 2009, PSE&G incurred average monthly costs of $835,935, while the Company is projecting monthly costs of only $831,451 for the July-December 2009 period. Thus, while I believe that the Company's postage expense claim is overstated, it may not be appropriate to use the 2009 projection of postage costs in this case.

Q. Has the United States Postal Service announced a price increase for 2010?

A. No, it has not. In fact, according to published reports, the postal service has announced that it will not increase prices in 2010.

Q. What level of postage expense do you recommend be included in the Company's revenue requirement?

A. I am recommending that the Company's actual postage costs to date of $5,015,610 be annualized, resulting in a test year cost of $10,031,220. This amount should be allocated 55% to electric operations and 45% to gas operations. I am then recommending a further adjustment to reflect the growth in customers that I have reflected in my customer annualization adjustments of 0.5% for the electric utility and of 1.0% for the gas utility. Since additional customers will result in the need for additional bills and mailings, it is appropriate to reflect growth in customers in my pro forma postage expense recommendation. My adjustments are shown in Schedule ACC-29E and Schedule ACC-26G.

O. Energy Master Plan ("EMP") Costs

Q. Please describe the Company's EMP Clause adjustment, as shown on Schedule MGK-42.

A. According to the testimony of Mr. Kahrer at page 40,

> Today, as part of its business, PSE&G is investing capital and incurring expenses to provide safe, adequate, proper and reliable services to its electric and gas customers as well as supporting other initiatives developed by the State. Among those initiatives is support for New Jersey's EMP. Return of and on the investments developed in support of the EMP and recovery of associated expenses is accomplished from receipt of revenue collected through the RGGI Recovery Charge (RRC). Within the test year operating income are revenue, depreciation/amortization expenses, O&M costs and expenses associated with over/(under) recovery for programs which are currently reflected in the RRC. This adjustment is required to remove those items from the test year operating income to arrive at an operating income for purposes of setting distribution base rates. The adjustment for gas reflects those items associated with the Company's Carbon Abatement Program approved by the Board. The adjustment for electric is for both the Carbon Abatement Program and the Solar Loan Program which was also approved by the Board. The adjustment to remove the items described above results in a decrease in test year operating income of $560,000 for electric distribution and $83,000 for gas distribution.

In its 6+6 Update, the Company updated its adjustment, reducing the net expense impact from $1.088 million (total company) to $796,000 (total company). In response to RCR-A-206 (Update), the Company indicated that intends to provide a further update to Schedule MGK-42 R-1. In that response, PSE&G indicated that it planned to remove revenues and expenses relating to the Solar Loan I program from the adjustment and to update the test year amounts filed with the 6+6 Update for the Carbon Abatement Program. The Company indicated that this further update would result in a net expense adjustment of $478,732.

Q. Before discussing particular adjustments, do you have any general comments about program costs that are recovered through RGGI surcharges?

A. Yes, I do. During the discovery process, it became evident that the Company's case is based on a test year that includes revenues and costs relating to many items other than electric and gas distribution rates. Instead of filing its case based on distribution revenues and expenses, the Company has included both revenues and costs related to RGGI programs, Societal Benefit Charges ("SBC"), Gas Remediation costs, Supply costs, and other items that should be excluded from consideration of base distribution rates. By making a few adjustments, such as the EMP Clause adjustment shown on Schedule MGK-42, the Company is apparently attempting to remove the impact of these other activities from base rate consideration. However, as demonstrated by the revisions that continue to be made to Schedule MGK-42, identifying the associated revenues and costs, even for a relatively simple program like the carbon abatement program, is a complicated exercise.

Q. How should revenues and expenses that are recovered through surcharge mechanisms be reflected in a utility's revenue requirement?

A. These revenues and expenses should not be reflected at all in the utility's revenue requirement. PSE&G should have filed a distribution base rate case, i.e., a case that reflected distribution revenues as well as the costs of providing distribution service. Unfortunately, it did not do so and we are now left with trying to back-into a pure distribution revenue requirement, as evidenced by the Company's EMP Clause adjustment.

Q. Why is it important that only distribution revenues and expenses be considered in a base rate case?

A. There are two principal reasons. First, there is a BPU-approved true-up process that allows the Company to recover 100% of certain costs through the various surcharge mechanisms applicable to RGGI costs, SBC costs, and other clauses. Therefore, to the extent that revenues and costs associated with these programs are included in the Company's filing, they can distort the test year financial results, as shown in the following example:

	Distribution Activities	Other Activities	Total
Revenues	$100	$50	$150
Revenue Requirement	$100	$60	$160
Net	$0	($10)	($10)

As shown above, a utility would appear to have a need for rate relief if its total revenue requirement exceeds its projected revenues, even if its distribution revenues are sufficient to cover its distribution cost of service. In the above example, the utility would appear to require rate relief of $10. However, the Company would recover the $10 under-recovery reflected above during the normal true-up process associated with its various clauses, presumably when it filed its next surcharge filing. The $10 under-recovery is recorded as a deferral on the Company's financial books and records of account, but unless that $10 deferral is reflected in the Company's income statement in some manner, that eventual recovery is not considered in the ratemaking process.

Second, since the Company will eventually recover prudent and incremental operating costs relating to programs recovered through surcharges, it is important to ensure that these costs are not also being recovered in base rates. This is especially critical for salary and wage costs, since payroll costs typically account for the majority of the administrative costs charged to the surcharge mechanism. While the Company does intend to track the amount of time that employees spend on programs recovered through surcharges, it has not attempted to eliminate all of these administrative costs from distribution rates in this case. In response to RCR-A-210, PSE&G indicated that "Specific positions are not recovered in a cost recovery mechanism; rather, costs for activities performed by employees in various positions are recovered through surcharge mechanisms." In response to RCR-A-6, PSE&G indicated that it "will utilize some of its employees in the RGGI programs which are included in the Company's base rates....It is not possible to identify the positions of all those employees who may become involved in supporting the various RGGI programs, or the percentage of time that may be spent on them because such support occurs as a part of the routine course of business." In response to S-PSEG-LABOR-5, the Company stated that "It is not possible to list all current employees that support RGGI programs and Solar Loan I. Resources in PSE&G are utilized on an as-needed basis to support the successful implementation of programs." In response to RCR-A-210, the Company identified 56 positions that "perform activities that are recovered through a surcharge mechanism" for the

RGGI and Solar Loan programs. In response to S-PSEG-LABOR-4, the Company identified salary and wage levels for these positions but failed to state if these costs are included in the salary and wage claim in this case. Thus, in spite of extensive discovery in this area by both Rate Counsel and Staff, there is still some uncertainty with regard to the costs included in base rates vs. the costs to be recovered through surcharge mechanisms.

Q. To summarize, what issues must the BPU address when evaluating the Company's revenue requirement request?

A. The BPU must base any rate increase recommendation on two important criteria. First, the BPU must ensure that any distribution rate increase awarded to the Company is necessary for the continued provision of safe and adequate distribution service, and is not being impacted by activities recovered through surcharges. Second, the BPU must ensure that any costs being recovered through base rates are not also recovered between base rate cases through a surcharge mechanism. In order to begin to meet these two challenges, I have asked the Company to identify the revenues and expenses included in its test year, separately for each program recovered through a surcharge mechanism. As of the preparation of this testimony, I have not yet received the requested data. In the interim, I am recommending several adjustments relating to the Company's EMP Clause adjustment, as discussed below.

Q. What are you recommending with regard to the Company's EMP Clause adjustment shown on Schedule MGK-42?

A. As stated above, the revenues and expenses associated with projects recovered through various surcharge mechanisms should be revenue neutral, i.e., program revenues should equal program costs. In fact, since the Company earns a return on the unamortized balances for many of these costs, revenues should exceed costs over the life of the program resulting in a net gain to shareholders. Thus, my first adjustment is to reverse the Company's EMP Clause adjustment, which resulted in a reduction to distribution net income. My reversal of the Company's adjustment is shown in Schedule ACC-30E and Schedule ACC-27G. It should be noted that this adjustment is based on the Company's claim that a total of $1.924 million of administrative costs associated with the Carbon Abatement program is being recovered through a surcharge mechanism and therefore is not being recovered through base rates, as is shown in PSE&G's workpapers.

Second, in addition to the costs that will be recovered through surcharge mechanisms, the Company is also proposing to recover $549,581 of its administrative costs associated with the Solar Loan I program directly through base rates, as noted in the response to RCR-A-209. These costs account for 50% of the Solar Loan I administrative costs. It is my understanding that PSE&G agreed that 50% of the administrative costs of the Solar Loan I program would not be passed on to ratepayers. In fact, as noted in the response to RCR-A-209, the BPU Order approving the Solar Loan I program noted that "PSE&G agrees that it shall recover 50% of the administrative costs of the Solar Program through the SPRC...".

The intent of the parties in that case was that the remaining 50% would be funded by shareholders, who are receiving a return at their overall weighted average cost of capital, in spite of the fact that the program is virtually risk-free. In this base rate case, however, PSE&G is attempting to "back-door" recovery of the 50% of administrative costs that it agreed to absorb in the Solar Loan I proceeding. Accordingly, at Schedule ACC-31E, I have made an adjustment to eliminate these costs from the Company's revenue requirement claim.

Q. Going forward, how can the BPU assure ratepayers that they are not being double-charged for administrative costs associated with programs that are recovered through surcharge mechanisms?

A. As additional surcharge-type programs proliferate, and as we move further away from this base rate case, it will become increasingly difficult for the BPU and other parties to ensure that there is no double-recovery of program costs. Therefore, it is imperative in this case to clearly identify all specific positions that are being recovered in base rates. The Company indicated in response to RCR-A-142 that "for those positions whose costs are recovered in the Company's base rate case, 100% of all payroll costs for such positions are included." Thus, it appears that the Company has not <u>allocated</u> any payroll costs between base rates and surcharge mechanisms, except for the Solar Loan I costs addressed above. Accordingly, the BPU should reject any future attempt to recover any portion of payroll costs related to existing employees through surcharge mechanisms. As part of any compliance filing resulting from this case, the Company should be required to clearly identify all employee positions included in its distribution rates. Moreover, in any future surcharge proceeding, PSE&G should be required to demonstrate that any claim for recovery of administrative costs involves new, incremental positions that were not included in the distribution rates resulting from this base rate case.

P. Uncollectible Costs

Q. Please describe the Company's claim for uncollectible costs.

A. With regard to the gas utility, PSE&G is projecting uncollectible costs of $33.5 million for the test year, based on its 6+6 Update. The Company has included an uncollectible rate of 1.42% in its revenue multiplier. This is an increase over the uncollectible rate of 1.13% used in the Company's initial filing. The electric utility recovers uncollectible costs through the SBC and therefore electric uncollectibles should not be an issue in this proceeding. Uncollectible costs recorded on the Company's income statement are based on additions to the uncollectible reserve. Thus, these costs do not directly correspond to the actual level of write-offs. In evaluating the Company's uncollectible claim, however, it is important to review the actual experience with regard to write-offs as well as recoveries of amounts that were previously written off, in order to determine if the level of additions proposed for the uncollectible reserve is appropriate. Generally, the annual reserve additions should be approximately equal to annual net write-offs of bad debts.

Q. Based on your review, are you recommending any adjustments to the Company's uncollectible expense or to the uncollectible factor proposed for the revenue multiplier?

A. I am not recommending any adjustment at this time to the $33.005 million included in the Company's projected test year expense. However, I am recommending that the BPU utilize an uncollectible factor of 1.2% instead of the 1.42% proposed by PSE&G.

Q. What is the basis for your recommendation?

A. In the response to RCR-A-41, the Company provided a five-year history showing the amount of bad debt write-offs, the amount of write-offs that were subsequently recovered, the annual reserve additions, and the total revenues from sales used in the bad debt calculations. This data shows the following uncollectible percentages, based on actual net write-offs:

Year	Net Write-off %
2005	1.02%
2006	1.34%
2007	1.18%
2008	1.09%
2009 (through June 30)	0.83%

Since 2006, the percentage of net write-offs has actually decreased. The three-year average (2008-2006) of actual net write-offs is 1.20%. Thus, I recommend that the revenue multiplier include an uncollectible factor of no greater than 1.20%. This recommendation is included later in the Revenue Multiplier section of this testimony.

Q. Why didn't you make a corresponding reduction to the amount of uncollectible costs included in the Company's test year claim?

A. As noted, the Company has included $33.005 million in its test year projection. Given its projected pro forma gas sales revenues of $2.806 billion, shown in Schedule MGK-19 R-1, this equates to a bad debt percentage of 1.17%, very close to the 1.2% that I have included in the revenue multiplier. Therefore, at this time, no adjustment to its actual uncollectible expense claim is necessary. Such an adjustment may be necessary once the Company files its 12+0 Update, based on the actual level of uncollectible costs included in its test year update.

Q. <u>Meals and Entertainment Expenses</u>

Q. Are you recommending any adjustment to the Company's meals and entertainment expense claim?

A. Yes, I am. According to the response to RCR-A-60 (Update), the Company has included in its filing approximately $1.37 million of meals and entertainment expenses that are not deductible on the Company's income tax return. These are costs that the IRS has determined are not appropriate deductions for federal tax purposes. If these costs are not deemed to be reasonable business expenses by the IRS, it seems reasonable to conclude that they are not reasonable business expenses to include in a regulated utility's cost of service. Accordingly, at Schedule ACC-32E and ACC-28G, I have made an adjustment to eliminate these costs from the Company's revenue requirement.

Q. Did the Company provide any additional information about these costs?

A. In response to RCR-A-166, the Company stated that these costs include "meals related to business travel or business meetings with clients or associates and business entertainment costs. Business entertainment costs include items such as ticket price (sic) to shows or sporting events where there is a business purpose that supports the cost." I find it difficult to conceive of a "business purpose" that would support ratepayers paying for tickets to shows or sporting events. Clearly, these are costs that should be borne by the Company's shareholders, and not its ratepayers. While there may be certain meals and entertainment costs that should be borne by ratepayers, there also clearly costs included in this category which should be entirely excluded from the Company's revenue requirement. Therefore, my recommendation to use the 50% IRS criteria provides a reasonable balance between shareholders and ratepayers and should be adopted by the BPU.

R. <u>Advertising Expense</u>

Q. Are you recommending any adjustments to the Company's claim for advertising costs?

A. Yes, I am. In addition to any advertising costs that may be booked to demonstration and selling expenses, miscellaneous sales expense, or miscellaneous general expense, the Company also included general advertising expense of approximately $6.36 million in its electric and gas claims. PSE&G provided a breakdown for these costs in the response to RCR-A-181.

Based upon my review of this response, many of these costs should not be charged to ratepayers. For example, PSE&G included approximately $2.07 million of corporate sponsorship costs in its claim. In addition, it included $1.96 million of costs relating to branding. I am recommending that the corporate sponsorship costs and branding costs be disallowed.

Branding costs relate to "[t]he creation and maintenance of PSEG level branding and advertising efforts. Corporate Branding and Investor advertising campaigns. GreenFest." The Company has included both internal costs relating to the branding effort as well as associated outside services costs. These advertising costs all appear to be corporate image or public relations costs that are directed toward promoting the corporate image of the utility, rather than toward the provision of regulated utility service to its customers. Corporate sponsorships are another vehicle for the Company to promote the corporate image, providing benefits to its shareholders. I understand that the BPU, like most regulatory agencies, has traditionally disallowed these types of costs.

Unless the Company can show a direct relationship between the advertising costs included in its claim and the provision of safe and adequate utility service, these costs should be disallowed. The Company has not made such a showing at this time. Therefore, I recommend that the branding costs and corporate sponsorship costs included in the Company's claim be disallowed. My adjustment is shown in Schedule ACC-33E and Schedule ACC-29G.

It should be noted that the response to RCR-A-181 also includes other advertising expense categories that perhaps should be disallowed, either in whole or in part, such as external communications or initiatives to promote shareholder goals. However, at this time, I do not have sufficient documentation to expand my recommendation beyond the branding and corporate sponsorship costs discussed above.

S. Dues / Lobbying Expenses

Q. Has the Company included any lobbying-related costs in its claim?

A. Yes, the Company has included membership dues in its revenue requirement for certain organizations that engage in lobbying activities. In response to RCR-A-56, PSE&G identified various membership costs that are included in its claim. Actual costs for the first six months of 2009 totaled $483,921 for the electric utility and $519,765 for the gas utility. In addition the Company has identified $256,760 in planned expenditures for its electric and gas operations during the second half of 2009. It should be noted that this data request response only included membership fees exceeding $750, and therefore it is likely that the response to RCR-A-56 does not reflect all such costs included in the Company's revenue requirement claim.

Most of the organizations included in this response engage in lobbying activities, the costs of which should not be charged to ratepayers. The largest expenditures are for dues to the Edison Electric Institute ("EEI") and the American Gas Association ("AGA"). In response to S-PREV-46, PSE&G noted that "EEI expenses associated with regular lobbying activities are 16% and for SFA Industry Structure 35%. AGA lobbying expenses are anticipated to be 4.38% and NJUA's lobbying expenses are anticipated to be approximately 1%." In addition to explicit lobbying costs, most of these organizations also engage in other activities that should not be charged to ratepayers, such as public affairs, media relations, and other advocacy initiatives.

Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of service?

A. No, they are not. Lobbying expenses are not necessary for the provision of safe and adequate utility service. Ratepayers have the ability to lobby on their own through the legislative process. Moreover, lobbying activities have no functional relationship to the provision of safe and adequate regulated utility service. If the Company were to immediately cease contributing to these types of efforts, utility service would in no way be disrupted. For all these reasons, I recommend that costs associated with lobbying activities be disallowed.

Q. How did you quantify your adjustment?

A. With two exceptions, I am recommending that 15% of the Company's membership dues identified in the response to RCR-A-56 be disallowed on the basis that such costs constitute lobbying activities or should not otherwise be charged to cost of service. I recognize that the specific level of lobbying/public affairs/media activity varies from organization to organization. However, based on my review of these organizations and on recommendations in other utility rate proceedings, I believe that a 15% disallowance is a reasonable overall recommendation. My adjustment is shown in Schedule ACC-34E and Schedule ACC-30G.

I did not include any disallowance for membership dues associated with the Georgia Tech Research Corp. or Center for Energy Workforce Development. It appears that these organizations do not engage in lobbying activities. Moreover, it appears that the vast majority of the services provided by these two organizations do in fact benefit ratepayers. Accordingly, I have included 100% of the annual membership dues for these two organizations in my revenue requirement recommendation.

Q. In quantifying your adjustment, how did you allocate the planned expenditures between the electric and gas utility?

A. Since the Company did not specifically assign planned expenditures for the second half of 2009, I have assumed a 50/50 split between the electric utility and the gas utility for these membership dues in quantifying my recommended adjustments.

T. <u>Gains/Losses on Sale of Property</u>

Q. How did the Company develop its claim relating to the gain on sale of property?

A. According to the testimony of Mr. Kahrer at page 35, PSE&G allocated "one-half of the gain on sales of property, net of associated income taxes, to the customer based on a five year average."[13] As shown in Schedule MGK-36, this net-of-tax gain was further reduced by the

13 It should be noted that while the Company states that it allocated only 50% of the gain to ratepayers, its workpapers are unclear as to whether 50% or 100% of the gain was allocated to ratepayers. If the Company's

Company's composite tax rate to develop the operating income impact of the property sales.

Q. Are you recommending any adjustment to the Company's claim associated with gains/losses on the sale of property?

A. Yes, I am recommending two adjustments. First, I am recommending that 100% of the gain be allocated to ratepayers. It is my understanding that prior to its 2002 base rate case, PSE&G flowed through 100% of the five-year average gain/loss through to ratepayers. Assuming that the assets sold were previously included in rate base, it is entirely appropriate to assign 100% of these gains to ratepayers. By using a five-year average, there is already an implicit sharing of gains/losses between ratepayers and shareholders, since only 20% of the gains/losses in any one year flow through the ratemaking equation. While I understand that the BPU has approved a 50/50 sharing mechanism for certain water cases, it is also my understanding that those cases do not involve a five-year averaging mechanism. Given the five-year averaging mechanism utilized for PSE&G, 100% of the resulting gains should be credited to the Company's revenue requirement. At Schedule ACC-35E and ACC-31G, I have made an adjustment to include 100% of the gain from the sale of these assets in my revenue requirement recommendation.

Q. What is your second adjustment?

A. In calculating its adjustment, the Company reduced its pre-tax gain by the income taxes due

testimony is in error, and in fact 100% of the gain was allocated to ratepayers, I will revise my adjustment accordingly.

on that gain. For electric operations, this gain was reduced by taxes of approximately 20% while the gain attributable to gas assets was reduced by taxes of approximately 40%, as shown on Schedule MGK-36. I assume that these different tax rates result from different tax treatment imposed by the IRS relating to the specific assets sold, the time that these assets may have been held by PSE&G, and other factors.

PSE&G then further reduced this net-of-tax gain by the composite income tax rate utilized in this case. This has the impact of double taxation. PSE&G does not pay taxes twice on this gain, it only pays taxes once. The BPU should either a) utilize the Company's net-of-tax gain as the operating income adjustment in this case (without any further reduction for additional income taxes), or b) it should utilize the pre-tax gain reduced by the composite income tax rate being utilized for the Company's revenue requirement. Under no circumstances should the BPU permit the Company to charge ratepayers twice for the taxes associated with the sale. Since option "b" is consistent with the tax treatment that I have used for other income adjustments, that is the method that I have used in my adjustment relating to the gain/loss on sale of property. This recommended income tax adjustment is also included in Schedule ACC-35E and Schedule ACC-31G.

U. <u>Interest on Customer Deposits</u>

Q. What adjustment are you recommending with regard to interest on customer deposits?

A. Since I am recommending that customer deposits be removed from the Company's capital structure and instead be reflected as a rate base reduction, it is necessary to make a corresponding adjustment to reflect interest on customer deposits "above-the-line". The Company is required to pay interest on its customer deposits. If customer deposits are removed from the Company's capital structure, the Company will not recover the costs of the interest paid on customer deposits unless a corresponding expense adjustment is made to its cost of service. Therefore, at Schedule ACC-36E and Schedule ACC-32G, I have made adjustments to reflect the interest on customer deposits as an operating expense for PSE&G.

Q. How did you quantify your adjustment?

A. N.J.A.C. 14:3-3.5 states that the annual interest rate on customers deposits shall be established each year by the BPU, based on "average yields on new six month Treasury Bills for the twelve-month period ending each September 30." The BPU published the 2010 rate of 0.43% on October 28, 2009 and that is the rate that I have reflected in my adjustment.

V. <u>Real Estate Tax Expense</u>

Q. How did the Company determine its real estate tax expense claim?

A. The Company's claim is based on 10 months of its projected 2010 real estate taxes and 2 months of its projected 2011 taxes. I am recommending two adjustments to the Company's claim. Specifically, I am recommending adjustments to reflect the impact of my plant-in-service adjustments and I am recommending that the 2011 increase included by PSE&G be disallowed.

Q. Please describe your first adjustment relating to the Company's property tax expense claim.

A. Since I am recommending an adjustment to PSE&G's utility plant-in-service claim, I have made a corresponding adjustment to its property tax expense claim. To quantify my adjustment, I developed a composite property tax expense rate, based on the Company's pro forma utility plant-in-service claim and its requested property tax expense claim. This resulted in a composite property tax rate of 0.19% for electric operations and of 0.10% for gas operations. I then reduced PSE&G's real estate tax expense claim by 0.19% of my recommended electric utility plant-in-service adjustment and by 0.10% of my recommendation gas utility plant-in-service adjustment. My real estate tax expense adjustment is shown in Schedule ACC-37E and Schedule ACC-33G.

Q. Please describe your second adjustment.

A. The Company's claim to include 2011 property tax increases reaches too far beyond the end of the test year in this case. Therefore, I recommend that the BPU deny the Company's request to include a portion of this projected 2011 increase in rates. At Schedule ACC-37E and ACC-33G, I have eliminated the 2011 increase for real estate taxes that was included in the Company's revenue requirement.

W. Depreciation Expense

Q. Have you made any adjustment to the Company's claim for pro forma depreciation expense?

A. Yes, I have made two adjustments. First, since I am recommending a reduction to the Company's utility plant-in-service claim, it is necessary to make a corresponding reduction to its depreciation expense claim. At Schedule ACC-38E and Schedule ACC-34G, I have adjustments to eliminate depreciation on the utility plant that I recommend be excluded from rate base. To quantify my adjustment, I have calculated composite depreciation rates of 2.75% for electric plant and of 2.01% for gas plant, based on the Company's depreciation expense claims and its utility plant-in-service claims for each utility. I then reduced the Company's pro forma depreciation expense by 2.75% of my recommended electric utility plant-in-service adjustment and by 2.01% of my recommended gas utility plant-in-service adjustment.

Q. Did you make a similar depreciation expense adjustment relating to your Capital Infrastructure Investment Program plant adjustment?

A. Yes, I did. Since I am recommending a reduction to the Capital Infrastructure Investment Program plant included in rate base at this time, it is necessary to make a corresponding adjustment to reduce the Company's pro forma claim associated with depreciation on Capital Infrastructure Investment Program projects. At Schedule ACC-39E and Schedule ACC-35G, I have made adjustments to eliminate depreciation on the Capital Infrastructure Investment

Program investment that I recommend be excluded from rate base at this time. To quantify my adjustment, I have calculated a composite depreciation rate of 2.45% for electric plant and of 1.61% for gas plant, based on the Company's depreciation expense claims for its Capital Infrastructure Investment Program projects. I then reduced the Company's pro forma depreciation expense by applying these percentages to my recommended Capital Infrastructure Investment Program plant adjustments.

Q. Is Rate Counsel accepting the depreciation rates and depreciation methodologies proposed by PSE&G in this case?

A. No. While I have used the Company's depreciation expense claim in this case to quantify the impact of the adjustments discussed above, Rate Counsel has not accepted either the Company's depreciation rates or its depreciation methodologies. It is my understanding that PSE&G did not file a depreciation study in this case. Therefore, its depreciation rates and methodologies have not been supported at this time. I also understand that the Company has now agreed to file a depreciation study within a relatively short period of time. Once this study is filed, Rate Counsel's depreciation witness will review the study and supporting documentation and determine what, if any, adjustments should be made to the Company's claim. The Company's study, and Rate Counsel's depreciation expense recommendations, are expected to be available prior to my cross-examination in this case. Therefore, when I update my recommendations to reflect the Company's 12+0 Update, I will also update my recommendations to reflect the revenue requirement impact of Rate Counsel's pro forma depreciation expense recommendations.

X. Interest Synchronization

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedule ACC-40E and Schedule ACC-36G. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Kahal. I am recommending a lower rate base than the rate base included in the Company's filing while Mr. Kahal's recommendations result in a lower overall cost of capital for PSE&G. Rate Counsel's recommendations, therefore, result in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under Rate Counsel's recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

Y. Income Taxes and Revenue Multiplier

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-41E and Schedule ACC-37G, I have used a composite income tax factor of 41.08%, which includes a corporate business tax rate of 9.36% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing. This composite income tax rate applies to both electric and gas adjustments.

My revenue multiplier, which is shown in Schedule ACC-42E and Schedule ACC-38G, reflects these same income tax factors. In addition, the revenue multiplier also includes the BPU and Rate Counsel assessments. The revenue multiplier for gas operations also includes the uncollectibles factor of 1.2% discussed earlier in my testimony. An allowance for uncollectibles is not included in Schedule ACC-42E, since PSE&G recovers its electric uncollectible costs as part of its SBC instead of through its electric distribution rates.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in your testimony?

A. For the electric utility, my adjustments indicate a revenue surplus at present rates of $15.439 million, as summarized on Schedule ACC-1E. This recommendation reflects revenue requirement adjustments of $162.455 million to the Company's requested revenue increase of $147.016 million. For the gas utility, my adjustments indicate a revenue deficiency at present rates of $13.723 million, as summarized on Schedule ACC-1G. This recommendation reflects revenue requirement adjustments of $92.224 million to the Company's requested revenue requirement increase of $105.948 million.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-43E and Schedule ACC-39G, I have quantified the revenue requirement impact of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

Q. Will your revenue requirement recommendations change as a result of the Company's 12+0 Update?

A. Yes, it will. While the ratemaking methodologies discussed in this testimony are not likely to change as a result of the Company's updates, my overall revenue requirement recommendation will change based on the Company's actual results for the full twelve months of the test year. In addition, my revenue requirement recommendation will be updated based on Rate Counsel's depreciation expense recommendations resulting from review of the Company's depreciation study. My recommendations will also be updated, as necessary, based on continued responses from the Company and other issues that may arise during the hearing phase of this case.

VIII. PROPOSED MODIFICATIONS TO THE CAPITAL ADJUSTMENT CHARGE

Q. What is the Capital Adjustment Charge ("CAC")?

A. The CAC is the mechanism that was approved by the BPU in April 2009 to recover costs associated with the Capital Infrastructure Investment Program. As discussed earlier, this program was designed to provide an economic stimulus to the New Jersey economy by accelerating certain investments in PSE&G's infrastructure. Pursuant to the program, PSE&G is permitted to recover a return on this investment, associated depreciation charges, and administrative costs through a CAC surcharge mechanism. The monthly revenue requirement and CAC revenues are subject to a monthly true-up, with interest. The parties envisioned that PSE&G would make this investment over a two-year period, from May 2009 through April 2011. The parties agreed that PSE&G would file a base rate case during this period. As outlined in the CIIP Stipulation in the Capital Infrastructure Investment Program proceeding, the parties agreed that capital expenditures would be rolled into base rates resulting from that proceeding to the extent possible, and that the base rate case would be reopened six months prior to the completion of the projects in order to permit base rates to be reset once all the investment had been made. At that point, the parties agreed that the CAC would be reset to bring the balance to zero over a reasonable period of time, at which point the CAC would terminate.

Q. What is the Company proposing in this case with regard to the CAC?

A. The Company's proposal contains two main elements. First, the Company is proposing to roll into base rates its projected cumulative expenditures at February 28, 2010 associated with the Capital Infrastructure Investment Program. This issue was addressed in the Rate Base Section of my testimony. In addition, the Company recently made a CAC filing, as envisioned in the CIIP Stipulation in BPU Docket Nos. EO09010049 and GO09010050, to reset the CAC rates to reflect the anticipated 2010 revenue requirement plus any over/under recovery incurred in 2009. Second, the Company is proposing to reset the CAC again effective with new rates in this case, to reflect a broad expansion of the types of costs to be recovered under the CAC.

