STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE IRENE JONES

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF	)	**BPU DOCKET No. ER11080469** **OAL DOCKET No. PUCRL 09929-2011**

DIRECT TESTIMONY OF ANDREA C. CRANE
ON BEHALF OF THE
DIVISION OF RATE COUNSEL

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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 90 Grove Street, Suite 211, 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. I became President of the firm in March 2008.

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 350 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, Washington, 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 since January 2008 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 August 5, 2011, Atlantic City Electric Company ("ACE" or "Company") filed a Petition with the State of New Jersey, Board of Public Utilities ("BPU" or "Board") seeking a base rate increase of $75.466 million, including sales and use taxes ("SUT"). The Company proposed to partially offset this increase with a credit of $17.071 million (including SUT) relating to excess depreciation expenses that were previously addressed by the BPU.

ACE proposed to transfer this credit from base rates to a separate, explicit item in the Company's tariff that would expire August 31, 2013, the end of the amortization period previously approved by the BPU. In addition, the Company requested a rate increase of approximately $501,000 (including SUT) in its Regulatory Asset Recovery Charge ("RARC"). ACE's initial request would have resulted in an electric distribution revenue increase of approximately 20.7% on electric distribution rates.

The Company's case is based on a test year consisting of the twelve months ending December 31, 2011. As originally filed, ACE's revenue requirement reflected actual results for three months and projected results for the last nine months of the test year (3+9). ACE subsequently updated its filing to reflect twelve months of actual results (12+0 Update). In that update, the Company increased its electric rate increase request to $96.587 million (including SUT) million and increased its RARC claim by an additional $182,000. Accordingly, the Company is now seeking an increase in its electric distribution rates and RARC of approximately 28.0%.

The Columbia Group, Inc. was engaged by The New Jersey 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 claim. I am also providing testimony on certain other issues that have been consolidated into this base rate case. These include the accounting aspects of the Company's Infrastructure Investment Plan (IIP) true-up filings (Docket Nos. EO09010049, EO09010054, EO11110846, EO10110847), the Company's request for deferral of costs incurred with regard to Hurricane Irene (Docket Nos.

EO11090518 and GO11090519), and an evaluation of the prudence of certain administrative expenses associated with the Company's Basic Generation Service ("BGS") (Docket No. ER11040250).

In developing my recommendations, I have relied upon the cost of capital and capital structure testimony of Matthew I. Kahal and on the testimony of Charles Salamone relating to the Company's Infrastructure Investment Program ("IIP").

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

A. The most significant revenue requirement issues in this proceeding are the Company's claim for a cost of equity of 10.75%; the appropriate rate treatment for a utility filing as part of a consolidated income tax group; the Company's proposals to include post-test year plant additions and a prepaid pension asset in rate base; and the Company's proposed weather normalization adjustment. ACE's last electric base rate case was resolved by BPU Order issued May 12, 2010. That case was based on a test year ending December 31, 2009.

III. SUMMARY OF CONCLUSIONS

Q. What are your 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 12+0 Update, and other documentation in this case, my conclusions are as follows:

1. The twelve months ending December 31, 2011 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 operations of 7.88%.

3. ACE has pro forma rate base of $509.616 million (see Schedule ACC-3).[1]

4. The Company has pro forma electric operating income at present rates of $36.930 million (see Schedule ACC-13).

5. ACE has a pro forma, electric base distribution revenue deficiency of $5.474 million (see Schedule ACC-1). This is in contrast to the Company's claimed revenue deficiency of $90.268 million (excluding SUT).

6. My recommendations reflect the transfer of the amortization of the excess depreciation reserve into a separate rider, as proposed by the Company. ACE should make a status filing on June 1, 2013 prior to terminating this rider and provide other parties the opportunity to review any remaining deferred balance at that time.

7. The BPU should terminate the Company's RARC and transfer $2,647,316 into base rates (see Schedule ACC-35). This transfer is not reflected in the revenue deficiency of $5.474 million discussed above.

8. When it files its compliance filing in this case, ACE should also file a compliance filing for its IIP surcharge and recover any remaining over-recovery or under-recovery over a 12-month period.

9. In its next base rate case, ACE should include internal labor costs that are now being

[1] Schedules ACC-1 and ACC-34 are summary schedules, ACC-2 is a cost of capital schedule, ACC-3 to ACC-12 are rate base schedules, and ACC-13 to ACC-33 are operating income schedules. Schedule ACC-35 relates to the RARC.

charged to Basic Generation Service ("BGS").

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that ACE 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
Long Term Debt	51.14%	6.47%%	3.31%
Common Equity	48.86%	10.75%	5.25%
Total	100.00%		8.56%

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

A. As shown on Schedule MIK-1 of Mr. Kahal's testimony, Rate Counsel is recommending an overall cost of capital for ACE of 7.88% based on the following capital structure and cost rates:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	51.31%	6.47%	3.32%
Short Term Debt	0.71%	0.35%	0.00%
Common Equity	47.98%	9.50%	4.56%
Total	100.00%		7.88%

Mr. Kahal's recommendation reflects an updated capital structure and a reduction to the Company's claimed cost of equity. 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-1, 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-1, my recommendations indicate that the Company currently has an electric base distribution revenue deficiency of $5.474 million.

V. RATE BASE ISSUES

A. Utility Plant-in-Service

Q. How did ACE determine its utility plant-in-service claim in this case?

A. The Company's claim for utility plant-in-service is based on its plant balances at December 31, 2011, the end of the test year. These balances include expenditures relating to the Infrastructure Investment Program. In addition, ACE included post-test year plant additions through June 30, 2012 in its rate base claim.

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 claim for plant held for future use.

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

A. The Company's claim for post-test year plant includes $54.352 million in distribution plant, offset by a $1.678 million addition to the depreciation reserve and further offset by an addition of $10.416 million to the deferred tax reserve, as shown in Schedule JCZ-17, (Adjustment No. 13). I am recommending that all post-test year plant additions, 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 June 30, 2012 to determine its need for rate relief, its pro forma revenues at present rates are based on test year customers. Moreover, the Company has not adjusted its depreciation reserve claim or its deferred income tax reserve claim, reserves that reduce rate base, to reflect normal reserve additions through June 30, 2012. ACE chose the test year in this case and that test year ends at December 31, 2011. 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, in the Elizabethtown Water Company Rate Case, 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. ACE 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, 2011 utility plant-in-service balances. My adjustment is shown in Schedule ACC-4.

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 $6.275 million of plant held for future use in its 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 Company facility.

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. It is my understanding that in previous cases the BPU has ordered the Company to limit plant held for future use to property that is expected to be in-service within ten years of the test year. ACE has not demonstrated that its claimed plant held for future use meets this criteria. Accordingly, I am recommending that plant held for future use be eliminated from the Company's rate base claim in this case. My adjustment is shown in Schedule ACC-5.

C. **Accumulated Depreciation**

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

A. The Company began with its balance for accumulated depreciation at December 31, 2011. ACE then made adjustments to reflect a) additions to the reserve based on depreciation on post-test year plant additions, b) additions to the reserve based on annualizing ACE's depreciation expense to reflect depreciation on test year plant, and c) additions to the reserve related to increases in cost of removal. It should be noted that the Company did not include a reserve addition based on normal additions to the reserve through June 30, 2012, even though it included post-test plant through that date in its rate base claim.

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 reserve additions related to this post-test year plant be eliminated from the reserve. This adjustment is shown in Schedule ACC-4 (along with the associated plant adjustment).

Second, the Company also included a depreciation reserve adjustment to increase the reserve for the additional cost of removal expense that ACE has included in its revenue requirement. I understand that the Company and Rate Counsel have reached an agreement to retain the current annual cost of removal expense of $2.935 million. Therefore, I have eliminated the reserve adjustment initially proposed by the Company from my pro forma rate base, at Schedule ACC-6.

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 cover cash outflows between the time that revenues are received from customers and the time that expenses must be paid. For example, assume that a utility bills its customers monthly and that it receives monthly revenues approximately 30 days after the midpoint of the date that service is provided. If the Company pays its employees weekly, it will have a need for cash prior to receiving the monthly revenue stream. If, on the other hand, the Company pays its interest expense semi-annually, it will receive these revenues well in advance of needing the funds to pay interest expense.

Q. Do utilities always have a positive cash working capital requirement?

A. No, they do not. The actual amount and timing of cash flows dictate whether or not a utility requires a cash working capital allowance. Therefore, one should examine actual cash flows through a lead/lag study in order to accurately measure a utility's need for cash working capital.

Q. Please describe the Company's claim for cash working capital.

A. The Company has based its cash working capital claim on a lead-lag study sponsored by its witness, Jay C. Ziminsky. The lag days were generally developed by analyzing invoices for the twelve months ending December 31, 2010. These lag days were then applied to test year expenses in order to develop the cash working capital claim reflected in Mr. Ziminsky's rate base claim.

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

A. Yes, I am recommending ACE's cash working capital claim be revised to eliminate cash working capital associated with non-cash items, such as depreciation and amortization expense and deferred taxes. I also recommend that non-contractual costs, such as utility operating income, be excluded from the lead/lag study. I recommend that the lead/lag study be revised to include the lag on interest expense. This adjustment reflects the fact that revenues are collected in rates for interest expense on a monthly basis but debt payments are made semi-annually to the bondholders. I also recommend that the lag on payment of interest on customer deposits be increased from 0 days to 365 days. Finally, I have revised the expense lag associated with Investment Tax Credits ("ITCs") from 0 days to (10.01) days.

Q. Please explain how ACE has treated the non-cash items you have eliminated in your adjustments to cash working capital.

A. ACE has included depreciation and amortization expenses, deferred tax expense and invested capital in the lead/lag calculation as expenses with zero-lag days. The inclusion of these items with a zero lag actually has a very significant impact on the cash working capital requirement because it reduces the average number of lag days for expenses. The reduction in the expense lags results in an increase in the overall cash working capital requirement net lag days, which has a very direct and significant impact on the calculation of the amount of cash working capital required by the Company.

Q. Why does ACE seek to include these items at a zero lag?

A. Mr. Ziminsky did not provide any testimony as to why he believes that these items should be included with a zero lag.

Q. What is the basis for your recommendation to exclude depreciation and amortization expense and deferred tax expense entirely from the lead/lag study?

A. It is inappropriate to include depreciation and amortization expense and deferred income taxes in a utility's cash working capital claim because these costs do not result in cash outflows by the utility. ACE does not make cash payments for depreciation, amortization, or deferred taxes on a specified date. The purpose of a lead/lag study is to match cash inflows, or revenues, with cash outflows, or expenses. Cash working capital reflects the need for investor-supplied funds to meet the day-to-day expenses of operations that arise from the timing differences between when ACE has to expend money to pay the expenses of operation and when revenues for utility service are received by the utility. Only items for which actual out-of-pocket cash expenditures should be made are included in a cash working capital allowance. Therefore, at Schedule ACC-7, I have made an adjustment to eliminate the cash working claims associated with depreciation and amortization expense and deferred taxes from ACE's cash working capital claim.

Q. Please explain why you have rejected the Company's claim for zero lag days for return on invested capital.

A. Return on invested capital includes a cost of equity as well as a cost of debt. The cost of debt component, i.e., interest expense, is addressed below. That component of invested capital has a lag of 91.25 days, assuming semi-annual interest payments, not the zero lag included in the Company's lead/lag study.

With regard to the cost of equity, this does not represent a contractual obligation of ACE. The Company is under no obligation to make payments to its stockholders. While ACE may make dividend payments, they are contractually not obligated to do so. Moreover, even if dividend payments are made, they are generally made no more frequently than quarterly. They are certainly not made on a daily basis, which is the assumption inherent in the use of a zero lag. In addition, companies generally retain a portion of their earnings rather than paying out all earnings as dividends, another fact not taken into account in the Company's study. Therefore, it is inappropriate to reflect a zero lag, and to correspondingly increase the Company's cash working capital, for the return on equity.

Q. Has ACE reflected a reduction in cash working capital related to the lag in its payment of interest expense?

A. No, it has not. The Company has failed to reflect the fact that the revenue requirement includes a component for interest expense, which is a contractual obligation of the utility.

Q. How is working capital generated by the Company's lag in the payment of its interest expense?

A. ACE collects revenues from ratepayers for interest expense on a monthly basis but pays its bondholders for interest only twice a year. Therefore, on average, the accrued interest funds are available to the Company, at no cost, to finance their operations between the time they collect the interest from customers and the time that interest payments are made to bondholders.

Q. How should this cost-free source of funds be reflected for ratemaking purposes?

A. The lag in the payment of interest expense must be reflected in the cash working capital calculation so that ratepayers are compensated for providing a cost-free source of capital to

ACE. In developing my adjustment, I included the interest expense at a lag of 91.25 days, which reflects semi-annual payments of interest.[2]

Q. Are you recommending any adjustment to the expense lag days reflected in the cash working capital study for the interest on customer deposits?

A. Yes, I am recommending an expense lag of 365 days for the interest on customer deposits, instead of the lag of 0 days included by the Company in its lead/lag study. ACE used an expense lag of 0 days on the basis that customers earn interest daily on their customer deposits. But interest on customer deposits is not paid on a daily basis. According to the Company's tariff, when a customer deposit is required, the Company will review a residential customer account at least once a year, and a commercial customer's account at least every two years, to determine if the customer has obtained satisfactory credit and if the customer deposit can be returned. My understanding is that the Company does not pay interest to the customer until the customer deposit is actually returned. Therefore, the expense lag associated with customer deposits is at least 365 days, and could be longer depending on the mix of residential vs. commercial deposits. Therefore, the 365 day expense lag reflected in my cash working capital calculation is reasonable.

Q. What expense lag did the Company use for ITCs?

A. ACE reflected an expense lag of 0 days. However, ACE does not receive the reduction in

2 Reflects the lag from the midpoint of the 182.5 day service period (365 / 2 / 2).

taxes associated with ITCs on a daily basis, but only receives this reduction as it actually pays taxes. Therefore, I recommend that the BPU utilize the same expense lag for ITCs as is used for current income taxes. Accordingly, I have made an adjustment to increase the expense lag for ITCs from 0 days to (10.01) days, is which the lag claimed by the Company for current taxes.

Q. What are the results of your cash working capital adjustments?

A. I have eliminated the zero lag days used by the Company for depreciation, amortization, deferred taxes and invested capital; reflected the lag in the payment of interest expense; revised the lag for interest on customer deposits; and revised the lag for ITCs. My adjustments result in a cash working capital allowance $83.266 million, as shown in Schedule ACC-7, instead of the $104.068 million included in the Company's claim.

Q. Do you have any additional comments regarding cash working capital?

A. Yes. I have not attempted to reflect the impact of my recommended expense adjustments in my pro forma cash working capital recommendation. However, I recommend that the cash working capital requirement be updated to reflect the actual level of expenses, including interest expense, found by the BPU to be appropriate.

E. Credit Facility Costs

Q. Please explain your recommended adjustment relating to the Company's rate base claim for credit facility costs.

A. ACE is requesting recovery of costs relating to a PHI credit facility. The Company's claim includes annual recurring maintenance costs associated with the credit facility, as well as amortization of closing or start-up credit costs. In addition, ACE is requesting that the average balance of unamortized costs be included in rate base and that shareholders be permitted to earn a return on this balance at the Company's overall cost of capital.

As discussed later in this testimony, I am recommending that credit facility costs be included in the Company's revenue requirement as long as the BPU includes short-term debt in the Company's capital structure. However, it does not follow that the unamortized balance should be included in rate base. Permitting these costs to be included in rate base will require ratepayers to pay not only a return, but also income taxes associated with this return, on these costs. Moreover, the Company is fully compensated for these associated start-up costs through the amortization expense that will be reflected in rates. Moreover, to my knowledge, the BPU does not have a general policy of routinely including unamortized balances in rate base. Therefore, at Schedule ACC-8, I have made an adjustment to eliminate the unamortized balance of credit facility costs from the Company's rate base claim.

F. Prepaid Pension Asset

Q. What is the prepaid pension asset?

A. As described by Mr. Ziminsky on page 16 of his Direct Testimony, a " prepaid pension asset arises when the accumulated contributions and growth in pension plan assets exceed the accumulated costs associated with the pension obligations." In this case, ACE has included a "prepaid pension asset" of over $35.9 million in rate base.

Q. How is pension expense determined for ratemaking purposes?

A. There are two methodologies used by regulatory commissions to determine the appropriate amount of pension expense to include in utility rates. Most state regulatory commissions, including the New Jersey BPU, utilize the accrual methodology set forth in Statement of Financial Accounting Standard ("SFAS") 87. This is the methodology that is required to be used for financial reporting purposes under Generally Accepted Accounting Principles ("GAAP"). This methodology was adopted by the Financial Accounting Standards Board ("FASB") in 1987. This methodology requires a company to accrue pension costs over the working life of the employee.

Under SFAS 87, each year, a company's pension expense is calculated. This calculation determines the amount of pension expense that must be recognized for financial reporting purposes, based on numerous factors. The calculation considers the accumulated amount that should have been accrued at the present time based on the demographics of a company's employees, the age at which such employees are likely to retire, the expected future return on pension plan assets, assumptions regarding future payroll levels, assumptions regarding an appropriate discount rate, and other factors. When calculating the annual pension cost, certain gains and losses are amortized over a multi-year period. This amortization helps to mitigate significant fluctuations that can occur from year-to-year in pension plan earnings.

Thus, the calculation of the pension cost is a snapshot at a point in time. It is impacted by what has happened in the past as well as what is expected to happen in the future. In addition, there is a gradual true-up of past estimates with actual results over time. Pursuant to SFAS 87, a pension expense can be either positive or negative. If it is positive, then the pension plan is under-funded at a given point in time from an actuarial perspective and additional amounts must be accrued. In that case, ratepayers are required to provide for additional recovery of costs in rates. If the pension expense is negative under SFAS 87, then the plan is over-funded at a given point in time, i.e., the accumulated annual accruals exceed the amount required pursuant to SFAS 87, and ratepayers receive a credit in cost of service due to the fact that the pension expense was higher than necessary in prior years.