Q. What types of costs does the Company propose should be recovered under the expanded CAC?

A. The Company is proposing to expand the use of the CAC to include recovery of all capital expenditures made between base rate cases, except for expenditures specifically relating to providing service to new customers. In addition, the Company is proposing a new tracking mechanism to track and recover the difference between the Company's actual pension costs and the annual pension costs recovered in base rates. Rate Counsel witness Robert Henkes is addressing the Company's request for a pension tracker.

Q. Turning to the first component, please summarize your recommendations with regard to rolling Capital Infrastructure Investment Program costs into base rates and resetting the CAC for anticipated Capital Infrastructure Investment Program costs.

A. I am recommending that Capital Infrastructure Investment Program plant expenditures through December 31, 2009, and associated depreciation expense, be rolled into base rates that result from this case. However, given uncertainty regarding the level of such expenditures, I have included only actual expenditures to date in my revenue requirement recommendation. To the extent that actual expenditures through December 31, 2009 are provided by the Company during the litigation phase of this proceeding, I will update my recommendation accordingly. Furthermore, my update will reflect any adjustments recommended by other Rate Counsel consultants reviewing the technical and capital budgeting aspects of the CIIP. Any expenditures not reflected in base rates that result from this case should continue to be collected through the CAC. As stated in the CIIP Stipulation, this base rate case should be reopened at some point in the future to address rolling the remaining Capital Infrastructure Investment Program investment into base rates. The CIIP Stipulation required PSE&G to file a base rate case at some point between April 3, 2009 and April 1, 2011. The CIIP Stipulation itself was dated April 9, 2009 and approved by BPU

Order dated April 28, 2009.[14] This base rate case was filed on May 29, 2009. I do not believe that the Board, Board Staff or Rate Counsel anticipated that this base rate case would be filed so soon after the Capital Infrastructure Investment Program Stipulation was approved. Therefore, there will be a longer period of time between the end of this base rate case and its reopening to address rolling the remaining expenditures into base rates than might have been anticipated when the CIIP Stipulation was signed. Nevertheless, the CIIP Stipulation provides for continued recovery of Capital Infrastructure Investment Program investment during this interim period. As noted, the Company recently filed a CAC petition to reset its rates effective January 1, 2010. All capital expenditures not reflected in base rates should continue to be recovered through the CAC mechanism until such time as they are transferred to base rates. Moreover, the CAC proceeding, and not this base rate case, is the appropriate forum in which to reset the CAC rates associated with Capital Infrastructure Investment Program projects. Thus, any changes to the CAC should be addressed in a dedicated CAC proceeding.

Q. Turning to the second major CAC issue, should the CAC be expanded to include <u>all</u> capital expenditures, other than those directly related to new business, between base rate cases?

A. No, it should not. The CAC was established for a very specific purpose, i.e., to collect costs over a limited period of time relating to a limited and well-defined investment program. The

14 The corresponding BPU Agenda Date was April 16, 2009.

CIIP Stipulation provided that once all costs associated with the Capital Infrastructure Investment Program were transferred to base rates, the "electric and gas CAC rates and tariffs will be recalculated to bring the balance to zero over a reasonable period of time and <u>such rates and tariffs will terminate upon reaching a zero balance</u>" (emphasis added). Yet, less than two months after the April 9, 2009 CIIP Stipulation was executed, PSE&G proposed to make the CAC permanent, to dramatically expand the capital expenditures that would be recovered through the CAC, and to further expand the CAC to recover pension costs that have nothing whatsoever to do with capital investment. The Company is attempting to circumvent not only the spirit, but also the letter, of the CIIP Stipulation by proposing to extend the CAC to recover various costs for which it was never intended.

Q. In addition to violating the Stipulation in the Capital Infrastructure Investment Program proceeding, what other objections do you have to the Company's proposal to expand the CAC to other costs?

A. Since Rate Counsel Robert Henkes is addressing the issue of whether or not the BPU should approve a pension tracker for PSE&G, I will limit my comments to the propriety of expanding the CAC to include all distribution capital projects other than those directly related to new businesses. The Company's proposal is nothing more than another attempt to shift risk from shareholders to ratepayers and to relieve management of its responsibility to manage the Company appropriately. Furthermore, implementation of a CAC-like mechanism would remove a powerful incentive for utility cost control between rate cases.

The Company's proposal results in single-issue ratemaking that will have a significant impact on utility rates. The Company is proposing to reset the CAC at the effective date of new base rates. In addition to anticipated Capital Infrastructure Investment Program costs, the Company is also proposing to begin recovery of electric and gas distribution capital expenditures that are expected to be made from the effective date of new rates through December 31, 2010. This proposal represents a significant and fundamental change in the manner in which a utility's investment is recovered. Moreover, this proposal only addresses one element of the ratemaking equation. By attempting to charge ratepayers for investment made between base rate cases, including projected investment, PSE&G is dismantling the regulatory process that attempts to match investment, expenses, and revenues. As such, this proposal violates the most basic principle of ratemaking and should be rejected.

Expanding the CAC to include additional distribution plant investment between base rate cases would significantly increase the costs that the Company recovers through tracking mechanisms, thereby further decreasing shareholder risk. At the present time, the Company already collects well over 70% of its revenue requirement on a dollar-for- dollar basis through clause type mechanisms. As shown in Schedule SS-E9 R-1, PSE&G's present distribution revenue is approximately $1.135 billion, yet its electric distribution revenue comprises only 21.5% of its total electric sales revenue, as reflected on Mr. Kahrer's schedule. (Schedule MGK-19 R-1.) Similarly, as shown in Schedule SS-G8 R-1, its present gas distribution revenue is approximately $668.874 million, yet its gas distribution revenue comprises only 26.7% of its total gas sales revenue as shown on Mr. Kahrer's schedule. (MGK-19 R-1.) Thus, PSE&G's shareholders are already insulated from the risk for the vast majority of the Company's costs. PSE&G's attempt to shift even more risk onto its ratepayers should be denied.

Q. How much additional investment does the Company estimate would be recovered through the expanded CAC?

A. In response to RCR-CAC-8, the Company identified electric capital expenditures of $1.086 billion from 2010 to 2013 that it is proposing to recover through an expanded CAC, and $513.540 million of natural gas capital expenditures. These amounts are in addition to the Capital Infrastructure Investment Program costs that have already been approved for recovery through the CAC. Assuming the cost of capital requested by the Company in this case, expanding the CAC to include distribution capital expenditures would result in further rate increases of approximately $260 million for electric customers and of approximately $77 million for gas customers during this period. Moreover, these increases would be in addition to any increases that would ordinarily be implemented, due to increases in supply costs, SBC costs, other RGGI surcharges, the approved CAC, or other surcharge mechanisms. In addition, ratepayers would be required to pay these costs without receiving any benefit from either cost decreases or incremental revenues that might occur during this period. Expansion of the CAC to include additional distribution capital expenditures between base rate cases is a bad idea, results in single-issue ratemaking, will unfairly shift risk from shareholders to ratepayers, and will cost ratepayers millions of dollars in higher utility bills. Therefore, I recommend that it be denied.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

List of Prior Testimonies

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Mid-Kansas Electric Company	E	Kansas	09-MKEE-969-RTS	10/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy, Inc.	E	Kansas	09-WSEE-925-RTS	9/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08050326 EO08080542	8/09	Demand Response Programs	Division of Rate Counsel
Public Service Electric and Gas Company	E	New Jersey	EO09030249	7/09	Solar Loan II Program	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	09-MDWE-792-RTS	7/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy and KG&E	E	Kansas	09-WSEE-641-GIE	6/09	Rate Consolidation	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	09-60	6/09	Cost of Capital	Division of the Public Advocate
Rockland Electric Company	E	New Jersey	GO09020097	6/09	SREC-Based Financing Program	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	09-29	6/09	Revenue Requirements Cost of Capital	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	08-269F	3/09	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	08-266F	2/09	Gas Cost Rates	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	09-KCPE-246-RTS	2/09	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08090840	1/09	Solar Financing Program	Division of Rate Counsel
Atlantic City Electric Company	E	New Jersey	EO06100744 EO08100875	1/09	Solar Financing Program	Division of Rate Counsel
West Virginia-American Water Company	W	West Virginia	08-0900-W-42T	11/08	Revenue Requirements	The Consumer Advocate Division of the PSC
Westar Energy, Inc.	E	Kansas	08-WSEE-1041-RTS	9/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Artesian Water Company	W	Delaware	08-96	9/08	Cost of Capital, Revenue, New Headquarters	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR08020113	9/08	Form 1205 Equipment & Installation Rates	Division of Rate Counsel
Pawtucket Water Supply Board	W	Rhode Island	3945	7/08	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey American Water Co.	W/WW	New Jersey	WR08010020	7/08	Consolidated Income Taxes	Division of Rate Counsel
New Jersey Natural Gas Company	G	New Jersey	GR07110889	5/08	Revenue Requirements	Division of Rate Counsel
Kansas Electric Power Cooperative, Inc.	E	Kansas	08-KEPE-597-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Public Service Electric and Gas Company	E	New Jersey	EX02060363 EA02060366	5/08	Deferred Balances Audit	Division of Rate Counsel
Cablevision Systems Corporation	C	New Jersey	CR07110894, et al.	5/08	Forms 1240 and 1205	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	08-MDWE-594-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	07-246F	4/08	Gas Service Rates	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR07100717-946	3/08	Form 1240	Division of Rate Counsel
Generic Commission Investigation	G	New Mexico	07-00340-UT	3/08	Weather Normalization	New Mexico Office of Attorney General
Southwestern Public Service Company	E	New Mexico	07-00319-UT	3/08	Revenue Requirements Cost of Capital	New Mexico Office of Attorney General
Delmarva Power and Light Company	G	Delaware	07-239F	2/08	Gas Cost Rates	Division of the Public Advocate
Atmos Energy Corp.	G	Kansas	08-ATMG-280-RTS	1/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Aquila /Black Hills / Kansas City Power & Light	G	Kansas	07-BHCG-1063-ACQ 07-KCPE-1064-ACQ	12/07	Utility Acquisitions	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	07-186	12/07	Cost of Capital Regulatory Policy	Division of the Public Advocate
Westar Energy, Inc.	E	Kansas	08-WSEE-309-PRE	11/07	Predetermination of Wind Generation	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Company	E/G	New Jersey	ER07050303 GR07050304	11/07	Societal Benefits Charge	Division of Rate Counsel
Public Service Company of New Mexico	E	New Mexico	07-00077-UT	10/07	Revenue Requirements Cost of Capital	New Mexico Office of Attorney General
Public Service Electric and Gas Company	E	New Jersey	EO07040278	9/07	Solar Cost Recovery	Division of Rate Counsel
Comcast Cable	C	New Jersey	CR07030147	8/07	Form 1205	Division of Rate Counsel
Kansas City Power & Light Company	E	Kansas	07-KCPE-905-RTS	8/07	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Cablevision Systems Corporation	C	New Jersey	CR06110781, et al.	5/07	Cable Rates - Forms 1205 and 1240	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	05-WSEE-981-RTS	4/07	Revenue Requirements Issues on Remand	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	06-285F	4/07	Gas Cost Rates	Division of the Public Advocate
Comcast of Jersey City, et al.	C	New Jersey	CR06070558	4/07	Cable Rates	Division of Rate Counsel
Westar Energy	E	Kansas	07-WSEE-616-PRE	3/07	Pre-Approval of Generation Facilities	Citizens' Utility Ratepayer Board
Woonsocket Water Division	W	Rhode Island	3800	3/07	Revenue Requirements	Division of Public Utilities and Carriers

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Aquila - KGO	G	Kansas	07-AQLG-431-RTS	3/07	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	06-287F	3/07	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	06-284	1/07	Revenue Requirements Cost of Capital	Division of the Public Advocate
El Paso Electric Company	E	New Mexico	06-00258 UT	11/06	Revenue Requirements	New Mexico Office of Attorney General
Aquila, Inc. / Mid-Kansas Electric Co.	E	Kansas	06-MKEE-524-ACQ	11/06	Proposed Acquisition	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	G	New Mexico	06-00210-UT	11/06	Revenue Requirements	New Mexico Office of Attorney General
Atlantic City Electric Company	E	New Jersey	EM06090638	11/06	Sale of B.L. England	Division of Rate Counsel
United Water Delaware, Inc.	W	Delaware	06-174	10/06	Revenue Requirements Cost of Capital	Division of the Public Advocate
Public Service Electric and Gas Company	G	New Jersey	GR05080686	10/06	Societal Benefits Charge	Division of Rate Counsel
Comcast (Avalon, Maple Shade, Gloucester)	C	New Jersey	CR06030136-139	10/06	Form 1205 and 1240 Cable Rates	Division of Rate Counsel
Kansas Gas Service	G	Kansas	06-KGSG-1209-RTS	9/06	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
New Jersey American Water Co. Elizabethtown Water Company Mount Holly Water Company	W	New Jersey	WR06030257	9/06	Regulatory Policy Taxes Cash Working Capital	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	06-145	9/06	Revenue Requirements Cost of Capital	Division of the Public Advocate
Artesian Water Company	W	Delaware	06-158	9/06	Revenue Requirements Cost of Capital	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	06-KCPE-828-RTS	8/06	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Midwest Energy, Inc.	G	Kansas	06-MDWG-1027-RTS	7/06	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	05-315F	6/06	Gas Service Rates	Division of the Public Advocate
Cablevision Systems Corporation	C	New Jersey	CR05110924, et al.	5/06	Cable Rates - Forms 1205 and 1240	Division of the Ratepayer Advocate
Montague Sewer Company	WW	New Jersey	WR05121056	5/06	Revenue Requirements	Division of the Ratepayer Advocate
Comcast of South Jersey	C	New Jersey	CR05119035, et al.	5/06	Cable Rates - Form 1240	Division of the Ratepayer Advocate
Comcast of New Jersey	C	New Jersey	CR05090826-827	4/06	Cable Rates - Form 1240	Division of the Ratepayer Advocate
Parkway Water Company	W	New Jersey	WR05070634	3/06	Revenue Requirements Cost of Capital	Division of the Ratepayer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Aqua Pennsylvania, Inc.	W	Pennsylvania	R-00051030	2/06	Revenue Requirements	Office of Consumer Advocate
Delmarva Power and Light Company	G	Delaware	05-312F	2/06	Gas Cost Rates	Division of the Public Advocate
Delmarva Power and Light Company	E	Delaware	05-304	12/05	Revenue Requirements Cost of Capital	Division of the Public Advocate
Artesian Water Company	W	Delaware	04-42	10/05	Revenue Requirements Cost of Capital (Remand)	Division of the Public Advocate
Utility Systems, Inc.	WW	Delaware	335-05	9/05	Regulatory Policy	Division of the Ratepayer Advocate
Westar Energy, Inc.	E	Kansas	05-WSEE-981-RTS	9/05	Revenue Requirements	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	05-EPDE-980-RTS	8/05	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Comcast Cable	C	New Jersey	CR05030186	8/05	Form 1205	Division of the Ratepayer Advocate
Pawtucket Water Supply Board	W	Rhode Island	3674	7/05	Revenue Requirements	Division of Public Utilities and Carriers
Delmarva Power and Light Company	E	Delaware	04-391	7/05	Standard Offer Service	Division of the Public Advocate
Patriot Media & Communications CNJ, LLC	C	New Jersey	CR04111453-455	6/05	Cable Rates	Division of the Ratepayer Advocate
Cablevision	C	New Jersey	CR04111379, et al.	6/05	Cable Rates	Division of the Ratepayer Advocate
Comcast of Mercer County, LLC	C	New Jersey	CR04111458	6/05	Cable Rates	Division of the Ratepayer Advocate
Comcast of South Jersey, LLC, et al.	C	New Jersey	CR04101356, et al.	5/05	Cable Rates	Division of the Ratepayer Advocate
Comcast of Central New Jersey LLC, et al.	C	New Jersey	CR04101077, et al.	4/05	Cable Rates	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	3660	4/05	Revenue Requirements	Division of Public Utilities and Carriers
Aquila, Inc.	G	Kansas	05-AQLG-367-RTS	3/05	Revenue Requirements Cost of Capital Tariff Issues	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	04-334F	3/05	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	04-301F	3/05	Gas Cost Rates	Division of the Public Advocate
Delaware Electric Cooperative, Inc.	E	Delaware	04-288	12/04	Revenue Requirements Cost of Capital	Division of the Public Advocate
Public Service Company of New Mexico	E	New Mexico	04-00311-UT	11/04	Renewable Energy Plans	Office of the New Mexico Attorney General

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Woonsocket Water Division	W	Rhode Island	3626	10/04	Revenue Requirements	Division of Public Utilities and Carriers
Aquila, Inc.	E	Kansas	04-AQLE-1065-RTS	10/04	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	04-121	8/04	Conservation Rates (Affidavit)	Division of the Public Advocate
Atlantic City Electric Company	E	New Jersey	ER03020110 PUC 06061-2003S	8/04	Deferred Balance Phase II	Division of the Ratepayer Advocate
Kentucky American Water Company	W	Kentucky	2004-00103	8/04	Revenue Requirements	Office of Rate Inter-vention of the Attorney General
Shorelands Water Company	W	New Jersey	WR04040295	8/04	Revenue Requirements Cost of Capital	Division of the Ratepayer Advocate
Artesian Water Company	W	Delaware	04-42	8/04	Revenue Requirements Cost of Capital	Division of the Public Advocate
Long Neck Water Company	W	Delaware	04-31	7/04	Cost of Equity	Division of the Public Advocate
Tidewater Utilities, Inc.	W	Delaware	04-152	7/04	Cost of Capital	Division of the Public Advocate
Cablevision	C	New Jersey	CR03100850, et al.	6/04	Cable Rates	Division of the Ratepayer Advocate
Montague Water and Sewer Companies	W/WW	New Jersey	WR03121034 (W) WR03121035 (S)	5/04	Revenue Requirements	Division of the Ratepayer Advocate
Comcast of South Jersey, Inc.	C	New Jersey	CR03100876,77,79,80	5/04	Form 1240 Cable Rates	Division of the Ratepayer Advocate
Comcast of Central New Jersey, et al.	C	New Jersey	CR03100749-750 CR03100759-762	4/04	Cable Rates	Division of the Ratepayer Advocate
Time Warner	C	New Jersey	CR03100763-764	4/04	Cable Rates	Division of the Ratepayer Advocate
Interstate Navigation Company	N	Rhode Island	3573	3/04	Revenue Requirements	Division of Public Utilities and Carriers
Aqua Pennsylvania, Inc.	W	Pennsylvania	R-00038805	2/04	Revenue Requirements	Pennsylvania Office of Consumer Advocate
Comcast of Jersey City, et al.	C	New Jersey	CR03080598-601	2/04	Cable Rates	Division of the Ratepayer Advocate
Delmarva Power and Light Company	G	Delaware	03-378F	2/04	Fuel Clause	Division of the Public Advocate
Atmos Energy Corp.	G	Kansas	03-ATMG-1036-RTS	11/03	Revenue Requirements	Citizens' Utility Ratepayer Board
Aquila, Inc. (UCU)	G	Kansas	02-UTCG-701-GIG	10/03	Using utility assets as collateral	Citizens' Utility Ratepayer Board
CenturyTel of Northwest Arkansas, LLC	T	Arkansas	03-041-U	10/03	Affiliated Interests	The Arkansas Public Service Commission General Staff

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Borough of Butler Electric Utility	E	New Jersey	CR03010049/63	9/03	Revenue Requirements	Division of the Ratepayer Advocate
Comcast Cablevision of Avalon Comcast Cable Communications	C	New Jersey	CR03020131-132	9/03	Cable Rates	Division of the Ratepayer Advocate
Delmarva Power and Light Company d/b/a Conectiv Power Delivery	E	Delaware	03-127	8/03	Revenue Requirements	Division of the Public Advocate
Kansas Gas Service	G	Kansas	03-KGSG-602-RTS	7/03	Revenue Requirements	Citizens' Utility Ratepayer Board
Washington Gas Light Company	G	Maryland	8959	6/03	Cost of Capital Incentive Rate Plan	U.S. DOD/FEA
Pawtucket Water Supply Board	W	Rhode Island	3497	6/03	Revenue Requirements	Division of Public Utilities and Carriers
Atlantic City Electric Company	E	New Jersey	EO03020091	5/03	Stranded Costs	Division of the Ratepayer Advocate
Public Service Company of New Mexico	G	New Mexico	03-000-17 UT	5/03	Cost of Capital Cost Allocations	Office of the New Mexico Attorney General
Comcast - Hopewell, et al.	C	New Jersey	CR02110818 CR02110823-825	5/03	Cable Rates	Division of the Ratepayer Advocate
Cablevision Systems Corporation	C	New Jersey	CR02110838, 43-50	4/03	Cable Rates	Division of the Ratepayer Advocate
Comcast-Garden State / Northwest	C	New Jersey	CR02100715 CR02100719	4/03	Cable Rates	Division of the Ratepayer Advocate
Midwest Energy, Inc. and Westar Energy, Inc.	E	Kansas	03-MDWE-421-ACQ	4/03	Acquisition	Citizens' Utility Ratepayer Board
Time Warner Cable	C	New Jersey	CR02100722 CR02100723	4/03	Cable Rates	Division of the Ratepayer Advocate
Westar Energy, Inc.	E	Kansas	01-WSRE-949-GIE	3/03	Restructuring Plan	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Company	E	New Jersey	ER02080604 PUC 7983-02	1/03	Deferred Balance	Division of the Ratepayer Advocate
Atlantic City Electric Company d/b/a Conectiv Power Delivery	E	New Jersey	ER02080510 PUC 6917-02S	1/03	Deferred Balance	Division of the Ratepayer Advocate
Wallkill Sewer Company	WW	New Jersey	WR02030193 WR02030194	12/02	Revenue Requirements Purchased Sewage Treatment Adj. (PSTAC)	Division of the Ratepayer Advocate
Midwest Energy, Inc.	E	Kansas	03-MDWE-001-RTS	12/02	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast-LBI Crestwood	C	New Jersey	CR02050272 CR02050270	11/02	Cable Rates	Division of the Ratepayer Advocate
Reliant Energy Arkla	G	Oklahoma	PUD200200166	10/02	Affiliated Interest Transactions	Oklahoma Corporation Commission, Public Utility Division Staff
Midwest Energy, Inc.	G	Kansas	02-MDWG-922-RTS	10/02	Gas Rates	Citizens' Utility Ratepayer Board

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Comcast Cablevision of Avalon	C	New Jersey	CR02030134 CR02030137	7/02	Cable Rates	Division of the Ratepayer Advocate
RCN Telecom Services, Inc., and Home Link Communications	C	New Jersey	CR02010044, CR02010047	7/02	Cable Rates	Division of the Ratepayer Advocate
Washington Gas Light Company	G	Maryland	8920	7/02	Rate of Return Rate Design (Rebuttal)	General Services Administration (GSA)
Chesapeake Utilities Corporation	G	Delaware	01-307, Phase II	7/02	Rate Design Tariff Issues	Division of the Public Advocate
Washington Gas Light Company	G	Maryland	8920	6/02	Rate of Return Rate Design	General Services Administration (GSA)
Tidewater Utilities, Inc.	W	Delaware	02-28	6/02	Revenue Requirements	Division of the Public Advocate
Western Resources, Inc.	E	Kansas	01-WSRE-949-GIE	5/02	Financial Plan	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	02-EPDE-488-RTS	5/02	Revenue Requirements	Citizens' Utility Ratepayer Board
Southwestern Public Service Company	E	New Mexico	3709	4/02	Fuel Costs	Office of the New Mexico Attorney General
Cablevision Systems	C	New Jersey	CR01110706, et al	4/02	Cable Rates	Division of the Ratepayer Advocate
Potomac Electric Power Company	E	District of Columbia	945, Phase II	4/02	Divestiture Procedures	General Services Administration (GSA)
Vermont Yankee Nuclear Power Corp.	E	Vermont	6545	3/02	Sale of VY to Entergy Corp. (Supplemental)	Department of Public Service
Delmarva Power and Light Company	G	Delaware	01-348F	1/02	Gas Cost Adjustment	Division of the Public Advocate
Vermont Yankee Nuclear Power Corp.	E	Vermont	6545	1/02	Sale of VY to Entergy Corp.	Department of Public Service
Pawtucket Water Supply Company	W	Rhode Island	3378	12/01	Revenue Requirements	Division of Public Utilities and Carriers
Chesapeake Utilities Corporation	G	Delaware	01-307, Phase I	12/01	Revenue Requirements	Division of the Public Advocate
Potomac Electric Power Company	E	Maryland	8796	12/01	Divestiture Procedures	General Services Administration (GSA)
Kansas Electric Power Cooperative	E	Kansas	01-KEPE-1106-RTS	11/01	Depreciation Methodology (Cross Answering)	Citizens' Utility Ratepayer Board
Wellsboro Electric Company	E	Pennsylvania	R-00016356	11/01	Revenue Requirements	Office of Consumer Advocate
Kent County Water Authority	W	Rhode Island	3311	10/01	Revenue Requirements (Surrebuttal)	Division of Public Utilities and Carriers
Pepco and New RC, Inc.	E	District of Columbia	1002	10/01	Merger Issues and Performance Standards	General Services Administration (GSA)

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Potomac Electric Power Co. & Delmarva Power	E	Delaware	01-194	10/01	Merger Issues and Performance Standards	Division of the Public Advocate
Yankee Gas Company	G	Connecticut	01-05-19PH01	9/01	Affiliated Transactions	Office of Consumer Counsel
Hope Gas, Inc., d/b/a Dominion Hope	G	West Virginia	01-0330-G-42T 01-0331-G-30C 01-1842-GT-T 01-0685-G-PC	9/01	Revenue Requirements (Rebuttal)	The Consumer Advocate Division of the PSC
Pennsylvania-American Water Company	W	Pennsylvania	R-00016339	9/01	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Potomac Electric Power Co. & Delmarva Power	E	Maryland	8890	9/01	Merger Issues and Performance Standards	General Services Administration (GSA)
Comcast Cablevision of Long Beach Island, et al	C	New Jersey	CR01030149-50 CR01050285	9/01	Cable Rates	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	3311	8/01	Revenue Requirements	Division of Public Utilities and Carriers
Pennsylvania-American Water Company	W	Pennsylvania	R-00016339	8/01	Revenue Requirements	Office of Consumer Advocate
Roxiticus Water Company	W	New Jersey	WR01030194	8/01	Revenue Requirements Cost of Capital Rate Design	Division of the Ratepayer Advocate
Hope Gas, Inc., d/b/a Dominion Hope	G	West Virginia	01-0330-G-42T 01-0331-G-30C 01-1842-GT-T 01-0685-G-PC	8/01	Revenue Requirements	Consumer Advocate Division of the PSC
Western Resources, Inc.	E	Kansas	01-WSRE-949-GIE	6/01	Restructuring Financial Integrity (Rebuttal)	Citizens' Utility Ratepayer Board
Western Resources, Inc.	E	Kansas	01-WSRE-949-GIE	6/01	Restructuring Financial Integrity	Citizens' Utility Ratepayer Board
Cablevision of Allamuchy, et al	C	New Jersey	CR00100824, etc.	4/01	Cable Rates	Division of the Ratepayer Advocate
Public Service Company of New Mexico	E	New Mexico	3137, Holding Co.	4/01	Holding Company	Office of the Attorney General
Keauhou Community Services, Inc.	W	Hawaii	00-0094	4/01	Rate Design	Division of Consumer Advocacy
Western Resources, Inc.	E	Kansas	01-WSRE-436-RTS	4/01	Revenue Requirements Affiliated Interests (Motion for Suppl. Changes)	Citizens' Utility Ratepayer Board
Western Resources, Inc.	E	Kansas	01-WSRE-436-RTS	4/01	Revenue Requirements Affiliated Interests	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	3137, Part III	4/01	Standard Offer Service (Additional Direct)	Office of the Attorney General
Chem-Nuclear Systems, LLC	SW	South Carolina	2000-366-A	3/01	Allowable Costs	Department of Consumer Affairs

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Southern Connecticut Gas Company	G	Connecticut	00-12-08	3/01	Affiliated Interest Transactions	Office of Consumer Counsel
Atlantic City Sewerage Corporation	WW	New Jersey	WR00080575	3/01	Revenue Requirements Cost of Capital Rate Design	Division of the Ratepayer Advocate
Delmarva Power and Light Company d/b/a Conectiv Power Delivery	G	Delaware	00-314	3/01	Margin Sharing	Division of the Public Advocate
Senate Bill 190 Re: Performance Based Ratemaking	G	Kansas	Senate Bill 190	2/01	Performance-Based Ratemaking Mechanisms	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	00-463-F	2/01	Gas Cost Rates	Division of the Public Advocate
Waitsfield Fayston Telephone Company	T	Vermont	6417	12/00	Revenue Requirements	Department of Public Service
Delaware Electric Cooperative	E	Delaware	00-365	11/00	Code of Conduct Cost Allocation Manual	Division of the Public Advocate
Commission Inquiry into Performance-Based Ratemaking	G	Kansas	00-GIMG-425-GIG	10/00	Performance-Based Ratemaking Mechanisms	Citizens' Utility Ratepayer Board
Pawtucket Water Supply Board	W	Rhode Island	3164 Separation Plan	10/00	Revenue Requirements	Division of Public Utilities and Carriers
Comcast Cablevision of Philadelphia, L.P.	C	Pennsylvania	3756	10/00	Late Payment Fees (Affidavit)	Kaufman, Lankelis, et al.
Public Service Company of New Mexico	E	New Mexico	3137, Part III	9/00	Standard Offer Service	Office of the Attorney General
Laie Water Company	W	Hawaii	00-0017 Separation Plan	8/00	Rate Design	Division of Consumer Advocacy
El Paso Electric Company	E	New Mexico	3170, Part II, Ph. 1	7/00	Electric Restructuring	Office of the Attorney General
Public Service Company of New Mexico	E	New Mexico	3137 - Part II Separation Plan	7/00	Electric Restructuring	Office of the Attorney General
PG Energy	G	Pennsylvania	R-00005119	6/00	Revenue Requirements	Office of Consumer Advocate
Consolidated Edison, Inc. and Northeast Utilities	E/G	Connecticut	00-01-11	4/00	Merger Issues (Additional Supplemental)	Office of Consumer Counsel
Sussex Shores Water Company	W	Delaware	99-576	4/00	Revenue Requirements	Division of the Public Advocate
Utilicorp United, Inc.	G	Kansas	00-UTCG-336-RTS	4/00	Revenue Requirements	Citizens' Utility Ratepayer Board
TCI Cablevision	C	Missouri	9972-9146	4/00	Late Fees (Affidavit)	Honora Eppert, et al
Oklahoma Natural Gas Company	G	Oklahoma	PUD 990000166 PUD 980000683 PUD 990000570	3/00	Pro Forma Revenue Affiliated Transactions (Rebuttal)	Oklahoma Corporation Commission, Public Utility Division Staff
Tidewater Utilities, Inc. Public Water Supply Co.	W	Delaware	99-466	3/00	Revenue Requirements	Division of the Public Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Delmarva Power and Light Company	G/E	Delaware	99-582	3/00	Cost Accounting Manual Code of Conduct	Division of the Public Advocate
Philadelphia Suburban Water Company	W	Pennsylvania	R-00994868 R-00994877 R-00994878 R-00994879	3/00	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Philadelphia Suburban Water Company	W	Pennsylvania	R-00994868 R-00994877 R-00994878 R-00994879	2/00	Revenue Requirements	Office of Consumer Advocate
Consolidated Edison, Inc. and Northeast Utilities	E/G	Connecticut	00-01-11	2/00	Merger Issues	Office of Consumer Counsel
Oklahoma Natural Gas Company	G	Oklahoma	PUD 990000166 PUD 980000683 PUD 990000570	1/00	Pro Forma Revenue Affiliated Transactions	Oklahoma Corporation Commission, Public Utility Division Staff
Connecticut Natural Gas Company	G	Connecticut	99-09-03	1/00	Affiliated Transactions	Office of Consumer Counsel
Time Warner Entertainment Company, L.P.	C	Indiana	48D06-9803-CP-423	1999	Late Fees (Affidavit)	Kelly J. Whiteman, et al
TCI Communications, Inc., et al	C	Indiana	55D01-9709-CP-00415	1999	Late Fees (Affidavit)	Franklin E. Littell, et al
Southwestern Public Service Company	E	New Mexico	3116	12/99	Merger Approval	Office of the Attorney General
New England Electric System Eastern Utility Associates	E	Rhode Island	2930	11/99	Merger Policy	Department of Attorney General
Delaware Electric Cooperative	E	Delaware	99-457	11/99	Electric Restructuring	Division of the Public Advocate
Jones Intercable, Inc.	C	Maryland	CAL98-00283	10/99	Cable Rates (Affidavit)	Cynthia Maisonette and Ola Renee Chatman, et al
Texas-New Mexico Power Company	E	New Mexico	3103	10/99	Acquisition Issues	Office of Attorney General
Southern Connecticut Gas Company	G	Connecticut	99-04-18	9/99	Affiliated Interest	Office of Consumer Counsel
TCI Cable Company	C	New Jersey	CR99020079 et al	9/99	Cable Rates Forms 1240/1205	Division of the Ratepayer Advocate
All Regulated Companies	E/G/W	Delaware	Reg. No. 4	8/99	Filing Requirements (Position Statement)	Division of the Public Advocate
Mile High Cable Partners	C	Colorado	95-CV-5195	7/99	Cable Rates (Affidavit)	Brett Marshall, an individual, et al
Electric Restructuring Comments	E	Delaware	Reg. 49	7/99	Regulatory Policy (Supplemental)	Division of the Public Advocate
Long Neck Water Company	W	Delaware	99-31	6/99	Revenue Requirements	Division of the Public Advocate
Delmarva Power and Light Company	E	Delaware	99-163	6/99	Electric Restructuring	Division of the Public Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Potomac Electric Power Company	E	District of Columbia	945	6/99	Divestiture of Generation Assets	U.S. GSA - Public Utilities
Comcast	C	Indiana	49C01-9802-CP-000386	6/99	Late Fees (Affidavit)	Ken Hecht, et al
Petitions of BA-NJ and NJPA re: Payphone Ops	T	New Jersey	TO97100792 PUCOT 11269-97N	6/99	Economic Subsidy Issues (Surrebuttal)	Division of the Ratepayer Advocate
Montague Water and Sewer Companies	W/WW	New Jersey	WR98101161 WR98101162 PUCRS 11514-98N	5/99	Revenue Requirements Rate Design (Supplemental)	Division of the Ratepayer Advocate
Cablevision of Bergen, Bayonne, Newark	C	New Jersey	CR98111197-199 CR98111190	5/99	Cable Rates Forms 1240/1205	Division of the Ratepayer Advocate
Cablevision of Bergen, Hudson, Monmouth	C	New Jersey	CR97090624-626 CTV 1697-98N	5/99	Cable Rates - Form 1235 (Rebuttal)	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	2860	4/99	Revenue Requirements	Division of Public Utilities & Carriers
Montague Water and Sewer Companies	W/WW	New Jersey	WR98101161 WR98101162	4/99	Revenue Requirements Rate Design	Division of the Ratepayer Advocate
PEPCO	E	District of Columbia	945	4/99	Divestiture of Assets	U.S. GSA - Public Utilities
Western Resources, Inc. and Kansas City Power & Light	E	Kansas	97-WSRE-676-MER	4/99	Merger Approval (Surrebuttal)	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	98-479F	3/99	Fuel Costs	Division of the Public Advocate
Lenfest Atlantic d/b/a Suburban Cable	C	New Jersey	CR97070479 et al	3/99	Cable Rates	Division of the Ratepayer Advocate
Electric Restructuring Comments	E	District of Columbia	945	3/99	Regulatory Policy	U.S. GSA - Public Utilities
Petitions of BA-NJ and NJPA re: Payphone Ops	T	New Jersey	TO97100792 PUCOT 11269-97N	3/99	Tariff Revision Payphone Subsidies FCC Services Test (Rebuttal)	Division of the Ratepayer Advocate
Western Resources, Inc. and Kansas City Power & Light	E	Kansas	97-WSRE-676-MER	3/99	Merger Approval (Answering)	Citizens' Utility Ratepayer Board
Western Resources, Inc. and Kansas City Power & Light	E	Kansas	97-WSRE-676-MER	2/99	Merger Approval	Citizens' Utility Ratepayer Board
Adelphia Cable Communications	C	Vermont	6117-6119	1/99	Late Fees (Additional Direct Supplemental)	Department of Public Service
Adelphia Cable Communications	C	Vermont	6117-6119	12/98	Cable Rates (Forms 1240, 1205, 1235) and Late Fees (Direct Supplemental)	Department of Public Service
Adelphia Cable Communications	C	Vermont	6117-6119	12/98	Cable Rates (Forms 1240, 1205, 1235) and Late Fees	Department of Public Service
Orange and Rockland/ Consolidated Edison	E	New Jersey	EM98070433	11/98	Merger Approval	Division of the Ratepayer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Cablevision	C	New Jersey	CR97090624 CR97090625 CR97090626	11/98	Cable Rates - Form 1235	Division of the Ratepayer Advocate
Petitions of BA-NJ and NJPA re: Payphone Ops.	T	New Jersey	TO97100792 PUCOT 11269-97N	10/98	Payphone Subsidies FCC New Services Test	Division of the Ratepayer Advocate
United Water Delaware	W	Delaware	98-98	8/98	Revenue Requirements	Division of the Public Advocate
Cablevision	C	New Jersey	CR97100719, 726 730, 732	8/98	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Potomac Electric Power Company	E	Maryland	Case No. 8791	8/98	Revenue Requirements Rate Design	U.S. GSA - Public Utilities
Investigation of BA-NJ IntraLATA Calling Plans	T	New Jersey	TO97100808 PUCOT 11326-97N	8/98	Anti-Competitive Practices (Rebuttal)	Division of the Ratepayer Advocate
Investigation of BA-NJ IntraLATA Calling Plans	T	New Jersey	TO97100808 PUCOT 11326-97N	7/98	Anti-Competitive Practices	Division of the Ratepayer Advocate
TCI Cable Company/ Cablevision	C	New Jersey	CTV 03264-03268 and CTV 05061	7/98	Cable Rates	Division of the Ratepayer Advocate
Mount Holly Water Company	W	New Jersey	WR98020058 PUC 03131-98N	7/98	Revenue Requirements	Division of the Ratepayer Advocate
Pawtucket Water Supply Board	W	Rhode Island	2674	5/98	Revenue Requirements (Surrebuttal)	Division of Public Utilities & Carriers
Pawtucket Water Supply Board	W	Rhode Island	2674	4/98	Revenue Requirements	Division of Public Utilities and Carriers
Energy Master Plan Phase II Proceeding - Restructuring	E	New Jersey	EX94120585U, EO97070457,60,63,66	4/98	Electric Restructuring Issues (Supplemental Surrebuttal)	Division of the Ratepayer Advocate
Energy Master Plan Phase I Proceeding - Restructuring	E	New Jersey	EX94120585U, EO97070457,60,63,66	3/98	Electric Restructuring Issues	Division of the Ratepayer Advocate
Shorelands Water Company	W	New Jersey	WR97110835 PUC 11324-97	2/98	Revenue Requirements	Division of the Ratepayer Advocate
TCI Communications, Inc.	C	New Jersey	CR97030141 and others	11/97	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Citizens Telephone Co. of Kecksburg	T	Pennsylvania	R-00971229	11/97	Alternative Regulation Network Modernization	Office of Consumer Advocate
Consumers Pennsylvania Water Co. - Shenango Valley Division	W	Pennsylvania	R-00973972	10/97	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Universal Service Funding	T	New Jersey	TX95120631	10/97	Schools and Libraries Funding (Rebuttal)	Division of the Ratepayer Advocate
Universal Service Funding	T	New Jersey	TX95120631	9/97	Low Income Fund High Cost Fund	Division of the Ratepayer Advocate
Consumers Pennsylvania Water Co. - Shenango Valley Division	W	Pennsylvania	R-00973972	9/97	Revenue Requirements	Office of Consumer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Delmarva Power and Light Company	G/E	Delaware	97-65	9/97	Cost Accounting Manual Code of Conduct	Office of the Public Advocate
Western Resources, Oneok, and WAI	G	Kansas	WSRG-486-MER	9/97	Transfer of Gas Assets	Citizens' Utility Ratepayer Board
Universal Service Funding	T	New Jersey	TX95120631	9/97	Schools and Libraries Funding (Rebuttal)	Division of the Ratepayer Advocate
Universal Service Funding	T	New Jersey	TX95120631	8/97	Schools and Libraries Funding	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	2555	8/97	Revenue Requirements (Surrebuttal)	Division of Public Utilities and Carriers
Ironton Telephone Company	T	Pennsylvania	R-00971182	8/97	Alternative Regulation Network Modernization (Surrebuttal)	Office of Consumer Advocate
Ironton Telephone Company	T	Pennsylvania	R-00971182	7/97	Alternative Regulation Network Modernization	Office of Consumer Advocate
Comcast Cablevision	C	New Jersey	Various	7/97	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Maxim Sewerage Corporation	WW	New Jersey	WR97010052 PUCRA 3154-97N	7/97	Revenue Requirements	Division of the Ratepayer Advocate
Kent County Water Authority	W	Rhode Island	2555	6/97	Revenue Requirements	Division of Public Utilities and Carriers
Consumers Pennsylvania Water Co. - Roaring Creek	W	Pennsylvania	R-00973869	6/97	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Consumers Pennsylvania Water Co. - Roaring Creek	W	Pennsylvania	R-00973869	5/97	Revenue Requirements	Office of Consumer Advocate
Delmarva Power and Light Company	E	Delaware	97-58	5/97	Merger Policy	Office of the Public Advocate
Middlesex Water Company	W	New Jersey	WR96110818 PUCRL 11663-96N	4/97	Revenue Requirements	Division of the Ratepayer Advocate
Maxim Sewerage Corporation	WW	New Jersey	WR96080628 PUCRA 09374-96N	3/97	Purchased Sewerage Adjustment	Division of the Ratepayer Advocate
Interstate Navigation Company	N	Rhode Island	2484	3/97	Revenue Requirements Cost of Capital (Surrebuttal)	Division of Public Utilities & Carriers
Interstate Navigation Company	N	Rhode Island	2484	2/97	Revenue Requirements Cost of Capital	Division of Public Utilities & Carriers
Electric Restructuring Comments	E	District of Columbia	945	1/97	Regulatory Policy	U.S. GSA - Public Utilities
United Water Delaware	W	Delaware	96-194	1/97	Revenue Requirements	Office of the Public Advocate
PEPCO/ BGE/ Merger Application	E/G	District of Columbia	951	10/96	Regulatory Policy Cost of Capital (Rebuttal)	GSA

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Western Resources, Inc.	E	Kansas	193,306-U 193,307-U	10/96	Revenue Requirements Cost of Capital (Supplemental)	Citizens' Utility Ratepayer Board
PEPCO and BGE Merger Application	E/G	District of Columbia	951	9/96	Regulatory Policy, Cost of Capital	U.S. GSA - Public Utilities
Utilicorp United, Inc.	G	Kansas	193,787-U	8/96	Revenue Requirements	Citizens' Utility Ratepayer Board
TKR Cable Company of Gloucester	C	New Jersey	CTV07030-95N	7/96	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
TKR Cable Company of Warwick	C	New Jersey	CTV057537-95N	7/96	Cable Rates (Oral Testimony)	Division of the Ratepayer Advocate
Delmarva Power and Light Company	E	Delaware	95-196F	5/96	Fuel Cost Recovery	Office of the Public Advocate
Western Resources, Inc.	E	Kansas	193,306-U 193,307-U	5/96	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Princeville Utilities Company, Inc.	W/WW	Hawaii	95-0172 95-0168	1/96	Revenue Requirements Rate Design	Princeville at Hanalei Community Association
Western Resources, Inc.	G	Kansas	193,305-U	1/96	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Environmental Disposal Corporation	WW	New Jersey	WR94070319 (Remand Hearing)	11/95	Revenue Requirements Rate Design (Supplemental)	Division of the Ratepayer Advocate
Environmental Disposal Corporation	WW	New Jersey	WR94070319 (Remand Hearing)	11/95	Revenue Requirements	Division of the Ratepayer Advocate
Lanai Water Company	W	Hawaii	94-0366	10/95	Revenue Requirements Rate Design	Division of Consumer Advocacy
Cablevision of New Jersey, Inc.	C	New Jersey	CTV01382-95N	8/95	Basic Service Rates (Oral Testimony)	Division of the Ratepayer Advocate
Cablevision of New Jersey, Inc.	C	New Jersey	CTV01381-95N	8/95	Basic Service Rates (Oral Testimony)	Division of the Ratepayer Advocate
Chesapeake Utilities Corporation	G	Delaware	95-73	7/95	Revenue Requirements	Office of the Public Advocate
East Honolulu Community Services, Inc.	WW	Hawaii	7718	6/95	Revenue Requirements	Division of Consumer Advocacy
Wilmington Suburban Water Corporation	W	Delaware	94-149	3/95	Revenue Requirements	Office of the Public Advocate
Environmental Disposal Corporation	WW	New Jersey	WR94070319	1/95	Revenue Requirements (Supplemental)	Division of the Ratepayer Advocate
Roaring Creek Water Company	W	Pennsylvania	R-00943177	1/95	Revenue Requirements (Surrebuttal)	Office of Consumer Advocate
Roaring Creek Water Company	W	Pennsylvania	R-00943177	12/94	Revenue Requirements	Office of Consumer Advocate
Environmental Disposal Corporation	WW	New Jersey	WR94070319	12/94	Revenue Requirements	Division of the Ratepayer Advocate

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Delmarva Power and Light Company	E	Delaware	94-84	11/94	Revenue Requirements	Office of the Public Advocate
Delmarva Power and Light Company	G	Delaware	94-22	8/94	Revenue Requirements	Office of the Public Advocate
Empire District Electric Company	E	Kansas	190,360-U	8/94	Revenue Requirements	Citizens' Utility Ratepayer Board
Morris County Municipal Utility Authority	SW	New Jersey	MM10930027 ESW 1426-94	6/94	Revenue Requirements	Rate Counsel
US West Communications	T	Arizona	E-1051-93-183	5/94	Revenue Requirements (Surrebuttal)	Residential Utility Consumer Office
Pawtucket Water Supply Board	W	Rhode Island	2158	5/94	Revenue Requirements (Surrebuttal)	Division of Public Utilities & Carriers
US West Communications	T	Arizona	E-1051-93-183	3/94	Revenue Requirements	Residential Utility Consumer Office
Pawtucket Water Supply Board	W	Rhode Island	2158	3/94	Revenue Requirements	Division of Public Utilities & Carriers
Pollution Control Financing Authority of Camden County	SW	New Jersey	SR91111718J	2/94	Revenue Requirements (Supplemental)	Rate Counsel
Roaring Creek Water Company	W	Pennsylvania	R-00932665	9/93	Revenue Requirements (Supplemental)	Office of Consumer Advocate
Roaring Creek Water Company	W	Pennsylvania	R-00932665	9/93	Revenue Requirements	Office of Consumer Advocate
Kent County Water Authority	W	Rhode Island	2098	8/93	Revenue Requirements (Surrebuttal)	Division of Public Utilities and Carriers
Wilmington Suburban Water Company	W	Delaware	93-28	7/93	Revenue Requirements	Office of Public Advocate
Kent County Water Authority	W	Rhode Island	2098	7/93	Revenue Requirements	Division of Public Utilities & Carriers
Camden County Energy Recovery Associates, Inc.	SW	New Jersey	SR91111718J ESW1263-92	4/93	Revenue Requirements	Rate Counsel
Pollution Control Financing Authority of Camden County	SW	New Jersey	SR91111718J ESW 1263-92	4/93	Revenue Requirements	Rate Counsel
Jamaica Water Supply Company	W	New York	92-W-0583	3/93	Revenue Requirements	County of Nassau Town of Hempstead
New Jersey-American Water Company	W/WW	New Jersey	WR92090908J PUC 7266-92S	2/93	Revenue Requirements	Rate Counsel
Passaic County Utilities Authority	SW	New Jersey	SR91121816J ESW0671-92N	9/92	Revenue Requirements	Rate Counsel
East Honolulu Community Services, Inc.	WW	Hawaii	7064	8/92	Revenue Requirements	Division of Consumer Advocacy
The Jersey Central Power and Light Company	E	New Jersey	PUC00661-92 ER91121820J	7/92	Revenue Requirements	Rate Counsel
Mercer County Improvement Authority	SW	New Jersey	EWS11261-91S SR91111682J	5/92	Revenue Requirements	Rate Counsel

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Garden State Water Company	W	New Jersey	WR9109-1483 PUC 09118-91S	2/92	Revenue Requirements	Rate Counsel
Elizabethtown Water Company	W	New Jersey	WR9108-1293J PUC 08057-91N	1/92	Revenue Requirements	Rate Counsel
New-Jersey American Water Company	W/WW	New Jersey	WR9108-1399J PUC 8246-91	12/91	Revenue Requirements	Rate Counsel
Pennsylvania-American Water Company	W	Pennsylvania	R-911909	10/91	Revenue Requirements	Office of Consumer Advocate
Mercer County Improvement Authority	SW	New Jersey	SR9004-0264J PUC 3389-90	10/90	Revenue Requirements	Rate Counsel
Kent County Water Authority	W	Rhode Island	1952	8/90	Revenue Requirements Regulatory Policy (Surrebuttal)	Division of Public Utilities & Carriers
New York Telephone	T	New York	90-C-0191	7/90	Revenue Requirements Affiliated Interests (Supplemental)	NY State Consumer Protection Board
New York Telephone	T	New York	90-C-0191	7/90	Revenue Requirements Affiliated Interests	NY State Consumer Protection Board
Kent County Water Authority	W	Rhode Island	1952	6/90	Revenue Requirements Regulatory Policy	Division of Public Utilities & Carriers
Ellesor Transfer Station	SW	New Jersey	SO8712-1407 PUC 1768-88	11/89	Regulatory Policy	Rate Counsel
Interstate Navigation Co.	N	Rhode Island	D-89-7	8/89	Revenue Requirements Regulatory Policy	Division of Public Utilities & Carriers
Automated Modular Systems, Inc.	SW	New Jersey	PUC1769-88	5/89	Revenue Requirements Schedules	Rate Counsel
SNET Cellular, Inc.	T	Connecticut	-	2/89	Regulatory Policy	First Selectman Town of Redding

APPENDIX B

Supporting Schedules

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim (A)	Recommended Adjustment	Recommended Position	
1. Pro Forma Rate Base	$3,843,343	($558,825)	$3,284,518	(B)
2. Required Cost of Capital	8.81%	-0.73%	8.08%	(C)
3. Required Return	$338,599	($73,126)	$265,473	
4. Operating Income @ Present Rates	252,175	22,374	274,549	(D)
5. Operating Income Deficiency	$86,424	($95,500)	($9,076)	
6. Revenue Multiplier	1.7011	1.7011	1.7011	(E)
7. Revenue Requirement Increase	**$147,016**	**($162,455)**	**($15,439)**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-4 R-1.
(B) Schedule ACC-3E.
(C) Schedule ACC-2E.
(D) Schedule ACC-14E.
(E) Schedule ACC-42E.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REQUIRED COST OF CAPITAL ($ MILLIONS)

	Capital Structure (%) (A)	Cost Rate (%) (A)	Weighted Cost (%)
1. Long Term Debt	49.19%	6.11%	3.01%
2. Preferred Stock	1.08%	5.03%	0.05%
3. Customer Deposits	0.00%	2.34%	0.00%
4. Common Equity	49.73%	10.10%	5.02%
5. Total Cost of Capital	100.00%		**8.08%**

Sources:
(A) Testimony of Mr. Kahal, Schedule MIK-1, page 1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
RATE BASE SUMMARY ($000)

		Company Claim (A)	Recommended Adjustment		Recommended Position
1.	Utility Plant in Service	$6,155,632	($147,102)	(B)	$6,008,530
2.	Plant Held for Future Use	3,580	(3,580)	(C)	$0
	Less:				
3.	Accumulated Depreciation	(1,936,751)	19,897	(D)	(1,916,854)
4.	Advances for Construction	(5,482)	0		(5,482)
5.	Net Utility Plant	$4,216,979	($130,785)		$4,086,194
	Plus:				
6.	Cash Working Capital	$208,113	($69,274)	(E)	$138,839
7.	Materials and Supplies	47,746	0		47,746
8.	Prepayments	6,718	0		6,718
	Less:				
9.	Customer Deposits	$0	($52,782)	(F)	($52,782)
10.	Accumulated Deferred Taxes	(636,213)	20,988	(G)	(615,225)
11.	Consolidated Income Taxes	0	(326,972)	(H)	(326,972)
12.	Total Rate Base	$3,843,343	($558,825)		$3,284,518

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.
(B) Schedule ACC-4E and Schedule ACC-5E.
(C) Schedule ACC-6E.
(D) Schedule ACC-7E and Schedule ACC-8E.
(E) Schedule ACC-9E.
(F) Schedule ACC-10E.
(G) Schedule ACC-11E and Schedule ACC-12E.
(H) Schedule ACC-13E.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
UTILITY PLANT IN SERVICE ($000)

1.	Projected Plant @ 12/31/09	$5,997,530	(A)
2.	Company Claim	6,046,450	(A)
3.	Recommended Adjustment	**($48,920)**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CAPITAL INFRASTRUCTURE PROJECTS
UTILITY PLANT IN SERVICE ($000)

1.	Actuals through July 2009	$11,000	(A)
2.	Company Claim	109,182	(B)
3.	Recommended Adjustment	**($98,182)**	

Sources:
(A) Response to RCR-ER-22. Reflects actuals through July 31, 2009.
(B) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PLANT HELD FOR FUTURE USE ($000)

1.	Company Claim	$3,580	(A)
2.	Utility Plant Adjustment	**($3,580)**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
ACCUMULATED DEPRECIATION-POST TEST YEAR ($000)

1.	Projected Test Year End Balance	($1,916,817)	(A)
2.	Company Claim	(1,935,800)	(A)
3.	Recommended Adjustment	**$18,983**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CAPITAL INFRASTRUCTURE PROJECTS
ACCUMULATED DEPRECIATION ($000)

1.	Actuals through July 2009	($36)	(A)
2.	Company Claim	(950)	(B)
3.	Recommended Adjustment	**$914**	

Sources:
(A) Response to RCR-ER-22. Reflects actuals through July 31, 2009.
(B) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CASH WORKING CAPITAL ($000)

1.	Cash Working Capital (Lead/Lag Study)	$210,535	(A)
2.	Company Claim (Lead/Lag Study)	279,809	(B)
3.	Recommended Adjustment	**($69,274)**	

Sources:
(A) Exhibit DEP-1.
(B) Company Filing, Schedule DMF-2-R1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CUSTOMER DEPOSITS ($000)

1.	Customer Deposits	($80,838)	(A)
2.	Allocation to Electric	65.29%	(B)
3.	Recommended Adjustment	**($52,782)**	

Sources:
(A) Response to RCR-A-219.
(B) Based on test year pro forma revenue per Company Filing, Exhibit P-7, Schedule MGK-19 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DEFERRED INCOME TAX RESERVE ($000)

1.	Projected Test Year End Balance	$613,261	(A)
2.	Company Claim	619,993	(A)
3.	Recommended Adjustment	**$6,732**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CAPITAL INFRASTRUCTURE PROJECTS
DEFERRED INCOME TAX RESERVE ($000)

1.	Actuals through July 2009	$1,964	(A)
2.	Company Claim	16,220	(B)
3.	Recommended Adjustment	**$14,256**	

Sources:
(A) Response to RCR-ER-22. Reflects actuals through July 31, 2009.
(B) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

Schedule ACC-13E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CONSOLIDATED INCOME TAXES ($000)

1. Sum of Net Taxable Losses for Companies With Cumulative Taxable Losses	($1,976,342)	(A)
2. Tax Loss Benefit Based on Annual Federal Income Tax Rate	(583,730)	(A)
3. Share of PSE&G-Electric Cumulative Positive Taxable Income to Total for Companies With Cumulative Taxable Income	56.01%	(A)
4. Total CIT Adjustment for PSE&G	**($326,972)**	

Sources:
(A) Derived from the response to S-PREV-90 (Update 3). Includes impact of $103.471 million of AMT payments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
OPERATING INCOME SUMMARY ($000)

			Schedule No.
1.	Company Claim	$252,175	1
	Recommended Adjustments:		
2.	Pro Forma Revenue - Weather Normalization	(75)	15E
3.	Pro Forma Revenue - Annualization	2,200	16E
4.	Salary and Wage Expense	483	17E
5.	Incentive Compensation Program Expense	8,502	18E
6.	Severance Expense	260	19E
7.	Payroll Tax Expense	707	20E
8.	Pension Expense	3,711	21E
9.	SERP Expense	496	22E
10.	Rate Case Expense	368	23E
11.	Injuries and Damages Expense	1,488	24E
12.	Customer Information System Amort. Expense	1,487	25E
13.	Management/Affiliated Standards Audit Expense	102	26E
14.	Vegetative Management Expense	1,900	27E
15.	Insurance Expense	351	28E
16.	Postage Expense	211	29E
17.	Energy Master Plan Costs	398	30E
18.	Solar Loan I Administrative Expense	324	31E
19.	Meals and Entertainment Expense	488	32E
20.	Advertising Expense	1,355	33E
21.	Dues / Lobbying Expense	45	34E
22.	Gain on Sale of Property	130	35E
23.	Interest on Customer Deposits	(134)	36E
24.	Real Estate Tax Expense	254	37E
25.	Depreciation Expense - Plant-in-Service	794	38E
26.	Depreciation - Capital Infrastructure	1,419	39E
27.	Interest Synchronization	(4,890)	40E
28.	Operating Income	**$274,549**	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PRO FORMA REVENUES - WEATHER NORMALIZATION ($000)

1. Weather Normalization Adjustment Based on 30 Years		($5,012)	(A)
2. Weather Normalization Adjustment Per Company		(5,139)	(B)
3. Recommended Adjustment		($127)	
4. Revenue Assessments @	0.22%	(0)	(C)
5. Net Revenue Adjustment		($127)	
6. Income Taxes @	41.08%	(52)	
7. Operating Income Impact		**($75)**	

Sources:
(A) Derived from the response to RCR-A-138 (Update).
(B) Company Filing, Exhibit P-7, Schedule MGK-35 R-1.
(C) Assessment rates per Schedule ACC-42E.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PRO FORMA REVENUE - ANNUALIZATION ($000)

1. RS Revenues Per Company		$488,745	(A)
2. GLP Revenues Per Company		259,746	(B)
3. Total RS/GLP Revenues Per Company		$748,491	
4. Recommended Annual. Adj.(%)		0.50%	(C)
5. Recommended Annual. Adj.($)		$3,742	
6. Revenue Assessments @	0.22%	8	(D)
7. Net Revenue Adjustment		$3,734	
8. Income Taxes @	41.08%	1,534	
9. Operating Income Impact		**$2,200**	

.