Q. What is the second method used by regulatory commissions?

A. A few regulatory commissions base a company's pension expense, for ratemaking purposes, on the amount of cash contributions required to be made to the pension fund. This is also referred to as the "cash methodology" to distinguish it from the accrual methodology discussed above. The actual cash funding of the plan, i.e., the amount of cash contributions to the dedicated trust that must be made by a company, is governed by the requirements of the Employee Retirement Income Security Act ("ERISA") and Internal Revenue Service ("IRS") regulations. The minimum pension plan contribution that must be made each year is determined pursuant to an ERISA formula, while the IRS determines the maximum amount of any contribution that is deductible for income tax purposes.

Q. Are you recommending any adjustment to the Company's claim relating to its prepaid pension asset?

A. Yes, I am recommending that this claim be denied. The Company's proposal to include a prepaid pension asset in rate base essentially mixes the two methodologies used by regulatory commissions to determine pension expense in rates. ACE is attempting to add a true-up for the difference between accrued pension expenses and cash contributions. I have several problems with the Company's proposal, as summarized below:

- ACE largely controls the amount and timing of contributions to its pension fund;
- SFAS 87 has been adopted by this Commission for the determination of pension expense and should be consistently applied.
- The Company's adjustment is retroactive in that it includes cash contributions made as far back as 1987; and
- The Company's adjustment is based on assumptions regarding amounts

collected from ratepayers that may not be accurate.

Q. How does ACE control the amount and timing of contributions to its pension fund?

A. The Company has wide discretion each year as to whether or not to make a contribution to its pension fund. As shown in the response to RCR-A-32, ACE made cash contributions to its pension plan in only three of the past ten years. While I do not have similar data for the period from 1987, when SFAS 87 was adopted, through 2001, it is likely that no pension contribution was required to be made in many, if not all, of those years as well. Moreover, since actual cash contributions from 2001-2010 ranged from $0 to $60 million, it is clear that the Company has significant discretion with regard to funding. Ratepayers should not be penalized as a result of funding decisions made by Company management. Rather, utility rates should be based solely on the cost of pension expense approved by the BPU pursuant to SFAS 87.

Q. What factors influence a company's decision with regard to pension funding?

A. Many factors influence a company's decision with regard to pension funding, including tax considerations, the availability of cash, and a company's financial position. Thus, ACE's funding decisions are dependent, at least in part, on its ability to manage its earnings and/or to minimize its tax expense.

Q. Why do you believe that it is important to ensure consistency from case-to-case in the manner in which the Company's pension expense is determined?

A. It is the consistency of using SFAS 87 expense for ratemaking that assures that, over the life of the plan, the expenses recognized pursuant to SFAS 87 will equate to the contributions made to the pension plan. While there are different assumptions and formula used to determine a Company's SFAS 87 expense and its required pension plan contributions, over the life of the plan the goal of both methodologies is the same, i.e., to recognize the Company's liability with regard to pension costs and to ensure that these costs are properly funded. If a hybrid approach is now adopted, i.e., using SFAS 87 to determine pension expense but also requiring ratepayers to pay a return on contributions to the plan, then ratepayers will be penalized by paying twice.

Q. Why do you believe that the Company's prepaid pension asset constitutes retroactive ratemaking?

A. I believe that the adjustment constitutes retroactive ratemaking for two reasons. First, the Company's pension asset was developed based on data beginning in 1987, almost twenty-five years ago. In the past, the BPU has never approved inclusion of a pension asset in rate base. Nor has the BPU ever approved a true-up mechanism to track actual SFAS 87 costs, or amounts collected in rates, and cash contributions. Therefore, the Company is requesting inclusion of an asset based on SFAS 87 expenses and funding decisions that occurred, in many cases, well before the beginning of the test period in this case. Accordingly, even if the

BPU believed that the Company's claim was appropriate conceptually, which it clearly is not, it would be retroactive ratemaking to permit ACE to include any differences between SFAS 87 expense and pension fund contributions that occurred almost twenty-five years ago, well before the BPU would have granted the requested ratemaking treatment.

Q. Is it possible to accurately quantify the amounts paid by ratepayers relating to pension expense since 1987?

A. No, it is not. The Company acknowledged in the response to RCR-A-32 that it "does not 'ear-mark' collections from customers to individual expense areas that are included in revenue requirement." Moreover, it is my understanding that most, if not all, of the Company's rate cases since 1987 have been settled cases. I am not aware of any of these stipulations that specifies the amount of pension costs being recovered from ratepayers. Nor am I aware of any mechanism to track amounts actually recovered from ratepayers relating to pension costs. Therefore, even if an amount had been specified, which it was not, there is no mechanism to true-up the pension expense included in the cost of service with amounts actually recovered from ratepayers.

Q. Has the Company requested authorization to include a pension asset in rate base in prior cases?

A. No, ACE has not proposed to include a pension asset in rate base in prior cases before the BPU. Nor has the BPU ever included a pension asset in rate base for any utility in New

Jersey. Thus, the Company's request is unprecedented in this state, and would unfairly charge ratepayers an additional $4.5 million of new charges.

Q. Why do you believe that ACE is requesting the inclusion of a pension asset in rate base in this case, given that it has not requested recognition of a pension asset in prior cases?

A. When SFAS 87 was first adopted, many companies found themselves with pension funds that were over-funded relative to the pension expenses incurred for financial reporting purposes. It is only over the past few years, as stock market returns have become more volatile and as pension funding mandates have been tightened, that companies have found it necessary to make large cash contributions to their pension funds. In fact many companies did not make any cash contributions to the fund for many years after the adoption of SFAS 87. Thus, these companies would have been required to include a reduction to rate base under the Company's proposed methodology. I am not aware of any company that proposed such a rate base reduction relating to the over-funding of pension plans during this period. It is only now, given the requirement to make cash contributions, that companies have suddenly decided that a rate base adjustment is appropriate.

Q. Is the pension asset proposed by the Company solely related to cash contributions that ACE has made?

A. No, it is not. As acknowledged by Mr. Ziminsky, the pension asset also includes the return on investments earned by pension fund. Thus, a prepaid pension asset can exist even if a utility does not actually make cash contributions to the plan. This is because in some years the actual market returns exceeded the returns assumed for funding purposes. Therefore, it is important to recognize that much of the prepaid pension asset can be the result of better-than-expected market returns, and not the result of cash outlays by the utility.

Q. What do you recommend?

A. I recommend that the BPU continue to base the Company's pension expense, for ratemaking purposes, solely on the expense determined pursuant to SFAS 87. I recommend that the Company's proposal for a hybrid approach, which would include a pension asset in rate base, be denied. At Schedule ACC-9, I have made an adjustment to eliminate the prepaid pension asset from rate base.

G. Storm Damage Costs

Q. Please explain the Company's adjustments with regard to storm damage costs.

A. ACE's filing includes two adjustments with regard to storm damage costs. First, ACE made an expense adjustment to reflect a three-year average of storm damage costs, excluding costs associated with Hurricane Irene. Second, ACE proposed that costs related to Hurricane Irene be amortized over three years, and that the unamortized balance be included in rate base.

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

A. As discussed more fully later in this testimony, I am recommending that the Company's three-year average include costs for Hurricane Irene. Unless a longer amortization period is used for costs related to Hurricane Irene, there is no rationale for removing these costs from the determination of the three-year average used to normalize storm damage costs. Since I am recommending that these costs be included in the development of normalized storm damage costs, there is no basis to include the unamortized balance in rate base.

Moreover, even if the BPU decided to use a different amortization period for costs related to Hurricane Irene, there is no basis for including the unamortized balance in rate base. As noted earlier with regard to credit facility costs, including these costs in rate base requires ratepayers to pay a return on these costs based on the overall cost of capital, as well as income taxes on any such return. Shareholders received a 10.3% authorized return on equity in the Company's last case because of certain risks that they were assuming, including operational risks associated with variable weather conditions. Shareholders do not have the right to expect that all unanticipated costs will be reimbursed, along with carrying costs, given the premium return that was awarded in the last case. Given the fact that I have included Hurricane Irene costs in my normalization adjustment, and given the fact that the BPU authorizes a risk-adjusted return on equity, I have made an adjustment to eliminate the unamortized balance of costs for Hurricane Irene from rate base. My adjustment is shown in Schedule ACC-10.

H. OPEB Liability

Q. Please describe the OPEB liability that the Company has reflected as a rate base reduction.

A. Presumably in an effort to make its prepaid pension asset more palatable, ACE has included an adjustment to reduce rate base by the amount by which accumulated OPEB costs exceed the associated contributions and market returns. In this case, the accumulated liability is greater than the contributions and market returns, resulting in a rate base reduction. This adjustment can be thought of as the mirror image of the prepaid pension asset adjustment discussed above.

Q. What do you recommend?

A. For ratemaking purposes, OPEB costs, like pension costs, are based on actuarial formulas that attempt to recover these costs over the working lives of the employees. The BPU has used the actuarial method for recovery of OPEB costs since it adopted SFAS 106 for ratemaking purposes. Similar to the discussion above with regard to pension costs, the actual cash outlay associated with OPEBs can vary each year from the cost recognized for ratemaking purposes. Consistent with my recommendation that the BPU continue to utilize the actuarial methodology for pension costs and reject the Company's claim to include the prepaid pension asset in rate base, I am making a similar recommendation with regard to OPEB costs. Although ratepayers would benefit from the inclusion of the pension liability in rate base, I do not believe it is appropriate to consider the cash implications for ratemaking purposes, given the fact that the BPU has adopted an accrual methodology, given the flexibility that utilities have with regard to funding, and given the impact of market returns on the calculation of the OPEB liability. Therefore, at Schedule ACC-11, I have made an adjustment to eliminate the OPEB liability from the Company's rate base claim.

I. Deferred Income Tax Reserve

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

Q. Yes, I am recommending one adjustment, resulting from my recommendation to utilize actual balances at December 31, 2011 for utility plant-in-service. ACE included a deferred income tax reserve adjustment to reflect additions to the reserve associated with depreciation on its post-test year plant additions. Since I am recommending that utility plant be limited to actual plant balances at December 31, 2011, I eliminated the Company's deferred income tax reserve adjustment associated with post-test plant additions. My adjustment is included in the utility plant-in-service adjustment shown in Schedule ACC-4.

J. Consolidated Income Taxes

Q. **Did ACE include a consolidated income tax adjustment in its filing?**

A. No, it did not. ACE calculated its pro forma income tax expense on a "stand-alone" basis. The Company's filing ignores the fact that ACE 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. ACE has been a member of a consolidated income tax group since at least 1991, although the various members of that group have changed with the merger of ACE and Delmarva Power and Light Company and with the eventual purchase of both companies by Pepco Holdings, Inc. ("PHI").

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.[3] In its Decision in the 1991 Jersey Central Power and Light Company ("JCP&L") base rate case (BPU Docket No. ER91121820J), dated February 25, 1993, at pages 7-8, the BPU held that:

3 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.

> 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 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 PHI has elected to file a consolidated income tax return for its subsidiaries, including ACE. Moreover, ACE 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 ACE and members of the consolidated income tax group. Because ACE has elected to file a consolidated tax return for its member companies, including ACE, I believe it is a settled matter that the tax savings should be shared with utility ratepayers.

Q. Did ACE 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 ACE 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 ACE has not introduced any compelling new arguments to support a departure from Board policy.

Q. How does PHI determine the actual amount of taxes paid by ACE to its parent each year?

A. The payment of taxes is governed by a Tax Sharing Agreement among the members of the consolidated income tax group. Pursuant to the agreement, ACE, and other subsidiaries with positive taxable income, pay the amount of their stand-alone tax liability to PHI. PHI then pays the amount of taxes due by the consolidated group to the IRS. Any excess funds are then allocated by PHI 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 affiliates that generated the income tax losses, effectively resulting in a subsidization of the unregulated affiliates, and other unprofitable companies, 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 a Tax Sharing Agreement does not negate the validity of a consolidated income tax adjustment. The Tax Sharing Agreement was not approved by the BPU and is nothing more than a contractual means to have the regulated and profitable subsidiaries subsidize unregulated ventures with ratepayer funds. According to the responses to RCR-A-114 and RCR-A-115, from 1991 to 2010, ACE paid almost 63% of all taxes that the parent paid to the Internal Revenue Service ("IRS") during this period.[4] This is in addition to amounts collected from other PHI companies with positive taxable income that were also reallocated by the parent to subsidiaries with tax losses.

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.

4 It is interesting to note that the information provided in this case differs from the information provided by ACE in the last case. In the last case, the response to RCR-A-125 (Update) indicated that ACE payments to the parent from 1991 to 2008 exceeded total payments made to the IRS by $66.6 million. In this case, the Company did not identify how much the parent paid to the IRS in 1993-1997 and those years were eliminated from my analysis.

The BPU should continue its practice of requiring a consolidated income tax adjustment for ACE in this case. My consolidated income tax adjustment for ACE is shown in Schedule ACC-12.

Q. How did you quantify your adjustment?

A. There are two principal 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 cumulative 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-121, 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 last Public Service Electric and Gas Company base rate case and in base rate cases involving New Jersey Natural Gas Company and New Jersey-American

Water Company. Unfortunately, the Company responded that "The Company has not prepared that analysis". However, ACE did provide underlying tax data in response to RCR-A-110 and I utilized that data to quantify my adjustment. Based on that response, I have quantified a rate base adjustment of $385.892 million.

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 date available. For each year, the taxable income or loss for each company 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 tax impact. The result was the total tax loss benefit for the consolidated group for each of the years in question. The annual tax loss benefit for those companies that had aggregated net losses was then itself aggregated from 1991 to the present. Adjustments were also 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 cumulative positive taxable income, based on each entity's share of the aggregated positive taxable income. This resulted in an allocation of 31.35% to ACE.

Q. Do you have any comment regarding the magnitude of this consolidated income tax adjustment?

A. While this adjustment is quite large, the magnitude is not unexpected, given the cumulative rate base methodology that has been adopted by the BPU and the magnitude of the tax losses incurred by the consolidated group.

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. Please summarize your recommendation on consolidated income taxes.

A. The BPU has a long-standing policy on consolidated income tax adjustments, and on how such adjustments should be quantified. The Company has not provided any rationale for why the BPU should deviate from its policy or why the BPU should treat ACE differently from the other utilities in New Jersey. Accordingly, the BPU should adopt the consolidated income tax adjustment that I have quantified at Schedule ACC-12. While this is a large adjustment, the BPU should keep in mind that the taxes paid by ACE to its parent since 1991 have in many years exceeded the total taxes actually paid to the IRS by the parent group. In other years, ACE paid no taxes to its parent in spite of the fact that ratepayers continued to pay for federal income taxes through their utility rates. And in some years, ACE received and retained payments of "excess" funds that were redistributed to subsidiaries with tax losses, without passing along the benefit of these payments to ratepayers. Given the fact that ACE participates in a consolidated income tax return, ratepayers should continue to be compensated through a consolidated income tax adjustment for payments to the parent company that exceed ACE's share of actual taxes paid to the IRS. Therefore, I recommend that the BPU continue its policy of requiring a consolidated income tax adjustment.

K. 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 rate base from $987.112 million, as reflected in the 12+0 Update, to $509.616 million, as summarized on Schedule ACC-3.

VI. OPERATING INCOME ISSUES

A. Pro Forma Revenues

Q. How did the Company determine its claim for pro forma revenues?

A. ACE began with its actual test year revenues, as reflected in the 12+0 Update. The Company then normalized its revenues for normal weather, annualized revenues for changes in the number of customers, and made an additional revenue adjustment for declining consumption.

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

A. Yes, I am recommending two adjustments, relating to weather normalization and to declining consumption.

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

A. The Company utilized a 20-year period to determine normal weather in calculating its pro forma weather-normalized revenue. This is the third normalization period used by the Company in its last four cases. In Docket No. ER03020110, ACE utilized a 15-year period for normal weather. In the case before that one, the Company used a period of 30 years. This frequent change from case to case illustrates why it is important for the BPU to adopt a consistent standard for normalized weather. ACE did propose a 20-year period in its last base rate case.

Q Do you agree with the use of 20 years to weather normalize sales?

A. No, I do not. Instead, I recommend that the BPU utilize a 30-year standard for normal weather.

Q. Why do you believe that 30-year data is more appropriate to utilize in developing the Company's weather normalization adjustment than the 20-year period recommended by the Company?

A. The 30-year normal has been established by the National Oceanic and Atmospheric Administration ("NOAA"), the government organization charged with establishing and recording the climatic conditions of the United States. The 30-year standard is the objective standard, established by the government body responsible for determining normal weather conditions. Moreover, the 30-year standard is the international standard adopted by the United Nation's World Meteorological Organization ("WMO"). The 30-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 30-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 year with many or few heating/cooling degree days has a much greater effect upon a 20-year average than it does upon a 30-year average. In fact, a single data point has a 5% impact on a 20-year average, but only a 3.3% impact on a 30-year average. Therefore, the effect of a single data point is 50% greater with a 20-year average than with a 30-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 year 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 30-year NOAA standard, ensures consistency from case to case.

Q. Are there other factors that lead you to favor the 30-year NOAA standard over the 20 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 30-year normal should be used?

A. Yes, there is. The use of 30 data points has its basis in the central limit theorem, which states that if the sample size has at least 30 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.

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 20-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 30-year period for determining what constitutes normal weather was not defined by ACE, or 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 30 years satisfactorily represents normal weather. To the extent weather patterns do exhibit a permanent change over time, such changes will be reflected in the 30-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 30-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 30-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.

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 2012 than it was in 1980. My recommendation that the BPU continue to utilize a 30-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 Informal Data Request No. 1-7, we asked the Company to provide the impact on its pro forma weather normalization adjustment if a 30-year normalization period had been used. The Company's response indicates that the use of a 30-year normal would increase its pro forma sales projection by 8,867 MWh, or 5.88% above the pro forma weather normalization adjustment included by ACE in its filing. Therefore, at Schedule ACC-14, I have made an adjustment to increase pro forma revenue by 5.88% of the weather normalization adjustment included by ACE in its filing.

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

A. Yes, it is. NOAA is initiating a workshop on April 24-25, 2012 to address the implications of using the traditional 30 year normals and to discuss options of alternative methodologies.

It should be noted that NOAA has initiated similar investigations in the past but in spite of those investigations it continues to utilize a 30 year period to define 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 30 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 30 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. What is the second revenue adjustment that you are recommending in this case?

A. The Company's pro forma revenue claim is based on an assumption that usage will decline in the future from its actual test year weather-normalized consumption. The Company examined the decline in usage between 2010 and 2011. It then made an adjustment to its weather normalized 2011 sales, to reflect a lower consumption level after the test year, based on the reduction that had occurred from 2010 to 2011. I recommend that this adjustment be rejected, for two reasons.