Sources:
(A) Company Filing, Schedule SS-E9 R-1, page 2, line 1, Col. 3.
(B) Company Filing, Schedule SS-E9 R-1, page 2, line 10, Col. 3.
(C) Testimony of Ms. Crane.
(D) Assessment rates per Schedule ACC-42E.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SALARY AND WAGE EXPENSE ($000)

1.	Total Recommended Adjustment		$820	(A)
2.	Income Taxes @	41.08%	337	
3.	Operating Income Impact		**$483**	

Sources:
(A) Reflects 2011 adjustments per Company Workpapers
to Schedule MGK-28 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INCENTIVE COMPENSATION PROGRAM EXPENSE ($000)

1.	Total Recommended Adjustment		$14,430	(A)
2.	Income Taxes @	41.08%	5,928	
3.	Operating Income Impact		**$8,502**	

Sources:
(A) Response to RCR-A-20 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SEVERANCE EXPENSE ($000)

1.	Three Year Average (2006-2008)		$120	(A)
2.	Company Claim		562	(A)
3.	Recommended Adjustment		$441	
4.	Income Taxes @	41.08%	181	
5.	Operating Income Impact		**$260**	

Sources:
(A) Response to RCR-A-14 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PAYROLL TAX EXPENSE ($000)

1. Salary and Wage Adjustment		$820	(A)
2. Incentive Compensation Adjustment		14,430	(B)
3. Severance Adjustment		441	(C)
4. Total Recommended Adjustments		$15,691	
5. Statutory Tax Rate		7.65%	(D)
6. Recommended Payroll Tax Adjustment		$1,200	
7. Income Taxes @	41.08%	493	
8. Operating Income Impact		**$707**	

Sources:
(A) Schedule ACC-17E.
(B) Schedule ACC-18E.
(C) Schedule ACC-19E.
(D) Reflects statutory social security and medicare tax rates.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PENSION EXPENSE ($000)

1.	Recommended Pension Adjustment		$37,200	(A)
2.	Allocation to PSE&G @	57.64%	21,440	(B)
3.	Allocation to Expense @	58.00%	12,435	(C)
4.	Allocation to Electric @	43.00%	5,347	(C)
5.	Service Company Allocation		951	(D)
6.	Total Recommended Adjustment		$6,298	(E)
7.	Income taxes @	0	2,587	
8.	Operating Income Impact		**3,711**	

Sources:
(A) Testimony of Mr. Serota, page 8.
(B) Allocation to PSE&G based on 2010 allocations per the response to RCR-PT-4, page 2.
(C) Allocation per Company Workpaper to Schedule MGK-31 R-1.
(D) Allocation to Service Company based on 2010 allocations per the response to RCR-PT-4, page 2. 51% of Service Company allocated to PSE&G per the response to RCR-PT-4.
Service Company costs allocated between electric and gas based on Company Workpapers to Schedule MGK-31 R-1.
(E) Line 4 + Line 5.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SERP EXPENSE ($000)

1.	PSE&G SERP Claim		$759	(A)
2.	Service Company SERP Claim	$5,128		(A)
3.	Service Company Allocation @	51.00%	2,615	(B)
4.	Total PSE&G SERP Costs		$3,375	(C)
5.	Allocation to Expense @	58.00%	1,957	(D)
6.	Allocation to Electric @	43.00%	842	(D)
7.	Income taxes @	41.08%	346	
8.	Operating Income Impact		**$496**	(E)

Sources:
(A) Reflects 10 months of 2010 cost and 2 months of 2011 cost per the response to RCR-PT-4, page 2.
(B) Allocation of Service Company costs (51%) per the response to RCR-PT-4.
(C) Line 1 + Line 3.
(D) Allocation based on Company Workpaper to Schedule MGK-31 R-1.
(E) Line 6 - Line 7.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
RATE CASE EXPENSE ($000)

1.	Company Claim		$750	(A)
2.	Recommended Amortization Period		3	(B)
3.	Annual Amortization		$250	
4.	Allocation to Ratepayers (%)		50.00%	(C)
5.	Allocation to Ratepayers ($)		$125	
6.	Company Claim		750	
7.	Recommended Adjustment		$625	
8.	Income Taxes @	41.08%	257	
9.	Operating Income Impact		**$368**	

Sources:
(A) Response to RCR-A-179. Reflects 50/50 split between electric and gas utilities.
(B) Recommendation of Ms. Crane.
(C) Reflects BPU Policy of 50/50 sharing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INJURIES AND DAMAGES EXPENSE ($000)

1. Annualized Test Year		$9,503	(A)
2. Company Claim		12,029	
3. Recommended Adjustment		$2,526	
4. Income Taxes @	41.08%	1,038	
5. Operating Income Impact		**$1,488**	

Sources:
(A) Annualized based on updated Income Statement provided in Company Workpapers to Schedule MGK-21-23 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CIS AMORTIZATION EXPENSE ($000)

1. Company Claim		$2,524	(A)
2. Income Taxes @	41.08%	1,037	
3. Operating Income Impact		**$1,487**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-38 R-1.

Schedule ACC-26E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
MANAGEMENT AND AFFILIATE STANDARDS AUDIT EXPENSE ($000)

1.	Company Claim		$1,849	(A)
2.	Test Year Projection		1,155	(A)
3.	Recommended Adjustment		$694	
4.	Amortization Period		4	(A)
5.	Recommended Adjustment (Annual)		$174	
6.	Income Taxes @	41.08%	71	
7.	Operating Income Impact		**$102**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MKG-37 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
VEGETATIVE MANAGEMENT EXPENSE ($000)

1. Three Year Average		$18,450	(A)
2. Company Claim		21,675	(A)
3. Recommended Adjustment		$3,225	
4. Income Taxes @	41.08%	1,325	
5. Operating Income Impact		**$1,900**	

Sources:
(A) Response to RCR-A-46.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INSURANCE EXPENSE ($000)

1.	Test Year Projection		$3,895	(A)
2.	Company Claim		4,490	(A)
3.	Recommended Adjustment		$595	
4.	Income Taxes @	41.08%	244	
5.	Operating Income Impact		**$351**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-41 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
POSTAGE EXPENSE ($000)

1.	Test Year Annualized Costs		$10,031	(A)
2.	Allocation to Electric (%)		55.00%	(B)
3.	Allocation to Electric ($)		$5,517	
4.	Pro Forma Customer Growth@	0.50%	28	(C)
5.	Pro Forma Postage Costs		$5,545	
6.	Company Claim		5,903	(D)
7.	Recommended Adjustment		$358	
8.	Income Taxes @	41.08%	147	
9.	Operating Income Impact		**$211**	

Sources:
(A) Based on annualizing actual costs from January-June 2009, per Company Workpaper to Schedule MGK-33 R-1.
(B) Allocation per Company Workpaper to Schedule MGK-33 R-1.
(C) Reflects impact of customer annualization adjustment per Schedule ACC-16E.
(D) Company Filing, Exhibit P-7, Schedule MGK-33 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
ENERGY MASTER PLAN COSTS ($000)

1.	Company Claim		$675	(A)
2.	Income Taxes @	41.08%	277	
3.	Operating Income Impact		**$398**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MKG-42 R-1.

Schedule ACC-31E

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SOLAR LOAN I ADMINISTRATIVE EXPENSE ($000)

1. Company Claim		$550	(A)
2. Income Taxes @	41.08%	226	
3. Operating Income Impact		**$324**	

Sources:
(A) Response to RCR-A-209.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
MEALS AND ENTERTAINMENT EXPENSE ($000)

1.	Recommended Adjustment		$829	(A)
2.	Income Taxes @	41.08%	341	
3.	Operating Income Impact		**$488**	

Sources:
(A) Response to RCR-A-60 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
ADVERTISING EXPENSE ($000)

1.	Corporate Branding		$1,081	(A)
2.	Sponsorships		1,219	(A)
3.	Total Recommended Adjustment		$2,299	
4.	Income Taxes @	41.08%	945	
5.	Operating Income Impact		**$1,355**	

Sources:
(A) Response to RCR-A-181 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DUES / LOBBYING EXPENSE ($000)

1.	Company Claim		$508	(A)
2.	Recommended Adjustment (%)		15.00%	(B)
3.	Recommended Adjustment ($)		$76	
4.	Income Taxes @	41.08%	31	
5.	Operating Income Impact		**$45**	

Sources:

(A) Response to RCR-A-56 (Update). Includes planned expenditures, allocated 50/50 between electric and gas.

(B) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
GAIN ON SALE OF PROPERTY ($000)

1.	Recommended Adjustment		$220	(A)
2.	Income Taxes @	41.08%	90	
3.	Operating Income Impact		**$130**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-36 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INTEREST ON CUSTOMER DEPOSITS ($000)

1. Pro Forma Customer Deposits		($52,782)	(A)
2. Interest @		0.43%	(B)
3. Pro Forma Interest Expense		($227)	
4. Income Taxes @	41.08%	(93)	
5. Operating Income Impact		**($134)**	

Sources:
(A) Schedule ACC-10E.
(b) BPU Notice dated October 28, 2009.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REAL ESTATE TAX EXPENSE ($000)

1. Utility Plant Per Company		$6,159,212	(A)
2. Projected 2010 Property Tax Expense		11,675	(B)
3. Composite Rate		0.19%	
4. Recommended Plant Adjustment		$150,682	(C)
5. Property Tax Adj. Due to Plant Adj.		$286	(D)
6. Company Claim for 2011 Increase		146	(B)
7. Total Recommended Tax Adjustment		$432	(E)
8. Income Taxes @	41.08%	177	
9. Recommended Adjustment		**$254**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1. Includes Plant Held for Future Use.
(B) Company Workpapers to Exhibit P-7, Schedule MGK-39 R-1.
(C) Schedule ACC-4E, Schedule ACC-5E, and Schedule ACC-6E.
(D) Line 3 X Line 4.
(E) Line 5 - Line 6.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DEPRECIATION EXPENSE - PLANT-IN-SERVICE ($000)

1.	Utility Plant Adjustment - Post Test Year		$48,920	(A)
2.	Composite Deprecation Rate		2.75%	(B)
3.	Recommended Adjustment		$1,348	
4.	Income Taxes @	41.08%	554	
5.	Operating Income Impact		**$794**	

Sources:
(A) Schedule ACC-4E.
(B) Composite rate based on Exhibit P-7, Schedule MGK-45 R-1 and Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DEPRECIATION EXPENSE - CAPITAL INFRASTRUCTURE ($000)

1. Plant in Service Adjustment		98,182	(A)
2. Composite Depreciation Rate		2.45%	(B)
3. Depreciation Expense Adjustments		$2,409	
4. Income Taxes @	41.08%	990	
5. Operating Income Impact		**$1,419**	

Sources:
(A) Schedule ACC-5E.
(B) Derived from Schedule MGK-40 R-1 and Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INTEREST SYNCHRONIZATION ($000)

1. Pro Forma Rate Base		$3,284,518	(A)
2. Weighted Cost of Debt		3.01%	(B)
3. Pro Forma Interest Expense		$98,716	
4. Company Claim		110,620	(C)
5. Recommended Adjustment		$11,904	
6. Increase in Income Taxes @	41.08%	4,890	
7. Operating Income Impact		**($4,890)**	

Sources:
(A) Schedule ACC-3E.
(B) Schedule ACC-2E.
(C) Company Filing, Exhibit P-7, Exhibit MGK-30 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INCOME TAX RATE

1. Revenue		100.00%	
2. State Income Taxes @	9.36%	9.36%	(A)
3. Federal Taxable Income		90.64%	
4. Income Taxes @	35.00%	31.72%	(A)
5. Operating Income		58.92%	
6. Total Tax Rate		**41.08%**	(B)

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-9 R-1.
(B) Line 1 - Line 5.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REVENUE MULTIPLIER

1.	Revenue		100.00%	
	Less:			
2.	BPU Assessments		0.19%	(A)
3.	RC Assessments		0.04%	(A)
4.	Uncollectibles		0.00%	(A)
5.	Taxable Income		99.78%	
6.	State Income Taxes @	9.36%	9.34%	(A)
7.	Federal Taxable Income		90.44%	
8.	Income Taxes @	35.00%	31.65%	(A)
9.	Operating Income		58.79%	
10.	Total Tax Rate		**40.99%**	(B)
11.	Revenue Multiplier		**1.7011**	(C)

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-9 R-1.
(B) Line 6 + Line 8.
(C) Line 1 / Line 9.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1.	Capital Structure/Cost of Capital	($47,560)
	Rate Base Adjustments:	
2.	Utility Plant in Service	(6,726)
3.	Economic Stimulus Plant	(13,499)
4.	Plant Held for Future Use	(492)
5.	Accumulated Depreciation	2,736
6.	Cash Working Capital	(9,525)
7.	Customer Deposits	(7,257)
8.	Accumulated Deferred Taxes	2,886
9.	Consolidated Income Taxes	(44,956)
	Operating Income Adjustments	
10.	Pro Forma Revenue - Weather Normalization	127
11.	Pro Forma Revenue - Annualization	(3,742)
12.	Salary and Wage Expense	(822)
13.	Incentive Compensation Program Expense	(14,462)
14.	Severance Expense	(442)
15.	Payroll Tax Expense	(1,203)
16.	Pension Expense	(6,312)
17.	SERP Expense	(844)
18.	Rate Case Expense	(626)
19.	Injuries and Damages Expense	(2,532)
20.	Customer Information System Amort. Expense	(2,530)
21.	Management/Affiliated Standards Audit Expense	(174)
22.	Vegetative Management Expense	(3,232)
23.	Insurance Expense	(596)
24.	Postage Expense	(359)
25.	Energy Master Plan Costs	(676)
26.	Solar Loan I Administrative Expense	(551)
27.	Meals and Entertainment Expense	(831)
28.	Advertising Expense	(2,305)
29.	Dues / Lobbying Expense	(76)
30.	Gain on Sale of Property	(220)
31.	Interest on Customer Deposits	227
32.	Real Estate Tax Expense	(433)
33.	Depreciation Expense - Plant-in-Service	(1,351)
34.	Depreciation - Capital Infrastructure	(2,414)
35.	Interest Synchronization	8,319
36.	Total Recommended Adjustments	($162,455)
37.	Company Claim	147,016
38.	Recommended Revenue Requirement Deficiency	**($15,439)**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim	Recommended Adjustment	Recommended Position	
	(A)			
1. Pro Forma Rate Base	$2,338,095	($173,750)	$2,164,345	(B)
2. Required Cost of Capital	8.81%	-0.73%	8.08%	(C)
3. Required Return	$205,986	($31,051)	$174,935	
4. Operating Income @ Present Rates	144,592	22,372	166,964	(D)
5. Operating Income Deficiency	$61,394	($53,424)	$7,970	
6. Revenue Multiplier	1.7257	(0.0039)	1.7218	(E)
7. Revenue Requirement Increase	**$105,948**	**($92,224)**	**$13,723**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-4 R-1.
(B) Schedule ACC-3G.
(C) Schedule ACC-2G.
(D) Schedule ACC-13G
(E) Schedule ACC-38G.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REQUIRED COST OF CAPITAL ($ MILLIONS)

	Capital Structure (%)	Cost Rate (%)	Weighted Cost (%)
	(A)	(A)	
1. Long Term Debt	49.19%	6.11%	3.01%
2. Preferred Stock	1.08%	5.03%	0.05%
3. Customer Deposits	0.00%	2.34%	0.00%
4. Common Equity	49.73%	10.10%	5.02%
5. Total Cost of Capital	100.00%		**8.08%**

Sources:
(A) Testimony of Mr. Kahal, Schedule MIK-1, page 1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
RATE BASE SUMMARY ($000)

	Company Claim	Recommended Adjustment		Recommended Position
	(A)			
1. Utility Plant in Service	$4,824,009	($101,084)	(B)	$4,722,925
2. Plant Held for Future Use	0	0		0
Less:				
3. Accumulated Depreciation	(1,957,763)	13,165	(C)	(1,944,598)
4. Advances for Construction	(4,479)	0		(4,479)
5. Net Utility Plant	$2,861,767	($87,919)		$2,773,848
Plus:				
6. Cash Working Capital	$70,307	($33,967)	(D)	$36,340
7. Materials and Supplies	12,747	0		12,747
8. Prepayments	4,059	0		4,059
Less:				
9. Customer Deposits	$0	($28,056)	(E)	($28,056)
10. Accumulated Deferred Taxes	(610,785)	22,248	(F)	(588,537)
11. Consolidated Income Taxes	0	(46,056)	(G)	(46,056)
12. Total Rate Base	**$2,338,095**	**($173,750)**		**$2,164,345**

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.
(B) Schedule ACC-4G and Schedule ACC-5G.
(C) Schedule ACC-6G and Schedule ACC-7G.
(D) Schedule ACC-8G.
(E) Schdule ACC-9G.
(F) Schedule ACC-10G and Schedule ACC-11G.
(G) Schedule ACC-12G.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
UTILITY PLANT IN SERVICE ($000)

1.	Projected Plant @ 12/31/09	$4,706,377	(A)
2.	Company Claim	4,724,858	(A)
3.	Recommended Adjustment	**($18,481)**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CAPITAL INFRASTRUCTURE PROJECTS
UTILITY PLANT IN SERVICE ($000)

1.	Actuals through July 2009	$16,549	(A)
2.	Company Claim	99,152	(B)
3.	Recommended Adjustment	**($82,603)**	

Sources:
(A) Quarterly report provided in response to informal discovery. Reflects actuals through July 2009.
(B) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
ACCUMULATED DEPRECIATION-POST TEST YEAR ($000)

1.	Projected Test Year End Balance	($1,944,567)	(A)
2.	Company Claim	(1,957,060)	(A)
3.	Recommended Adjustment	**$12,493**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CAPITAL INFRASTRUCTURE PROJECTS
ACCUMULATED DEPRECIATION ($000)

1.	Actuals through July 2009	($31)	(A)
2.	Company Claim	(703)	(B)
3.	Recommended Adjustment	**$672**	

Sources:
(A) Quarterly report provided in response to informal discovery. Reflects actuals through July 2009.
(B) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CASH WORKING CAPITAL ($000)

1.	Cash Working Capital (Lead/Lag Study)	$123,699	(A)
2.	Company Claim (Lead/Lag Study)	157,666	(B)
3.	Recommended Adjustment	**($33,967)**	

Sources:
(A) Exhibit DEP-1.
(B) Company Filing, Schdule DMF-2-R1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CUSTOMER DEPOSITS ($000)

1.	Customer Deposits	($80,838)	(A)
2.	Allocation to Gas	34.71%	(B)
3.	Recommended Adjustment	**($28,056)**	

Sources:
(A) Response to RCR-A-219.
(B) Based on test year pro forma revenue per Company Filing, Exhibit P-7, Schedule MGK-19 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DEFERRED INCOME TAX RESERVE ($000)

1.	Projected Test Year End Balance	$585,057	(A)
2.	Company Claim	592,103	(A)
3.	Recommended Adjustment	**$7,046**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CAPITAL INFRASTRUCTURE PROJECTS
DEFERRED INCOME TAX RESERVE ($000)

1.	Actuals through July 2009	$3,479	(A)
2.	Company Claim	18,681	(B)
3.	Recommended Adjustment	**$15,202**	

Sources:
(A) Quarterly report provided in response to informal discovery. Reflects actuals through July 2009.
(B) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CONSOLIDATED INCOME TAXES ($000)

1.	Sum of Net Taxable Losses for Companies With Cumulative Taxable Losses	($1,976,342)	(A)
2.	Tax Loss Benefit Based on Annual Federal Income Tax Rate	(583,730)	(A)
3.	Share of PSE&G-Electric Cumulative Positive Taxable Income to Total for Companies With Cumulative Taxable Income	7.89%	(A)
4.	Total CIT Adjustment for PSE&G	**($46,056)**	

Sources:
(A) Derived from the response to S-PREV-90 (Update 3). Includes impact of $103.471 million of AMT payments.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
OPERATING INCOME SUMMARY ($000)

			Schedule No.
1.	Company Claim	$144,592	1
	Recommended Adjustments:		
2.	Pro Forma Revenue - Weather Normalization	2,508	14G
3.	Pro Forma Revenue - Annualization	3,259	15G
4.	Salary and Wage Expense	546	16G
5.	Incentive Compensation Program Expense	6,805	17G
6.	Severance Expense	219	18G
7.	Payroll Tax Expense	579	19G
8.	Pension Expense	4,401	20G
9.	SERP Expense	588	21G
10.	Rate Case Expense	368	22G
11.	Customer Information System Amort. Expense	1,217	23G
12.	Management/Affiliated Standards Audit Expense	84	24G
13.	Insurance Expense	204	25G
14.	Postage Expense	(34)	26G
15.	Energy Master Plan Costs	71	27G
16.	Meals and Entertainment Expense	319	28G
17.	Advertising Expense	1,019	29G
18.	Dues / Lobbying Expense	57	30G
19.	Gain on Sale of Property	52	31G
20.	Interest on Customer Deposits	(71)	32G
21.	Real Estate Tax Expense	99	33G
22.	Depreciation - Plant-in-Service	219	34G
23.	Depreciation - Capital Infrastructure	785	35G
24.	Interest Synchronization	(923)	36G
25.	Net Operating Income	**$166,964**	

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PRO FORMA REVENUES - WEATHER NORMALIZATION ($000)

1.	Weather Normalization Adjustment Based on 30 Years		$9,885	(A)
2.	Weather Normalization Adjustment Per Company		14,203	(B)
3.	Recommended Adjustment		$4,318	
4.	Revenue Assessments @	1.42%	61	(C)
5.	Net Revenue Adjustment		$4,257	
6.	Income Taxes @	41.08%	1,749	
7.	Operating Income Impact		**$2,508**	

Sources:
(A) Derived from the response to RCR-A-138 (Update).
(B) Company Filing, Exhibit P-7, Schedule MGK-35 R-1.
(C) Assessment rates per Schedule ACC-38G.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PRO FORMA REVENUE - ANNUALIZATION ($000)

1. Residential Revenues Per Company		$481,512	(A)
2. General Service Revenues Per Company		79,559	(B)
3. Total RSG/GSG Revenues Per Company		$561,071	
4. Recommended Annual. Adj.(%)		1.00%	(C)
5. Recommended Annual. Adj.($)		$5,611	
6. Revenue Assessments @	1.42%	80	(D)
7. Net Revenue Adjustment		$5,531	
8. Income Taxes @	41.08%	2,272	
9. Operating Income Impact		**$3,259**	

.

Sources:
(A) Company Filing, Schedule SS-G8 R-1, page 2, line 4, Col. 3.
(B) Company Filing, Schedule SS-G8 R-1, page 2, line 5, Col. 3.
(C) Testimony of Ms. Crane.
(D) Assessment rates per Schedule ACC-38G.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SALARY AND WAGE EXPENSE ($000)

1.	Total Recommended Adjustment		$927	(A)
2.	Income Taxes @	41.08%	381	
3.	Operating Income Impact		**$546**	

Sources:
(A) Reflects 2011 adjustments per Company Workpapers
to Schedule MGK-28 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INCENTIVE COMPENSATION PROGRAM EXPENSE ($000)

1.	Total Recommended Adjustment		$11,550	(A)
2.	Income Taxes @	41.08%	4,745	
3.	Operating Income Impact		**$6,805**	

Sources:
(A) Response to RCR-A-20 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SEVERANCE COSTS ($000)

1.	Three Year Average (2006-2008)		$96	(A)
2.	Company Claim		469	(A)
3.	Recommended Adjustment		$373	
4.	Income Taxes @	41.08%	153	
5.	Operating Income Impact		**$219**	

Sources:
(A) Response to RCR-A-14 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PAYROLL TAX EXPENSE ($000)

1. Salary and Wage Adjustment		$927	(A)
2. Incentive Compensation Adjustment		11,550	(B)
3. Severance Adjustment		373	(C)
4. Total Recommended Adjustments		$12,850	
5. Statutory Tax Rate		7.65%	(D)
6. Recommented Payroll Tax Adjustment		$983	
7. Income Taxes @	41.08%	404	
8. Operating Income Impact		**$579**	

Sources:
(A) Schedule ACC-16G.
(B) Schedule ACC-17G.
(C) Schedule ACC-18G.
(D) Reflects statutory social security and medicare tax rates.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
PENSION EXPENSE ($000)

1.	Recommended Pension Adjustment		$37,200	(A)
2.	Allocation to PSE&G @	57.64%	21,440	(B)
3.	Allocation to Expense @	58.00%	12,435	(C)
4.	Allocation to Gas @	51.00%	6,342	(C)
5.	Service Company Allocation		1,128	(D)
6.	Total Recommended Adjustment		$7,470	(E)
7.	Income taxes @	41.08%	3,069	
8.	Operating Income Impact		**4,401**	

Sources:
(A) Testimony of Mr. Serota, page 8.
(B) Allocation to PSE&G based on 2010 allocations per the response to RCR-PT-4, page 2.
(C) Allocation per Company Workpaper to Schedule MGK-31 R-1.
(D) Allocation to Service Company based on 2010 allocations per the response to RCR-PT-4, page 2. 51% of Service Company allocated to PSE&G per the response to RCR-PT-4. Service Company costs allocated between electric and gas based on Company Workpapers to Schedule MGK-31 R-1.
(E) Line 4 + Line 5.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
SERP EXPENSE ($000)

1. PSE&G SERP Claim		$759	(A)
2. Service Company SERP Claim	$5,128		(A)
3. Service Company Allocation @	51.00%	2,615	(B)
4. Total PSE&G SERP Costs		$3,375	(C)
5. Allocation to Expense @	58.00%	1,957	(D)
6. Allocation to Gas @	51.00%	998	(D)
7. Income taxes @	41.08%	410	
8. Operating Income Impact		**$588**	(E)

Sources:
(A) Reflects 10 months of 2010 cost and 2 months of 2011 cost per the response to RCR-PT-4, page 2.
(B) Allocation of Service Company costs (51%) per the response to RCR-PT-4.
(C) Line 1 + Line 3.
(D) Allocation based on Company Workpaper to Schedule MGK-31 R-1.
(E) Line 6 - Line 7.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
RATE CASE COSTS ($000)

1.	Company Claim		$750	(A)
2.	Recommended Amortization Period		3	(B)
3.	Annual Amortization		$250	
4.	Allocation to Ratepayers (%)		50.00%	(C)
5	Allocation to Ratepayers ($)		$125	
6	Company Claim		750	
7	Recommended Adjustment		$625	
8	Income Taxes @	41.08%	257	
9.	Operating Income Impact		**$368**	

Sources:
(A) Response to RCR-A-179. Reflects 50/50 split between electric and gas utilities.
(B) Recommendation of Ms. Crane.
(C) Reflects BPU Policy of 50/50 sharing.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
CIS AMORTIZATION EXPENSE ($000)

1.	Company Claim		$2,065	(A)
2.	Income Taxes @	41.08%	848	
3.	Operating Income Impact		**$1,217**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-38 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
MANAGEMENT AND AFFILIATE STANDARDS AUDIT ($000)

1.	Company Claim		$1,513	(A)
2.	Test Year Projection		945	(A)
3.	Recommended Adjustment		$568	
4.	Amortization Period		4	(A)
5.	Recommended Adjustment (Annual)		$142	
6.	Income Taxes @	41.08%	58	
7.	Operating Income Impact		**$84**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MKG-37 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INSURANCE EXPENSE ($000)

1. Test Year Projection		$2,581	(A)
2. Company Claim		2,928	(A)
3. Recommended Adjustment		$347	
4. Income Taxes @	41.08%	143	
5. Operating Income Impact		**$204**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-41 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
POSTAGE EXPENSE ($000)

1.	Test Year Annualized Costs		$10,031	(A)
2.	Allocation to Gas (%)		45.00%	(B)
3.	Allocation to Gas ($)		$4,514	
4.	Pro Forma Customer Growth@	1.00%	45	(C)
5.	Pro Forma Postage Costs		$4,559	
6.	Company Claim		4,502	(D)
7.	Recommended Adjustment		($57)	
8.	Income Taxes @	41.08%	(23)	
9.	Operating Income Impact		**($34)**	

Sources:
(A) Based on annualizing actual costs from January-June 2009, per Company Workpaper to Schedule MGK-33 R-1.
(B) Allocation per Company Workpaper to Schedule MGK-33 R-1.
(C) Reflects impact of customer annualization adjustment per Schedule ACC-15G.
(D) Company Filing, Exhibit P-7, Schedule MGK-33 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
ENERGY MASTER PLAN COSTS ($000)

1.	Company Claim		$120	(A)
2.	Income Taxes @	41.08%	49	
3.	Operating Income Impact		**$71**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MKG-42 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
MEALS AND ENTERTAINMENT EXPENSE ($000)

1.	Recommended Adjustment		$541	(A)
2.	Income Taxes @	41.08%	222	
3.	Operating Income Impact		**$319**	

Sources:
(A) Response to RCR-A-60 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
ADVERTISING EXPENSE ($000)

1. Corporate Branding		$882	(A)
2. Sponsorships		849	(A)
3. Total Recommended Adjustment		$1,730	
4. Income Taxes @	41.08%	711	
5. Operating Income Impact		**$1,019**	

Sources:
(A) Response to RCR-A-181 (Update).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DUES / LOBBYING EXPENSE ($000)

1.	Company Claim		$646	(A)
2.	Recommended Adjustment (%)		15.00%	(B)
3.	Recommended Adjustment ($)		$97	
4.	Income Taxes @	41.08%	40	
5.	Operating Income Impact		**$57**	

Sources:

(A) Response to RCR-A-56 (Update). Includes planned expenditures, allocated 50/50 between electric and gas.

(B) Recommendation of Ms. Crane.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
GAIN ON SALE OF PROPERTY ($000)

1.	Recommended Adjustment		$89	(A)
2.	Income Taxes @	41.08%	37	
3.	Operating Income Impact		**$52**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-36 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INTEREST ON CUSTOMER DEPOSITS ($000)

1.	Pro Forma Customer Deposits		($28,056)	(A)
2.	Interest @		0.43%	(B)
3.	Pro Forma Interest Expense		($121)	
4.	Income Taxes @	41.08%	(50)	
5.	Operating Income Impact		**($71)**	

Sources:
(A) Schedule ACC-9G.
(B) BPU Notice dated October 28, 2009.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REAL ESTATE TAXES ($000)

1.	Utility Plant Per Company		$4,824,009	(A)
2.	Projected 2010 Property Tax Expense		4,800	(B)
3.	Composite Rate		0.10%	
4.	Recommended Plant Adjustment		$101,084	(C)
5.	Property Tax Adj. Due to Plant Adj.		$101	(D)
6.	Company Claim for 2011 Increase		67	(B)
7.	Total Recommended Tax Adjustment		$168	(E)
8.	Income Taxes @	41.08%	69	
9.	Recommended Adjustment		**$99**	

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-5 R-1.
(B) Company Workpapers to Exhibit P-7, Schedule MGK-39 R-1.
(C) Schedule ACC-4G and Schedule ACC-5G.
(D) Line 3 X Line 4.
(E) Line 5 - Line 6.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DEPRECIATION EXPENSE - PLANT IN SERVICE ($000)

1. Utility Plant Adjustment - Post Test Year		$18,481	(A)
2. Composite Deprecation Rate		2.01%	(B)
3. Recommended Adjustment		$372	
4. Income Taxes @	41.08%	153	
5. Operating Income Impact		**$219**	

Sources:
(A) Schedule ACC-4G.
(B) Composite rate based on Exhibit P-7, Schedule MGK-45 R-1 and Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
DEPRECIATION EXPENSE - CAPITAL INFRASTRUCTURE ($000)

1. Plant in Service Adjustment		82,603	(A)
2. Composite Depreciation Rate		1.61%	(B)
3. Depreciation Expense Adjustments		$1,333	
4. Income Taxes @	41.08%	548	
5. Operating Income Impact		**$785**	

Sources:
(A) Schedule ACC-5G.
(B) Derived from Schedule MGK-40 R-1 and Schedule MGK-5 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INTEREST SYNCHRONIZATION ($000)

1.	Pro Forma Rate Base		$2,164,345	(A)
2.	Weighted Cost of Debt		3.01%	(B)
3.	Pro Forma Interest Expense		$65,050	
4.	Company Claim		67,296	(C)
5.	Recommended Adjustment		$2,246	
6.	Increase in Income Taxes @	41.08%	923	
7.	Operating Income Impact		**($923)**	

Sources:
(A) Schedule ACC-3G.
(B) Schedule ACC-2G.
(C) Company Filing, Exhibit P-7, Exhibit MGK-30 R-1.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
INCOME TAX RATE

1. Revenue		100.00%	
2. State Income Taxes @	9.36%	9.36%	(A)
3. Federal Taxable Income		90.64%	
4. Income Taxes @	35.00%	31.72%	(A)
5. Operating Income		58.92%	
6. Total Tax Rate		**41.08%**	(B)

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-9 R-1.
(B) Line 1 - Line 5.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REVENUE MULTIPLIER

1.	Revenue		100.00%	
	Less:			
2.	BPU Assessments		0.19%	(A)
3.	RC Assessments		0.04%	(A)
4.	Uncollectibles		1.20%	(B)
5.	Taxable Income		98.58%	
6.	State Income Taxes @	9.36%	9.23%	(C)
7.	Federal Taxable Income		89.35%	
8.	Income Taxes @	35.00%	31.27%	(A)
9.	Operating Income		58.08%	
10.	Total Tax Rate		**40.50%**	(C)
11.	Revenue Multiplier		**1.7218**	(D)

Sources:
(A) Company Filing, Exhibit P-7, Schedule MGK-9 R-1.
(B) Testimony of Ms. Crane.
(C) Line 6 + Line 8.
(D) Line 1 / Line 9.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
GAS OPERATIONS
TEST YEAR ENDING DECEMBER 31, 2009
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1.	Capital Structure/Cost of Capital	($29,284)
	Rate Base Adjustments:	
2.	Utility Plant in Service	(2,572)
3.	Economic Stimulus Plant	(11,496)
4.	Plant Held for Future Use	0
5.	Accumulated Depreciation	1,832
6.	Cash Working Capital	(4,727)
7.	Customer Deposits	(3,904)
8.	Accumulated Deferred Taxes	3,096
9.	Consolidated Income Taxes	(6,409)
	Operating Income Adjustments	
10.	Pro Forma Revenue - Weather Normalization	(4,318)
11.	Pro Forma Revenue - Annualization	(5,611)
12.	Salary and Wage Expense	(940)
13.	Incentive Compensation Program Expense	(11,717)
14.	Severance Expense	(378)
15.	Payroll Tax Expense	(997)
16.	Pension Expense	(7,577)
17.	SERP Expense	(1,013)
18.	Rate Case Expense	(634)
19.	Customer Information System Amort. Expense	(2,095)
20.	Management/Affiliated Standards Audit Expense	(144)
21.	Insurance Expense	(352)
22.	Postage Expense	58
23.	Energy Master Plan Costs	(122)
24.	Meals and Entertainment Expense	(549)
25.	Advertising Expense	(1,755)
26.	Dues / Lobbying Expense	(98)
27.	Gain on Sale of Property	(90)
28.	Interest on Customer Deposits	122
29.	Real Estate Tax Expense	(170)
30.	Depreciation - Plant-in-Service	(378)
31.	Depreciation - Capital Infrastructure	(1,352)
32.	Interest Synchronization	1,589
33.	Revenue Multiplier	(239)
34.	Total Recommended Adjustments	($92,224)
35.	Company Claim	105,948
36.	Recommended Revenue Requirement Deficiency	**$13,723**

APPENDIX C

Referenced Data Requests

RCR-A-6
RCR-A-8
RCR-A-14 (Update)
RCR-A-20 (Update)
RCR-A-21 (Update)
RCR-A-24
RCR-A-41 and Update
RCR-A-46
RCR-A-50
RCR-A-51
RCR-A-56 (Update)
RCR-A-60 (Update)
RCR-A-67 (Partial)
RCR-A-138 (Update) - Partial
RCR-A-142
RCR-A-146
RCR-A-166
RCR-A-179
RCR-A-181 (Update)
RCR-A-206 (Update)
RCR-A-207
RCR-A-209
RCR-A-210
RCR-A-217
RCR-A-219
RCR-A-220
RCR-A-221
RCR-A-222
RCR-CAC-8
RCR-CI-30
RCR-ER-22 (Partial)
RCR-PT-4
DCA-12
S-PP-2
S-PREV-46
S-PREV-59 (Voluminous - Not Included)
S-PREV-88
S-PREV-90 (Update 3) - (Confidential - Not Included)
S-PREV-91
S-PSEG-LABOR-4
S-PSEG-LABOR-5

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMPLOYEE POSITIONS SUPPORTING RGGI PROGRAMS

QUESTION:

Please identify any positions included in the Company's base rate case that are expected to provide any services to any programs that are recovered through RGGI clauses or any other surcharges. For each such position, please:

a. identify the position;
b. state the percentage of time that the position is expected to provide services to programs whose costs are recovered through clauses or surcharges;
c. state the total current salary/wages and benefits for the position;
d. state the salary/wages and benefits for the position included in the Company's base rate case;
e. state the salary/wages and benefits expected to be recovered through clauses and/or surcharges, and;
f. identify the applicable clause or surcharge that will be used to recover a portion of the position's costs.

ANSWER:

(a to d, f) PSE&G will utilize some of its employees in the RGGI programs which are included in the Company's base rates, such as our large customer account personnel and our customer inquiry staff. It is not possible to identify the positions of all those employees who may become involved in supporting the various RGGI programs, or the percentage of time that may be spent on them because such support occurs as a part of the routine course of business.

(e) No employees included in the Company's base rate case are included as administrative costs in the RGGI programs.

RESPONSE TO ADVOCATE
REQUEST: RCR-A-8
WITNESS(S): KAHRER
PAGE 1 OF 1
RATE CASE 2009

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PERCENTAGE OF SALARY AND WAGE INCREASES GRANTED

QUESTION:
Provide the percentage of salary and wage increases granted in each of the last five years, as well as any increases in 2009 to date. Please provide this information separately for electric and gas operations.

ANSWER:
The percent wage/salary increases from 2004 through 2009 for non –union (executive/officer level and MAST) and bargaining unit associates are shown below. Salary adjustments for executives and MAST associates are effective in January and March respectively. Bargaining unit wage adjustments are effective each May 1st. Note the increases do not differ for the electric and gas operations.

Date	Non-Union	Bargaining Unit
2004	3.50%	3.50%
2005	3.50%	3.25%
2006	3.50%	3.25%
2007	3.75%	3.25%
2008	3.75%	3.25%
2009	3.00%	3.25%

RESPONSE TO ADVOCATE
REQUEST: RCR-A-14 (UPDATE)
WITNESS(S): KAHRER
PAGE 1 OF 1
RATE CASE 2009

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SEVERANCE EXPENSE

QUESTION:
Provide the total amount of employee severance expenses in each of the last three years and as reflected in the filing. Please provide this information separately for electric and gas operations.

ANSWER:
The schedule below lists the total amount of employee severance expenses in each of the last three years and the test year. (The test year has been updated to reflect 6 months actual and 6 months plan). The service company numbers represent PSE&G's share of the service company severance expenses for each respective year. Please note that the prior numbers represented both O&M and Capital values while the update is reflective only of the O&M impact.

Year		**Electric**	**Gas**	**Total**
2006				
	PSE&G	8,326	9,259	17,585
	Service Company	8,050	6,795	14,845
	Total	16,376	16,054	32,429
2007				
	PSE&G	0	0	0
	Service Company	250,283	210,607	460,889
	Total	250,283	210,607	460,889
2008				
	PSE&G	0	0	0
	Service Company	94,203	62,770	156,973
	Total	94,203	62,770	156,973
Test Year				
	PSE&G	2,211	3,751	5,962
	Service Company	559,473	465,729	1,025,202
	Total	561,684	469,479	1,031,164

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

INCENTIVE COMPENSATION BY PROGRAM 6N6 UPDATE

QUESTION:
Please provide a description of all incentive compensation programs provided to employees. For each program, please provide:
a. a description of the program;
b. the amount included in the Company's claim, and;
c. the actual amount incurred in each of the past five years.

Please provide this information separately for electric and gas operations.

ANSWER:
a. See response to S-PREV-59

b.&c. The amount of incentive compensation the Company is claiming in its Electric filing for the years 2004 through 2008 and for the test year consisting of six months of actual and six months of plan data is detailed in the tables (1 through 3) that follow

Table 1: Utility costs for Electric Operations;

$000s	**2004**	**2005**	**2006**	**2007**	**2008**	**Test Year**
MICP	543	215	201	406	275	238
PIP	4,858	3,371	2,500	5,416	2,298	3,995
LTIP	0	0	1,207	1,142	1,066	1,170
Total	5,401	3,586	3,907	6,964	3,639	5,404

Table 2: Service Company costs for Electric Operations

$000s	**2004**	**2005**	**2006**	**2007**	**2008**	**Test Year**
MICP	835	868	1,173	932	1,953	927
PIP	2,620	3,549	3,314	3,655	4,348	3,906
LTIP	0	0	3,139	4,056	3,743	4,193
Total	3,455	4,418	7,626	8,643	10,043	9,026

Table 3: Total costs for Electric Operations

$000s	**2004**	**2005**	**2006**	**2007**	**2008**	**Test Year**
MICP	1,378	1,084	1,374	1,339	2,227	1,165
PIP	7,478	6,920	5,814	9,070	6,646	7,901
LTIP	0	0	4,346	5,198	4,809	5,363
Total	8,855	8,004	11,533	15,607	13,682	14,430

The amount of incentive compensation the Company is claiming for in its Gas filing for the years 2004 through 2008 and for the test year consisting of six months of actual and six months of plan data is detailed in the tables (4 through 6) that follow

Table 4: Utility costs for Gas Operations;

$000s	2004	2005	2006	2007	2008	Test Year
MICP	471	183	136	442	260	203
PIP	4,217	2,857	1,697	5,891	2,175	3,410
LTIP	0	0	906	976	677	963
Total	4,688	3,039	2,740	7,309	3,111	4,577

Table 5: Service Company costs for Gas Operations

$000s	2004	2005	2006	2007	2008	Test Year
MICP	663	701	969	791	1,340	713
PIP	2,082	2,866	2,737	3,102	2,984	3,005
LTIP	0	0	2,342	2,969	2,489	3,255
Total	2,746	3,567	6,049	6,862	6,812	6,973

Table 6: Total costs for Gas Operations

$000s	2004	2005	2006	2007	2008	Test Year
MICP	1,135	884	1,105	1,233	1,600	917
PIP	6,299	5,722	4,435	8,992	5,159	6,415
LTIP	0	0	3,249	3,946	3,165	4,218
Total	7,434	6,606	8,788	14,171	9,924	11,550

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

OFFICER INCENTIVE COMPENSATION PROGRAMS 6N6 UPDATE

QUESTION:
Please provide a description of all incentive compensation programs provided to officers. For each program, please provide:

a. a description of the program,
b. the amount included in the Company's claim, and;
c. the actual amount incurred in each of the past five years.

Please provide this information separately for electric and gas operations.

ANSWER:
a. See response to S-PREV-59

b-c. The amount of the Officers' incentive compensation for the Utility and the Service Company included in electric operations for the years 2004 through 2008 and for the test year consisting of six months of actual and six months of plan data is detailed in the table 1 below:

Table 1: Officers incentive compensation in electric operations

$000s	**2004**	**2005**	**2006**	**2007**	**2008**	**Test Year***
Utility						
MICP	543	215	201	406	275	238
LTIP	0	0	914	654	683	787
Total	543	215	1,115	1,060	958	1,025
Service Company						
MICP	835	868	1,173	932	1,953	927
LTIP	0	0	2,997	3,611	3,058	2,989
Total	835	868	4,170	4,543	5,011	3,916
Grand Total						
MICP	1,378	1,083	1,374	1,338	2,228	1,165
LTIP	0	0	3,911	4,265	3,741	3,776
Total	1,378	1,083	5,285	5,603	5,969	4,941

The amount of the Officers' incentive compensation for the Utility and the Service Company included in gas operations for the years 2004 through 2008 and for the test year consisting of six months of actual and six months of plan data is detailed in the table 2 below:

Table 2: Officers' incentive compensation in gas operations

$000s	**2004**	**2005**	**2006**	**2007**	**2008**	**Test Year***
Utility						
MICP	471	183	136	442	260	203
LTIP	0	0	686	560	434	648
Total	471	183	822	1,002	694	851
Service Company						
MICP	663	701	969	791	1,340	713
LTIP	0	0	2,236	2,644	2,033	2,321
Total	663	701	3,205	3,435	3,373	3,034
Grand Total						
MICP	1,135	884	1,105	1,233	1,600	916
LTIP	0	0	2,922	3,204	2,467	2,969
Total	1,135	884	4,027	4,437	4,067	3,885

*6 months actual, 6 months estimated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SUPPLEMENTAL EMPLOYEE RETIREMENT PROGRAM COSTS

QUESTION:
Describe and quantify any Supplemental Employee Retirement Program ("SERP") costs included in the Company's filing and describe how the Company's claim for SERP costs was determined. Please provide this information separately for electric and gas operations.

ANSWER:
Listed is a description of the Supplemental Employee Retirement Program. For the costs included in this program, please refer to the response to RCR-A-28.

Limited Supplemental Benefits Plan (SERP):
Assisting in attracting and retaining a stable pool of key managerial talent and to encourage long-term key employee commitment by providing selected employees with certain limited supplemental death and retirement benefits. The Plan provides such benefits to a select group of management or highly compensated employees who terminate after becoming eligible for immediately payable periodic benefits under the Pension Plan or for early or normal retirement benefits under the Cash Balance Plan ("the qualified plans").

Retirement Income Reinstatement Plan (RIRP):
Assisting in attracting and retaining a stable pool of key managerial and professional talent and long-term key employee commitment by providing certain supplemental retirement benefits for certain employees who participate in the Pension Plan or Cash Balance Plan ("the qualified plans").

The RIRP takes into account compensation that is limited under the qualified plans by Section 401(a)(17) of the Internal Revenue Code ("IRC"), currently $245,000 for 2009. (Also, the maximum annual benefit payable from the qualified plan is $195,000.) The qualified plan benefit plus the RIRP benefit equals the amount that the participant would be entitled to if the qualified plans were not subject to IRC compensation limits.

Mid Career Hire Supplemental Retirement Income Plan (MCHP):
Assisting in attracting and retaining a stable pool of key managerial and professional talent and long-term key employee commitment by providing certain supplemental retirement benefits based upon additional service credit for a selected number of key employees who participate in the Pension Plan or Cash Balance Plan ("the qualified plans").

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

BAD DEBT WRITE-OFF

QUESTION:
Provide, separately for electric and gas operations, for each of the past five years as well as projected for the test year:

a. the amount of bad debts written-off;
b. the amount of bad debts written off that were subsequently recovered;
c. the amount of any additions to a bad debt reserve, if applicable, and
d. the total revenues from electric sales.

ANSWER:

a.

(000's)	2005	2006	2007	2008	2009*
ELECTRIC	$32,758	$42,953	$39,472	$45,715	$14,098
GAS	$33,652	$45,017	$39,616	$40,622	$9,087

b.

(000's)	2005	2006	2007	2008	2009*
ELECTRIC	$(7,096)	$(8,374)	$(7,685)	$(8,362)	$(3,107)
GAS	$(5,815)	$(8,540)	$(5,931)	$(9,412)	$(1,744)

c.

(000's)	2005	2006	2007	2008	2009*
ELECTRIC	$30,438	$37,261	$32,588	$47,395	$7,620
GAS	$33,309	$40,098	$33,764	$41,466	$16,792

d.

(000's)	2005	2006	2007	2008	2009*
ELECTRIC**	$4,104,125	$4,365,402	$4,986,630	$5,332,374	$1,168,907
GAS**	$2,702,684	$2,720,762	$2,854,472	$2,864,287	$1,378,355

*Year to date through March 2009

**Total billed sales used in bad debt calculations

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

BAD DEBT WRITE-OFF (6+6 UPDATE)

QUESTION:
Provide, separately for electric and gas operations, for each of the past five years as well as projected for the test year:

a. the amount of bad debts written-off;
b. the amount of bad debts written off that were subsequently recovered;
c. the amount of any additions to a bad debt reserve, if applicable, and
d. the total revenues from electric sales.

ANSWER:
a & b

(000's)	**2009***
ELECTRIC**	$20,736
GAS**	$15,812

c.

(000's)	**2009***
ELECTRIC	$17,241
GAS	$22,905

d.

(000's)	**2009***
ELECTRIC***	$2,392,647
GAS***	$1,895,735

*Year to date through June 2009
**Net write-offs (write-offs less recoveries)
***Total billed sales used in bad debt calculations

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

VEGETATION MANAGEMENT COSTS

QUESTION:
Please identify the vegetative management costs incurred by the Company in each of the past five years, and as projected by the test year.

ANSWER:
Costs incurred for 2004 through the plan for 2009 are as follows:

Electric Distribution Vegetation Management Costs ($000's)

	2004	**2005**	**2006**	**2007**	**2008**	**2009 Plan**
O&M	12,754	15,290	23,528	18,561	13,260	21,675
Capital	365	527	1,478	955	2,772	469

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

RATE CASE EXPENSES - CONSULTANTS CONTRACTS

QUESTION:
Provide a copy of all contracts with consultants or other third parties for rate case services claimed in this filing.

ANSWER:
The contracts and invoices between the Company and its outside legal counsel and expert witnesses are confidential, proprietary and subject to the Attorney-Client privilege and therefore are not discoverable.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

REQUESTS FOR PROPOSAL

QUESTION:
Please provide copies of all Requests for Proposal issued by PSE&G with regard to the provision of rate case services in this case.

ANSWER:
This is not applicable. The Company did not prepare a request for proposal for any rate case services.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ASSOCIATION MEMBERSHIPS

QUESTION:
Provide the amount of expenses for memberships and dues included in the filing indicating the organization paid and the employees who participate (union, management, directors, etc.). Please provide this information separately for electric and gas operations.

ANSWER:
Attached is a breakdown of all club dues/membership fees incurred in the test year (six months of actual and six months plan data). The attached also indicates the identity of the organization, the amount paid to the organization and the associated account numbers of such payments. Of these charges, all memberships are corporate, thus no individual memberships are included.

PSE&G (DC10)
Memberships (expenditures exceeding $750)
Natural Account 5140300 by FERC Account
2009

Vendor	Account	Jan-June Actuals	Electric	Gas
Georgia Tech Research Corp.	9588001	97,200.00	97,200.00	
Common Ground Alliance	9880002	10,000.00		10,000.00
New Jersey Chamber of Commerce	9930101	32,900.00	32,900.00	
Southern NJ Development Council	9930101	1,645.00	1,645.00	
Woodbridge Metro Chamber of Commerce	9930101	1,645.00	1,645.00	
Morris County Chamber of Commerce	9930101	3,500.00	3,500.00	
Better Business Bureau of NJ	9930102	4,700.00		4,700.00
Nation's Port	9930102	9,400.00		9,400.00
Greater Elizabeth Chamber of Commerce	9930102	940.00		940.00
Statewide Hispanic Chamber of Commerce	9930102	4,700.00		4,700.00
Hudson County Chamber of Commerce	9930102	9,400.00		9,400.00
Center for Energy Workforce Development	9930101	7,307.00	7,307.00	
Center for Energy Workforce Development	9930102	4,693.00		4,693.00
Leadership New Jersey	9930101	3,653.00	3,653.00	
Leadership New Jersey	9930102	2,347.00		2,347.00
Conference Board	9930101	10,960.00	10,960.00	
Conference Board	9930102	7,040.00		7,040.00
Public Affairs Council	9930101	1,827.00	1,827.00	
Public Affairs Council	9930102	1,173.00		1,173.00
American Gas Association	9930202	459,248.00		459,248.00
Edison Electric Institute	9930201	315,017.03	315,017.03	
Mercer Regional Chamber of Commerce	9930101	936.90	936.90	
Mercer Regional Chamber of Commerce	9930102	694.00		694.00
Gateway Regional Chamber of Commerce	9930101	4,630.50	4,630.50	
Gateway Regional Chamber of Commerce	9930102	3,430.00		3,430.00
Regional Planning Partnership	9930101	2,700.00	2,700.00	
Regional Planning Partnership	9930102	2,000.00		2,000.00
		1,003,686.43	483,921.43	519,765.00

Remaining Planned Expenditures 7/1/2009 - 12/31/2009	256,759.74

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
NONDEDUCTIBLE MEALS & ENTERTAINMENT EXPENDITURES

QUESTION:
Provide the amount of meal expenses included in the test year but disallowed for tax purposes. Please provide this information separately for electric and gas operations.

ANSWER:

See the updated attached schedule showing the nondeductible meals & entertainment expenditures included in the test period for Electric Distribution and Gas Distribution through June 30, 2009.

2009 Rate Case
Public Service Electric & Gas Company
Unallowable Meals and Entertainment Included in Test Period

6 Months Actuals/6 Months Estimate

		Electric Distribution		Gas Distribution	
Year 2009:		**Total Meals & Entertainment**	**50% Disallowed for Tax**	**Total Meals & Entertainment**	**50% Disallowed for Tax**
Jan	**Actual**	124,142	62,071	79,580	39,790
Feb	**Actual**	95,612	47,806	71,452	35,726
Mar	**Actual**	87,120	43,560	56,338	28,169
Apr	**Actual**	75,498	37,749	68,894	34,447
May	**Actual**	53,684	26,842	76,864	38,432
Jun	**Actual**	52,632	26,316	63,798	31,899
Jul	**Estimated**	194,906	97,453	110,742	55,371
Aug	**Estimated**	194,906	97,453	110,742	55,371
Sep	**Estimated**	194,906	97,453	110,742	55,371
Oct	**Estimated**	194,906	97,453	110,742	55,371
Nov	**Estimated**	194,906	97,453	110,742	55,371
Dec	**Estimated**	194,906	97,453	110,742	55,371
			829,062		**540,689**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAXES - TAX ALLOCATION AGREEMENTS

QUESTION:
Do the members of the consolidated income tax group have a tax sharing agreement? If so, please provide a copy of the agreement.

ANSWER:
Attached are tax allocation agreements between Public Service Enterprise Group Inc. and the following companies: Public Service Electric & Gas Company, PSEG Power LLC and Subsidiary LLC's, PSEG Power New York Inc., PSEG Services Corporation, Holding's LLC, Resources LLC, CEA(Global) and Enterprise Group Development Corporation

Tax Allocation Agreement Between Public Service Enterprise Group Incorporated and Public Service Electric and Gas Company

The following tax allocation agreement, effective May 1, 1986, results from the restructuring of Public Service Electric and Gas Company and the inception of the new holding company structure with Public Service Enterprise Group Incorporated ("Enterprise") as parent. The consolidated affiliated group consists of Enterprise and its subsidiaries: Public Service Electric and Gas Company ("PSE&G") and its subsidiaries, Community Energy Alternatives Incorporated ("CEA") and its subsidiaries, and Public Service Resources Corporation ("PSRC") and its subsidiaries. This agreement applies to PSE&G and its subsidiaries (hereinafter referred to as "PSE&G").

An Internal Revenue Service ruling has been received providing that the affiliated group with PSE&G as common parent which existed immediately before the restructuring will continue in existence for consolidated return purposes with Enterprise as the new common parent. The ruling further provides that the affiliated group can continue to join in the annual filing of a consolidated Federal Income Tax return. Enterprise intends to so file a consolidated Federal Income Tax return for itself, its subsidiaries and their subsidiaries (the "Group"). PSE&G consents to be included in the consolidated return. Enterprise and PSE&G therefore agree to the following method of allocating consolidated Federal Income Tax liability and for compensating PSE&G for the use of its net operating losses and/or tax credits, if any, in arriving at such tax liability. The agreement also applies to refund claims and the carryback of net operating losses and/or tax credits.

The primary goal of this allocation agreement is, to the maximum extent possible, to allocate to PSE&G the tax liability or savings for the consolidated group which are generated by PSE&G. Therefore, the parties hereto agree as follows:

1. PSE&G shall compute its liability on a stand alone basis solely by reference to its respective items of income, gain, loss, deduction and credit.

2. If PSE&G generates a net tax liability on a stand alone basis, it shall pay the amount of such separate return liability to Enterprise.

3. If PSE&G incurs a net operating loss and/or tax credits, on a stand alone basis, PSE&G shall receive the tax savings to the extent such savings can be utilized by the Group.

4. The provisions of this agreement shall be administered by the Income Tax Department of Public Service Electric and Gas Company (Tax Department), whose decisions with respect to tax liability, and the interpretation and application of this Agreement, shall be final and binding on the parties hereto.

5. All tax payments, including estimated tax payments, as calculated by the Tax Department, shall be paid by Enterprise to PSE&G or by PSE&G to Enterprise no later than five working days after the member is notified of such amount. The amounts due may be paid either by the actual remittance of cash or via inter-company accounts, as determined, from time to time by Enterprise.

6. Adjustments to consolidated Federal Income Tax liability or refunds made by the Internal Revenue Service on audit of the consolidated return shall be determined in accordance with paragraphs 1 through 3.

7. This agreement shall apply to all tax years beginning with the year 1986 unless Enterprise and PSE&G agree in writing to terminate this agreement.

In Witness Whereof, the parties hereto have duly executed this agreement by their duly authorized officers.

Public Service Enterprise Group Incorporated

By ______________ Date 8/7/86

Title Chairman of the Board

Public Service Electric and Gas Company

By Everett Morris Date 8/11/86

Title Senior Executive Vice President

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
WEATHER NORMALIZED SALES METHODOLOGY

QUESTION:
The workpapers to Exhibit P-7, SCHEDULE MGK-35, do not describe the Company's weather normalization methodology, nor do the workpapers show how the monthly volume adjustments for January-March were determined. Therefore, separately for gas and electric:

a) please provide a narrative describing how the Company has weather normalized electric and gas sales,
b) provide, by month and by customer class, the weather normalized usage assumed in the Company's test year claim,
c) please provide all assumptions, workpapers, and supporting calculations showing the entire derivation of the Company's normalized sales claim,
d) state whether cooling and/or heating degree days were used in the weather normalization adjustment,
e) state the period of time used to determine "normal" weather for purposes of weather normalizing sales, and
f) provide the effect on the Company's weather normalization adjustment if the Company had used a thirty-year period to normalize sales.

ANSWER:
ELECTRIC SALES
a) Please see the attached narrative describing how the Company has weather normalized electric sales.

b) The table below provides, by month and by customer class, the weather normalized electric usage assumed in the Company's test year claim.

Weather-Normalized Residential Electric Sales by Rate (kWh)

Calendar-Month	RS	RHS	WH-R	RLM	Total
January-09	1,136,194,566	28,190,124	136,320	23,734,461	1,188,255,471
February-09	925,650,694	19,630,714	164,359	18,911,793	964,357,560
March-09	978,778,827	19,963,505	249,611	20,233,714	1,019,225,657
April-09	858,906,350	11,327,369	428,337	16,488,717	887,150,773
May-09	848,350,469	7,718,989	210,253	15,171,498	871,451,210
June-09	1,333,421,921	10,043,019	244,463	28,873,177	1,372,582,580

c) The assumptions, workpapers, and supporting calculations showing the entire derivation of the Company's normalized electric sales claim are contained in the attached narrative.

d) Heating degree days and the temperature humidity index were used in the electric weather normalization adjustment.

e) The 1989-2008 period was used to determine "normal" weather for purposes of weather normalizing electric sales.

f) The calculations for the individual rate- and customer-class groups using normal weather as defined by the 30 year period, 1979-2008 is contained in the attached narrative.

GAS SALES

a) Please see the attached narrative describing how the Company has weather normalized gas sales.

b) The table below provides, by month and by customer class, the weather normalized gas usage assumed in the Company's test year claim,

Weather-Normalized Gas Sales by Customer Class (therms)

Calendar-Month	Residential	Commercial	Industrial	Lighting	Total
January-09	261,159,666	148,740,070	13,135,670	57,345	423,092,751
February-09	220,309,908	124,437,797	11,575,880	53,326	356,376,911
March-09	192,441,479	111,073,307	10,210,652	57,776	313,783,214
April-09	95,392,526	56,012,593	5,204,650	2,058	156,611,827
May-09	49,085,640	35,035,839	4,317,637	65,588	88,504,703
June-09	42,472,880	36,520,927	2,833,162	2,187	81,829,155

c) The assumptions, workpapers, and supporting calculations showing the entire derivation of the Company's normalized gas sales claim are contained in the attached narrative.

d) Heating degree days were used in the gas weather normalization adjustment. More detail is contained in the attached narrative.

e) The 1989-2008 period was used to determine "normal" weather for purposes of weather normalizing gas sales.

f) The effect on the Company's weather normalization adjustment if the Company had used a thirty-year period to normalize sales instead of the twenty-year period that was used is shown in the attached narrative.