First, the Company's adjustment is entirely speculative. Any declines in usage that occurred in the test year are already embodied in the actual test year results. To make a further future year adjustment is speculative and does not meet the test for a known and measurable adjustment to the test year. Moreover, electric industry sales have generally been increasing, as customers acquire more electric appliances and more sophisticated communication devices. While this growth may have slowed in the test year, due to generally poor economic conditions, there is no reason to believe that usage will continue to trend downward. Therefore, the Company's adjustment is contrary to past experience with regard to electric usage. For both of these reasons, the Company's adjustment to reduce actual test year consumption for future declines in usage should be rejected. My adjustment is shown in Schedule ACC-15.

B. Salary and Wage Expense

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

A. The Company's claim is based on projected payroll costs for the twelve months from July 2012 through June 2013. As shown in the Company's workpapers, ACE began with its test year costs for each month of the test year, separately identifying union and non-union employee costs. For union employees, the Company reflected annual payroll increases of 2%. For non-union employees, the Company annualized a payroll increase of 3.01% that was effective during the test year. In addition, ACE reflected an additional non-union increase of 3.0%, effective March 1, 2012, and an additional non-union increase of 3.0% effective March 1, 2013. These adjustments resulted in an increase of $2,226,941 to the Company's test year expense.

Q. Are you recommending any adjustment to the Company's claim for salaries and wages?

A. Yes, I am recommending that only test year salary and wage increases be included in the Company's revenue requirement. I recommend that these increases be annualized, to reflect what the Company's costs would have been had these increases been in effect for a full twelve months. I recommend that the Commission exclude all post-test year increases from the Company's revenue requirement.

It should be noted that it was the Company that selected the test year in this case. Most of the salary and wage increases reflected in the Company's claim reach too far beyond the end of the test year, especially when one considers that the Company's claim is based on customers at December 31, 2011, the end of the test year in this case. The Company has including post-test year increases that reflect salary and wage levels through June 2013, or 18 months beyond the end of the test year. These adjustments reach too far beyond the test period and distort the regulatory triad of synchronizing rate base, revenues, and expenses. Therefore, I recommend that the BPU limit salary and wage increases to the increases that occurred during the test year, annualized to reflect a full year of costs. Since the union increase occurred in January, no adjustment to actual test year costs is required. However, the non-union increase occurred in March. Therefore, I have made a test year adjustment to include two months (January and February) of non-union salaries at levels that reflect the March 2011 non-union increase of 3.01%. My adjustment at Schedule ACC-16.

C. <u>Incentive Compensation Program Expense</u>

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

A. The Company has included $2.462 million of non-officer incentive compensation costs in its revenue requirement claim. The majority of these costs relate to the Company's Annual Incentive Plan ("AIP"), a copy of which was provided in the response to RCR-A-24. This plan is available to all PHI management employees that do not participate in any other incentive plan. The plan has an earnings threshold, i.e., no payments are made unless earnings meet certain targeted levels. According to the Plan, "[f]or Utility Operations employees, the Utility Operations' earnings must reach a 93% threshold to qualify for any potential payout. Potential payout for Corporate Services employees is based on an overall corporate earnings threshold of 90%. Corporate Services employees are eligible to receive a payout only to the extent that Power Delivery and/or Non-Regulated earnings meet or exceed threshold levels and such awards shall not exceed 50% of target if PHI corporate earnings do not exceed threshold levels." Thus, the program requires that financial goals be reached prior to any awards being made.

If the earnings threshold is met, an individual's award is then based on a combination of business unit goals and individual goals. Virtually no information about these respective goals was included in the AIP description provided by the Company. However, the plan does indicate that award percentages increase as pay scales rise. Thus, the highest paid employees are eligible for a proportionately greater incentive award. For example, while the target award for pay grades 1-4 is 5% of base pay, employees in pay grades 15-16 are eligible for awards of up to 15% of base pay. Thus, not only do more highly paid employees receive larger nominal awards, but they receive larger proportional awards as well.

Q. Did the Company include officer incentive program costs in its revenue requirement claim?

A. No, the Company made an adjustment to eliminate $952,000 in incentive program costs relating to officers. However, it should be noted that the Company defined "officers" as Named Executives Officers, i.e., only those individuals whose compensation the Company is required to disclose in its Proxy Statement. Therefore, the Company's claim for non-officer incentive compensation costs includes costs for many executives and upper management personnel.

Q. Do you believe that the incentive compensation program costs are appropriate costs to pass through to ratepayers?

A. No, I do not. I have several concerns about these types of programs, especially as designed and implemented by ACE. The Company's incentive plan is heavily weighted toward financial objectives, no payout being made unless certain financial goals are met. 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 largely on earnings criteria may 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 earrings, a spiral that does not directly benefit ratepayers, but does benefit shareholders and the management to whom such awards are 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 some 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 it 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 ACE 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 ACE employees being well compensated separate and apart from these employee incentive plans?

A. Yes, they are. Although salaried employees did not receive an increase in 2009, these employees have consistently been awarded annual payroll increases in the 3.0% to 3.7% range. Thus, there is no indication that the employees of ACE are underpaid or that the Company would have difficulty attracting qualified employees in the absence of these programs.

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 be 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.[5]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be 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.[6]

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

5 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.
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, Order Adopting in Part/Modifying in Part/Rejecting in Part Initial Decision at 25-26 (June 6, 2001).

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.[7]

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.

Q. What do you recommend?

A. I recommend that the BPU deny the Company's request for recovery of incentive plan compensation costs. My adjustment is shown in Schedule ACC-17.

D. <u>Payroll Tax Expense</u>

Q. What adjustment have you made to the Company's payroll tax expense claim?

A. Since I am recommending a reduction to the Company's claims for salaries and wages and incentive compensation costs, it is necessary to make a corresponding adjustment to eliminate certain payroll taxes from the Company's revenue requirement claim. At Schedule ACC-18, I have eliminated payroll taxes associated with my recommended salary and wage and incentive compensation plan adjustments. To quantify my adjustment, I utilized the

7 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).

statutory social security and medicare tax rate of 7.65% and applied it to my recommended adjustments for salaries and wages and for incentive compensation program costs.

E. Supplemental Executive Retirement Program ("SERP") Expense

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.

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

A. As shown in the response to S-AREV-184, the Company incurred total SERP expense of $1,293,614 in the test year. The vast majority of these costs were allocated from the Service Company.

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

A. No, I do not. The officers of the Company are already well compensated. In 2010, Mr. Rigby's salary was $881,667, which represents an increase of 10.7% over his 2009 salary.[8] Increases for the other Named Executive Officers ("NEOs") ranged from 3.4% to 26.3%. In 2010, salaries for the remaining NEOs range from $245,301 to $484,917. Total

8 The Company's 2011 Proxy Statement is not yet available.

compensation for these employees ranged from $1.2 million for Mr. Huffman to over $3.5 million for Mr. Rigby. Moreover, the officers that receive SERP benefits are also included in the normal retirement plans of the Company, so ratepayers are already paying retirement costs for these executives. If ACE wants to provide further retirement benefits to select officers and executives 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-19.

F. Medical Benefit Expense

Q. How did the Company determine its medical benefits expense claim in this case?

A. ACE's claim is based on a projected 8.0% increase in medical and on a projected 5.0% increase in dental and vision benefit costs.[9] The Company indicated that its projection was based on a study performed by Lake Consulting, its benefit plan consultant. That study was provided as an attachment to Mr. Ziminsky's testimony.

Unfortunately, the referenced study provides no data that is specific to ACE or PHI. Instead, the study is based on trends in medical premiums by several major insurance companies. Moreover, the study is based on trends in Virginia, Maryland, and the District of Columbia. Thus, there is no information about trends in medical premium costs in New Jersey. However, even if the BPU found that cost trends in this state are similar to those in the areas included in the study, the Lake Study still fails to support a post-test year

9 The 8.0% increase shown on Schedule JCZ-7 for dental costs is a typographical error, per the response to S-AREV-182.

adjustment for ACE's electric operations. The use of general cost trends does not rise to the level of a known and measurable change.

Q. Have medical insurance costs increased consistently from year to year?

A. No, they have not. As shown in the response to S-AREV-61 (Update), costs rose from 2007 to 2010, but fell dramatically in 2011. Moreover, as noted in the response to RCR-A-42, "plan offerings will change in 2012 with the elimination of the Standard Indemnity Plans and CareFirst EPO and the addition of the PHI HMO. Further, all newly hired union employees now must enter the management medical plans." Given these changes, and the fact that ACE has not supported its claimed post-test increases, I am recommending that the BPU deny ACE's pro forma adjustment relating to medical benefit costs. My adjustment is shown in Schedule ACC-20.

G. <u>Corporate Structuring Expense</u>

Q. Please describe the Company's adjustment with regard to corporate restructuring.

A. As discussed on pages 16-18 of Mr. Kamerick's testimony, Pepco Holdings, Inc. ("PHI"), the ultimate parent company of ACE, recently exited certain competitive energy services businesses. Mr. Kamerick states on page 16, lines 19-21 that "[t]his change in strategic direction required us to closely analyze our corporate structure, and to reduce costs and the overhead that was previously borne by these discontinued businesses."

Mr. Kamerick goes on to state that PHI subsequently conducted a comprehensive review of its corporate services organization in an effort to reduce corporate costs that would now be allocated over a smaller base. The Company identified nearly $28 million of O&M savings, including the reduction of a significant number of full-time employees and contractors. In addition, the Company decided not to fill a number of open positions.

In Adjustment No. 18, Mr. Ziminsky included an adjustment to amortize severance costs related to this corporate reorganization over a period of three years, resulting in a net increase to test year severance expense of $1.677 million.

Q. Do you believe that ratepayers should bear these severance costs?

A. No, I do not. This reorganization was driven by PHI's decision to sell or otherwise terminate its competitive businesses. The employees that were terminated were obviously not necessary to the provision of safe and reliable utility service, otherwise they would still be employed by PHI. The Company's adjustment is an attempt to have regulated utility ratepayers pay for severance costs associated with employees that previously served competitive businesses. Any severance costs incurred by PHI should have been recovered in the selling price of the competitive businesses that were sold and/or should be absorbed by shareholders. Ratepayers should not be required to provide severance costs for employees that were not necessary in the past and which will not be necessary in the future.

Q. What do you recommend?

A. I recommend that the BPU reject the Company's attempt to recover these severance costs from regulated New Jersey ratepayers. My adjustment is shown in Schedule ACC-21.

H. Rate Case Expense

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

A. ACE's rate case expense claim is based on total estimated costs for the current case of $511,390. The Company is proposing a three-year amortization period for these costs, resulting in an annual rate case expense claim of $170,463. In addition to its claim for rate case costs, ACE has also included a normalization adjustment to normalize other regulatory costs based on a three-year average of such costs.

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

A. Yes, I am recommending one adjustment. The BPU has a long-standing policy of requiring a 50/50 sharing of rate case costs between shareholders and ratepayers. This policy is based on the assumption that base rate case filings provide benefits to both shareholders and ratepayers, and therefore should be allocated equally between the two groups. The Company has not reflected any sharing of rate base costs in its filing. Accordingly, at Schedule ACC-22, I have made an adjustment to allocate 50% of the Company's claimed rate case costs to shareholders.

I. Non-Recurring Expense

Q. Has ACE included any non-recurring costs in its claim?

A. Yes, according to the response to S-AREV-25 (Update), the Company's test year costs include a non-recurring cost of $1,323,976 relating to a sick leave accrual for ACE's unionized employees. These employees are being transitioned to a sick leave policy that is similar to that offered to Potomac Electric Power Company's union employees. The transition to this new policy required ACE to take a one-time charge related to the change in sick leave policy.

Q. Should non-recurring costs be included in utility rates?

A. No, they should not. Utility rates are designed to be prospective and to reflect a normalized level of future costs, not recovery of previously-incurred costs. Non-recurring costs are generally excluded from a regulated utility's revenue requirement. Therefore, at Schedule ACC-23, I have made an adjustment to eliminate these non-recurring costs from the Company's claim.

J. Credit Facilities Expense

Q. Has ACE requested recovery of costs associated with a PHI credit facility?

A. Yes, it has. In its 12+0 Update, ACE included a rate base adjustment of $1.329 million and an operating expense claim of $760,000 relating to a short-term credit facility operated by PHI.

Q. Are you recommending any adjustment relating to the Company's claim for credit facility costs?

A. Yes, I am. My recommended adjustment to the Company's rate base claim was discussed previously in the Rate Base section of this testimony. With regard to operating expenses, I am recommending two adjustments.

First, the Company has included $91,428 of closing costs related to short-term credit facilities that expired during the test year. In addition, the Company included $238,248 relating to closing costs for the new credit facility executed in August 2011. I am not recommending any adjustment to the costs for the new credit facility, but I am recommending that costs for the expired short-term credit facility be eliminated from the Company's revenue requirement. Since this credit facility has been replaced, it is no longer providing any benefit to ratepayers. To the extent that there are any unrecovered costs associated with that facility, these costs should be borne by the Company's shareholders, and not its ratepayers. My adjustment to eliminate the closing costs associated with the previous credit agreement is shown in Schedule ACC-24.

Second, the Company's ongoing maintenance costs are based on annualizing costs incurred in the last quarter of the test year, 2011. However, as shown in the Company's workpapers, ACE incurred costs for a 92-day period during that time. Annualzing these costs therefore results in recovery of costs for 368 days, instead of 365 days that would reflect a normal calendar year. Therefore, at Schedule ACC-24, I have also made an adjustment to eliminate $11,000 of ongoing credit facility costs. My adjustment is based on the Company's assumption that $250 million of short-term debt will be available at an annual cost of 0.2%. This equates to a $500,000 maintenance fee instead of the $511,000 included in the Company's filing.

Q. Do you have any other comments regarding the Company's claim for credit facility costs?

A. Yes, I do. I have included these costs in my revenue requirement recommendation because Rate Counsel is recommending that short-term debt be included in the Company's pro forma capital structure, as discussed by Mr. Kahal. If the BPU decides to exclude short-term debt from the Company's capital structure, then I recommend that all credit facility costs be excluded from the Company's revenue requirement. There is no rationale for including these costs in utility rates if ratepayers are not receiving any of the benefits of this short-term credit facility. Moreover, the only way that ratepayers would receive benefit from this credit facility is if the Company's capital structure included short-term debt and its associated weighted cost. If short-term debt is not included in the Company's capital structure, then ratepayers should not be required to pay for a short-term credit facility that is not providing them with any resulting benefit. The Company cannot have it both ways, i.e., exclude short-term debt from the capital structure but include the costs of the credit facility in its revenue requirement. Accordingly, if the Board permits ACE to exclude short-term debt from its capital structure, then it should also make an adjustment to exclude all credit facility costs from its revenue requirement.

In addition, I note that the Company's credit facility costs are based on a credit line of $250 million, although Mr. Kahal has included only $11.8 million of short-term debt in his pro forma capital structure. While I have included credit facility costs on the entire $250 million in my revenue requirement, the BPU may choose to limit recover of credit facility costs to costs associated with the amount of short-term debt actually reflected in the capital structure. Rate Counsel would support such an adjustment.

K. Storm Damage Expense

Q. Are you recommending any adjustment to the Company's claim for costs associated with storm damage?

A. I am recommending an adjustment, although my recommended adjustment has no impact on the Company's revenue requirement claim. As noted earlier, the Company has proposed to normalize storm damage costs based on a three-year average of actual costs incurred, excluding costs for Hurricane Irene. In addition, the Company is proposing to amortize costs incurred for Hurricane Irene over a three-year period and to include the unamortized balance in rate base. The Company's proposed rate base adjustment is discussed in the Rate Base section of my testimony.

With regard to the normalized expense, the impact on the annual revenue requirement is the same regardless of whether the Company includes Hurricane Irene in its normalization adjustment and utilizes a three-year average, or if it excludes Hurricane Irene but then uses a three-year amortization period for the Hurricane Irene costs. Since the Company is proposing a three-year amortization period for the Hurricane Irene costs, there is no reason to exclude Hurricane Irene from the Company's normalization adjustment. If, however, the BPU decides that a longer amortization period is appropriate for the costs incurred in Hurricane Irene, then I would agree that these costs should be removed from the Company's normalization adjustment and amortized as a separate adjustment over the amortization period approved by the BPU. In either case, I would oppose the inclusion of any unamortized balance in rate base, as previously discussed.

L. <u>Meals and Entertainment Expense</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-61 the Company has included in its filing approximately $70,500 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 appropriate to conclude that they are not reasonable business expenses to include in a regulated utility's cost of service. Accordingly, at Schedule ACC-25, 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. No, it did not. However, in its most recent Proxy Statement, PHI acknowledged that the Company incurred costs for a variety of sporting and entertainment events. Moreover, it stated that such perquisites were made available to employees when not needed for "business purposes." I find it difficult to conceive of a business purpose that would support ratepayers paying for tickets to entertainment or sporting events. Clearly, these are costs that should be borne by the Company's shareholders, and not its ratepayers. While there may be costs for certain meals included in this category that should be borne by ratepayers, there are also clearly costs 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. My adjustment is shown in Schedule ACC-25.

M. <u>Membership Dues Expense</u>

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

A. Yes, I am. In response to RCR-A-158, the Company indicated that 20.69% of dues paid to the Edison Electric Institute ("EEI") were booked below the line. These dues related to lobbying and other political activities undertaken by EEI on behalf of its members. The Company did not identify any other adjustments made to remove lobbying and political activity costs from its membership dues expenses.

Q. Do you believe that a further adjustment is warranted?

A. Yes, I do. In response to an informal request seeking an update to RCR-A-58, ACE identified various membership costs that are included in its test year claim. Actual costs for the test year amounted to $406,020. Most of the organizations included in this response engage in some lobbying activities, the costs of which should not be charged to ratepayers. The largest expenditures are for dues to EEI, the New Jersey Utilities Association ("NJUA"), New Jersey Shares, the Corporate Executive Board, and the Conference Board. Many of the other dues are for memberships in the various Chambers of Commerce, which clearly engage in lobbying activities. 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. I am recommending that 20% of the Company's membership dues identified in the updated response to RCR-A-58 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 20% disallowance is a reasonable overall recommendation. This is the adjustment that was made by ACE with regard to the EEI dues. Accordingly, I did not include EEI dues in my adjustment, nor did I include any membership dues for New Jersey Shares in my recommended disallowance. My adjustment, which is shown in Schedule ACC-26, reflects a 20% disallowance of all remaining dues claimed by the Company.