Weather Adjustment Sample Calculations

RS

Month	Heating Degree Days Actual	Heating Degree Days Normal	Heating Degree Days Difference	Temperature/Humidity Actual	Temperature/Humidity Normal	Temperature/Humidity Difference	HDD Coefficient	Weather Adjustment	THI Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	-		-	380,840	(69,436,476)		-	(69,436,476)
Feb-09	656.4	695.1	38.7	-		-	383,078	14,806,474		-	14,806,474
Mar-09	561.8	552.4	(9.4)	-		-	382,196	(3,590,585)		-	(3,590,585)
Apr-09	232.5	243.0	10.6	376.2	140.1	(236.1)	382,327	4,035,717	170,070	(40,151,815)	(36,116,099)
May-09	36.7	50.8	14.1	585.8	749.5	163.7	382,015	5,395,842	169,931	27,817,767	33,213,608
Jun-09				1,412.3	2,998.8	1,586.5		-	170,101	269,868,311	269,868,311

RHS

Month	Heating Degree Days Actual	Heating Degree Days Normal	Heating Degree Days Difference	Temperature/Humidity Actual	Temperature/Humidity Normal	Temperature/Humidity Difference	HDD Coefficient	Weather Adjustment	THI Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	-		-	21,670	(3,951,026)		-	(3,951,026)
Feb-09	656.4	695.1	38.7	-		-	21,542	832,619		-	832,619
Mar-09	561.8	552.4	(9.4)	-		-	21,461	(201,622)		-	(201,622)
Apr-09	232.5	243.0	10.6	376.2	140.1	(236.1)	21,353	225,390	718	(169,554)	55,837
May-09	36.7	50.8	14.1	585.8	749.5	163.7	21,262	300,312	715	117,064	417,376
Jun-09				1,412.3	2,998.8	1,586.5		-	713	1,131,968	1,131,968

RLM

Month	Heating Degree Days Actual	Heating Degree Days Normal	Heating Degree Days Difference	Temperature/Humidity Actual	Temperature/Humidity Normal	Temperature/Humidity Difference	HDD Coefficient	Weather Adjustment	THI Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	-		-	7,473	(1,362,560)		-	(1,362,560)
Feb-09	656.4	695.1	38.7	-		-	7,478	289,023		-	289,023
Mar-09	561.8	552.4	(9.4)	-		-	7,465	(70,131)		-	(70,131)
Apr-09	232.5	243.0	10.6	376.2	140.1	(236.1)	7,471	78,856	2,829	(667,994)	(589,138)
May-09	36.7	50.8	14.1	585.8	749.5	163.7	7,459	105,355	2,825	462,456	567,810
Jun-09				1,412.3	2,998.8	1,586.5		-	2,830	4,489,903	4,489,903

WH-R

Month	Heating Degree Days Actual	Heating Degree Days Normal	Heating Degree Days Difference	Temperature/Humidity Actual	Temperature/Humidity Normal	Temperature/Humidity Difference	HDD Coefficient	Weather Adjustment	THI Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	-		-	20	(3,585)		-	(3,585)
Feb-09	656.4	695.1	38.7	-		-	20	756		-	756
Mar-09	561.8	552.4	(9.4)	-		-	19	(183)		-	(183)
Apr-09	232.5	243.0	10.6	376.2	140.1	(236.1)	19	205		-	205
May-09	36.7	50.8	14.1	585.8	749.5	163.7	19	272		-	272
Jun-09				1,412.3	2,998.8	1,586.5		-		-	-

Month	Total Weather Adjustment
Jan-09	(74,753,647)
Feb-09	15,928,871
Mar-09	(3,862,521)
Apr-09	(36,649,196)
May-09	34,199,067
Jun-09	275,490,182
	210,352,756

Weather Adjustment Sample Calculations – 30 Year Normal Weather

	Heating Degree Days			Temperature/Humidity			RS				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	808.9	(182.3)	-		-	380,840	(69,436,476)		-	(69,436,476)
Feb-09	656.4	695.1	38.7	-		-	383,078	14,806,474		-	14,806,474
Mar-09	561.8	552.4	(9.4)	-		-	382,196	(3,590,585)		-	(3,590,585)
Apr-09	232.5	243.0	10.6	376.2	140.1	(236.1)	382,327	4,035,717	170,070	(40,151,815)	(36,116,099)
May-09	36.7	50.8	14.1	585.8	749.5	163.7	382,015	5,395,842	169,931	27,817,767	33,213,608
Jun-09				1,412.3	2,998.8	1,586.5		-	170,101	269,868,311	269,868,311

	Heating Degree Days			Temperature/Humidity			RHS				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	21,670	(3,007,435)		-	(3,007,435)
Feb-09	656.4	709.8	53.4	-		-	21,542	1,150,446		-	1,150,446
Mar-09	561.8	552.4	(9.3)	-		-	21,461	(200,163)		-	(200,163)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	21,353	220,394	718	(184,521)	35,873
May-09	36.7	46.6	9.8	585.8	792.8	207.0	21,262	209,249	715	148,050	357,298
Jun-09				1,412.3	2,797.5	1,385.2		-	713	988,342	988,342

	Heating Degree Days			Temperature/Humidity			RLM				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	7,473	(1,037,151)		-	(1,037,151)
Feb-09	656.4	709.8	53.4	-		-	7,478	399,348		-	399,348
Mar-09	561.8	552.4	(9.3)	-		-	7,465	(69,623)		-	(69,623)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	7,471	77,108	2,829	(726,959)	(649,851)
May-09	36.7	46.6	9.8	585.8	792.8	207.0	7,459	73,408	2,825	584,864	658,272
Jun-09				1,412.3	2,797.5	1,385.2		-	2,830	3,920,217	3,920,217

	Heating Degree Days			Temperature/Humidity			WH-R				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	20	(2,729)		-	(2,729)
Feb-09	656.4	709.8	53.4	-		-	20	1,045		-	1,045
Mar-09	561.8	552.4	(9.3)	-		-	19	(182)		-	(182)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	19	200		-	200
May-09	36.7	46.6	9.8	585.8	792.8	207.0	19	190		-	190
Jun-09				1,412.3	2,797.5	1,385.2		-		-	-

Month	Total Weather Adjustment
Jan-09	(73,483,792)
Feb-09	16,357,313
Mar-09	(3,860,553)
Apr-09	(36,729,876)
May-09	34,229,368
Jun-09	274,776,871
	211,289,332

Weather Adjustment Sample Calculations – 30 Year Normal Weather

	Heating Degree Days			Temperature/Humidity			RS				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	380,840	(52,853,542)		-	(52,853,542)
Feb-09	656.4	709.8	53.4	-		-	383,078	20,458,406		-	20,458,406
Mar-09	561.8	552.4	(9.3)	-		-	382,196	(3,564,596)		-	(3,564,596)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	382,327	3,946,252	170,070	(43,696,073)	(39,749,821)
May-09	36.7	46.6	9.8	585.8	792.8	207.0	382,015	3,759,669	169,931	35,180,893	38,940,562
Jun-09				1,412.3	2,797.5	1,385.2		-	170,101	235,627,022	235,627,022

	Heating Degree Days			Temperature/Humidity			RHS				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	21,670	(3,007,435)		-	(3,007,435)
Feb-09	656.4	709.8	53.4	-		-	21,542	1,150,446		-	1,150,446
Mar-09	561.8	552.4	(9.3)	-		-	21,461	(200,163)		-	(200,163)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	21,353	220,394	718	(184,521)	35,873
May-09	36.7	46.6	9.8	585.8	792.8	207.0	21,262	209,249	715	148,050	357,298
Jun-09				1,412.3	2,797.5	1,385.2		-	713	988,342	988,342

	Heating Degree Days			Temperature/Humidity			RLM				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	7,473	(1,037,151)		-	(1,037,151)
Feb-09	656.4	709.8	53.4	-		-	7,478	399,348		-	399,348
Mar-09	561.8	552.4	(9.3)	-		-	7,465	(69,623)		-	(69,623)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	7,471	77,108	2,829	(726,959)	(649,851)
May-09	36.7	46.6	9.8	585.8	792.8	207.0	7,459	73,408	2,825	584,864	658,272
Jun-09				1,412.3	2,797.5	1,385.2		-	2,830	3,920,217	3,920,217

	Heating Degree Days			Temperature/Humidity			WH-R				Total
							HDD	Weather	THI	Weather	Weather
Month	Actual	Normal	Difference	Actual	Normal	Difference	Coefficient	Adjustment	Coefficient	Adjustment	Adjustment
Jan-09	991.2	852.4	(138.8)	-		-	20	(2,729)		-	(2,729)
Feb-09	656.4	709.8	53.4	-		-	20	1,045		-	1,045
Mar-09	561.8	552.4	(9.3)	-		-	19	(182)		-	(182)
Apr-09	232.5	242.8	10.3	376.2	119.3	(256.9)	19	200		-	200
May-09	36.7	46.6	9.8	585.8	792.8	207.0	19	190		-	190
Jun-09				1,412.3	2,797.5	1,385.2		-		-	-

	Total
	Weather
Month	Adjustment
Jan-09	(56,900,857)
Feb-09	22,009,246
Mar-09	(3,834,563)
Apr-09	(40,363,599)
May-09	39,956,323
Jun-09	240,535,581
	201,402,130

CORRECTED

Weather Adjustment Sample Calculations

Residential

	Heating Degree Days			RSG-Heating		RSG-Nonheating		Total
Month	Actual	Normal	Difference	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	249,551	(45,499,226)	4,745	(865,216)	(46,364,442)
Feb-09	656.4	695.1	38.7	250,237	9,671,998	4,744	183,343	9,855,342
Mar-09	561.8	552.4	(9.4)	249,024	(2,339,488)	4,717	(44,318)	(2,383,807)
Apr-09	232.5	243.0	10.6	256,924	2,712,003	4,804	50,708	2,762,711
May-09	36.7	50.8	14.1	237,874	3,359,886	4,424	62,484	3,422,370
Jun-09	1.0	1.5	0.5	255,552	123,517	4,715	2,279	125,795
Jul-09								

Commercial

	Heating Degree Days			GSG-Heating		GSG-Nonheating		LVG		Total
Month	Actual	Normal	Difference	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	44,523	(8,117,684)	4,767	(869,216)	79,544	(14,502,878)	(23,489,778)
Feb-09	656.4	695.1	38.7	44,523	1,720,886	4,767	184,267	79,544	3,074,497	4,979,649
Mar-09	561.8	552.4	(9.4)	44,523	(418,280)	4,767	(44,788)	79,544	(747,290)	(1,210,357)
Apr-09	232.5	243.0	10.6	44,523	469,973	4,767	50,323	79,544	839,644	1,359,941
May-09	36.7	50.8	14.1	44,523	628,877	4,767	67,338	79,544	1,123,538	1,819,753
Jun-09	1.0	1.5	0.5	44,523	21,520	4,767	2,304	79,544	38,446	62,270

Industrial

	Heating Degree Days			GSG-Heating		GSG-Nonheating		LVG		Total
Month	Actual	Normal	Difference	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	Total Weather Adjustment
Jan-09	991.2	808.9	(182.3)	3,198	(583,067)	438	(79,862)	7,406	(1,350,267)	(2,013,196)
Feb-09	656.4	695.1	38.7	3,198	123,606	438	16,930	7,406	286,246	426,782
Mar-09	561.8	552.4	(9.4)	3,198	(30,044)	438	(4,115)	7,406	(69,575)	(103,734)
Apr-09	232.5	243.0	10.6	3,198	33,757	438	4,624	7,406	78,174	116,554
May-09	36.7	50.8	14.1	3,198	45,170	438	6,187	7,406	104,605	155,962
Jun-09	1.0	1.5	0.5	3,198	1,546	438	212	7,406	3,579	5,337

Month	Total Weather Adjustment
Jan-09	(71,867,416)
Feb-09	15,261,773
Mar-09	(3,697,898)
Apr-09	4,239,205
May-09	5,398,085
Jun-09	193,403
	(50,472,847)

Weather Adjustment Sample Calculations 30-Year Normal Weather

Residential

	Heating Degree Days			RSG-Heating		RSG-Nonheating		Total
Month	Actual	Normal	Difference	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	Weather Adjustment
Jan-09	991.2	852.4	(138.8)	249,551	(34,633,025)	4,745	(658,584)	(35,291,609)
Feb-09	656.4	709.8	53.4	250,237	13,363,997	4,744	253,329	13,617,326
Mar-09	561.8	552.4	(9.3)	249,024	(2,322,555)	4,717	(43,997)	(2,366,552)
Apr-09	232.5	242.8	10.3	256,924	2,651,883	4,804	49,584	2,701,467
May-09	36.7	46.6	9.8	237,874	2,341,073	4,424	43,537	2,384,610
Jun-09	1.0	2.0	0.9	255,552	239,793	4,715	4,424	244,217

Commercial

	Heating Degree Days			GSG-Heating		GSG-Nonheating		LVG		Total
Month	Actual	Normal	Difference	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	Weather Adjustment
Jan-09	991.2	852.4	(138.8)	44,523	(6,179,005)	4,767	(661,628)	79,544	(11,039,277)	(17,879,910)
Feb-09	656.4	709.8	53.4	44,523	2,377,783	4,767	254,605	79,544	4,248,095	6,880,483
Mar-09	561.8	552.4	(9.3)	44,523	(415,252)	4,767	(44,464)	79,544	(741,881)	(1,201,597)
Apr-09	232.5	242.8	10.3	44,523	459,555	4,767	49,208	79,544	821,031	1,329,793
May-09	36.7	46.6	9.8	44,523	438,184	4,767	46,919	79,544	782,849	1,267,952
Jun-09	1.0	2.0	0.9	44,523	41,778	4,767	4,473	79,544	74,639	120,890

Industrial

	Heating Degree Days			GSG-Heating		GSG-Nonheating		LVG		Total
Month	Actual	Normal	Difference	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	HDD Coefficient	Weather Adjustment	Weather Adjustment
Jan-09	991.2	852.4	(138.8)	3,198	(443,818)	438	(60,789)	7,406	(1,027,794)	(1,532,401)
Feb-09	656.4	709.8	53.4	3,198	170,788	438	23,393	7,406	395,512	589,693
Mar-09	561.8	552.4	(9.3)	3,198	(29,826)	438	(4,085)	7,406	(69,072)	(102,983)
Apr-09	232.5	242.8	10.3	3,198	33,008	438	4,521	7,406	76,441	113,970
May-09	36.7	46.6	9.8	3,198	31,473	438	4,311	7,406	72,886	108,670
Jun-09	1.0	2.0	0.9	3,198	3,001	438	411	7,406	6,949	10,361

	Total
Month	Weather Adjustment
Jan-09	(54,703,920)
Feb-09	21,087,502
Mar-09	(3,671,132)
Apr-09	4,145,230
May-09	3,761,233
Jun-09	375,468
	(29,005,620)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMPLOYEE POSITIONS IN RATE CASE SUPPORTING RGGI PROGRAMS

QUESTION:

Regarding the response to RCR-A-6, has PSE&G included 100% of all payroll costs for all employee positions in the rate case? If not, please:

a) identify each position for which less than 100% of the cost is included in the rate case claim,
b) quantify the amount and percentage of salary and wage costs included in the rate case claim, and
c) state how the Company expects to recover the remaining cost for each position.

ANSWER:

Yes, for those positions whose costs are recovered in the Company's base rate case, 100% of all payroll costs for such positions are included.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
NUMBER OF EMPLOYEE POSITIONS BY DEPARTMENT

QUESTION:
Regarding the response to RCR-A-11, please explain why actual employees generally exceeded planned employees through March 2009.

ANSWER:
With regard to the response to RCR-A-11, the reason that actual employees are greater than plan employees for the first quarter of 2009, is primarily due to challenges in the implementation of the Customer Information System.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

MEALS AND ENTERTAINMENT

QUESTION:
With regard to RCR-A-60, Page 2 of 2, what types of charges are included under Meals and Entertainment?

ANSWER:
RCR-A-60 shows the non-deductible piece of business meals and entertainment. Business meals and entertainment are generally 50% tax deductible. Business meals and entertainment include expenses such as meals related to business travel or business meetings with clients or associates and business entertainment costs. Business entertainment costs include items such as ticket price to shows or sporting events where there is a business purpose that supports the cost.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

RATE CASE EXPENSES UPDATED

QUESTION:
With regard to the response to S-PREV-38, page 2 of 2, please provide the most recent update of actual rate case costs to date.

ANSWER:
See the attached work paper showing the rate case expense included in the test year period, updated through June 2009.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

RATE CASE EXPENSES-CURRENT CASE

DOCKET # GR09050422

$000's

	Test Year Cumulative To Date As Of 6/30/09	Estimated Total for Rate Case
Category:		
Legal Fees	146	405
Consultant Fees	159	915
Court Reporting, transcripts, other	12	180
	317	1,500

RESPONSE TO ADVOCATE
REQUEST: RCR-A-181 (UPDATE)
WITNESS(S): KAHRER

RATE CASE 2009

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GENERAL ADVERTISING

QUESTION:
Regarding the response to S-PREV-42, are the General advertising amounts of $3,528,423 for electric and $2,829,756 for gas attributable to any specific programs? If so, please describe all programs in detail and provide the amount of advertising expense associated with each program.

ANSWER:
Attached, please find the updated activities and dollar amounts associated with general advertising expenses found in FERC account number 930.1 for six months actual and six months plan 2009 for both gas and electric.

Gas Distribution **FERC- Account Number 930.1**
6 months Actual

CF-P-E-Ext Comm	Provides external communications support for PSEG at the corporate level. This includes press relations, speechwriting, external event coordination and Executive support.	$76,658.00
CF-P-E-PT-ExtComm	O/S consultants and expenses required for external communications for PSEG which includes press relations, speechwriting, external event coordination and Executive support.	$11,765.00
CF-P-PT-ExtComm	O/S consultants and expenses required for external communications to support Operating Companies/Lines of Business goals. Services include press relations, speechwriting, external event coordination and executive support.	$2,913.00
CF-P-E-Adv & Br	The creation and maintenance of PSEG level branding and advertising efforts. Corporate Branding and Investor advertising campaigns. GreenFest.	$29,862.00
CF-P-E-PT-Adv & Br	Outside Services, materials, media and events for the creation, improvement and maintenance of PSEG corporate level branding and advertising efforts (e.g. Corporate Branding and investor advertising campaigns, GreenFest).	$437,287.00
CF-P-E-Advertising Svcs	Development, execution and production of communications that achieve PSEG business goals. Services include media purchasing, advertising/promotional materials, internal communications, presentation materials, annual report & other initiatives.	$29,747.00
CF-P-E-PT-Advertising Svcs	O/S consultants and materials for the development and execution of communications that achieve PSEG/OC business goals. Media, adv/promotional materials, internal communications, presentation materials, printing, etc.	$49,877.00
CF-P-PT-Advertising Svcs	O/S consultants and materials for the development and execution of communications that achieve LOB business goals. Media, adv/promotional materials, internal communications, presentation materials, printing, etc. (e.g. Utility Legal Ads)	$107,373.00
CF-P-External Communications	Provides external communications support for the Operating Companies/LOB of PSEG. This includes press relations, speechwriting, external event coordination and executive support.	$138,713.00
CF-T-Outlook	Communicates info. to PSEG employees via 3 products: PSEG Outlook- a monthly print publication; Outlook Online- a tri-weekly on-line publication; and Outlook This Morning- a daily compendium of news clips on the company and the energy industry.	$64,400.00
CF-P-Advertising Svcs	Provides support in the development, execution and production of LOB communications that achieve business goals. Media purchasing, adv/promo materials, presentation materials, bill stuffers, newsletters, WorryFree and other initiatives.	$48,018.00
CF-P-Communications Consulting	Internal Communications to develop, manage and implement strategic communications plans to support OC/LOB objectives and ensure alignment with overall corporate messages. Speechwriting, development of computer-based presentations/programs.	$134,685.00
Corp. Memberships		$46,423.00
Corp. Sponsorships		$572,556.00
six months of actual		$1,750,277.00

Gas Distribution
6 months Plan

FERC- Account Number 930.1

CF-P-E-External Communications	Provides external communications support for PSEG at the corporate level. This includes press relations, speechwriting, external event coordination and Executive support.	$109,586.00
CF-P-E-PT-External Communications	O/S consultants and expenses required for external communications for PSEG which includes press relations, speechwriting, external event coordination and Executive support.	$14,571.00
CF-P-E-Advertising and Branding	The creation and maintenance of PSEG level branding and advertising efforts. Corporate Branding and Investor advertising campaigns. GreenFest.	$26,630.00
CF-P-E-PT-Advertising and Branding	The creation and maintenance of PSEG level branding and advertising efforts. Corporate Branding and Investor advertising campaigns. GreenFest.	$387,976.00
CF-P-E-Advertising Svcs	Outside Services, materials, media and events for the creation, improvement and maintenance of PSEG corporate level branding and advertising efforts (e.g. Corporate Branding and investor advertising campaigns, GreenFest).	$29,798.00
CF-P-External Comm	Provides external communications support for the Operating Companies/LOB of PSEG. This includes press relations, speechwriting, external event coordination and executive support.	$100,954.00
CF-P-PT-External Communications	O/S consultants and expenses required for external communications to support Operating Companies/Lines of Business goals. Services include press relations, speechwriting, external event coordination and executive support.	$4,200.00
CF-P-Advertising Svcs	Provides support in the development, execution and production of LOB communications that achieve business goals. Media purchasing, adv/promo materials, presentation materials, bill stuffers, newsletters, WorryFree and other initiatives.	$32,923.00
CF-P-E-PT-Advertising Svcs	Development, execution and production of communications that achieve PSEG business goals. Services include media purchasing, advertising/promotional materials, internal communications, presentation materials, annual report & other initiatives.	$78,399.00
Corp. Memberships		$42,038.00
Corp. Sponsorships		$276,024.00
six months plan		**$1,103,099.00**

Electric Distribution **FERC- Account Number 930.1**

6 months Actual

CF-P-E-Ext Comm	Provides external communications support for PSEG at the corporate level. This includes press relations, speechwriting, external event coordination and Executive support.	$93,906.00
CF-P-E-PT-ExtComm	O/S consultants and expenses required for external communications for PSEG which includes press relations, speechwriting, external event coordination and Executive support.	$140,598.00
CF-P-PT-ExtComm	O/S consultants and expenses required for external communications to support Operating Companies/Lines of Business goals. Services include press relations, speechwriting, external event coordination and executive support.	$3,568.00
CF-P-E-Adv & Br	The creation and maintenance of PSEG level branding and advertising efforts. Corporate Branding and Investor advertising campaigns. GreenFest.	$36,580.00
CF-P-E-PT-Adv & Br	Outside Services, materials, media and events for the creation, improvement and maintenance of PSEG corporate level branding and advertising efforts (e.g. Corporate Branding and investor advertising campaigns, GreenFest).	$535,676.00
CF-P-E-Advertising Svcs	Development, execution and production of communications that achieve PSEG business goals. Services include media purchasing, advertising/promotional materials, internal communications, presentation materials, annual report & other initiatives.	$36,439.00
CF-P-E-PT-Advertising Svcs	O/S consultants and materials for the development and execution of communications that achieve PSEG/OC business goals. Media, adv/promotional materials, internal communications, presentation materials, printing, etc.	$61,099.00
CF-P-PT-Advertising Svcs	O/S consultants and materials for the development and execution of communications that achieve LOB business goals. Media, adv/promotional materials, internal communications, presentation materials, printing, etc. (e.g. Utility Legal Ads)	$131,531.00
Communications and Advertising	Provides external communications support for the Operating Companies/LOB of PSEG. This includes press relations, speechwriting, external event coordination and executive support.	$29,528.00
CF-T-Outlook	Communicates info. to PSEG employees via 3 products: PSEG Outlook- a monthly print publication; Outlook Online- a tri-weekly on-line publication; and Outlook This Morning- a daily compendium of news clips on the company and the energy industry.	$78,890.00
CF-P-Advertising Svcs	Provides support in the development, execution and production of LOB communications that achieve business goals. Media purchasing, adv/promo materials, presentation materials, bill stuffers, newsletters, WorryFree and other initiatives.	$58,822.00
CF-P-Communications Consulting	Internal Communications to develop, manage and implement strategic communications plans to support OC/LOB objectives and ensure alignment with overall corporate messages. Speechwriting, development of computer-based presentations/programs.	$160,582.00
Corp. Memberships		$4,407.00
Corp. Sponsorships		$835,622.00
six months of actual		**$2,207,248.00**

Electric Distribution **FERC- Account Number 930.1**
6 months plan

CF-P-E-Ext Comm	Provides external communications support for PSEG at the corporate level. This includes press relations, speechwriting, external event coordination and Executive support.	$134,243.00
CF-P-E-PT-ExtComm	O/S consultants and expenses required for external communications for PSEG which includes press relations, speechwriting, external event coordination and Executive support.	$17,850.00
CF-P-PT-ExtComm	O/S consultants and expenses required for external communications to support Operating Companies/Lines of Business goals. Services include press relations, speechwriting, external event coordination and executive support.	$5,145.00
CF-P-E-Adv & Br	The creation and maintenance of PSEG level branding and advertising efforts. Corporate Branding and Investor advertising campaigns. GreenFest.	$32,622.00
CF-P-E-PT-Adv & Br	Outside Services, materials, media and events for the creation, improvement and maintenance of PSEG corporate level branding and advertising efforts (e.g. Corporate Branding and investor advertising campaigns, GreenFest).	$475,809.00
CF-P-E-Advertising Svcs	Development, execution and production of communications that achieve PSEG business goals. Services include media purchasing, advertising/promotional materials, internal communications, presentation materials, annual report & other initiatives.	$36,503.00
CF-P-External Communications	Provides external communications support for the Operating Companies/LOB of PSEG. This includes press relations, speechwriting, external event coordination and executive support.	$123,669.00
CF-P-PT-External Communications	O/S consultants and expenses required for external communications to support Operating Companies/Lines of Business goals. Services include press relations, speechwriting, external event coordination and executive support.	$96,039.00
CF-P-Advertising Svcs	Provides support in the development, execution and production of LOB communications that achieve business goals. Media purchasing, adv/promo materials, presentation materials, bill stuffers, newsletters, WorryFree and other initiatives.	$40,331.00
Corp. Memberships		$7,983.00
Corp. Sponsorships		$383,103.00
six months of plan		**$1,353,297.00**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SOLAR LOAN ADJUSTMENT

QUESTION:
The workpapers to Schedule MGK-42 do not show any amounts relating to the Solar Loan Programs although Mr. Kahrer's testimony at page 40 states that these amounts are included in that adjustment. Please clarify if Schedule MGK-42 includes amounts associated with the Solar Loan programs, quantify the amounts included in Schedule MGK-42 relating to such programs, and provide supporting assumptions, workpapers, and calculations.

ANSWER:
Schedule MGK-42, R-1 included amounts associated with the Solar Loan I program. Attached is an updated schedule which illustrates the amounts in the Carbon Abatement program updated through June 30, 2009. The amounts for the Solar Loan I program adjustment and the underlyng calculation have been deleted from this schedule and Schedule MGK-42, R-1 will be revised to reflect this change in the Company's next update. Please see Response RCR-A-207 for additional information regarding the administrative costs for Solar Loan I.

ELECTRIC

	Jan - June	July - Dec	12 Months
	Carbon Abatement		
Operating Revenues	400,523	548,649	949,172
Amortization of Program Investment	5,444	349,895	355,339
Administrative Costs	161,840		161,840
Over/(Under) Recovery	230,529	-	230,529
Interest on Over/(Under) Recovery	456	-	456
	398,269	349,895	748,164
Net Income (Expense)	2,254	198,754	201,008

GAS

	Jan - June	July - Dec	12 Months
	Carbon Abatement		
Operating Revenues	594,268	635,895	1,230,163
Amortization of Program Investment	18,131	367,198	385,329
Administrative Costs	422,399		422,399
Over/(Under) Recovery	143,897		143,897
Interest on Over/(Under) Recovery	814		814
	585,241	367,198	952,439
Net Income (Expense)	9,027	268,697	277,724

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SOLAR LOAN AND CARBON ABATEMENT ADMINISTRATIVE EXPENSES

QUESTION:
Regarding the response to RCR-A-206, are the administrative expenses shown in that schedule being recovered through the carbon abatement and/or solar loan program? If not, please explain how the administrative costs included in this response are being recovered.

ANSWER:
The administrative expenses shown in the response to RCR-A-206 (UPDATE) are being recovered through the carbon abatement program. The administrative expenses for the Solar Loan I program will be collected through the SPRC and through base rates as approved in the Board's Order. The amounts listed for Solar Loan in the response to RCR-A-206 were incorrectly included and have been removed as illustrated in RCR-A-206 (UPDATE). Due to this revision, the adjustment on Schedule MGK-42, R-1 will be revised in the next update.

RESPONSE TO ADVOCATE
REQUEST: RCR-A-209
WITNESS(S): KAHRER

RATE CASE 2009

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SOLAR LOAN I ADMINISTRATIVE COSTS

QUESTION:
Regarding the response to RCR-EE-3, where it states that "The remaining 50% is included in expense", please a) state if this remaining 50% is included in the Company's test year claim in this case, b) quantify the amount of the "remaining 50%" included in the Company's test year claim, and c) explain the rationale for including these costs in base rates.

ANSWER:

(a) See response RCR-A-207.

(b) The actual amount of administrative expenses incurred through September 30, 2009 that are reflected in the test year are:
9 months actual (January - September 2009): $344,497
3 months projected (October - December 2009): $205,084
12 months total (January - December 2009): $549,581

(c) The BPU Order approving the Solar Loan I program indicates that: "PSE&G agrees that it shall recover 50% of the administrative costs of the Solar Program through the SPRC, based on the annual grand total amounts set forth in Attachment D to the Settlement." 50% of the administrative costs for the Solar Loan I program are recovered through the SPRC, while the remainder is accounted for as O&M. PSE&G is treating these costs consistently with how other O&M costs are treated in a rate case.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
POSITIONS RECOVERED THROUGH SURCHARGE MECHANISM

QUESTION:
Please identify all current positions at the Company whose costs are or will be recovered through a surcharge mechanism (RGGI, carbon abatement, solar loan programs, etc.) instead of through base rates.

ANSWER:
Specific positions are not recovered in a cost recovery mechanism; rather, costs for activities performed by employees in various positions are recovered through surcharge mechanisms. That said, the following positions perform activities that are recovered through a surcharge mechanism, for the following programs: RGGI programs and Solar Loan.

(2) Manager – Asset Management
(1) DSM Service Consultant
(1) Renewables and Energy Solutions Specialist
(1) Business Intelligence Associate
(2) Product Manager
(1) Manager – Business Development
(48) Energy Assistants

PSE&G Gas Service technicians perform work for the Carbon Abatement Thermostat program, however, these technicians are not dedicated to the program since they perform work for the program during a routine service visit to a customer's home.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAXES - CALCULATION

QUESTION:
Please quantify a consolidated income tax adjustment using the methodology adopted by the BPU in Docket No. ER02100724, I/M/O Rockland Electric Company For Approval of Changes in Electric Rates, its Depreciation Rates, and For Other Relief.

ANSWER:
The Company does not know the details of the consolidated tax adjustment methodology utilized in or approved in Docket No. ER02100724, and has not done such a calculation. The Company is providing an update of the consolidated tax information, to include information through 2009, provided to Rate Counsel's witness and utilized in Rate Counsel's witnesses' testimony in the last several Public Service base rate proceedings. (See Attached)

Public Service Electric and Gas Company - Base Rate Case
Consolidated Income Tax Benefits
($000)
Reflecting LILO/SILO Disallowances(1)
Adjusting Amounts to Properly Treat Non-jurisdictional Transmission Income

Year	Taxable Income/(Loss) Total PSEG (1)	Regulated PSE&G	Less Transmission Business (2)	Adjusted Regulated PSE&G	Non-regulated PSEG Subsidiaries	Tax Rate	Tax Benefits Assigned to PSE&G	AMT Payments	Tax Benefits Assigned to PSE&G Net of AMT
1991	224,033	538,385	39,773	498,612	(274,579)	34%	(93,357)	56,008	(37,349)
1992	407,870	639,247	40,529	598,718	(190,848)	34%	(64,888)	10,132	(54,756)
1993	258,029	427,471	36,711	390,760	(132,731)	35%	(46,456)	37,331	(9,125)
1994	475,837	708,507	43,775	664,732	(188,895)	35%	(66,113)		(66,113)
1995	595,683	699,501	47,784	651,717	(56,034)	35%	(19,612)		(19,612)
1996	806,927	684,439	49,720	634,719	172,208	35%	60,273		60,273
1997	793,052	836,047	58,548	777,499	15,553	35%	5,444		5,444
1998	1,060,343	963,748	78,540	885,208	175,135	35%	61,297		61,297
1999	1,342,185	523,535	77,405	446,130	896,055	35%	313,619		313,619
2000	665,800	467,340	73,620	393,720	272,080	35%	95,228		95,228
2001	657,762	314,963	84,145	230,818	426,945	35%	149,431		149,431
2002	370,024	106,752	18,623	88,129	281,895	35%	98,663		98,663
2003	69,563	252,199	9,653	242,546	(172,983)	35%	(60,544)		(60,544)
2004	588,151	628,220	91,176	537,044	51,108	35%	17,888		17,888
2005	595,333	751,228	110,289	640,939	(45,606)	35%	(15,962)		(15,962)
2006	1,076,482	571,360	96,161	475,199	601,283	35%	210,449		210,449
2007	2,065,703	833,057	144,451	688,606	1,377,097	35%	481,984		481,984
2008	2,133,552	329,479	80,496	248,983	1,884,569	35%	659,599		659,599
2009 (est)	1,922,637	252,666	64,770	187,896	1,734,741	35%	607,159		607,159
								Total	2,497,573

(1) - The Internal Revenue Service has disallowed approximately $1.7 billion of deductions included in the Non-regulated subsidiaries column. The Company is contesting this disallowance, however, there have been a number of Court cases decided involving similar transactions, the majority of which are in favor of the IRS. For finanical statement purposes, the Company has provided a reserve for the loss of a majority of these tax benefits. As such, the Company has excluded these tax losses from the Total PSEG column.

(2) - Adjustment to remove nonjurisdictional Transmission taxable income to arrive at taxable income associated with the NJ regulated PSE&G.

Transmission Income amounts are from page 3.

Since the amount is positive, all tax benefits have been absorbed by income of the nonregulated subsidiaries. As such, no Consolidated Tax Adjustment is appropriate.

Computation of BPU Regulated Distribution Taxable Income

Taxable Income Breakdown

	A Total PSE&G	B PSE&G Gas Operations	C PSE&G Electric	D Electric Distribution Share of Taxable Income (C*K)	E Transmission Share of Taxable Income (C*M)	F Combined Gas & Electric Distribution Taxable Income (B+D)	Unadjusted gas Plant %	Unadjusted electric Plant %
1991	538,385	38,171	500,214	96,783	39,773	134,955	7.1%	92.9%
1992	639,247	156,552	482,695	97,455	40,529	254,006	24.5%	75.5%
1993	427,471	(18,552)	446,023	94,513	36,711	75,960	-4.3%	104.3%
1994	708,507	184,708	523,799	114,600	43,775	299,308	26.1%	73.9%
1995	699,501	119,055	580,446	125,914	47,784	244,969	17.0%	83.0%
1996	684,439	86,787	597,652	135,717	49,720	222,504	12.7%	87.3%
1997	836,047	144,218	691,829	162,544	58,548	306,762	17.3%	82.8%
1998	963,748	71,317	892,431	225,487	78,540	296,805	7.4%	92.6%
1999	523,535	133,868	389,667	312,262	77,405	446,130	25.6%	74.4%
2000	467,340	93,094	374,246	300,626	73,620	393,720	19.9%	80.1%
2001	314,963	(111,382)	426,345	342,200	84,145	230,818	-35.4%	135.4%
2002	106,752	10,743	96,009	77,385	18,623	88,129	10.1%	89.9%
2003	252,199	199,517	52,682	43,028	9,653	242,546	79.1%	20.9%
2004	628,220	114,717	513,503	422,327	91,176	537,044	18.3%	81.7%
2005	751,228	120,445	630,783	520,494	110,289	640,939	16.0%	84.0%
2006	571,360	28,841	542,519	446,358	96,161	475,199	5.0%	95.0%
2007	833,057	91,774	741,283	596,832	144,451	688,606	11.0%	89.0%
2008	329,479	(78,247)	407,726	327,230	80,496	248,983	-23.7%	123.7%
2009	252,666	(43,761)	296,427	231,657	64,770	187,896	-17.3%	117.3%

	G Electric Distribution Net Plant	H Generation Net Plant	I Transmission Net Plant	J Total Electric Net Plant	K Distribution Plant % (G/J)	L Generation Plant % (H/J)	M Transmission Plant % (I/J)
1991	1,550,884	5,827,362	637,343	8,015,589	19.3%	72.7%	8.0%
1992	1,646,600	5,824,265	684,779	8,155,644	20.2%	71.4%	8.4%
1993	1,733,668	5,774,453	673,392	8,181,513	21.2%	70.6%	8.2%
1994	1,815,725	5,789,796	693,570	8,299,091	21.9%	69.8%	8.4%
1995	1,906,279	6,157,957	723,421	8,787,657	21.7%	70.1%	8.2%
1996	1,961,230	5,956,884	718,497	8,636,611	22.7%	69.0%	8.3%
1997	1,998,590	5,788,043	719,895	8,506,528	23.5%	68.0%	8.5%
1998	2,121,283	5,535,430	738,869	8,395,582	25.3%	65.9%	8.8%
1999	2,796,469	See Note 1	693,200	3,489,669	80.1%	See Note 1	19.9%
2000	2,795,121	See Note 1	684,495	3,479,616	80.3%	See Note 1	19.7%
2001	2,832,376	See Note 1	696,466	3,528,842	80.3%	See Note 1	19.7%
2002	2,901,267	See Note 1	698,207	3,599,474	80.6%	See Note 1	19.4%
2003	3,127,172	See Note 1	701,576	3,828,748	81.7%	See Note 1	18.3%
2004	3,238,972	See Note 1	699,261	3,938,233	82.2%	See Note 1	17.8%
2005	3,436,866	See Note 1	728,246	4,165,112	82.5%	See Note 1	17.5%
2006	3,567,576	See Note 1	768,583	4,336,159	82.3%	See Note 1	17.7%
2007	3,711,705	See Note 1	898,346	4,610,051	80.5%	See Note 1	19.5%
2008	3,891,356	See Note 1	957,247	4,848,603	80.3%	See Note 1	19.7%
2009(est)	3,999,328	See Note 1	1,118,190	5,117,518	78.1%	See Note 1	21.9%

Note1: Since the deregulation of PSE&G's Generation business, PSE&G has separately accounted for the operations of the generation business including a determination of taxable income. As such, allocation of Consolidated PSE&G income to Generation beyond 1999 is unnecessary since actual information is available.

Revision to Taxable Income Due to Disallowed LILO/SILO Deductions.

	Taxable Income as Reported	LILO/SILO Adjustments	IRS Revised Taxable Income
1991	224,033		224,033
1992	407,870		407,870
1993	258,029		258,029
1994	475,837		475,837
1995	595,683		595,683
1996	806,927		806,927
1997	727,552	65,500	793,052
1998	928,306	132,037	1,060,343
1999	1,118,680	223,505	1,342,185
2000	395,508	270,292	665,800
2001	355,336	302,426	657,762
2002	55,044	314,980	370,024
2003	(211,073)	280,636	69,563
2004	306,838	281,313	588,151
2005	316,393	278,940	595,333
2006	800,554	275,928	1,076,482
2007	1,797,516	268,187	2,065,703
2008	1,930,269	203,283	2,133,552
2009 (est)	3,078,156	(1,155,519)	1,922,637

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER DEPOSITS

QUESTION:
Please provide the balance of customer deposits, by month, for each of the past 24 months and as projected for the remainder of the test year.

ANSWER:
Attached is the balance of customer deposits by month, for each of the past 24 months and projected for the remainder of the year.

CUSTOMER DEPOSITS

	2007	2008	2009	
January		72,407,541	85,214,047	
February		72,615,219	86,911,982	
March		72,938,133	87,208,150	
April		73,163,573	81,022,295	
May		74,171,623	79,825,949	
June		73,173,364	78,092,089	
July	65,019,731	77,977,959	78,847,000	Projected
August	66,261,522	77,111,936	79,241,000	Projected
September	68,069,264	77,652,291	79,638,000	Projected
October	69,883,098	80,982,959	80,036,000	Projected
November	70,898,513	81,651,022	80,436,000	Projected
December	71,798,916	84,115,446	80,838,000	Projected

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER DEPOSITS – OTHER THAN RETAIL

QUESTION:
Does the Company collect customer deposits from any customers other than retail customers? If so, please identify the other customers from whom customer deposits are collected and provide the amount of customer deposits at June 30, 2009 attributable to non-retail operations.

ANSWER:
No. The Company does not collect customer deposits from any customers other than retail customers.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

MONTHLY ELECTRIC AND GAS CUSTOMERS

QUESTION:
Please provide the actual number of customers, by customer class, for each of the past sixty months.

ANSWER:
The attached tables show the requested electric and gas customer information, by customer class for the past 60 months.

ELECTRIC PRINT

ELECTRIC CUSTOMERS

Month/Year	RS	RHS	RLM	WHS	WH	GLP	LPL	HTS	BPL	BPL-POF	PSAL	HS	HEP	TOTAL
Oct-04	1,750,657	16,467	14,149	70	4,213	252,469	8,187	209	2,613	-	22,126	1,811	1	2,068,689
Nov-04	1,769,629	16,528	14,103	72	4,005	252,877	8,043	194	2,626	1	22,350	1,824	1	2,088,176
Dec-04	1,770,091	16,278	14,264	64	3,948	254,507	7,929	199	2,624	1	22,286	1,827	1	2,090,007
Jan-05	1,760,404	16,179	14,231	63	4,053	253,745	8,032	207	2,628	1	22,240	1,818	1	2,079,486
Feb-05	1,772,600	16,003	14,039	61	3,824	254,616	8,198	213	2,626	1	22,375	1,820	1	2,092,492
Mar-05	1,767,382	16,148	13,877	64	3,760	253,983	8,182	201	2,624	2	22,302	1,820	-	2,086,521
Apr-05	1,764,621	15,924	14,280	60	3,323	256,052	8,209	196	2,511	89	21,169	1,834	-	2,084,885
May-05	1,772,601	15,831	14,063	61	3,205	253,990	8,412	201	2,517	89	21,295	1,787	1	2,090,787
Jun-05	1,760,527	15,676	14,050	56	3,152	254,320	8,275	200	2,508	89	21,128	1,818	1	2,078,592
Jul-05	1,789,892	15,641	14,138	59	3,137	256,902	8,340	198	2,505	89	21,091	1,822	1	2,110,619
Aug-05	1,770,357	15,365	14,120	57	3,053	255,480	8,306	207	2,503	89	21,061	1,819	1	2,089,308
Sep-05	1,776,231	15,464	14,061	55	2,981	255,369	8,430	207	2,512	88	21,047	1,794	1	2,095,204
Oct-05	1,777,535	15,263	14,043	55	2,965	255,243	8,507	228	2,518	88	21,095	1,794	1	2,096,315
Nov-05	1,766,510	14,870	13,931	57	2,874	256,013	8,511	211	2,521	88	21,298	1,787	1	2,085,741
Dec-05	1,789,195	15,305	14,146	48	2,990	256,858	8,364	197	2,531	88	21,483	1,815	1	2,109,983
Jan-06	1,772,377	14,980	13,895	50	2,838	256,097	8,713	219	2,526	88	21,333	1,770	1	2,091,999
Feb-06	1,765,269	14,588	13,982	50	2,817	255,730	8,939	249	2,533	88	21,375	1,777	2	2,084,532
Mar-06	1,804,134	15,233	14,124	49	2,881	258,308	8,542	200	2,537	88	21,604	1,805	3	2,126,578
Apr-06	1,774,972	14,733	13,943	48	2,767	255,642	8,639	195	2,533	88	21,516	1,779	3	2,094,043
May-06	1,769,122	14,633	13,965	48	2,738	257,329	8,630	197	2,543	88	21,571	1,772	1	2,089,851
Jun-06	1,801,829	14,643	14,022	47	2,790	258,460	8,704	184	2,538	89	21,586	1,769	1	2,123,825
Jul-06	1,766,639	14,303	13,824	48	2,696	253,519	8,462	223	2,524	89	20,437	1,742	1	2,081,763
Aug-06	1,792,059	14,428	13,987	43	2,678	257,814	8,555	207	2,537	89	21,320	1,775	1	2,112,772
Sep-06	1,800,498	14,426	13,964	47	2,664	259,150	8,724	200	2,553	89	21,357	1,793	1	2,122,755
Oct-06	1,779,847	14,172	13,802	40	2,615	257,136	8,843	210	2,557	90	21,277	1,726	1	2,099,661
Nov-06	1,780,630	13,964	13,918	43	2,584	259,447	8,656	205	2,555	90	21,336	1,781	1	2,102,583
Dec-06	1,799,325	14,171	13,933	47	2,626	257,104	8,567	199	2,566	90	21,321	1,720	1	2,118,997
Jan-07	1,780,674	13,654	13,824	42	2,544	259,539	8,820	197	2,562	90	21,351	1,760	1	2,102,472
Feb-07	1,798,546	13,991	13,941	44	2,529	259,379	8,472	205	2,563	90	21,225	1,750	1	2,120,163
Mar-07	1,805,933	14,047	14,048	43	2,535	261,871	8,522	209	2,563	90	21,442	1,770	1	2,130,496
Apr-07	1,785,534	13,670	13,786	41	2,460	257,924	8,649	194	2,561	91	21,287	1,758	2	2,105,456
May-07	1,799,644	13,624	13,837	42	2,474	260,397	8,811	196	2,563	91	21,278	1,746	1	2,122,188
Jun-07	1,804,227	13,731	13,961	42	2,436	260,395	8,746	198	2,567	91	21,330	1,755	1	2,127,002
Jul-07	1,799,626	13,398	13,815	40	2,409	259,389	8,775	199	2,563	91	21,115	1,731	1	2,120,703
Aug-07	1,772,267	13,144	13,675	38	2,380	258,026	8,826	209	2,555	91	20,893	1,712	1	2,091,399
Sep-07	1,838,661	13,603	14,093	43	2,422	263,988	8,897	201	2,567	91	21,115	1,765	1	2,164,982
Oct-07	1,793,365	13,234	13,789	40	2,331	260,244	8,878	216	2,564	91	21,025	1,734	1	2,115,141
Nov-07	1,800,946	13,087	13,792	40	2,349	260,870	8,705	202	2,570	91	21,121	1,735	1	2,123,120
Dec-07	1,804,593	13,045	13,659	38	2,304	261,102	8,599	203	2,574	91	21,171	1,691	1	2,126,729
Jan-08	1,775,856	12,883	13,634	36	2,231	259,121	8,788	211	2,563	91	20,948	1,734	1	2,095,830
Feb-08	1,836,852	12,995	13,973	41	2,352	265,065	8,750	205	2,571	91	21,332	1,749	1	2,163,584
Mar-08	1,805,279	12,838	13,675	34	2,234	260,488	8,786	209	2,571	91	20,935	1,719	1	2,126,592
Apr-08	1,805,410	12,817	13,731	36	2,232	262,314	8,876	200	2,566	91	20,974	1,724	1	2,128,704
May-08	1,796,848	12,561	13,618	34	2,202	260,245	8,805	208	2,570	91	20,956	1,709	1	2,117,612
Jun-08	1,808,385	12,846	13,675	35	2,199	260,666	8,738	207	2,563	91	20,846	1,715	1	2,129,733
Jul-08	1,801,195	12,612	13,659	33	2,155	263,628	8,710	210	2,559	91	20,624	1,726	1	2,125,015
Aug-08	1,826,025	12,589	13,805	33	2,232	262,461	8,738	209	2,565	91	20,610	1,712	1	2,148,806
Sep-08	1,815,006	12,535	13,778	34	2,233	263,394	8,840	215	2,570	91	20,488	1,723	1	2,138,641
Oct-08	1,801,208	12,305	13,529	31	2,149	261,386	8,895	197	2,573	91	20,470	1,682	1	2,122,337
Nov-08	1,819,258	12,491	13,735	32	2,193	263,664	8,755	204	2,575	91	20,494	1,697	1	2,142,965
Dec-08	1,806,923	12,262	13,598	28	2,154	263,034	8,504	200	2,562	91	20,354	1,715	1	2,129,244
Jan-09	1,809,978	12,260	13,535	31	2,124	262,541	8,419	204	2,553	91	20,175	1,694	1	2,131,451
Feb-09	1,811,202	12,223	13,547	30	2,097	263,070	8,823	212	2,562	91	19,982	1,691	1	2,133,404
Mar-09	1,804,704	12,151	13,514	30	2,104	261,786	8,811	206	2,556	91	19,710	1,669	1	2,125,199
Apr-09	1,861,593	12,725	13,577	30	2,490	272,140	6,943	139	2,928	89	21,349	1,804	1	2,193,288
May-09	1,712,913	11,552	11,316	26	2,329	237,823	9,048	216	2,863	92	19,044	1,590	1	2,006,458
Jun-09	1,821,275	12,216	13,375	30	2,465	279,059	10,418	221	2,468	90	21,967	1,781	1	2,162,871
Jul-09	1,822,266	12,359	13,162	30	2,460	268,733	9,941	211	4,854	92	21,371	1,697	1	2,154,687
Aug-09	1,845,344	12,340	13,572	28	2,451	266,154	9,976	221	3,639	91	21,146	1,683	1	2,174,167
Sep-09	1,854,694	12,430	15,151	27	2,464	272,357	11,291	223	3,812	91	21,458	1,803	2	2,193,312

GAS PRINT

NATURAL GAS CUSTOMERS

Month/Year	RSG	GSG	LVG	TSG-F	TSG-NF	CIG	SLG	COGEN CONTRACT
Oct-04	1,523,849	137,163	17,917	93	313	32	15	8
Nov-04	1,549,579	138,495	17,964	91	317	30	15	8
Dec-04	1,548,101	139,873	18,054	95	324	29	15	8
Jan-05	1,542,544	139,312	17,944	88	319	29	15	8
Feb-05	1,554,096	139,999	18,120	89	316	30	15	8
Mar-05	1,547,939	139,083	18,176	88	333	30	15	8
Apr-05	1,545,824	139,640	18,430	84	270	29	15	8
May-05	1,550,030	137,656	18,232	88	274	29	15	8
Jun-05	1,542,387	137,956	18,111	84	263	29	15	8
Jul-05	1,556,580	138,317	18,393	87	257	29	15	8
Aug-05	1,545,895	137,546	18,352	84	255	29	15	8
Sep-05	1,549,021	136,952	18,330	83	265	30	15	8
Oct-05	1,552,134	137,246	18,740	85	258	29	15	8
Nov-05	1,548,497	138,046	18,530	85	253	28	15	8
Dec-05	1,569,471	140,181	18,520	82	263	28	15	8
Jan-06	1,558,321	138,835	18,488	94	280	28	15	8
Feb-06	1,548,636	138,310	18,351	81	287	29	15	8
Mar-06	1,581,409	139,684	18,464	85	270	28	15	8
Apr-06	1,559,618	138,040	18,943	84	267	28	15	8
May-06	1,547,454	137,473	18,309	83	276	28	15	8
Jun-06	1,582,164	138,887	18,575	84	278	28	15	8
Jul-06	1,544,442	134,925	18,044	89	260	28	15	8
Aug-06	1,561,892	136,818	18,230	83	261	28	15	8
Sep-06	1,577,679	138,554	18,418	89	267	31	15	8
Oct-06	1,558,054	137,186	18,442	86	263	27	15	8
Nov-06	1,563,828	138,647	18,187	81	271	28	15	8
Dec-06	1,575,618	137,786	18,311	85	266	28	15	8
Jan-07	1,556,255	137,815	18,119	77	281	26	15	8
Feb-07	1,579,862	139,606	18,116	76	264	28	15	8
Mar-07	1,585,881	140,399	18,540	76	269	26	15	8
Apr-07	1,564,282	138,302	18,375	71	266	26	15	8
May-07	1,583,361	139,116	18,229	70	271	25	15	8
Jun-07	1,575,408	138,273	18,099	74	259	25	15	8
Jul-07	1,568,342	137,339	18,091	73	264	25	15	8
Aug-07	1,568,230	137,485	18,116	71	259	25	15	8
Sep-07	1,590,214	138,149	18,159	68	291	25	15	8
Oct-07	1,568,517	137,496	18,110	68	263	25	15	8
Nov-07	1,576,378	138,339	18,127	65	265	25	15	8
Dec-07	1,585,625	139,221	18,164	64	261	25	15	8
Jan-08	1,561,830	138,353	18,212	63	256	25	15	8
Feb-08	1,608,468	141,166	18,477	64	256	25	15	8
Mar-08	1,584,528	138,947	18,294	62	253	24	15	8
Apr-08	1,583,294	139,575	18,398	64	253	26	15	8
May-08	1,577,889	138,570	18,090	64	253	25	15	8
Jun-08	1,581,000	137,932	17,917	64	250	25	15	8
Jul-08	1,578,703	139,390	18,135	67	263	25	15	8
Aug-08	1,589,724	138,471	17,975	63	250	25	15	8
Sep-08	1,586,329	138,643	18,065	63	252	25	15	8
Oct-08	1,578,294	137,871	18,011	64	249	26	15	8
Nov-08	1,595,124	139,486	17,985	63	255	29	15	8
Dec-08	1,588,955	139,944	17,996	63	251	24	15	7
Jan-09	1,591,281	140,063	18,054	60	257	24	15	7
Feb-09	1,594,656	140,704	18,283	59	252	24	16	7
Mar-09	1,586,719	139,305	18,131	61	265	30	16	7
Apr-09	1,632,846	144,863	16,192	59	235	16	9	7
May-09	1,510,182	126,453	16,482	56	246	24	16	7
Jun-09	1,619,905	152,881	20,978	62	236	23	9	7
Jul-09	1,618,271	147,785	19,795	63	252	24	23	7
Aug-09	1,634,406	148,481	19,810	56	261	23	9	7
Sep-09	1,653,417	149,969	20,809	112	460	32	23	7

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CUSTOMER DEPOSITS – DECLINE

QUESTION:
Regarding the updated response to RCR-A-72, what is the reason for the decline in customer deposits from March 31, 2009 to June 30, 2009?

ANSWER:
On March 31, 2009, we implemented a new Customer Care System. During the period March 31 through June 30, deposit activity was limited to new customer applications only. The process to pursue deposits on delinquent customers was reinstated in July, 2009.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ADDITIONAL CAC COSTS

QUESTION:
Reference: Responses to RCR-CAC-4 and RCR-CAC-5. Is the Company proposing to limit the CAC to the costs associated with the infrastructure program approved in BPU Docket Nos. EO09010049 and GO09010050? If not, then please estimate the annual capital expenditures, over and above those approved in BPU Docket Nos. EO09010049 and GO09010050, which the Company anticipates would be eligible for recovery through the CAC in each of the next five years.

ANSWER:
No. The Company, in this base rate case, is proposing to include infrastructure costs that were not in the Company's filing for BPU Docket Nos.EO09010049 and GO09010050. Please see the attached schedule which provides non-new business investments through 2013. Note that this assumes that none of the investment is rolled into base distribution rates through a base rate case after the conclusion of this filing.

Electric and Gas Capital Expenditures
$ millions

	2009	2010	2011	2012	2013	Total
Electric Distribution						
Capital Spending						
New Business	103.02	90.40	94.82	107.30	105.68	
Environmental Regulatory	14.02	11.20	11.62	11.82	12.03	
Reliability Enhancements	89.76	219.50	102.44	77.79	95.31	
Replace Facilities	160.65	273.60	161.29	110.91	112.65	
Support Facilities	13.09	43.58	45.39	43.11	46.14	
General Plant	16.90	12.30	6.25	6.95	5.15	
Total	**$ 397.43**	**$ 650.58**	**$ 421.81**	**$ 357.88**	**$ 376.96**	

Electric						
Net of new business	294.41	560.18	326.99	250.58	271.28	1,703
Stipulated stimulus in docket EO09010049	98.48	254.09	68.75			421
Net of stipulated CAC spend	**$ 195.94**	**$ 306.09**	**$ 258.24**	**$ 250.58**	**$ 271.28**	**$ 1,282.14**

Gas Distribution

Capital Spending						
New Business	55.83	65.13	66.62	70.15	72.35	
Environmental Regulatory	40.32	63.97	40.21	40.03	41.71	
Reliability Enhancements	27.15	35.62	29.21	30.54	31.82	
Replace Facilities	132.50	192.53	63.39	57.63	60.26	
Support Facilities	1.41	2.36	2.83	3.53	4.22	
Total	**$ 257.21**	**$ 359.61**	**$ 202.26**	**$ 201.88**	**$ 210.36**	

Gas						
Net of new business	201.38	294.48	135.64	131.73	138.01	901
Stipulated stimulus in docket G009010050	86.68	173.70	12.62			273
Net of stipulated CAC spend	**$ 114.70**	**$ 120.78**	**$ 123.02**	**$ 131.73**	**$ 138.01**	**$ 628.24**

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

AVERAGE SPEED OF ANSWER

QUESTION:
Reference PSE&G's response to RCR-CI-12. Please explain all the reasons why the Average Speed of Answer (ASA) dropped in 2009 and please explain what initiatives PSE&G is implementing to increase the ASA in 2009.

ANSWER:
IIn RCR-CI-12, ASA was defined as the percentage of calls answered by a representative within 30 seconds after the customer indicates their desire to speak to a representative. (On PSE&G Call Center scorecards, this definition is our Service Level metric)

ASA decreased with the implementation of our new customer information system on March 30, 2009. This decrease was due to two factors – increased call volume and the length of time to handle the calls. The increase in call volume associated with implementation of the new Customer Care System was exacerbated by the declining economy and associated inquires by our customers. There are many initiatives underway to improve the ASA, including training, system refinements, data conversion clean-up efforts, reducing billing exception backlogs and hiring temporary employees to augment the call center staff. The training includes using internal and consultant personnel to develop additional training modules and to conduct full day one on one training sessions with each call center representative in an effort to accelerate them along the learning curve. It is yielding significant results. There were 30 additional call center representatives hired during the summer and another 50 are being hired during October and November to return the ASA to pre implementation levels.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
APPENDIX D 'STIMULUS' STIPULATION

QUESTION:
Referring to Mr. Daly's testimony on page 10 line 13, please provide all information described in Appendix D of the Board of Public Utilities Decision and Order Approving Stipulation Docket No. EO09010049 and Docket No. GO09010050 for all of the qualifying projects funded under this program.

ANSWER:
Responses to this Discovery Request rely on the following documents, which are identified throughout this answer as follows:

REFERENCE 1: Petition, *I/M/O the Petition of Public Service Electric and Gas Company For Approval of An Increase in Electric and Gas Rates*, Dkt. No. GR09050422 (Filed: May 29, 2009)

REFERENCE 2: Order, *I/M/O the Petition of Public Service Electric and Gas Company For* Approval *of A Capital Economic Stimulus Infrastructure Investment Program and An Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and 48:21.1*, Dkt. No. EO09010050 (NJ BPU) (Approved April 28, 2009) - (Attached)

REFERENCE 3: Quarterly Filing by PSE&G for the Period Ending June 30, 2009 filed with the Board of Public Utilities on July 31, 2009, *I/M/O the Petition of Public Service Electric and Gas Company For Approval of A Capital Economic Stimulus Infrastructure Investment Program and An Associated Cost Recovery Mechanism Pursuant to N.J.S.A. 48:2-21 and 48:21.1*, Dkt. No. EO09010050 - (Attached)

REFERENCE 4: PSE&G Capital Stimulus Infrastructure Investment Program Electric Revenue Requirements Calculation through July 31, 2009 - (Attached)

REFERENCE 5: Monthly beginning and Ending Balances for Over/Under Recoveries - (Attached)

REFERENCE 6: Interest Rate Calculation Support for May, June and July 2009 - (Attached)

The following numbered paragraphs and answers refer to the identical numbered paragraphs of Appendix D, "Minimum Filing Requirements." Appendix D and this requests:

1. Public Service Electric and Gas Company's (the Company's) income statement for the most recent 12 month period, as filed with the New Jersey Board of Public Utilities ("BPU").
   - See **REFERENCE 1** at Schedules 10 - 15.

2. The Company's balance sheet for the most recent 12 month period, as filed with the BPU.
   - See REFERENCE 1 at Schedule 10.

3. The Company's overall approved capital budget broken down by major categories, including distribution and incremental capital expenditures for the Qualifying Projects, both budgeted and actual amounts
   - See REFERENCE 2 at Appendix A and REFERENCE 3

4. For each Qualifying Project or proposed new project:
   a. The original project summary for each Qualifying Project;
   b. Capital expenditures incurred to date;
   c. Appropriate metric (e.g., poles replaced, linear feet of installed cable, etc.)
   - See REFERENCES 2 AND 3

5. Anticipated project timeline with updates and expected changes.
   - See **REFERENCE 3**

6. A schedule detailing the Qualifying Projects and Non-Qualifying Projects to date as compared to the Company's original approved capital spending plans.
   - See **REFERENCE 3**

7. A summary of expenditures for each of the Qualifying Projects that identify each expenditure from project inception through the end of the most recent quarter,
   - See **REFERENCE 3**

8. A calculation of the proposed rate adjustment based on details related to Qualifying Projects included in Plant in Service.
   - See **REFERENCE 2** at Appendix E.

14. The interest rate used each month for over/under recoveries, and all supporting documentation and calculations for the interest rate.