N. Advertising Expense

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

A. Yes, I am recommending that $25,000 in advertising costs be disallowed. These costs were identified in the response to S-AREV-36 (Update) and relate to Atlantic City Convention Center advertising. It appears that these costs relate to corporate image advertising, which should be disallowed for ratemaking purposes.

Corporate image advertising is generally disallowed by regulated commissions on the basis that such advertising is not necessary for the provision of safe and reliable regulated utility service. Unless the Company can show a direct relationship between these advertising costs and the provision of safe and reliable utility service, these costs should be disallowed. The Company has not made such a showing at this time. Therefore, I recommend that these costs be disallowed. My adjustment is shown in Schedule ACC-27.

O. Interest on Customer Deposits

Q. How was interest on customer deposits reflected in the Company's filing?

A. Since customer deposits are 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. Since interest expense is typically booked below-the-line, 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. ACE included such an adjustment at Schedule JCZ-19 (Adjustment 15).

Q. Are you proposing any changes to the Company's adjustment relating to interest on customer deposits?

A. Yes, I am. In calculating its adjustment, ACE reflected an interest rate on customer deposits of 0.19%. 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 2012 rate of 0.13% on November 9, 2011 and that is the rate that I have reflected in my adjustment. My adjustment is shown in Schedule ACC-28.

P. Depreciation Expense

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

A. Yes, I have made two adjustments. First, since I am recommending that post-test year plant additions be excluded from rate base, it is necessary to make a corresponding adjustment to eliminate the associated depreciation expense. At Schedule ACC-29, I have made an adjustment to eliminate depreciation expense associated with the utility plant that I recommend be excluded from rate base.

In addition, as noted earlier, it is my understanding that the Company and Rate Counsel have agreed that ACE will withdraw its cost of removal adjustment (Adjustment 10). ACE had initially requested an increase in its annual cost of removal expense from $2.935 million to $11.010 million. However, the parties have agreed that $2.935 will continue to be reflected in the Company's revenue requirement for cost of removal. Accordingly, at Schedule ACC-30, I have made an adjustment to reduce the Company's cost of removal expense from the $11.010 million reflected in ACE's claim to $2.935 million.

Q. 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-31. 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, which results 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.

R. <u>Income Taxes and Revenue Multiplier</u>

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

A. As shown on Schedule ACC-32, I have used a composite income tax factor of 40.85%, which includes a corporate business tax rate of 9.0% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing.

My revenue multiplier, which is shown in Schedule ACC-35, incorporates these tax rates. In addition, the revenue multiplier also includes the BPU and Rate Counsel assessments.

Q. Are you recommending any adjustment to the BPU and Rate Counsel assessment rates contained in the Company's revenue multiplier?

A. Yes, I am. I understand that the BPU and Rate Counsel assessments are based on a percentage of utility revenue, subject to a cap of 0.25%. ACE has assumed assessments of 0.25% for both the BPU and Rate Counsel assessments in its revenue multiplier. However, the actual BPU and Rate Counsel assessments have generally been well below the cap.

The current BPU assessment is 0.1857%, while the current Rate Counsel assessment is 0.0353%. These are the assessment rates that I have reflected in my revenue multiplier, as shown in Schedule ACC-33. Since the actual assessments have traditionally been less than the maximum permitted rate, the Company's proposal to use the maximum rate of 0.25% will result in excess recovery from ratepayers. Therefore, my adjustment to utilize the current assessment rates should be adopted.

VII. REVENUE REQUIREMENT SUMMARY

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

A. My adjustments indicate a revenue deficiency at present rates of $5.474 million, as summarized on Schedule ACC-1. This recommendation reflects revenue requirement adjustments of $84.794 million to the Company's requested revenue increase of $90.268 million.

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

A. Yes, at Schedule ACC-34, I have quantified the revenue requirement impact of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

VIII. REGULATORY ASSET RECOVERY CHARGE ("RARC")

Q. Please describe the RARC.

A. As discussed beginning on page 19 of Mr. Janocha's testimony, the RARC is a rider mechanism, designed to recover certain regulatory assets, that was approved as part of the Company's unbundling proceeding in BPU Docket Nos. EO97070455, EO97070456, and EO97070457. The RARC is currently recovering the following regulatory assets: a) OPEB costs associated with the implementation of SFAS 106, b) costs associated with asbestos removal, c) costs associated with the 2008 Board-mandated management audit of the Company; d) legal costs related to litigation with the Department of Energy ("DOE"); and e) costs related to efforts to restructure certain non-utility generation ("NUG") contracts. The Company is currently recovering approximately $2.6 million annually through the RARC.

ACE is proposing to increase its annual RARC to approximately $3.24 million. This claim includes continuation of all of the RARC costs that are currently being collected. In addition, ACE is requesting that six new projects be approved for recovery through the RARC.

Q. Please describe the new projects that ACE is seeking to recover through the RARC.

A. ACE is proposing to add recovery of the following program costs to the RARC: a) $167,231 of costs associated with the redemption of preferred stock; b) $121,927 of costs associated with the Long Term Capacity Agreement Pilot Program ("LCAPP") proceeding initiated by the BPU on January 28, 2011; c) $288,181 of costs associated with PJM assessments relating to default of PJM members; d) $492,650 of costs relating to additional taxes incurred as a result of a change in Medicare Part D; e) $128,935 of additional costs relating to the Management Audit; f) $46,987 of outside services consulting costs relating to a Department of Transportation ("DOT") audit of certain utility relocation costs; and g) an undercollection of RARC charges in the amount of $1,379,106. The BPU has already approved a 15-year amortization period, without carrying costs, for the preferred stock redemption. ACE is requesting that the remaining RARC costs be recovered over a 4-year period with carrying costs on the unrecovered balance at the 2-year Treasury rate plus 60 basis points.

Q. Do you have any general comments about the RARC?

A. Yes, I do. Mr. Janocha states on page 19 of his testimony that the RARC is "designed to recover Board-approved regulatory assets that are not directly related to the current provision of electric power supply, transmission and delivery of electric power, or customer service." In my opinion, the Company has attempted to expand the use of the RARC in each base rate case to guarantee recovery of certain charges that clearly relate directly to the provision of electric power supply, transmission and delivery of electric power, or customer service and should be recovered through base rates, not through a separate clause. It should be noted that ACE is the only New Jersey utility that currently has an RARC surcharge. To the extent that similar types of costs are recovered by other utilities in New Jersey, those companies typically recover such costs through base rates over some appropriate amortization or normalization period.

Q. What is the major difference between recovering costs through base rates and recovering such costs through the RARC?

A. Recovering such costs through the RARC guarantees dollar-for-dollar recovery and therefore shifts the risk of recovery from shareholders to ratepayers. This is contrary to the way in which utility rates are established for the majority of non-fuel operating and maintenance expenses. We should not lose sight of the fact that regulation is supposed to be a substitute for competition. Accordingly, utilities are provided with an opportunity, but not a guarantee, to earn a return and to recover their prudently-incurred costs. Moreover, the traditional ratemaking process is designed to provide an incentive to utilities to minimize costs between base rate cases. If utilities are guaranteed dollar-for-dollar recovery of such costs, they lose this incentive to minimize costs.

Q. How should non-recurring costs or costs that do not reoccur each year be treated for ratemaking purposes?

A. Such costs are generally amortized or normalized over a multi-year period in base rates. Amortization is the recovery of a previously-incurred cost while normalization is the recovery of a normal level of prospective costs in rates. Amortization is, by definition, retroactive ratemaking. Hence, amortizations are generally limited to costs for which a utility has previously sought an accounting order requesting authorization for a deferral.

Q. What criteria to you believe the BPU should utilize to determine if a cost should be amortized?

A. First, the BPU should consider only test year costs, unless an expenditure was previously approved for deferred accounting treatment by the BPU. I understand that the BPU has approved deferred accounting treatment for the LCAPP costs and the costs to retire the Company's preferred stock. In addition, the BPU has historically authorized the amortization of management audit costs.

In addition, I recommend that the BPU should consider the magnitude of the cost when determining whether to permit a deferral and eventual amortization. Costs that are authorized for this accounting treatment should be significant in magnitude. The BPU should not lose sight of the fact that actual costs always vary from costs approved in the base rate case. A utility should not be guaranteed recovery simply because a cost was greater than anticipated or because it was not anticipated at the time that rates were established. While some costs are greater than anticipated, or some costs were not anticipated at all, in some cases costs are less than those included in a company's approved revenue requirement, or costs that were expected did not materialize. Thus, in order to receive deferred accounting treatment and/or amortization, I believe that a cost should have a material impact on the utility's financial condition.

Q. What do you recommend?

A. There is no rationale for treating ACE differently from the other New Jersey utilities with regard to the RARC. Therefore, I am recommending that the BPU reject the Company's attempt to expand the RARC. Instead, I recommend that the RARC be terminated and that future amortizations be reflected in base rates. This treatment would be consistent with the BPU's practice with regard to the other New Jersey utilities.

Q. If amortizations are included in base rates, isn't there a possibility that a utility will over-recover?

A. Yes, there is. However, given the frequency with which ACE is expected to file base rates cases, I do not believe that this is a serious concern. Assuming that ACE files rate cases approximately every two years, the parties will have the opportunity to reset rates relatively soon after any amortization expires.

Q. What amortizations do you recommend be reflected in base rates?

A. First, I am recommending that amortization expense of $2,607,993 authorized in the Company's last base rate case be transferred to base rates. Second, I understand that the BPU has already approved recovery of the preferred stock redemption costs. Therefore, I am not opposed to including recovery of these costs in base rates, based on the 15-year amortization period previously approved by the BPU. Similarly, I am not opposed to the inclusion of LCAPP costs or management audit costs, based on the four-year recovery periods proposed by ACE. The BPU has already authorized deferral of LCAPP costs and has authorized the utilities to seek recovery in their base rate cases. Moreover, management audit costs have traditionally been amortized by the BPU and, as noted earlier, other utilities in New Jersey recover these costs in base rates. I am recommending that the remaining items: the PJM default costs, the Medicare taxes, and the outside consulting fees relating to the DOT audit, be disallowed.

Q. Why do you recommend that the PJM default costs, the Medicare tax change, and the outside consulting fees relating to the DOT audit be excluded?

A. With regard to the PJM default costs and Medicare tax change, these costs were not incurred in the test year. The PJM default costs were incurred from January 2008 to September 2009, while the Medicare tax change occurred in March 2010. Thus, these costs are clearly outside of the test year in this case. Moreover, there is no rationale for treating these costs differently from other unanticipated costs that arise from time to time. As previously discussed, shareholders are expected to absorb unanticipated cost variations between base rate cases, just as they benefit from unanticipated expense reductions or revenue increases. With regard to the DOT audit expenditures, the Company incurred less than $50,000 of such costs. I do not believe that this expenditure rises to a level that warrants extraordinary ratemaking treatment.

Q. Do you have any recommendation with regard to the under-recovery of $1,379,106 proposed by ACE?

A. Yes, I do. Since I am recommending that RARC items be moved back into base rates, I am not opposed to including a one-time adjustment to reflect the balance of any over-recovery or under-recovery that occurred prior to the transition back into base rates. However, I do not believe that the Company has correctly quantified its under-recovery. As a result of an informal request, ACE provided me with the schedule supporting its deferred balance of $1,379,106.

In the last case, BPU Docket No. ER09080664, ACE was authorized to continue recovery of $1,810,000 in annual RARC charges relating to SFAS 106 and asbestos removal costs. In addition, the Company was authorized to begin recovery of $6,829,968 in total charges relating to three new amortization. However, in that case it was estimated that ACE would have an over-recovery of $3.7 million by the time that new rates went into effect. In the Order in that case, the BPU stated that [t]he Company shall credit the RARC with the entirety of the over recovered balance as of that date. Attached to the Stipulation as Exhibit C is the revised calculation of the RARC to be effective as of that date." Exhibit C indicated a credit to the RARC of $3,703,000. Thus, the new costs projected to be recovered pursuant to the RARC were $6,829,968, less the RARC credit of $3,703,000, for a net cost of $3,126,968, as shown in Exhibit C to Stipulation in that case. The $3,126,968 was then amortized over 4 years, with carrying costs at the 2 year Treasury rate plus 60 basis points, resulting in an annual incremental annual RARC charge of $797,993. In addition, the Company was authorized to continue to collect $1,810,000 relating to the prior two RARC items. Therefore, the RARC rate was set to recover $2,607,993 annually in RARC charges. This new RARC rate assumed that the RARC would be credited with $3.7 million as of the effective date of new rates.

I believe that there are two problems with the Company's calculation of the deferred balance. First, ACE did not credit the RARC with $3.7 million, as required pursuant to the Order. Instead, ACE has been crediting the RARC with $76,590 per month. Thus, the RARC has not yet received all of the credit to which it is due. Second, since the last case, ACE has been amortizing approximately $2.5 million annually relating to the SFAS 106 implementation costs, instead of the $1.54 million authorized by the BPU. These two factors are responsible for the under-recovery reported by ACE.

Q. What do you believe is the correct deferred balance in the RARC at the end of the test year?

A. In the last case, ACE was authorized to amortize $2,607,993 annually related to the RARC. Thus, from June 2010 through December 2011, the Company should have amortized approximately $4,129,322. Actual revenues through that date were $4,267,488. Thus, I believe that the RARC is actually over-recovered by $138,166. This over-recovery should be taken into account when these costs are transferred back into base rates. I am proposing that this over-recovery be used to offset a portion of the LCAPP and Management Audit fees that I am proposing to include in base rates. These costs total $250,862 as shown on Schedule JFJ-6, page 1. I recommend that $112,696 of these costs ($250,862 - $138,166) be included in base rates and amortized over a four-year period, resulting in an annual amortization expense of $28,174. For reasons discussed previously in this testimony with regard to storm damage costs and credit facility costs, I am not recommending any carrying charges on this amortization.

Q. What impact will your recommendation to move certain items back into base rates have on the Company's revenue requirement?

A. My recommendation will increase base rates by $2,647,316. This includes the $28,174 calculated above with regard to LCAPP and Management Audit costs, $2,607,993 that was previously authorized for recovery in the last case and $11,149 to reflect the 15-year amortization previously approved for preferred stock costs. My recommendation is shown in

Schedule ACC-35.

IX. INFRASTRUCTURE INVESTMENT PROGRAM ("IIP") SURCHARGE

Q. What is the IIP surcharge?

A. The IIP surcharge is the mechanism that was approved by the BPU in April 2009 to recover costs associated with an Infrastructure Investment Program, which was proposed in BPU Docket No. EO09010054. This program was part of an initiative by former-Governor Corzine designed to provide an economic stimulus to the New Jersey economy by accelerating certain investments in ACE's infrastructure. Pursuant to the program, ACE was permitted to recover a return on this investment and associated depreciation charges through an IIP surcharge mechanism. The monthly revenue requirement and IIP revenues are subject to a monthly true-up, with interest. The investment subject to the IIP was specifically identified in a stipulation signed by the parties and approved by the BPU. The investment consists of sixteen specific projects totaling $27.613 million. On November 12, 2010, ACE filed a Petition requesting an increase in its IIP surcharge, based on projected costs for the 2011 calendar year.[10] It is my understanding that the rates proposed in that Petition were never implemented.

Q. What is the Company proposing in this case with regard to the infrastructure investment expenditures?

10 BPU Docket No. EO10110847.

A. The Company filed a Petition on October 11, 2011, reporting the completion of its IIP and requesting that expenditures be rolled into base rates ("Roll-in Petition).[11] In that Petition, the Company reported total expenditures of $26.3 million. These expenditures are included in the Company's rate base claim in this case.

Q. Are you recommending any adjustment to the Company's claim with regard to the amount of IIP plant that should be included in rate base?

A. Rate Counsel witness Charles Salamone is reviewing the underlying details of the projects included in the Company's Roll-in Petition. As of the preparation date of this testimony, I do not have Mr. Salamone's final recommendations and therefore I have not reflected any rate base adjustment in my revenue requirement. However, should Mr. Salamone recommend any adjustment to the Company's IIP expenditures, then it would be necessary to revise my revenue requirement recommendation to reflect the impact of Mr. Salamone's recommendations.

Q. What is ACE proposing with regard to any deferred IIP balance that may exist when new base rates are implemented?

A. The Company is proposing that there be a reconciliation of its IIP revenue requirement and IIP surcharge revenues when new base rates are established, and that any deferred balance be recovered from or returned to ratepayers over a subsequent 12-month period. ACE is

11 BPU Docket No. EO11110846.

proposing to make a compliance filing relating to this reconciliation when it makes its compliance filing in the base rate case. I believe that this is a reasonable approach to dealing with any deferred balance that may exist when new base rates are established.

X. REQUEST FOR STORM DAMAGE DEFERRAL

Q. Did the Company request a deferral of costs associated with Hurricane Irene?

A. Yes, it did. On August 26, 2011, the Company filed a Joint Petition with Public Service Electric and Gas Company whereby both companies requested deferred accounting treatment for costs associated with Hurricane Irene.[12] The BPU later consolidated that proceeding as it pertained to ACE with this base rate case.

Q. Does your revenue requirement address the issues raised in the Company's Petition requesting deferral of costs associated with Hurricane Irene?

A. Yes, it does. As discussed earlier, I am recommending that storm damage costs be normalized based on a three-year average, including the test year costs associated with Hurricane Irene. Thus, no further action would be necessary with regard to recovery of Hurricane Irene costs or with regard to the Company's request to defer these costs.

12 BPU Docket Nos. EO11090518 and GO11090519.

XI. BASIC GENERATION SERVICE "(BGS") ADMINISTRATIVE COSTS

Q. Please discuss the BGS issue that has been deferred to this proceeding.

A. In the Company's most recent BGS proceeding, BPU Docket No. EO11040250, Rate Counsel raised an issue with regard to the prudency of administrative costs included by the utilities in their proposed BGS charges. As a result, the BPU authorized Rate Counsel and the other parties to address the issue of prudence with regard to ACE's BGS administrative costs in this base rate case proceeding.

Q. How does the Company's claim for administrative costs compare with the BGS administrative costs incurred by the other electric utilities?

A. All of the utilities receive tranche fees from electric generation suppliers that are intended to compensate the utilities for at least a portion of their BGS administrative costs. The tranche fees received by the other three utilities cover the vast majority of their BGS administrative costs. For the period July 2008 through June 2011, PSE&G recovered 100% of its BGS administrative costs through tranche fees, while JCP&L and RECO recovered approximately 94.4% and 89.5% of their respective BGS administrative costs through tranche fees during this period. However, during this time, ACE recovered only 33.8% of its BGS administrative costs through tranche fees. For the period July 2008 to June 2011, ACE claimed BSG administrative costs of $2,580,296 but received only $873,900 in tranche fees from suppliers.

Q. What types of costs are included in BGS administrative costs?

A. While I have limited data available from the other utilities, it appears that the vast majority of the BGS administrative costs charged by the other utilities relate to charges from NERA, which runs the BGS auction for generation supply, and charges for Boston Pacific, the consultant to the BPU. However, in the case of ACE, the vast majority of BGS administrative costs relate to internal labor costs. As shown in the response to RCR-A-166, from July 2008 to June 2011, $1,715,396 of internal labor costs were charged to the BGS during this period.

Q. What is the problem with charging large amounts of internal labor costs through the BGS?

A. The problem is that it is difficult to ensure that such costs are not being double-counted in rates. This is especially true given the proliferation of clause and surcharge mechanisms that ratepayers are now facing. From a practical standpoint, it is simply not possible to verify labor costs for each of these clauses and for base rates, given the fact that an employee's payroll costs can be allocated to a number of different surcharge mechanisms. In addition, since the vast majority of BGS administrative costs charged by the other utilities are recovered through tranche fees, it appears that ACE is the only New Jersey utility charging large amounts of internal labor costs to the BGS.

Q. What do you recommend?

A. I am recommending that ACE cease charging internal labor costs to the BGS. Instead, these costs should be recovered in base rates. I understand that the Company's BGS rates for the upcoming BGS year are already approved and that these rates include the internal labor costs requested by ACE. Therefore, I am not making any quantitative adjustment to my revenue requirement. However, ACE should not include internal labor costs in future BGS administrative costs and instead those costs should be included in test year charges in the Company's next base rate case. This will facilitate review of labor costs and make ACE's BGS administrative costs comparable to the administrative costs being charged by the other New Jersey utilities.

XII. EXCESS DEPRECIATION RESERVE AMORTIZATION

Q. Please describe the Company's proposal with regard to the excess depreciation reserve amortization.

A. As discussed on page 17 of Mr. Janocha's testimony, ACE has been amortizing an excess depreciation reserve balance of approximately $131 million over 8.25 years, as previously authorized by the BPU. This amortization began on June 1, 2005 and should be completed by August 31, 2013. The Company has been amortizing this refund through base rates, i.e., base rates reflect an annual credit associated with this amortization.

In this case, ACE is proposing to transfer this amortization from base rates to a separate, explicit item in the ACE tariff, with a termination date of August 31, 2013. Moreover, ACE is requesting that the tariff expire on that date.

Q. Do you have any concerns about the Company's proposal?

A. While I generally recommend that amortizations be included in base rates, I am not opposed to the Company's request to transfer this amortization to a separate tariff rider, given the magnitude of the amortization and the fact that it will expire shortly. However, I am opposed to an automatic termination of this rider. Instead, I recommend that the Company be required to make a status filing on June 1, 2013, at which time ACE should report on how much of the excess depreciation reserve has been refunded to date and how much is expected to be refunded by August 31, 2013. Other parties should then have 30 days to file any comments regarding expiration of the rider. If no one opposes its expiration, then the rider could terminate on August 31, 2013. However, if any party has a concern regarding the amount actually refunded to ratepayers, they can request that the BPU continue the rider until such time as their concerns are resolved by the BPU. I believe that my recommendation provides a reasonable balance between the Company's desire to terminate the rider at August 31, 2013 and Rate Counsel's objective to ensure that the appropriate amounts are ultimately refunded to ratepayers.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

List of Testimonies Filed Since January 2008

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	12-MKEE-380-RTS	4/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	11-381F	2/12	Gas Cost Rates	Division of the Public Advocate
Atlantic City Electric Company	E	New Jersey	EO11110650	2/12	Infrastructure Investment Program (IIP-2)	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	11-384F	2/12	Gas Service Rates	Division of the Public Advocate
New Jersey American Water Co.	W/WW	New Jersey	WR11070460	1/12	Consolidated Income Taxes Cash Working Capital	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	12-WSEE-112-RTS	1/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Puget Sound Energy, Inc.	E/G	Washington	UE-111048 UG-111049	12/11	Conservation Incentive Program and Others	Public Counsel
Puget Sound Energy, Inc.	G	Washington	UG-110723	10/11	Pipeline Replacement Tracker	Public Counsel
Empire District Electric Company	E	Kansas	11-EPDE-856-RTS	10/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable	C	New Jersey	CR11030116-117	9/11	Forms 1240 and 1205	Division of Rate Counsel
Artesian Water Company	W	Delaware	11-207	9/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS (Remand)	7/11	Rate Case Costs	Citizens' Utility Ratepayer Board
Midwest Energy, Inc.	G	Kansas	11-MDWE-609-RTS	7/11	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power & Light Company	E	Kansas	11-KCPE-581-PRE	6/11	Pre-Determination of Ratemaking Principles	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	10-421	5/11	Revenue Requirements Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company	E	Kansas	11-MKEE-439-RTS	4/11	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
South Jersey Gas Company	G	New Jersey	GR10060378-79	3/11	BGSS / CIP	Division of Rate Counsel
Chesapeake Utilities Corporation	G	Delaware	10-296F	3/11	Gas Service Rates	Division of the Public Advocate
Westar Energy, Inc.	E	Kansas	11-WSEE-377-PRE	2/11	Pre-Determination of Wind Investment	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	G	Delaware	10-295F	2/11	Gas Cost Rates	Attorney General
Delmarva Power and Light Company	G	Delaware	10-237	10/10	Revenue Requirements Cost of Capital	Division of the Public Advocate
Pawtucket Water Supply Board	W	Rhode Island	4171	7/10	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey Natural Gas Company	G	New Jersey	GR10030225	7/10	RGGI Programs and Cost Recovery	Division of Rate Counsel

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Kansas City Power & Light Company	E	Kansas	10-KCPE-415-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atmos Energy Corp.	G	Kansas	10-ATMG-495-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	10-EPDE-314-RTS	3/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	09-414 and 09-276T	2/10	Cost of Capital Rate Design Policy Issues	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	09-385F	2/10	Gas Cost Rates	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	09-398F	1/10	Gas Service Rates	Division of the Public Advocate
Public Service Electric and Gas Company	E	New Jersey	ER09020113	11/09	Societal Benefit Charge Non-Utility Generation Charge	Division of Rate Counsel
Delmarva Power and Light Company	G	Delaware	09-277T	11/09	Rate Design	Division of the Public Advocate
Public Service Electric and Gas Company	E/G	New Jersey	GR09050422	11/09	Revenue Requirements	Division of Rate Counsel
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

Company	Utility	State	Docket	Date	Topic	On Behalf Of
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
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

APPENDIX B

Supporting Schedules

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim	Recommended Adjustment	Recommended Position	
	(A)			
1. Pro Forma Rate Base	$987,112	($477,497)	$509,616	(B)
2. Required Cost of Capital	8.56%	-0.68%	7.88%	(C)
3. Required Return	$84,508	($44,347)	$40,161	
4. Operating Income @ Present Rates	31,369	5,561	36,930	(D)
5. Operating Income Deficiency	$53,139	($49,908)	$3,231	
6. Revenue Multiplier	1.6991		1.6944	(E)
7. Revenue Increase Excluding RARC	**$90,268**	**($84,794)**	**$5,474**	
8 RARC Roll-in			$2,653	(F)
9 Total Revenue Increase			**$8,128**	

Sources:
(A) Company Filing, Schedule JCZ-2, 12+0 Update.
(B) Schedule ACC-3.
(C) Schedule ACC-2.
(D) Schedule ACC-13.
(E) Schedule ACC-33.
(F) Schedule ACC-35 (includes assessments).

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
REQUIRED COST OF CAPITAL

	Capital Structure (%)	Cost Rate (%)	Weighted Cost (%)
	(A)	(A)	
1. Long Term Debt	51.31%	6.47%	3.32%
2. Short Term Debt	0.71%	0.35%	0.00%
3. Common Equity	47.98%	9.50%	4.56%
4. Total Cost of Capital	100.00%		**7.88%**

Sources:

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

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
RATE BASE SUMMARY ($0000

		Company Claim (A)		Recommended Adjustment		Recommended Position
1.	Utility Plant in Service	$1,754,675	(A)	$0		$1,754,675
2.	Plant Closing	54,352	(B)	(54,352)	(E)	$0
3.	Plant Held for Future Use	6,275	(A)	(6,275)	(F)	$0
	Less:					
4.	Accumulated Depreciation	(585,135)	(A)	0		(585,135)
5.	Plant Closing	(1,678)	(B)	1,678	(E)	$0
6.	Ann. Of Dep. On Year End	(979)	(C)	0		($979)
7.	Normalization of COR	(4,776)	(C)	4,776	(G)	$0
8.	Advances for Construction	(427)	(A)	0		(427)
9.	Net Utility Plant	$1,222,307		($54,173)		$1,168,134
	Plus:					
10.	Cash Working Capital	$104,068	(D)	($20,801)	(H)	$83,266
11.	Materials and Supplies	15,999	(A)	0		15,999
12.	Credit Facility	1,329	(C)	(1,329)	(I)	0
13.	Prepaid Pension Asset	35,908	(C)	(35,908)	(J)	0
14.	Storm Damage Costs	5,127	(C)	(5,127)	(K)	0
	Less:					
15.	Customer Deposits	(25,928)	(A)	0		(25,928)
16.	Accumulated Deferred Taxes	(345,964)	(A)	0		(345,964)
17.	Plant Closing	(10,416)	(B)	10,416	(E)	0
18.	OPEB Liability	(15,317)	(C)	15,317	(L)	0
19.	Consolidated Income Taxes	0		(385,892)	(M)	(385,892)
20.	Total Rate Base	**$987,112**		**($477,497)**		**$509,616**

Sources:
(A) Company Filing, Schedule JCZ-1, 12+0 Update.
(B) Company Filing, Schedule JCZ-17 (Adjustment 13), 12+0 Update.
(C) Company Filing, Schedule JCZ-3, 12+0 Update.
(D) Company Filing, Schedule JCZ-1, 12+0 Update, and
Schedule JCZ-3, 12+0 Update.
(E) Schedule ACC-4.
(F) Schedule ACC-5.
(G) Schedule ACC-6.
(H) Schedule ACC-7.
(I) Schedule ACC-8.
(J) Schedule ACC-9.
(K) Schedule ACC-10.
(L) Schedule ACC-11.
(M) Schedule ACC-12.

Schedule ACC-4

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
PLANT CLOSING ADJUSMENT-RATE BASE ($000)

1. Company Plant Claim	($54,352)	(A)
2. Depreciation Reserve	1,678	(A)
3. Net Plant Adjustment	($52,674)	
4. Deferred Income Taxes	10,416	(A)
5. Net Rate Base Adjustment	($42,258)	

Sources:
(A) Company Filing, Schedule JCZ-17 (Adjustment 13), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
PLANT HELD FOR FUTURE USE ($000)

1.	Company Claim	$6,275	(A)
2.	Recommended Adjustment	**($6,275)**	

Sources:
(A) Company Filing, Schedule JCZ-1, 12+0 Update.

Schedule ACC-6

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
ACCUMULATED DEPRECIATION - COST OF REMOVAL

1.	Company Claim	($4,776)	(A)
2.	Recommended Adjustment	**$4,776**	

Sources:
(A) Company Filing, Schedule JCZ-3, 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
CASH WORKING CAPITAL ($000)

	Amount	Expense Lead/Lag Days	Revenue Lag	Net Lag	Net Lag %	Rate Counsel Recommendation
1. Total Revenue Lag						
	(A)	(A)	(A)			
Operation and Maintenance Expenses:						
2. Cost of Electric Supply	$823,134	35.05	54.83	19.78	5.42%	$44,607
3. Other O & M Expenses	161,241	21.77	54.83	33.06	9.06%	14,604
4. Interest on Customer Deposits (B)	42	365.00	54.83	(310.17)	-84.98%	(35)
5. Depreciation and Amortization (C)	0	0.00	54.83	54.83	15.02%	0
6. Taxes Other than Income Taxes	25,087	(48.09)	54.83	102.92	28.20%	7,074
7. NJ State Sales Taxes	73,081	(51.10)	54.83	105.93	29.02%	21,210
Income Taxes:						
8. Current	(22,964)	(10.01)	54.83	64.84	17.76%	(4,079)
9. Deferred (C)	0	0.00	54.83	54.83	15.02%	0
10. ITC Adjustment (D)	(641)	(10.01)	54.83	64.84	17.76%	(114)
11. Invested Capital (C)	0	0.00	54.83	54.83	15.02%	0
12. Interest Expense (E)	16,918	91.25	54.83	-36.42	-9.98%	(1,688)
13. Total Requirements						**$83,266.25**

Sources:
(A) Company Workpapers, 12+0 Update, unless otherwise noted. Includes proposed Company adjustments.
(B) Reflects Ms. Crane's recommended expense lag of 365 days.
(C) Reflects elimination of non-cash expenses and return on equity.
(D) Reflects expense lag of current income taxes.
(E) Interest Expense per Schedule ACC-31.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
CREDIT FACILITY ($000)

1.	Company Claim	$1,329	(A)
2.	Recommended Adjustment	**($1,329)**	

Sources:
(A) Company Filing, Schedule JCZ-3, 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
PREPAID PENSION ASSET

1.	Company Claim	$35,908	(A)
2.	Recommended Adjustment	**($35,908)**	

Sources:
(A) Company Filing, Schedule JCZ-3.

Schedule ACC-10

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
STORM DAMAGE COSTS

1.	Company Claim	$5,127	(A)
2.	Recommended Adjustment	**($5,127)**	

Sources:
(A) Company Filing, Schedule JCZ-3.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
OPEB LIABILITY

1.	Company Claim	($15,317)	(A)
2.	Recommended Adjustment	**$15,317**	

Sources:
(A) Company Filing, Schedule JCZ-3.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
CONSOLIDATED INCOME TAXES ($000)

1.	Sum of Net Taxable Losses for Companies With Cumulative Taxable Losses	($3,529,409)	(A)
2.	Tax Loss Benefit Based on Annual Federal Income Tax Rate	(1,230,786)	(A)
3.	Share of ACE Cumulative Positive Taxable Income to Total for Companies With Cumulative Taxable Income	31.35%	(B)
4.	Total CIT Adjustment for ACE	**($385,892)**	

Sources:
(A) Derived from response to RCR-A-110.
(B) Derived from response to RCR-A-110, Includes impact of AMT payments.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
OPERATING INCOME SUMMARY ($000)

			Schedule No.
1.	Company Claim	$31,369	1
	Recommended Adjustments:		
2.	Pro Forma Revenue - Weather Normalization	$155	14
3.	Pro Forma Revenue - Usage Per Customer	1,020	15
4.	Salary and Wage Expense	1,113	16
5.	Incentive Compensation Program Expense	773	17
6.	Payroll Tax Expense	144	18
7.	Supplemental Executive Retirement Plan Expense	765	19
8.	Medical Benefit Expense	369	20
9.	Corporate Restructuring Expense	992	21
10.	Rate Case Expense	50	22
11.	Non Recurring Expense	708	23
12.	Credit Facility Expense	55	24
13.	Meals and Entertainment Expense	38	25
14.	Membership Dues Expense	23	26
15.	Advertising Expense	13	27
16.	Interest Expense on Customer Deposits	9	28
17.	Depreciation Expense - Post Test Year Plant	993	29
18.	Depreciation Expense - Cost of Removal	4,776	30
19.	Interest Synchronization	(6,436)	31
20.	Operating Income	**$36,930**	

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
PRO FORMA REVENUE - WEATHER NORMALIZATION

1.	Incremental Sales Adjustment - 30 Yrs. (Mwh)		8,867	(A)
2.	Incremental Sales Adjustment - 20 Yrs. (Mwh)		150,764	(B)
3.	Percentage Adjustment		5.88%	(C)
4.	Company Claimed Impact		$4,450	(D)
5.	Total Recommended Adjustment		$262	
6.	Income taxes @	40.85%	107	
7.	Operating Income Impact		**$155**	

Sources:
(A) Response to DRC Informal Request 1-7.
(B) Company Workpapers, 12+0 Update.
(C) Line 1 / Line 2.
(D) Company Filing, Schedule JCZ-4 (Adjustment 1), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
PRO FORMA REVENUE - USAGE PER CUSTOMER ($000)

1. Proposed Revenue Adjustment		1,962	(A)
2. Less Variable Expenses		238	(B)
3. Revenue Adj. Net of Expenses		$1,724	
4. Income Taxes @	40.85%	704	
5. Operating Income Impact		**$1,020**	

Sources:
. (A) Company Filing, Schedule JCZ-5 (Adjustment 2), 12+0 Update.
(B) Company workpapers, 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
SALARY AND WAGE EXPENSE

1. Annualized Test Year Payroll Expense		$147	(A)
2. Company Claim		2,227	(A)
3. Recommended Adjustment		$2,080	
4. ACE Distribution (%)		90.44%	(B)
5. ACE Distribution ($)		$1,881	
6. Income taxes @	40.85%	769	
7. Operating Income Impact		**$1,113**	

Sources:
(A) Derived from Company Workpapers.
(B) Company Filing, Schedule JCZ-6 (Adjustment 3), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
INCENTIVE COMPENSATION PROGRAM EXPENSE ($000)

1. Total Recommended Adjustment		$2,462	(A)
2. Percentage Expensed		53.10%	(B)
3. Recommended Expense Adjustment		$1,307	
4. Income Taxes @	40.85%	534	
5. Operating Income Impact		**$773**	

Sources:
(A) Response to DRC Informal Request 1-2.
(B) Reflects inverse of 2011 capitalization ratio of 46.9% per the response to S-AREV-52, Update, Attachment 1.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
PAYROLL TAX EXPENSE ($000)

1.	Salary and Wage Expense Adjustment		$1,881	(A)
2.	Incentive Compensation Expense Adjustment		1,307	(B)
3.	Total Recommended Adjustments		$3,189	
4.	Statutory Tax Rate		7.65%	(C)
5.	Recommended Payroll Tax Adjustment		$244	
6.	Income Taxes @	40.85%	100	
7.	Operating Income Impact		**$144**	

Sources:
(A) Schedule ACC-16.
(B) Schedule ACC-17.
(C) Reflects statutory rates.