    The interest rates used for the over/under recoveries were:
    May - April '09 annualized interest rate .70%, monthly interest rate .0583%
    June - May '09 annualized interest rate .74%, monthly interest rate .0617%
    July - June '09 annualized interest rate .71%, monthly interest rate .0592%

    - See also **REFERENCE 6**

15. The interest expense to be charged or credited to the ratepayer

    - See **REFERENCE 2** (at Para. 19 of the Stipulation) and **REFERENCE 5**

REFERENCE 4

PSE&G Capital Stimulus Infrastructure Investment Program
Electric Revenue Requirements Calculation - Monthly
($'s)

Appendix B-1

Monthly Pre-Tax WACC	0.94243%
Income Tax Rate	41.084%

			Property Accounting	Property Accounting	Property Accounting	Prior Month + Col 3	Col 2 - Col 4		(Col 6 - Col 3) * [Income Tax Rate]	Prior + Col 7	Col 5 - Col 8	(Prior Col 9 + Col 9) / 2 * Monthly Pre Tax WACC		Col 3 + Col 10 + Col 11
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Month	Year	Program Investment	Gross Plant	Depreciation Expense	Accumulated Depreciation	Net Plant	Tax Depreciation	Deferred Tax Exp	Accumulated Deferred Tax	Net Investment	Return Requirement	O&M Expense	Calendar Revenue Requirements
1	Jan	2009	-	-	-	-	-	-	-	-	-	-	-	-
2	Feb	2009	-	-	-	-	-	-	-	-	-	-	-	-
3	Mar	2009	-	-	-	-	-	-	-	-	-	-	-	-
4	Apr	2009	-	-	-	-	-	-	-	-	-	-	-	-
5	May	2009	2,827,262	2,827,262	4,433	4,433	2,822,829	1,121,535	458,950	458,950	2,363,879	11,139	56,129	71,701
6	Jun	2009	4,025,045	6,852,307	12,269	16,703	6,835,605	1,853,416	756,417	1,215,367	5,620,238	37,622	46,961	96,853
7	Jul	2009	4,147,498	10,999,805	19,557	36,259	10,963,546	1,841,185	748,398	1,963,765	8,999,781	68,892	260,829	349,278
8	Aug	2009	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
9	Sept	2009	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
10	Oct	2009	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
11	Nov	2009	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
12	Dec	2009	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
13	Jan	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
14	Feb	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
15	Mar	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
16	Apr	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
17	May	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
18	Jun	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
19	Jul	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
20	Aug	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
21	Sept	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
22	Oct	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
23	Nov	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
24	Dec	2010	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
25	Jan	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
26	Feb	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
27	Mar	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
28	Apr	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
29	May	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
30	Jun	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
31	Jul	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
32	Aug	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
33	Sept	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
34	Oct	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
35	Nov	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817
36	Dec	2011	-	10,999,805	-	36,259	10,963,546	-	-	1,963,765	8,999,781	84,817	-	84,817

REFERENCE 4

PSE&G Capital Stimulus Infrastructure Investment Program
Electric & Gas CAC Under/(Over) Calculation

41.084% Tax Rate

	Electric CAC Under/(Over) Calculation	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	
(1)	Grand Total CAC Revenue	388,617.47	700,000.00	966,000.00	-	-	-	-	-	
(2)	Revenue Requirements	71,700.92	96,852.68	349,277.86	-	-	-	-	-	
(3)	Monthly Under/(Over) Recovery	(316,916.55)	(603,147.32)	(616,722.14)	-	-	-	-	-	Row 2 - Row 1
(4)	Deferred Balance	(316,916.55)	(920,063.87)	(1,536,786.01)	(1,536,786.01)	(1,536,786.01)	(1,536,786.01)	(1,536,786.01)	(1,536,786.01)	Prev Row 4 + Row 3
(5)	Monthly Interest Rate	0.0583%	0.0617%	0.0592%						[Prev Mth Annualized Wghtd Avg STD/CP Rate]/12
(6)	Monthly Interest Expense/(Credit) - Net of Tax	54.5	167.1	267.9	-	-	-	-	-	(Prev Row 4 + Row 4) / 2 * (1 - Tax Rate) * Row 5
(7)	Cumulative Interest	54.5	221.60	489.45	489.45	489.45	489.45	489.45	489.45	Prev Row 7 + Row 6
(8)	Balance Added to Subsequent Year's Revenue Requirements									Row 4 + Row 7

	Gas CAC Under/(Over) Calculation	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	
(1)	Grand Total CAC Revenue	301,770.00	500,000.00	400,000.00	-	-	-	-	-	
(2)	Revenue Requirements	38,602.46	100,944.02	226,191.68	-	-	-	-	-	
(3)	Monthly Under/(Over) Recovery	(263,167.54)	(399,055.98)	(173,808.32)	-	-	-	-	-	Row 2 - Row 1
(4)	Deferred Balance	(263,167.54)	(662,223.52)	(836,031.84)	(836,031.84)	(836,031.84)	(836,031.64)	(836,031.84)	(836,031.84)	Prev Row 4 + Row 3
(5)	Monthly Interest Rate	0.0583%	0.0617%	0.0592%						[Prev Mth Annualized Wghtd Avg STD/CP Rate]/12
(6)	Monthly Interest Expense/(Credit) - Net of Tax	45.2	120.3	145.7	-	-	-	-	-	(Prev Row 4 + Row 4) / 2 * (1 - Tax Rate) * Row 5
(7)	Cumulative Interest	45.2	165.52	311.23	311.23	311.23	311.23	311.23	311.23	Prev Row 7 + Row 6
(8)	Balance Added to Subsequent Year's Revenue Requirements									Row 4 + Row 7

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PENSION TRACKER—2008 PENSION EXPENSE VS. 2010 PENSION EXPENSE

QUESTION:

With regard to page 17, lines 14-19, please provide the following information:

a. Provide actual source documentation in support of the claimed 2008 pension expenses of \$8.3 million. In addition, provide a breakout between the electric and gas portions of the \$8.3 million expense and indicate as to whether the \$8.3 million represents an O&M expense number. If not, provide the O&M expense portion of the \$8.3 million.
b. Provide the latest actuarial report showing that PSE&G's 2009 pension expense has increased to \$73.70 million. In addition, indicate exactly where the \$73.70 million number can be found in this actuarial report.
c. Provide the "PSE&G analysis" from which the Company has concluded that the pension expense will increase to about \$82 million in 2010. In addition, if any actuary study supports this "PSE&G analysis", indicate how and provide a copy of these actuary documents.

ANSWER:

a. The \$8.3 million expense level on page 17, lines 14-19, is the amount charged to the Administrative and General account 926. Including the pension expense for Service Company employees providing services in support of the electric and gas distribution operations, which is charged to the 923 account, brings the total pension cost charged to O&M to \$13.3 million for calendar year 2008. This is the actual O&M expense charged to the electric and gas distribution operations. The electric distribution amount is \$7.1 million and gas distribution is \$6.2 million.

b. The actuarial report for 2009 has not been issued by Hewitt Associates at this time; however, Hewitt has provided the 2009 pension expense split by company which is the source for recording the 2009 pension expense. See Responses RCR-A-26, S-PREV-70 and S-PREV-77.

c. The actuarial reports for 2009 have not been issued by Hewitt Associates at this time; however, Hewitt has provided projected pension expense for 2009 - 2011 which is attached. The \$82 million figure in the question represents the pension expenses for the twelve months ending February 28, 2011 that are charged to O&M expense for PSE&G electric distribution, gas distribution and that portion of Service Company associated with labor in support of the PSE&G electric and gas distribution operations. In general the \$82 million reflects ten-twelfth of 2010 and two-twelfth of 2011. The PSE&G distribution portion is 94% of the total PSE&G, of which 58% is assumed to be O&M expense with the balance being capital. Fifty-one percent of the Service Company total figure is estimated to be charged to the PSE&G electric and gas distribution operations. See the response to S-PREV-7 for the work papers in support of Schedule MGK-31.

Public Service Enterprise Group
Projected Pension Expense by Plan and Company

Projections of future accounting results are based on the following assumptions:

- The FAS 87 discount rate is 6.80% for 2009 and beyond;
- The proposed mortality assumption change to generational mortality and 50% of the proposed retirement rates cost increase are reflected beginning in 2010;
- Market Value of Plan Assets as of 1/1/2009 is assumed to return 8.75% in 2009 and thereafter; and
- Contributions are assumed to be made on 7/1 of each year, and amounts are determined by fully funding PBO over 5 years. Contributions in 2010 will be $250M, and the remainder necessary to reach a fully funded PBO will be contributed levelly among 2011-2014;
- All other actuarial assumptions (e.g., turnover, retirement, mortality) are exactly realized.

	PSEG Total	Power	PSE&G	Services Corp.	Holdings Companies Subtotal
2009 Expense					
Qualified Pension Plans					
Final-Average-Pay Pension Plan	$ 193,338,000	$ 58,974,000	$ 112,301,000	$ 21,484,000	$ 579,000
Cash Balance Plan (Nonunion)	6,526,000	2,466,000	1,233,000	2,608,000	219,000
Union Cash Balance Plan	6,841,000	1,271,000	5,565,000	5,000	-
Total All Qualified Plan	$ 206,705,000	$ 62,711,000	$ 119,099,000	$ 24,097,000	$ 798,000
Nonqualified Pension Plans	9,277,000	2,649,000	760,000	5,208,000	660,000
Total All Pensions	$ 215,982,000	$ 65,360,000	$ 119,859,000	$ 29,305,000	$ 1,458,000
2010 Expense Estimate					
Qualified Pension Plans					
Final-Average-Pay Pension Plan	$ 199,537,000	$ 60,865,000	$ 115,902,000	$ 22,172,000	$ 598,000
Cash Balance Plan (Nonunion)	6,863,000	2,593,000	1,296,000	2,743,000	231,000
Union Cash Balance Plan	7,428,000	1,379,000	6,042,000	5,000	-
Total All Qualified Plan	$ 213,828,000	$ 64,837,000	$ 123,240,000	$ 24,920,000	$ 829,000
Nonqualified Pension Plans	9,153,000	2,571,000	760,000	5,143,000	679,000
Total All Pensions	$ 222,979,000	$ 67,408,000	$ 124,000,000	$ 30,063,000	$ 1,508,000
2011 Expense Estimate					
Qualified Pension Plans					
Final-Average-Pay Pension Plan	$ 174,889,000	$ 53,424,000	$ 101,579,000	$ 19,363,000	$ 523,000
Cash Balance Plan (Nonunion)	7,169,000	2,724,000	1,333,000	2,828,000	284,000
Union Cash Balance Plan	8,040,000	1,506,000	6,529,000	5,000	-
Total All Qualified Plan	$ 190,098,000	$ 57,654,000	$ 109,441,000	$ 22,196,000	$ 807,000
Nonqualified Pension Plans	8,987,000	2,487,000	756,000	5,054,000	690,000
Total All Pensions	$ 199,085,000	$ 60,141,000	$ 110,197,000	$ 27,250,000	$ 1,497,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CALL CENTER STAFFING AND HOURS

QUESTION:
Please provide a breakdown of staffing levels at the call centers. Are there any plans to increase the current staffing levels? What are the hours of the call centers?

ANSWER:
The chart below represents the full-time equivalent (FTE) staffing levels at our call centers since 2006. The numbers reported for 2009 are as of June 30. The current business plan does not reflect our present plans to increase staffing by 50 employees. General Inquiry is open 24 hours per day, 365 days per year. The Collection Call Center is open from 7:30am-8:00pm, Monday-Friday. The Construction Inquiry Center is open from 8:00am-3:30pm, Monday-Friday.

General Inquiry Call Center

	2006	2007	2008	2009
Northern	248	246	307	298
Southern	50	57	62	57
Total	298	303	369	355

Construction Inquiry Call Center

	2006	2007	2008	2009
Northern	33	37	44	38
Southern	12	12	12	10
Total	45	49	56	48

Collection Call Center

	2006*	2007**	2008	2009
Inbound	116	87	104	100
Outbound		50	49	45
Total	116	137	153	145

* The 2006 Collection Call Center staffing level (116), includes both Inbound and Outbound.

** Outbound Collection was split from Inbound beginning in 2007.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PLANT HELD FOR FUTURE USE

QUESTION:

Plant Held for Future Use (PHFU) - Provide a description and the cost of each plant or land site, the date each item was constructed or purchased and placed in the PHFU Account, the associated projected in-service date of each item, changes in projected in-service date since original property acquisition, prior regulatory treatment and the purpose for each item's proposed inclusion in rate base. Also, provide support showing that the item's in-service date and proposed usage are consistent with the Company's current load forecast. Provide a separate list for gas plant and electric plant.

ANSWER:

ELECTRIC:

PSE&G has purchased substation property in strategic areas of the service territory to meet future electric demand. Factors influencing land purchases include projected future demands, land availability and initial purchase price. The Company regularly reviews load forecasts using capacity and actual and projected demand and re-evaluates the need for the land held for future use. If land is no longer required or other alternatives to serve future load are determined to be viable at a lower cost, the land is removed from the plant held for future use category. Tables II-VII (attached) detail the current projected area capacities, actual electric demand for 2008 and future forecasts for the six sites listed in Table I. These properties were included as PHFU in the Company's 2002 base rate case which was resolved through settlement. Table I below details substation land held for future use, the year the land was purchased and the current forecasted service date.

Table I

Property Held for Future Use	Year Purchased	Estimated Service Date	Cost($)
Bergenfield Substation	1984	2011	$ 346,139
Stanley Terrace Substation	1973	2012-13	$ 539,467
Montgomery Area Substation	1977	2013	$1,237,109
Ridge Road Substation	1991	2016	$ 789,150
Pemberton Substation	1980	2016-17	$ 489,291
Blenheim Area Substation	1982	2018-19	$ 172,536

GAS:

Gas Delivery has no Plant Held for Future Use (PHFU).

BERGENFIELD SUBSTATION

SUBSTATION	CAPACITY (MVA)	ACTUAL 2008 (MVA)	2009 (MVA)	2010 (MVA)	2011 (MVA)	2012 (MVA)	2013 (MVA)	2014 (MVA)	2015 (MVA)	2016 (MVA)	2017 (MVA)	2018 (MVA)
Leonia 1	76.0	76.2	76.6	78.1	79.7	81.3	82.9	84.6	86.3	88.0	89.8	91.5
Leonia 2	76.0	75.1	79.2	81.1	82.9	84.7	86.6	88.5	90.4	92.4	94.4	96.5
New Milford 1	79.0	84.9	84.9	86.6	88.3	90.1	91.9	93.7	95.6	97.6	99.6	101.6
New Milford 2	85.0	83.2	82.6	84.4	86.1	88.0	89.8	91.7	93.7	95.7	97.7	99.9
TOTAL	316.0	319.4	323.3	330.2	337.0	344.1	351.2	358.5	366.0	373.7	381.5	389.5
Deficit		3.4	7.3	14.2	21.0	28.1	35.2	42.5	50.0	57.7	65.5	73.5

Table II

Stanley Terrace

SUBSTATION	CAPACITY (MVA)	ACTUAL 2008 (MVA)	2009 (MVA)	2010 (MVA)	2011 (MVA)	2012 (MVA)	2013 (MVA)	2014 (MVA)	2015 (MVA)	2016 (MVA)	2017 (MVA)	2018 (MVA)
Doremus 1	57.9	55.5	54.4	57.1	57.6	58.0	58.4	58.8	59.2	59.5	59.9	60.3
Doremus 2	64.5	64.1	63.1	63.5	64.0	64.5	65.0	65.5	66.0	66.5	67.0	67.5
Springfield Road	83.0	87.0	84.8	87.0	89.2	91.4	93.6	95.7	97.8	99.9	102.0	104
TOTAL	205.4	206.6	202.3	207.6	210.8	213.9	217.0	220.0	223.0	225.9	228.9	231.8
Deficit		1.2	-	2.2	5.4	8.5	11.6	14.6	17.6	20.5	23.5	26.4

Table III

MONTGOMERY SUBSTATION

SUBSTATION	CAPACITY (MVA)	ACTUAL 2008 (MVA)	2009 (MVA)	2010 (MVA)	2011 (MVA)	2012 (MVA)	2013 (MVA)	2014 (MVA)	2015 (MVA)	2016 (MVA)	2017 (MVA)	2018 (MVA)
Mount Rose	77.5	65.4	64.9	70.1	74.6	76.3	80.1	83.9	87.8	91.8	95.8	99.9
Rocky Hill	16.0	13.8	14.3	15.9	16.1	16.4	16.7	16.9	17.2	17.5	17.7	18.0
TOTAL	93.5	79.2	79.2	86.0	90.7	92.7	96.8	100.8	105.0	109.3	113.5	117.9
Deficit		-	-	-	-	-	3.3	7.3	11.5	15.8	20.0	24.4

Table IV

RIDGE ROAD SUBSTATION

SUBSTATION	CAPACITY (MVA)	ACTUAL 2008 (MVA)	2009 (MVA)	2010 (MVA)	2011 (MVA)	2012 (MVA)	2013 (MVA)	2014 (MVA)	2015 (MVA)	2016 (MVA)	2017 (MVA)	2018 (MVA)
Clarksville	152.0	88.3	91.2	98.8	105.3	111.3	113.1	114.9	116.6	118.4	120.1	121.8
Penns Neck	143.0	109.9	109.8	119.8	130.6	142.5	145.6	148.5	151.5	154.4	157.2	160.1
Plainsboro	83.6	80.7	79.0	82.1	84.6	85.8	88.0	90.2	92.4	94.5	96.7	98.8
Sand Hills	89.3	77.0	83.7	87.2	90.2	93.4	96.5	99.5	102.6	105.6	108.7	111.7
Village Road	8.0	8.9	8.8	9.1	9.3	9.6	9.8	10.1	10.3	10.6	10.8	11.0
TOTAL	475.9	364.8	372.5	397.0	420.0	442.6	453.0	463.2	473.4	483.5	493.5	503.4
Deficit		-	-	-	-	-	-	-	-	7.6	17.6	27.5

Table V

PEMBERTON SUBSTATION

SUBSTATION	CAPACITY (MVA)	ACTUAL 2008 (MVA)	2009 (MVA)	2010 (MVA)	2011 (MVA)	2012 (MVA)	2013 (MVA)	2014 (MVA)	2015 (MVA)	2016 (MVA)	2017 (MVA)	2018 (MVA)
Bustleton	92.5	86.2	87.9	93.6	97.1	100.4	104.7	109.0	113.4	117.9	122.6	127.2
Levitown 1	77.2	76.7	78.1	78.7	79.3	79.9	80.5	81.0	81.6	82.1	82.6	83.1
Levitown 2	79.9	75.0	78.5	80.2	82.0	83.8	85.7	87.6	89.6	91.6	93.7	95.8
Lumberton	79.0	67.0	71.6	74.4	77.4	80.5	83.7	87.1	90.5	94.2	98.0	102.1
Southampton	60.0	18	17.8	17.9	18.2	18.3	18.5	18.7	18.8	19	18.1	18.3
TOTAL	388.6	322.9	333.9	344.8	354.0	362.9	373.1	383.4	393.9	404.8	415.0	426.5
Deficit		-	-	-	-	-	-	-	5.3	16.2	26.4	37.9

Table VI

BLENHEIM SUBSTATION

SUBSTATION	CAPACITY (MVA)	ACTUAL 2008 (MVA)	2009 (MVA)	2010 (MVA)	2011 (MVA)	2012 (MVA)	2013 (MVA)	2014 (MVA)	2015 (MVA)	2016 (MVA)	2017 (MVA)	2018 (MVA)
Beaver Brook	85.2	83.0	84.2	86.5	88.9	91.4	93.6	95.7	97.9	99.9	102.0	104.0
Deptford	116.6	87.6	90.1	92.1	94.2	96.3	98.3	100.3	102.2	104.1	106.0	107.9
Hilltop/Runnemede	60.0	38.9	38.2	38.5	38.8	39.2	39.5	39.8	40.1	40.3	40.6	40.9
Thorofare	56.1	56.3	58.1	59.1	60.1	61.1	62.2	63.1	64.1	65.1	66.0	66.9
TOTAL	317.9	265.8	270.6	276.2	282.0	288.0	293.6	298.9	304.3	309.4	314.6	319.7
Deficit		-	-	-	-	-	-	-	-	-	-	1.8

Table VII

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

ASSOCIATION/CLUB DUES

QUESTION:

Association/Club Dues - Submit the following information for dues on a test year basis:

a) The total amount of dues included in test year expenses, including the account number(s) in which these expenses have been booked.

b) The portion of the dues to be submitted in (a) associated with "media communications" (advertising) and associated with lobbying and/or "government relations".

c) With regard to the "media communications" (advertising) portion to be identified in S-PREV-46 (b), please submit the following additional information:
   1) A detailed description of the type of advertising covered, including the purpose and objectives of such advertising.
   2) Samples of the type of advertising.
   3) Is AGA/NJUA advertising geared towards the specific New Jersey service territory of Petitioner or is it nationwide advertising? Please explain.

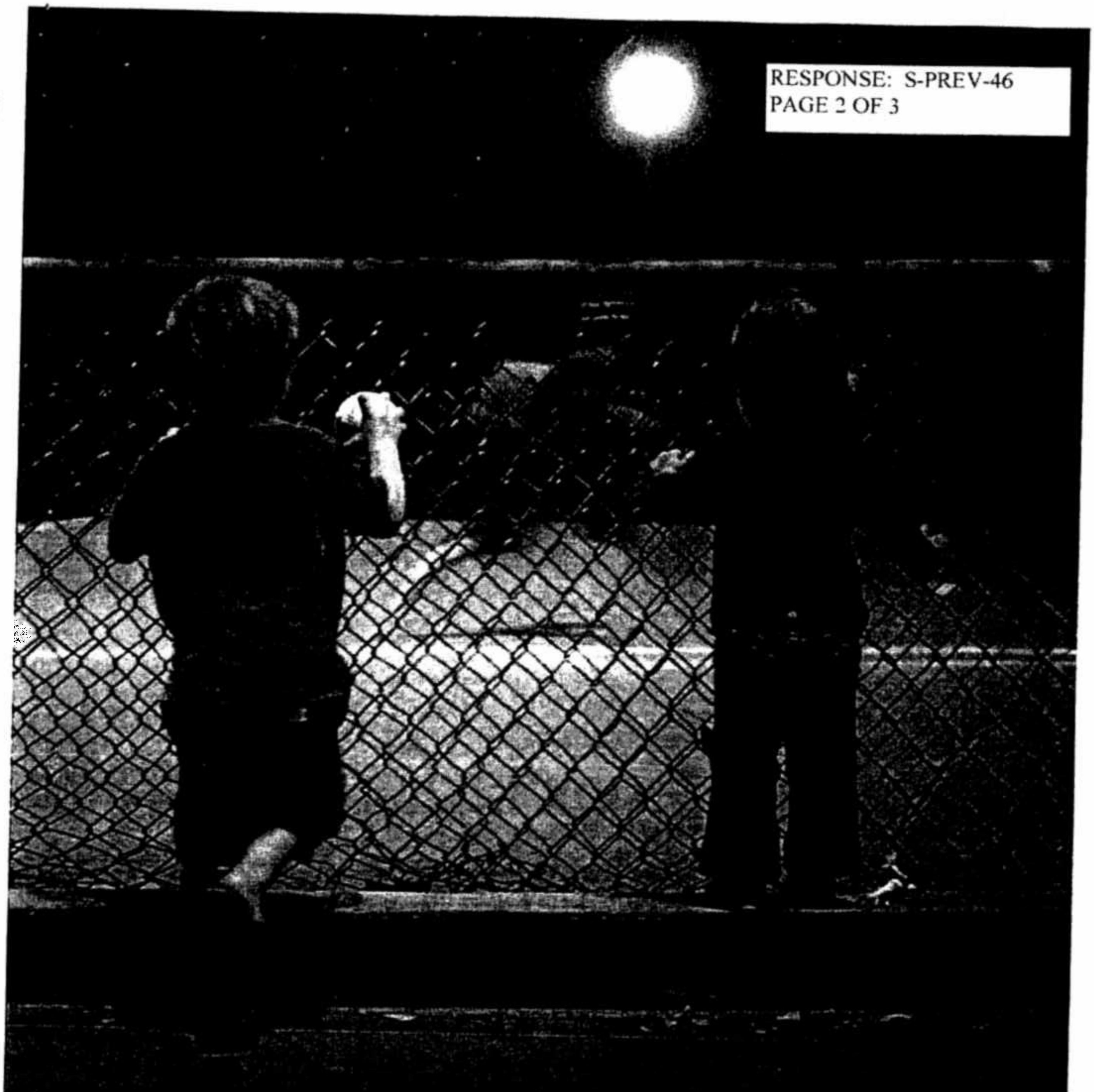
ANSWER:

a) Dues and membership included in the Test Year 2009 Plan are:
EPRI expenditures have traditionally been included in the dues category but in reality these payments are made for targeted research and development projects which are selected based on their potential value for new technology to yield improved reliability, lower risk and lower cost. The projects funded for electric distribution in 2009 will total $1,155,000.

EEI at $734,677 to Order #1544780 and FERC Account 930.2
NJUA at $74,235 to Order #9DCRMBRSH and FERC Account 930.1
AGA at $459,248 to Order 1549200 and FERC Account 930.2

b) All of ERPI amounts are dedicated to research and development. EEI expenses associated with regular lobbying activities are 16% and for SFA Industry Structure 35%. AGA lobbying expenses are anticipated to be 4.38% and NJUA's lobbying expenses are anticipated to be approximately 1%.

c)
   1) EEI is the only trade association with media expenses. Approximately 1% of dues payments are for advertising.
   2) See attached samples of advertising.
   3) All of the EEI advertising is for national advertising.



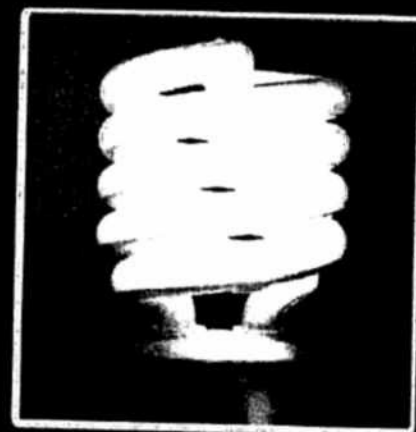
We're Proud to Join You In Lighting the Way For Literacy and Kids

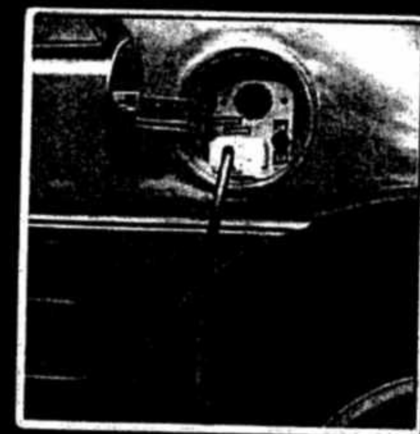
Edison Electric Institute and our member electric companies are pleased to be sponsors of the 2009 Congressional Baseball Game and to support the Washington Literacy Council and the Boys and Girls Clubs of Greater Washington.

EEI EDISON ELECTRIC INSTITUTE

www.eei.org

There's a direct line between energy and the economy.





Electricity runs through it.

Working together, we're building a brighter electric system that increases efficiency, powers the economy and delivers a low carbon future.

SMART GRID | ENERGY EFFICIENCY |

America's Electric Companies: New Ideas for a Brighter Future.

EEI EDISON ELECTRIC INSTITUTE
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAXES - MEMBER OF CONSOLIDATED GROUP

QUESTION:
Consolidated Tax Savings – What year did Petitioner begin filing its federal income tax return as part of a consolidated tax return? Has Petitioner filed as part of a consolidated tax return each year since then? What was the name of the parent company that filed the consolidated tax return that included Petitioner in each year since 1991?

ANSWER:
Public Service Electric & Gas Company (PSE&G) began filing as part of the consolidated tax return of Public Service Enterprise Group Incorporated in 1986 and has filed as a member of this consolidated group ever since.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAXES - TAXABLE INCOME & LIABILITY

QUESTION:

Consolidated Tax Savings –

a) For each of the years 1991 through the present, please provide the taxable income / (loss) for Petitioner and each its affiliates included in the consolidated tax return (broken down by company), the total consolidated taxable income, any alternative minimum tax payments, the federal income tax rate, and the federal tax liability. Also, please indicate which of these companies are regulated.

b) If actual data is not available for the current year, please provide estimated data for the current year in the same format.

c) Please provide actual data for the current year in the same format as soon as it becomes available.

ANSWER:

Attached is an update to S-PREV-90(UPDATE 2) showing revised federal tax information based on Company's 2008 tax return and including the Company's latest projection for 2009, which is confidential and subject to the terms of the Confidentiality Agreement.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONSOLIDATED TAXES - FEDERAL TAX PAYMENTS

QUESTION:

Consolidated Tax Savings –

a) What were Petitioner's payments to its parent company for Federal Income Taxes for each of the years 1991 through the present?

b) What were the consolidated group's payments to the Internal Revenue Service for Federal Income Taxes for each of the years 1991 through the present?

ANSWER:

See attached schedule showing PSE&G's Federal tax payment to parent company and the consolidated group's (Public Service Enterprise Group) payment to the IRS for years 1991 until present.

2009 Rate Case

Public Service Electric and Gas Company
Consolidated Tax Savings
PSE&G and Enterprise Federal Tax Payments

Years 1991 - 2008

Year	PSE&G's Federal Tax Payments to Enterprise	Enterprise Federal Tax Payments to IRS
2008 (1)	114,489,851	675,594,306
2007	258,446,708	626,764,137
2006	199,194,836	277,721,322
2005	262,556,139	109,479,334
2004	219,217,135	107,393,463
2003	87,589,906	-
2002	37,151,661	19,755,555
2001	106,818,003	53,109,845
2000	162,554,982	126,265,952
1999	212,391,918	379,475,470
1998	337,252,666	324,907,153
1997	291,891,208	160,035,293
1996	239,466,364	152,166,153
1995	244,647,678	171,911,715
1994	247,753,427	163,840,091
1993	149,283,044	128,141,029
1992	217,344,135	149,908,945
1991	183,007,377	133,568,697

(1) Per Extension Payment

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

EMPLOYEE POSITIONS CREATED FOR RGGI AND SOLAR LOAN I

QUESTION:

RE: Employee Positions Supporting RGGI Programs

Please provide a list of all employee positions created for use in RGGI programs and Solar Loan I and their associated salaries.

ANSWER:

Employee salaries are confidential employee information. However, each position is associated with a grade level that has associated competitive ranges for compensation.

Manager - Business Development - Grade 9 - Competitive market range 107,200 - $145,000
Manager - Asset Management- Grade 8 - Competitive market range $89,400 - $121,000
DSM Service Consultant Renewables - Grade 7 - Competitive market range $77,700 - $105,100
Renewables and Energy Solutions Specialist - Grade 7 - Competitive market range $77,700 - $105,100
Product Manager - Grade 7 - Competitive market range $77,700 - $105,100
Energy Assistants - $15.80 per hour

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
EMPLOYEES SUPPORTING RGGI PROGRAMS AND SOLAR LOAN I

QUESTION:
RE: Employee Positions Supporting RGGI Programs
Please provide a list of all current employees that support RGGI programs and Solar Loan I and their associated salaries.

ANSWER:
It is not possible to list all current employees that support RGGI programs and Solar Loan I. Resources in PSE&G are utilized on an as-needed basis to support the successful implementation of programs.