Schedule ACC-19

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
SUPPLMENTAL EXECUTIVE RETIREMENT PLAN EXPENSE ($000)

1.	Recommended Expense Adjustment		$1,294	(A)
2.	Income Taxes @	40.85%	528	
3.	Operating Income Impact		**$765**	

Sources:
(A) Response to S-AREV-184.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
MEDICAL BENEFIT EXPENSE ($000)

1.	Recommended O&M Adjustment		$624	(A)
2.	Income Taxes @	40.85%	255	
3.	Operating Income Impact		**$369**	

Sources:
(A) Company Filing, Schedule JCZ-7 (Adjustment 4), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
CORPORATE RESTRUCTURING EXPENSE ($000)

1.	Recommended Adjustment		$1,677	(A)
2.	Income Taxes @	40.85%	685	
3.	Operating Income Impact		**$992**	

Sources:
(A) Schedule JCZ-22 (Adjustment 18), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
RATE CASE EXPENSE ($000)

1.	Pro Forma Cost		$511	(A)
2.	Recommended Amortization Period		3	(A)
3.	Annual Amortization		$170	
4.	Allocation to Ratepayers (%)		50.00%	(B)
5.	Allocation to Ratepayers ($)		$85	
6.	Company Claim		170	(A)
7.	Recommended Adjustment		$85	
8.	Income Taxes @	40.85%	35	
9.	Operating Income Impact		**$50**	

Sources:
(A) Company Workpapers.
(B) Recommendation of Ms. Crane.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
NON RECURRING EXPENSE ($000)

1. Non-Recurring Expense		$1,324	(A)
2. Allocation to Distribution		90.44%	(B)
3. Allocation to Distribution ($)		$1,197	
4. Income Taxes @	40.85%	489	
5. Operating Income Impact		**$708**	

Sources:
(A) Response to S-AREV-25 (Update).
(B) Based on Company Workpapers.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
CREDIT FACILITIES EXPENSE ($000)

1. Closing Cost Adjustment		$91	(A)
2. Ongoing Maintenance Adjustment		11	(B)
3. Total Recommended Adjustment		$102	
4. Allocation to Distribution		90.44%	(C)
5. Allocation to Distribution ($)		$93	
6. Income Taxes @	40.85%	38	
7. Operating Income Impact		**$55**	

Sources:
(A) Derived from Company Workpapers. Reflects elimination of
of $7,619 per month associated with costs of prior credit facilities.
(B) Reflects fees of 0.2% annually on commitment of $250 million.
(C) Company Filing, Schedule JCZ-18 (Adjustment 14), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
MEALS AND ENTERTAINMENT EXPENSE ($000)

1.	Recommended Adjustment		$70	(A)
2.	Allocation to Distribution		90.44%	(B)
3.	Allocation to Distribution ($)		$64	
4.	Income Taxes @	40.85%	26	
5.	Operating Income Impact		**$38**	

Sources:
(A) Response to RCR-A-61.
(B) Based on Company Workpapers.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
MEMBERSHIP DUES EXPENSE ($000)

1. Test Year Membership Dues		$219	(A)
2. Recommended Adjustment (%)		20.00%	(B)
3. Membership Dues Adjustment		$44	
4. Allocation to Distribution		90.44%	(C)
5. Allocation to Distribution ($)		$40	
6. Income Taxes @	40.85%	16	
7. Operating Income Impact		**$23**	

Sources:
(A) Response to Informal DRC 2-4. Excludes EEI and NJ Shares dues
(B) Testimony of Ms. Crane.
(C) Based on Company Workpapers.

Schedule ACC-27

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
ADVERTISING COSTS

1.	Recommended Adjustment		$25	(A)
2.	Allocation to Distribution		90.44%	(B)
3.	Allocation to Distribution ($)		$23	
4.	Income Taxes @	40.85%	9	
5.	Operating Income Impact		**$13**	

Sources:
(A) Response to S-AREV-36-Update.
(B) Based on Company Workpapers.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
INTEREST ON CUSTOMER DEPOSITS ($000)

1.	Pro Forma Customer Deposits		$25,928	(A)
2.	Interest @		0.13%	(B)
3.	Pro Forma Interest Expense		$34	
4.	Company Claim		49	(C)
5.	Recommended Adjustment		$15	
6	Income Taxes @	40.85%	6	
7	Operating Income Impact		**$9**	

Sources:
(A) Schedule ACC-3.
(b) BPU Notice dated November 9, 2011.
(C) Company Filing, Schedule JCZ-19 (Adjustment 15), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
DEPRECIATION EXPENSE - POST TEST YEAR PLANT ($000)

1.	Depreciation Expense Adjustments		$1,678	(A)
2.	Income Taxes @	40.85%	685	
3.	Operating Income Impact		**$993**	

Sources:
(A) Company workpapers, Schedule JCZ-17 (Adjustment 13), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
DEPRECIATION EXPENSE - COST OF REMOVAL ($000)

1.	Company Claim		$11,010	(A)
2.	COR in Current Rates		2,935	(A)
3.	Recommended Adjustment		$8,075	
4.	Income Taxes @	40.85%	3,299	
5.	Operating Income Impact		**$4,776**	

Sources:
(A) Company Filing, Schedule JCZ-14 (Adjustment 10) , 12+0 Update

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
INTEREST SYNCHRONIZATION ($000)

1. Pro Forma Rate Base		$509,616	(A)
2. Weighted Cost of Debt		3.32%	(B)
3. Pro Forma Interest Expense		$16,918	
4. Company Claim		32,673	(C)
5. Recommended Adjustment		$15,755	
6. Increase in Income Taxes	40.85%	6,436	
7. Operating Income Impact		**($6,436)**	

Sources:
(A) Schedule ACC-3.
(B) Schedule ACC-2.
(C) Company Filing, Schedule JCZ-24 (Adjustment 20), 12+0 Update.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
INCOME TAX RATE

1.	Revenue		100.00%	
2.	State Income Taxes @	9.00%	9.00%	(A)
3.	Federal Taxable Income		91.00%	
4.	Income Taxes @	35.00%	31.85%	(A)
5.	Operating Income		59.15%	
6.	Total Tax Rate		**40.85%**	(B)

Sources:
(A) Response to DRC Informal Request 1-1.
(B) Line 1 - Line 5.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
REVENUE MULTIPLIER

1. Revenue		100.00%	
Less:			
2. BPU Assessments		0.19%	(A)
3. RC Assessments		0.04%	(A)
4. Taxable Income		99.78%	
5. State Income Taxes @	9.00%	8.98%	
6. Federal Taxable Income		90.80%	
7. Income Taxes @	35.00%	31.78%	
8. Operating Income		59.02%	
9. Revenue Multiplier		**1.6944**	(B)

Sources:
(A) Rates reflect most recent assessment rates.
(B) Line 1 / Line 8.

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1.	Capital Structure/Cost of Capital	($11,382)
	Rate Base Adjustments:	
2.	Plant Closing Adjustments	(5,643)
3.	Plant Held for Future Use	(838)
4.	Accumulated Depreciation - COR	638
5.	Cash Working Capital	(2,778)
6.	Credit Facility	(177)
7.	Prepaid Pension Asset	(4,795)
8.	Storm Damage Costs	(685)
9.	OPEB Liability	2,045
10.	Consolidated Income Taxes	(51,527)
	Operating Income Adjustments	
11.	Pro Forma Revenue - Weather Normalization	(262)
12.	Pro Forma Revenue - Usage Per Customer	(1,728)
13.	Salary and Wage Expense	(1,886)
14.	Incentive Compensation Program Expense	(1,310)
15.	Payroll Tax Expense	(244)
16.	Supplemental Executive Retirement Plan Expense	(1,296)
17.	Medical Benefit Expense	(625)
18.	Corporate Restructuring Expense	(1,681)
19.	Rate Case Expense	(85)
20.	Non Recurring Expense	(1,200)
21.	Credit Facility Expense	(93)
22.	Meals and Entertainment Expense	(64)
23.	Membership Dues Expense	(40)
24.	Advertising Expense	(23)
25.	Interest Expense on Customer Deposits	(15)
26.	Depreciation Expense - Post Test Year Plant	(1,682)
27.	Depreciation Expense - Cost of Removal	(8,093)
28.	Interest Synchronization	10,905
29.	Revenue Multiplier	(231)
30.	Total Recommended Adjustment	($84,793)
31.	Company Claim	90,268
32.	Recommended Deficiency	**$5,475**

ATLANTIC CITY ELECTRIC COMPANY
TEST YEAR ENDING DECEMBER 31, 2011
REGULATORY ASSET RECOVERY CHARGE

	RARC Additions:		
1.	LCAPP	$121,927	(A)
2.	2008 Management Audit Costs	128,935	(A)
	Less:		
3.	Over-recovery at 12/31/12	(138,166)	(B)
4.	Total Costs to be Recovered For New Programs (Excludes Redemption of Preferred Stock)	$112,696	
5.	Amortization Period	4	(A)
6.	Annual Amortization - New Projects	$28,174	
7.	Preferred Stock Redemption Amortization	11,149	(A)
8.	Annual Amortization - Existing Projects	2,607,993	(A)
9.	Total Annual Amortization Expense	**$2,647,316**	
10.	Total Including Revenue Assessments	**$2,653,169**	(C)

Sources:
(A) Schedule JFJ-6, page 1.
(B) Testimony of Ms. Crane. Reflects over-collection at 12/31/12.
(C) Revenue assessments per Schedule ACC-35.

APPENDIX C

Referenced Data Requests

RCR-A-24
RCR-A-32
RCR-A-42
RCR-A-58
RCR-A-61
RCR-A-110*
RCR-A-114
RCR-A-115*
RCR-A-121
RCR-A-158
RCR-A-166
DRC-Informal 1-1
DRC-Informal 1-2
DRC Informal 1-7
DRC Informal 2-4

S-AREV-25 (Update)
S-AREV-36 (Update)
S-AREV-52 (Update)
S-AREV-61 (Update)
S-AREV-182
S-AREV-184

*** Confidential Responses Not Included**

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Data Requests – Set DRC-1

11/16/2011

Jay C. Ziminsky

Question No. : RCR-A-24

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.

RESPONSE:

See RCR-A-24, Attachments 1, 2 and 3.

Pepco Holdings, Inc.

2011
Annual Incentive Plan

An Overview of the Annual Incentive Plan (AIP)

The purpose of the AIP is to monetarily recognize eligible management employees who achieve or exceed pre-established annual goals that are crucial to the improved performance of the employee's Team and PHI as a whole. Employees have an opportunity to earn awards for the performance and results they help to achieve.

Earning awards is intended to be challenging. PHI has established goals that must be met in order to enhance our competitiveness as a company within our industry. Specific, measurable goals provide a clear line of sight linking work results to important financial, customer and employee strategic objectives.

Many high-performing companies use incentive pay in combination with base pay to drive the performance and results essential to their success. As PHI strives to be competitive, we are including both base pay and incentive pay as part of our total market-based pay program.

Incentive pay does not become part of an employee's base pay; it must be earned every year by meeting stretch goals for that year. Teamwork will always be a key factor in earning awards.

Plan Year

The Plan Year is January 1 to December 31.

Eligibility

All PHI management employees who do not participate in any other incentive plan are eligible to participate in the AIP (excluding PES employees). New hires must be employed and actively at work before October 1 of the plan year in order to be eligible for that year. Part Time management employees, in addition to being employed and actively at work before October 1 must also have a regular schedule of at least 20 hours per week in order to be a participant in the plan. Awards for new hires are prorated based on the amount of time an employee is employed during the year. For example, an employee hired on April 1 and who is still employed on December 31 would be eligible for an award based on nine months of employment.

Performance Measures

Performance will be measured at the Business Unit level only and is based on the 2011 Executive Incentive Plan. For Utility Operations employees, the Utility Operations' earnings must reach a 93% threshold to qualify for any potential payout. Potential payout for Corporate Services employees is based on an overall corporate earnings threshold of 90%. **Corporate Services employees are eligible to receive a payout only to the extent that Power Delivery and/or Non-Regulated earnings meet or exceed threshold levels and such awards shall not exceed 50% of target if PHI corporate earnings do not exceed threshold levels.** The plan is intended to support the PHI WAY and PHI's Blueprint for the Future and align employees with key business goals and executive area balanced scorecards.

Target Awards

A position's pay grade and salary determines the target award. Target awards will range from 5% to 15% percent of base pay. Target awards are higher for higher grades due to the greater scope and responsibility of positions at higher levels and their potential impact on results.

A target award is expressed as a percent of base salary. The target awards are market based.

Pay Grade	Target Award (% of base pay)
15 – 16	**15%**
13 – 14	**12%**
11 – 12	**10%**
8 – 10	**8%**
5 – 7	**6%**
1 – 4	**5%**

Rewarding Exceptional Results

The actual award potential will range from zero to a maximum of 150% of target award level depending on performance at the Business Unit level. Awards can exceed 100% of the targets only for truly exceptional results that are documented.

Award Calculation Using "Multipliers"

At year's end, the Company will assess performance results and assign scores that equate to Business Unit "multipliers" that can be as high as 150% of target award level. The multipliers are used to mathematically determine the actual award payment as follows:

Business Unit Performance Multiplier	×	Individual AIP Award Percent	×	Employee's Base Salary	=	Annual Incentive Plan Payout

Business Unit Goals

- Business Unit performance goals are weighted as follows:

  (1) 50% for the PHI Balanced Scorecard (based on the Utility Operations Balanced Scorecard)

  (2) 50% for the Executive Area Balanced Scorecard

Business Unit Goals (continued)

(3) 25% for the Group Balanced Scorecard (Optional)
(If used, the Executive Area weight reduces to 25%)

The formula for Corporate Services employees when PHI Corporate Earnings are met is:
[50% (Utility BSC x 90% + Competitive BSC x 10%) + 50% Executive Area BSC (Tier 2 = 25% + Tier 3 = 25% where applicable)] x Salary x AIP Percent
NOTE: To create better alignment with Power Delivery, Corporate Services employees' payout is capped at 50% when PD meets or exceeds its threshold target and PHI does not meet PHI's Corporate Earnings threshold.

Award Payment

- The target award will be calculated using the employee's base salary in effect on the last day of the plan year unless the employee receives a promotion or salary adjustment during the plan year. In those instances the award will be prorated. (See bullet 6).
- The target award for part-time employees will be calculated using the employee's base earnings during the part-time status.
- The award will be paid following the end of the plan year and generally is paid sometime in March. Awards are subject to federal, state and local taxes, as required by law.
- If an employee terminates employment after the plan year ends, but before the award payout is made, he/she will still receive the award.
- Each employee will receive an individual payout sheet that shows how his/her award was calculated and the associated Business Unit multipliers used in the calculation.
- In certain situations, awards will be prorated:
  - If an employee changes pay grades during the plan year and becomes eligible for a different target incentive award, the award will be prorated according to the number of days spent in each grade and the salary associated with the grade for that time period.
  - If an employee transfers from one Business Unit to another Business Unit during the year, the award he/she receives will be prorated according to the number of days spent in each Business Unit and the associated salary during the time spent in each Business Unit.
  - If an employee changes status from full-time to part-time or vice versa during the year, the award will be prorated according to the number of days spent in the part-time status and the number of days spent in the full-time status. The prorated award will use the base earnings during the part-time status for the part-

time piece and the salary during the full-time status for the full-time piece of the calculation.

- When a bargaining unit employee is transferred to a management position or vice versa the award is prorated based on the employee's transfer date.

Award Payment (continued)

- If the employee is a management new hire who is eligible for the plan and was actively at work prior to October 1 of the plan year, the award is prorated based on the number of days employed by the Company.

- In cases of death, long-term disability or retirement, awards are prorated based on the number of days that the Incentive Plan participant was an active employee during the plan year.

- If the employee is absent from work for 20 or more consecutive days in a paid or unpaid status (with the exception of vacation and floating holidays), the award is prorated based on the number of days actively at work during the plan year. The paid or unpaid leave status includes illness, FMLA, military leave, workers' compensation, approved and unapproved absences, suspensions and jury duty.

- No award payment will be made in any of the following situations:

  - When the employee's overall individual annual performance rating is a 1 (Unsatisfactory) in the Performance Accountability System (PAS). In addition, a rating of 2 (Performance Improvement Needed) for two consecutive years is not eligible for an award (starting with the 2005 performance year).

  - When the employee terminates employment (for reasons other than death, disability or retirement) before the end of the plan year. In addition, a prorated award will not be paid if an employee retires from a severance leave of absence.

Reporting Results

- Business Unit Goals

  Business Unit leaders will report results to People Strategy & HR and to eligible employees quarterly.

  - Business Unit leaders should publish a report for their management employees discussing Business Unit goal results.

  - Business Unit leaders should report on:
    - Progress or problems regarding each Business Unit goal
    - Each Business Unit goal's performance result and multiplier
    - The composite Business Unit multiplier based on each goal's weighting factor

Continuation of the Plan

The Company may continue, terminate or adjust the Plan at any time.

myPHI HR

Pepco Holdings, Inc

PHI Management Recognition Award Program

Effective May 1, 2011

Objective:

To design and implement a consistent PHI wide recognition program to reward management employees for significant contributions to the success of the business that are above and beyond day to day responsibilities. Awards under this program will reinforce that PHI values those employees who are having an impact on the future of PHI's business, and are focused on continuous improvement.

Implementation:

The recognition program is effective May 1, 2011. Phase 1 of this program will provide guidelines for granting monetary awards and cash–in-kind awards (gift cards, certificates) purchased directly by managers. Phase 2 of this program will provide an internet based vendor to support non-monetary recognition awards (Late 2011).

Eligibility:

- Full-time Management employees, excluding Executive compensation participants.
- PAS rating of a 3 or higher.
- Must be actively at work for the period of time being recognized; otherwise, award will be prorated or forfeited.
- Maximum number of awards: Limit of one per year for monetary awards greater than or equal to $1,000. Cash-in-kind and/or non-monetary awards should not normally exceed $1,000 in any one year;
- This program does not apply to employees at Pepco Energy Services.

Criteria for Awards:

The following are examples of contributions that are aligned with PHI values and have a positive impact on the business that could be considered for a recognition award:

- Extraordinary level of customer service.
- Significant contribution while assisting with a special project, restoration initiative, or customer service intervention.
- Contributions that have elevated PHI's image in the community and in the industry.
- Identification of significant cost savings or revenue generating opportunities.
- Work assignment(s) above and beyond normal job expectations.

myPHI HR   Pepco Holdings, Inc

Phase 1 Recognition Award Levels and Approval

Amount of award should be tailored to level of contribution, with appropriate business area consensus as determined by the ELT member in consultation with your assigned HR Business partner team.

Award Levels and Approval (Cont):

- Gift Certificates/Cards <$500 – Typically requires Cost Center head approval.
- >$500 and less than $1,000 – Requires first level executive approval, may also require ELT member approval.
- >$1,000 but < $5,000 – Requires ELT member approval.
- > $5,000 – Requires ELT consensus and VP, PS&HR Approval

It is recommended that all monetary awards be hand delivered as a separate check in a way that is personalized to the recipient (make it meaningful with a one-on-one discussion or in a team meeting based on accomplishment).

Administrative Guidelines (Phase 1):

- Supervisor or Manager reviews recognition recommendation with the HR Business Partner team for consistency and appropriateness of the proposed award.
- Supervisor or Manager will prepare the appropriate Payroll form (Employee Gift Form for cards/certificates, PHI Management Employee Recognition Award Form for cash awards).
- Supervisor or Manager will follow the recognition award approval/consensus process established by the ELT member depending on award level.
- Awards **are not** to be communicated to the recipient prior to the completion of the approval process.
- Upon approval, depending on the type of award, one of the following will occur:
    - **Gift Card/Certificate** - Manager purchases gift and presents to employee; Manager must report amount of gift card with employee ID# to Payroll so it can be reported as taxable income using the Employee Gift Form.
    - **Cash Award** – Manager completes the One Time Payment Request Form and sends to Payroll for processing.
- Awards will be provided to the employee in a way that is meaningful.

Budgeting and Reporting

- Award expenses will be expensed to the cost center of the recipient.
- Compensation will monitor award activity monthly. The VP, PS&HR will review recognition award activity with ELT quarterly to assure consistency across business areas.

ATLANTIC CITY ELECTRIC COMPANY
BPU DOCKET NO.: ER11080469
RCR-A-24, Attachment 2

3+9 MONTHS ENDING DECEMBER 2011
NON-EXECUTIVE INCENTIVE EXPENSE
($000)

Comp. Code	General Ledger Account	Apr10-Mar 11 Activity	ACE Apr10-Mar 11 Activity	ACE - Dist. Apr10-Mar 11 Activity
1500	710020 Salaries - Incentive Pay	$42,372	$42,372	$37,914
1500	710022 Salaries - Employee Recognition Awards	$41,915	$41,915	$37,505
1500	710055 Salaries - Safety Incentive	$454,169	$454,169	$406,390
1500	710060 Salaries - AIP / MVP	$1,013,324	$1,013,324	$906,720
1500	710061 Salaries - Incentives Other	$0	$0	$0
1500	710066 Salaries - Incentive	($465,218)	($465,218)	($416,276)
9000	SC7900 - Incentive Allocation (Non-Exec)	$1,670,808	$1,670,808	$1,495,036
	Total	$2,757,371	$2,757,371	$2,467,289
			ACE Dist. % =	89.48%

ATLANTIC CITY ELECTRIC COMPANY
BPU DOCKET NO.: ER11080469
RCR-A-24, Attachment 3
NON-EXECUTIVE INCENTIVE EXPENSE
($000)

Comp.		ACE Distribution				
Code	General Ledger Account	2006	2007	2008	2009	2010
1500	710020 Salaries - Incentive Pay	$49,054	$198,259	$23,560	$24,055	$33,991
1500	710022 Salaries - Employee Recognition Awards	$26,015	$26,555	$43,123	$43,199	$19,568
1500	710055 Salaries - Safety Incentive	$52,665	$107,857	$168,062	$388,782	$428,626
1500	710060 Salaries - AIP / MVP	$153,465	$657,568	$1,025,328	$859,415	$899,261
1500	710061 Salaries - Incentives Other	$32,986	$6,115	$0	$0	$0
1500	710066 Salaries - Incentive	$0	$0	($424,186)	($152,697)	($269,903)
9000	Incentive Allocation (Non-Exec)	$76,422	$1,641,122	$2,530,458	$1,131,087	$1,667,131
	Total	$390,606	$2,637,475	$3,366,346	$2,293,840	$2,778,675

ATLANTIC CITY ELECTRIC COMPANY
BPU DOCKET NO.: ER11080469
RCR-A-24, Attachment 3

NON-EXECUTIVE INCENTIVE EXPENSE
($000)

2006

Comp. Code	General Ledger Account	Jan-Dec 06 Activity	ACE 12+0 12ME Dec 06	ACE - Dist. 12+0 12ME Dec 06
1500	710020 Salaries - Incentive Pay	$83,312	$83,312	$49,054
1500	710022 Salaries - Employee Recognition Awards	$44,183	$44,183	$26,015
1500	710055 Salaries - Safety Incentive	$89,445	$89,445	$52,665
1500	710060 Salaries - AIP / MVP	$260,640	$260,640	$153,465
1500	710061 Salaries - Incentives Other	$56,022	$56,022	$32,986
1500	710066 Salaries - Incentive	$0	$0	$0
9000	Incentive Allocation (Non-Exec)	$129,792	$129,792	$76,422
	Total	$663,394	$663,394	$390,606
			ACE Dist. % =	58.88%

2007

Comp. Code	General Ledger Account	Jan-Dec 07 Activity	ACE 12+0 12ME Dec 07	ACE - Dist. 12+0 12ME Dec 07
1500	710020 Salaries - Incentive Pay	$219,047	$219,047	$198,259
1500	710022 Salaries - Employee Recognition Awards	$29,339	$29,339	$26,555
1500	710055 Salaries - Safety Incentive	$119,166	$119,166	$107,857
1500	710060 Salaries - AIP / MVP	$726,514	$726,514	$657,568
1500	710061 Salaries - Incentives Other	$6,756	$6,756	$6,115
1500	710066 Salaries - Incentive	$0	$0	$0
9000	Incentive Allocation (Non-Exec)	$1,813,194	$1,813,194	$1,641,122
	Total	$2,914,016	$2,914,016	$2,637,475
			ACE Dist. % =	90.51%

2008

Comp. Code	General Ledger Account	Jan-Dec 08 Activity	ACE 12+0 12ME Dec 08	ACE - Dist. 12+0 12ME Dec 08
1500	710020 Salaries - Incentive Pay	$25,839	$25,839	$23,560
1500	710022 Salaries - Employee Recognition Awards	$47,295	$47,295	$43,123
1500	710055 Salaries - Safety Incentive	$184,319	$184,319	$168,062
1500	710060 Salaries - AIP / MVP	$1,124,510	$1,124,510	$1,025,328
1500	710061 Salaries - Incentives Other	$0	$0	$0
1500	710066 Salaries - Incentive	($465,218)	($465,218)	($424,186)
9000	Incentive Allocation (Non-Exec)	$2,775,234	$2,775,234	$2,530,458
	Total	$3,691,978	$3,691,978	$3,366,346
			ACE Dist. % =	91.18%

ATLANTIC CITY ELECTRIC COMPANY
BPU DOCKET NO.: ER11080469
RCR-A-24, Attachment 3

NON-EXECUTIVE INCENTIVE EXPENSE
($000)

Comp. Code	2009 General Ledger Account	Jan-Dec 09 Activity	ACE 12+0 12ME Dec 09	ACE - Dist. 12+0 12ME Dec 09
1500	710020 Salaries - Incentive Pay	$26,500	$26,500	$24,055
1500	710022 Salaries - Employee Recognition Awards	$47,591	$47,591	$43,199
1500	710055 Salaries - Safety Incentive	$428,304	$428,304	$388,782
1500	710060 Salaries - AIP / MVP	$946,780	$946,780	$859,415
1500	710061 Salaries - Incentives Other	$0	$0	$0
1500	710066 Salaries - Incentive	($168,220)	($168,220)	($152,697)
9000	Incentive Allocation (Non-Exec)	$1,246,069	$1,246,069	$1,131,087
	Total	$2,527,024	$2,527,024	$2,293,840
			ACE Dist. % =	90.77%

Comp. Code	2010 General Ledger Account	Jan-Dec 10 Activity	ACE 12+0 12ME Dec 10	ACE - Dist. 12+0 12ME Dec 10
1500	710020 Salaries - Incentive Pay	$37,600	$37,600	$33,991
1500	710022 Salaries - Employee Recognition Awards	$21,646	$21,646	$19,568
1500	710055 Salaries - Safety Incentive	$474,133	$474,133	$428,626
1500	710060 Salaries - AIP / MVP	$994,737	$994,737	$899,261
1500	710061 Salaries - Incentives Other	$0	$0	$0
1500	710066 Salaries - Incentive	($298,559)	($298,559)	($269,903)
9000	Incentive Allocation (Non-Exec)	$1,844,132	$1,844,132	$1,667,131
	Total	$3,073,689	$3,073,689	$2,778,675
			ACE Dist. % =	90.40%

Comp. Code	12ME March 2011 General Ledger Account	Apr10-Mar 11 Activity	ACE Apr10-Mar 11 Activity	ACE - Dist. Apr10-Mar 11 Activity
1500	710020 Salaries - Incentive Pay	$42,372	$42,372	$37,914
1500	710022 Salaries - Employee Recognition Awards	$41,915	$41,915	$37,505
1500	710055 Salaries - Safety Incentive	$454,169	$454,169	$406,390
1500	710060 Salaries - AIP / MVP	$1,013,324	$1,013,324	$906,720
1500	710061 Salaries - Incentives Other	$0	$0	$0
1500	710066 Salaries - Incentive	($465,218)	($465,218)	($416,276)
9000	Incentive Allocation (Non-Exec)	$1,670,808	$1,670,808	$1,495,036
	Total	$2,757,371	$2,757,371	$2,467,289
			ACE Dist. % =	89.48%

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469

Response to DRC Data Requests – Set DRC-1

10/18/2011

Kathleen A. White and Jay C. Ziminsky

Question No. : RCR-A-32

Regarding the Company's claim for a pension asset, for each year since SFAS 87 was adopted, please provide: a) the actual pension cost booked by the Company, b) the amount of any contributions to the pension fund, and c) the amount collected from ratepayers relating to pension costs.

RESPONSE:

a) The Company has data for the prior 10 years related to pension costs. The costs below reflect ACE's total pension costs booked that are either capitalized or expensed.

	ACE (000's)
Year	**Total**
2001	$ 8,580
2002	$ 11,036
2003	$ 10,511
2004	$ 6,903
2005	$ 8,044
2006	$ 4,829
2007	$ 2,573
2008	$ 2,454
2009	$ 9,105
2010	$ 11,956

b) Pension contributions for the periods above were made as follows:

	(000s)
Year	**Amount**
2003	$ 20,000
2005	$ 60,000
2009	$ 60,000

c) The Company does not "ear-mark" collections from customers to individual expense areas that are included in revenue requirement.

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IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469

Response to DRC Data Requests – Set DRC-1

10/17/2011

Jay C. Ziminsky

Question No. : RCR-A-42

Describe any changes in benefits offered to a) officers or b) employees in any of the past 5 years or projected for the future.

RESPONSE:

Officers and employees are in the same health and welfare benefit plans and qualified retirement plans. The Company redesigned the benefit plans offered to management employees in 2005. This included the elimination of heritage medical plans and the implementation of PPO and HMO medical plans with increased deductibles and co-pays, and prescription coinsurance. Also in 2005, the Company eliminated the retiree medical subsidies for new hires after January 1, 2005.

Since that time, the Company eliminated the fully insured HMOs, consolidated vendors, and raised deductibles and co-pays in the PPO and HMO plans. Changes in the prescription plan have included an increase to the out-of-pocket maximum and implementing an incentivized mail order design. In addition, PHI has increased employee contributions for management employees toward the goal of 80-20 cost share in 2012. Management new hires after January 1, 2005 are also participants in the PHI Retirement Sub-Plan, a new defined benefit pension plan

The benefits program for Local 210 and Local 210-5 union employees were modified as a result of their contract negotiations in 2006 and again in 2010. The changes have included increased co-pays and plan deductibles over the term of the contracts, as well as incentivized mail order in the prescription plan. In addition, their plan offerings will change in 2012 with the elimination of the Standard Indemnity Plans and CareFirst EPO and the addition of the PHI HMO. Further, all newly hired union employees now must enter the management medical plans. In 2014, all union employees will enter the management medical plans.

In addition, the Company has implemented all changes required by Health Care Reform and the Mental Health Parity Act, including the elimination of lifetime maximums and covering preventive at no cost to the employee.

Modifications were also made to the pension plan for union employees. These provisions included changes to the interest rate and early retirement eligibility, the elimination of the lump

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469

Response to DRC Data Requests – Set DRC-1

11/10/11

Vincent Maione

Question No. : RCR-A-58
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.).

RESPONSE:

The following provides a breakdown of all membership dues for the test year (actuals incurred January 1, 2011 – March 31, 2011). All memberships are corporate memberships.

Membership and Association Dues Jan. 1, 2011 to March 31, 2011	
Amount	Vendor Name
925.00	CAPE MAY COUNTY CHAMBER OF COMMERCE
1,500.00	SALEM COUNTY CHAMBER OF COMMERCE
5,000.00	PLANSMART NJ
100.00	SOUTHERN NJ DEVELOPMENT COUNCIL
4,377.50	NJ STATE CHAMBER OF COMMERCE
395.00	NJ ASSOCIATION OF COUNTIES
3,600.00	NJ ALLIANCE FOR ACTION
10,000.00	LEADERSHIP NEW JERSEY
125.00	METROPOLITAN BUSINESS AND CIVIC ASSOC
69,780.90	NEW JERSEY UTILITIES ASSOCIATION
1,000.00	SOUTHERN OCEAN COUNTY CHAMBER OF COMMERCE
2,500.00	GREATER ATLANTIC CITY CHAMBER OF COMMERCE
75.00	CHAMBER OF COMMERCE OF MIDDLE TOWNSHIP
100.00	OCEAN CITY CHAMBER OF COMMERCE
500.00	NEW JERSEY SEED
150.00	OCEAN COUNTY MAYORS ASSOC.
295.00	OCEAN CITY CHAMBER OF COMMERCE
28,088.00	NJ SHARES
600.00	GLOUCESTER COUNTY CHAMBER COMMERCE
41,856	EEI Dues (first quarter)
620	MINORITY SUPPLIER DEVELOPMENT COUNCIL

3,569	NATIONAL MINORITY SUPPLIER COUNCIL
3,510	UTILITY WATER RESOURCE GROUP
1,616	WILDLIFE HABITAT COUNCIL
3,192	UTILITY HEALTH SCIENCE GROUP
646	WATER RESOURCE ASSOCIATION
6,468	CLEAN ENERGY GROUP
1,035	ENVIRONMENTAL HEALTH & SCIENCE
1,267	CORPORATE EXECUTIVE BOARD
6,331	NATIONAL ASSOCIATION OF MANUFACTURERS

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469

Response to DRC Data Requests – Set DRC-1

10/17/2011

Jay C. Ziminsky

Question No. : RCR-A-61

Provide the amount of meals expenses included in the test year but disallowed for tax purposes.

RESPONSE:

The meals expenses disallowed for tax purposes totals $70,489 in the test year.

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Data Requests – Set DRC-1

11/29/2011

Atlantic City Electric

Question No. : Confidential RCR-A-114

Please provide, for each year since 1991, the actual income taxes paid by the consolidated group.

RESPONSE:

See the company's response to Confidential RCR-A-110.

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469

Response to DRC Data Requests – Set DRC-1

10/17/2011

Jay C. Ziminsky

Question No. : RCR-A-121

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.

RESPONSE:

The Company has not prepared that analysis.

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Data Requests – Set DRC-8

1/13/2012

Vincent Maione

Question No. : RCR-A-158

Regarding the response to S-AREV-39, what percentage of the EEI dues was booked below the line by the Company?

RESPONSE:

The percentage of EEI dues booked below the line by the Company is 20.69%.

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Dkt. No.: ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Data Requests – Set DRC-8

01/13/2012

Atlantic City Electric

Question No. : RCR-A-166

Regarding the response to RCR-38b in BPU Docket No. EO11040250, please identify, by category, all internal labor costs (including labor incurred by any parent, subsidiary, or affiliate of ACE) included in this response. Please provide this information separately for "FP-BGS Administrative Costs", "BGS-Admin", and "CIEP-BGS".

RESPONSE:

See RCR-A-166, Attachment 1.

RCR-A 166

Attachment 1

Atlantic City Electric Company

Schedule of Internal labor in FP - BGS Administrative Costs

Period 07/01/08 - 06/30/09

Description		Amount
IT Customer Care Systems	$	21,112.00
Power Procurement Services	$	66,679.00
Market Settlements	$	111,393.00
Total	**$**	**199,184.00**

Period 07/01/09 - 06/30/10

Description		Amount
IT Customer Care Systems	$	6,952.50
Power Procurement Services	$	166,569.50
Market Settlements	$	108,581.00
Total	**$**	**282,103.00**

Period 07/01/10 - 06/30/11

Description		Amount
IT Customer Care Systems	$	13,141.50
Power Procurement Services	$	128,334.00
Market Settlements	$	95,879.75
Total	**$**	**237,355.25**

DRC - 8 RCR- A 166

Attachment 1

Atlantic City Electric Company

Schedule of Internal labor in CIEP - BGS Costs

Period 07/01/08 - 06/30/09

Description		Amount
IT Customer Care System	$	5,597.63
Power Procure Services	$	17,182.25
Market Settlements	$	60,725.00
Total	**$**	**83,504.88**

Period 07/01/09 - 06/30/10

Description		Amount
IT Customer Care System	$	2,111.50
Power Procure Services	$	30,130.50
Market Settlements	$	64,041.75
Total	**$**	**96,283.75**

Period 07/01/10 - 06/30/11

Description		Amount
Distribution Tester	$	388.00
It Customer Care System	$	8,688.50
Power Procure Services	$	24,281.50
Market Settlements	$	46,610.50
Total	**$**	**79,968.50**

DRC - 8 RCR- A 166

Attachment 1

Atlantic City Electric Company

Schedule of Internal labor in BGS General Administrative Costs

Period 07/01/08 - 06/30/09

Description		Amount
System Operator	$	173,652.30
Power Controller	$	100,275.80
IT Contractors	$	12,876.00
Energy Management System Support	$	23,590.00
Electric Systems Operation	$	22,480.50
Environment Analyst	$	3,648.00
IT Customer Care System	$	5,720.00
Power Procure Services	$	5,148.00
Load Settlements	$	96,900.40
Total	**$**	**444,291.00**

Period 07/01/09 - 06/30/10

Description		Amount
Energy Management System Support	$	58,710.00
IT Customer Care System	$	9,270.00
Power Procure Services	$	18,335.00
Load Settlements	$	81,759.15
Total	**$**	**168,074.15**

Period 07/01/10 - 06/30/11

Description		Amount
Supplier Relations	$	332.00
Energy Management System Support	$	52,015.00
IT Customer Care Sysem	$	5,864.00
Load Settlements	$	66,420.40
Total	**$**	**124,631.40**

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Informal Set 1 – Andrea Crane Request

ACE

Question No. : Set 1 – Question 1

Please provide supporting documentation for the revenue multiplier of 1.6991

RESPONSE:

Please see RCR-Informal-Set 1 Q 1 , Attachment 1.

	A	B	C	D	E	I	J	K	L
1							Use		
2							For		
3					**Atlantic City Electric**		Tariff		
4					**Revenue Conversion Factor**		Development		
5							And		
6							Filings		
7		(1)			(2)				
8		Line					use actually bpu		
9		No.			Particulars		Factor		
10									
11		1		**Tax Rates**					
12		2			BPU Assessment		0.00250	=+J20	
13		3			Ratepayer Advocate Assessment		0.00250	=+J21	
14		4			State Income Tax		0.09000	0.09	
15		5			Federal Income Tax		0.35000	0.35	
16		6							
17		7		**Conversion Factor**					
18		8			Revenue Increase				
19		9							
20		10			BPU Assessment	**X**	0.00250	0.0025	
21		11			Ratepayer Advocate Asses	**X**	0.00250	0.0025	
22		12			Total	**X**	0.00500	=+J21+J20	
23		13							
24		14			State Taxable Income	**X**	0.99500	=1-J22	
25		15			State Income Tax	**X**	0.08955	=+J24*J14	
26		16							
27		17			Federal Taxable Income	**X**	0.90545	=+J24-J25	
28		18			Federal Income Tax	**X**	0.31691	=+J27*J15	
29		19							
30		20			Total Additional Taxes	**X**	0.41146	=+J28+J25+J22	
31		21							
32		22			Increase in Earnings (1 - ac	**X**	0.58854	=1-J30	
33		23							
34		24			Revenue Conversion Facto	**X**	1.69911	=1/J32	

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Informal Set 1 – Andrea Crane Request

ACE

Question No. : Set 1 – Question 2

Please provide the incentive compensation amount included in the 12+0 ending December 2011.

RESPONSE:

Please see RCR-Informal-Set 1 Q 2 , Attachment 1.

ATLANTIC CITY ELECTRIC COMPANY
BPU DOCKET NO.: ER11080469

12+0 MONTHS ENDING DECEMBER 2011
NON-EXECUTIVE INCENTIVE EXPENSE
($000)

12ME December 2011

Comp. Code	ıl Ledger Account	Jan-Dec 11 Activity	ACE 12+0 12ME Dec 11	ACE - Dist. 12+0 12ME Dec 11
1500	710020 Salaries - Incentive Pay	$39,731	$39,731	$35,935
1500	710022 Salaries - Employee Recognition Awards	$50,030	$50,030	$45,250
1500	710055 Salaries - Safety Incentive	$449,101	$449,101	$406,188
1500	710060 Salaries - AIP / MVP	$1,026,016	$1,026,016	$927,979
1500	710061 Salaries - Incentives Other	$0	$0	$0
1500	710066 Salaries - Incentive	($551,493)	($551,493)	($498,797)
9000	Incentive Allocation (Non-Exec)	$1,708,995	$1,708,995	$1,545,697
	Total	$2,722,381	$2,722,381	$2,462,252
			ACE Dist. % =	90.44%

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO <u>N.J.S.A.</u> 48:2-21 AND <u>N.J.S.A</u> 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Informal Set 1 – Andrea Crane Request

ACE

Question No. : Set 1 – Question 7

Please redo the 12+0 Weather Normalization adjustment based on 30 year normal weather.

RESPONSE:

Response will be provided as soon as practical.

ACE WN BILLED SALES 20-Year vs 30-Year

	RES WN Sales 20-Year (MWh)	RES WN Sales 30-Year (MWh)	RES WN SALES Difference (MWh)	COM WN Sales 20-Year (MWh)	COM WN Sales 30-Year (MWh)	COM WN SALES Difference (MWh)	Total WN Sales 20-Year (MWh)	Total WN Sales 30-Year (MWh)	Total WN SALES Difference (MWh)
Jan-11	423,085	428,651	5,566	354,242	354,976	734	777,327	783,627	6,300
Feb-11	362,715	363,834	1,119	330,221	330,369	148	692,936	694,203	1,267
Mar-11	336,554	336,248	(306)	321,557	321,517	(40)	658,111	657,765	(346)
Apr-11	292,267	293,693	1,426	309,736	309,924	188	602,002	603,617	1,614
May-11	266,009	266,503	494	333,753	333,686	(67)	599,762	600,189	427
Jun-11	331,606	332,127	521	364,451	364,628	176	696,058	696,755	697
Jul-11	467,005	467,245	240	420,328	420,410	81	887,333	887,655	322
Aug-11	564,167	565,088	921	427,023	427,334	312	991,190	992,422	1,233
Sep-11	457,144	454,262	(2,883)	403,164	402,188	(976)	860,308	856,450	(3,859)
Oct-11	309,933	310,333	400	348,050	347,995	(55)	657,983	658,328	345
Nov-11	269,089	268,736	(353)	311,611	311,564	(47)	580,699	580,300	(399)
Dec-11	343,756	344,876	1,119	323,234	323,381	148	666,990	668,257	1,267
Total	4,423,330	4,431,596	8,265	4,247,369	4,247,971	602	8,670,700	8,679,567	8,867

ACE Billing CDD 65

30-Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1981-2010	0.0	0.0	0.3	4.0	26.4	120.3	272.6	330.3	209.8	61.7	8.1	0.4	1034.0
std dev	0.2	0.0	0.8	5.3	20.4	36.6	40.6	56.9	45.1	25.0	9.7	0.7	118.0
20-Year													
1991-2010	0.0	0.0	0.2	4.7	28.3	118.6	272.0	328.0	216.8	63.1	6.9	0.4	1038.9
std dev	0.1	0.0	0.8	6.1	21.5	39.0	48.8	62.3	44.7	27.6	8.7	0.6	118.6
Comparison													
CDD65	0.0	0.0	0.1	-0.7	-1.9	1.7	0.6	2.3	-6.9	-1.4	1.2	0.1	-4.9

ACE Billing HDD 65

30-Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1981-2010	933.3	967.3	760.0	572.3	285.4	94.9	9.2	1.8	22.6	165.0	427.7	698.9	4938.3
std dev	129.4	115.1	74.4	61.5	53.0	37.7	8.1	2.9	13.7	45.5	60.4	98.5	357.2
20-Year													
1991-2010	894.3	960.0	762.0	563.1	278.1	99.8	10.2	1.4	18.1	158.9	429.9	691.6	4867.3
std dev	109.5	112.0	77.6	66.8	49.4	41.2	8.1	3.0	12.7	45.3	53.4	102.3	351.1
Comparison													
CDD65	39.0	7.3	-2.0	9.2	7.3	-4.9	-1.0	0.4	4.5	6.1	-2.2	7.4	71.0

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Informal Set 2 – Andrea Crane Request

ACE

Question No. : Set 2 – Question 4

Update membership dues for the 2011 – (Please update RCR –A-58)

RESPONSE:

The following provides a breakdown of all membership dues for the test year (actuals incurred January 1, 2011 –December 31, 2011). All memberships are corporate memberships.

Membership and Association Dues Jan. 1, 2011 to December 31, 2011	
Amount	**Vendor Name**
925.00	CAPE MAY COUNTY CHAMBER OF COMMERCE
1,500.00	SALEM COUNTY CHAMBER OF COMMERCE
5,000.00	PLANSMART NJ
100.00	SOUTHERN NJ DEVELOPMENT COUNCIL
4,377.50	NJ STATE CHAMBER OF COMMERCE
395.00	NJ ASSOCIATION OF COUNTIES
3,600.00	NJ ALLIANCE FOR ACTION
10,000.00	LEADERSHIP NEW JERSEY
125.00	METROPOLITAN BUSINESS AND CIVIC ASSOC
69,780.90	NEW JERSEY UTILITIES ASSOCIATION
1,000.00	SOUTHERN OCEAN COUNTY CHAMBER OF COMMERCE

4,688.00	GREATER ATLANTIC CITY CHAMBER OF COMMERCE
75.00	CHAMBER OF COMMERCE OF MIDDLE TOWNSHIP
100.00	OCEAN CITY CHAMBER OF COMMERCE
500.00	NEW JERSEY SEED
150.00	OCEAN COUNTY MAYORS ASSOC.
295.00	OCEAN CITY CHAMBER OF COMMERCE
28,088.00	NJ SHARES
600.00	GLOUCESTER COUNTY CHAMBER COMMERCE
159,091.00	EEI Dues
620.00	MINORITY SUPPLIER DEVELOPMENT COUNCIL
3,569.00	NATIONAL MINORITY SUPPLIER COUNCIL
3,510.00	UTILITY WATER RESOURCE GROUP
1,616.00	WILDLIFE HABITAT COUNCIL
3,192.00	UTILITY HEALTH SCIENCE GROUP
646.00	WATER RESOURCE ASSOCIATION
6,468.00	CLEAN ENERGY GROUP
1,035.00	ENVIRONMENTAL HEALTH & SCIENCE
250.00	ATLANTIC COUNTY HISTORICAL SOCIETY
75.00	BARNEGAT CHAMBER OF COMMERCE
660.00	BRIDGETON AREA CHAMBER OF COMMERCE
625.00	BUILDERS LEAGUE OF SOUTH JERSEY
7,078.00	CHAMBER OF COMMERCE OF SOUTHERN NJ
425.00	GREATER WILDWOOD CHAMBER OF COMMERCE
340.00	MILLVILLE CHAMBER OF COMMERCE
3,765.00	NEW JERSEY TECHNOLOGY COUNCIL
5,000.00	NEW JERSEY ENERGY COALITION

3,600.00	NEW JERSEY BUSINESS & INDUSRY ASSOCIATION
3,700	SOUTHERN NJ DEVELOPMENT COUNCIL
500.00	CAMDEN COUNTY HERO
5,000.00	NJ CORPORATE WETLANDS RESTORATION PARTNERSHIP
5,000.00	NJ AUDBON SOCIETY
2,116.00	THE CENTER FOR CORPORATE CITIZENSHIP
2,503.00	ASSOCIATION OF ILLUMINATING ENGINEERS
6,300.00	CONSORTIUM FOR ENERGY EFFICIENCY
10,345.00	THE CONFERENCE BOARD
6,192.00	ELECTRIC DRIVE TRANPORTATION ASSOCIATION
2,315.00	SMARTGRID CONSUMER COLLABORATIVE
5,406.00	UTILITIES TELECOM COUNCIL, INC
17,449.00	CORPORATE EXECUTIVE BOARD
6,331.00	NATIONAL ASSOCIATION OF MANUFACTURERS

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to BPU Staff Data Requests – Set BPU-1

03/06/12

Jay C. Ziminsky and Kathleen A. White

Question No. : S-AREV-25 Update

Recurring/Non-recurring - (a) Provide the details of any expenses included in the pro forma ratemaking results that can be considered to be of an abnormal, non-recurring nature and/or which do not occur annually but occur over an extended time period (b) provide the details of any extraordinary test year expenses. Update this response with each set of updated workpapers you provide.

RESPONSE

In July 2011, the Company recorded an amount to expense of $1,323,976 associated with the initial sick pay accrual for both ACE unions -- Local 210 and Local 210-5 -- transitioning to a sick leave policy similar to Potomac Electric Power Company's union policy. The policy was effective July 4, 2011.

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to BPU Staff Data Requests – Set BPU-1

03/06/12

Vincent Maione

Question No. : S-AREV-36 Update

Advertising - Provide a breakdown of all advertising costs of $5,000 or more per advertisement stating the type and purpose of such advertising. Update this response with each set of updated workpapers you provide.

RESPONSE:

Listed below are the advertising costs of $5,000 or more per advertisement:

- Green Bill - $120,626
- Storm Season Preparedness - $63,907
- Agency Account Management - $15,635
- Atlantic City Convention Center - $25,000

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to DRC Data Requests – Set BPU-1

03/06/12

Kathleen A. White and Jay C. Ziminsky

Question No. : S-AREV-52 Update

Employee Compensation - Submit for each of the five years ended at test year-end the payroll expense, the capitalized payroll, and the percent capitalized of payroll (capitalized payroll/payroll expense). Also show the two, three, four and five year weighted average percent capitalized of payroll. Update this response with each set of updated workpapers you provide.

RESPONSE

See S-AREV-52 Update, Attachment 1 for the ACE-only Distribution-related amounts for payroll expense, capitalized payroll, non-utility payroll, percent capitalized and weighted average percent capitalized for the years 2006 through 2011.

ACE only Distribution-related Payroll Amounts

Estimated:	2011	2010	2009	2008	2007
Distribution - Payroll Expense	26,161,604	23,177,971	21,467,422	19,858,037	18,177,334
Distribution - Capitalized Payroll	26,021,570	29,364,532	25,178,320	23,719,650	21,104,607
Distribution - Non Utility	3,264,402	2,823,373	2,715,533	2,881,818	3,327,977
Total Distribution Payroll	55,447,576	55,365,876	49,361,275	46,459,505	42,609,918
% Distribution - Capitalized Payroll of Total Distrib. Payroll	46.9%	53.0%	51.0%	51.1%	49.5%
Weighted Average % Capitalized		2YR	3YR	4YR	5YR
		49.98%	50.30%	50.47%	50.31%

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to BPU Staff Data Requests – Set BPU-1

03/06/12

Jay C. Ziminsky and Kathleen A. White

Question No. : S-AREV-61 Update

Employee Compensation/Health Insurance - Submit the total health/life insurance expense for each of the five years ended at test year end and also itemize any related credits or refunds by carrier that were issued each year.

RESPONSE:

See S-AREV-61 Update, Attachment 1 for the total medical, dental, vision and life insurance expenses, before capitalization and employee contributions, for the years 2007 through 2011.

Atlantic City Electric Company
Health & Life Insurance
(000's)

	2007	2008	2009	2010	2011
Medical Insurance	$ 4,562	$ 4,548	$ 5,100	$ 5,269	$ 4,975
Dental Insurance	$ 441	$ 447	$ 441	$ 465	$ 471
Vision Insurance	$ 110	$ 111	$ 134	$ 149	$ 138
Life Insurance	$ 333	$ 360	$ 371	$ 405	$ 420
Total	$ 5,446	$ 5,466	$ 6,046	$ 6,288	$ 6,004

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to BPU Staff Data Requests – Set BPU-14

03/23/12

Jay C. Ziminsky

Question No. : S-AREV-182

Reference Company's 12+0 Update, Schedule JCZ-7, Adjustment 4, Line

Why was the percentage increase for dental expenses revised from 5.00% to 8.00%?

RESPONSE

The percentage increase for dental expenses calculated in Schedule JCZ-7, Adjustment 4 was not revised from 5% to 8%. The value of 8% on Line 2 was a typographical error which should have been 5%. The calculation for dental expenses is correct and has assumed a 5% increase. *See* S-AREV-182, Attachment 1 for the corrected Schedule JCZ-7.

ATLANTIC CITY ELECTRIC COMPANY
12+0 MONTHS ENDING DECEMBER 2011
BENEFITS
($000)

(1) Line No.	(2) Item	(3) Medical $	(4) Dental	(5) Vision	(6) Total
1	Test Year Benefits to ACE	$ 8,285	$ 786	$ 231	$ 9,302
2	Percent Increase	8.00%	5.00%	5.00%	
3	Estimated Benefits Increase - rate Effective Period	$ 994	$ 59	$ 17	$ 1,070
5	Benefits Recorded to O & M	64.48%	64.48%	64.48%	
6	Benefits Increase to ACE O & M	$ 641	$ 38	$ 11	$ 690
7	Benefits Increase to Distribution Function	90.44%	90.44%	90.44%	
8	Impact to O & M Expense	$ 580	$ 34	$ 10	$ 624
9	Impact to State Income Taxes	$ (52)	$ (3)	$ (1)	$ (56)
10	Impact to Federal Income Taxes	$ (185)	$ (11)	$ (3)	$ (199)
11	Impact to Operating Income	$ (343)	$ (20)	$ (6)	$ (369)

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A 48:2-21.1 AND FOR OTHER APPROPRIATE RELIEF

BPU Docket No. ER11080469 and OAL Docket No. PUC 09929-2011

Response to BPU Staff Data Requests – Set BPU-14

03/23/12

Jay C. Ziminsky

Question No. : S-AREV-184

Reference Discovery Response RCR-A-29

According to this response, the total SERP Expense in cost of service was $812,692 during 2011, with 89.48% ($727,195) being allocated to ACE. At the end of 2011, were these amounts revised? If so, please provide an update to this response.

RESPONSE

Yes, these amounts were updated to actual values at the end of 2011. *See* S-AREV-184, Attachment 1 for the updated SERP expenses in the 12 + 0 Months Ending December 2011 Update.

ATLANTIC CITY ELECTRIC
2011 SERP EXPENSE

ITEM	ACE	SERV CO	TOTAL
GL 721007 - "SERP"	$ 103,886	$ 6,440,652	
ACE %	100.00%	23.65%	
EXPENSE %	46.75%	90.71%	
DISTRIBUTION %	90.44%	90.44%	
TOTAL	$ 43,930	$ 1,249,684	$ 1,293,614