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

I/M/O THE VERIFIED PETITION OF JERSEY	)	
CENTRAL POWER & LIGHT COMPANY FOR	)	
REVIEW AND APPROVAL OF INCREASES IN	)	**OAL DKT NO. PUC16310-2012N**
AND OTHER ADJUSTMENTS TO ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE, AND	)	**BPU DOCKET NO. ER12111052**
FOR APPROVAL OF OTHER PROPOSED TARIFF	)	
REVISIONS IN CONNECTION THEREWITH;	)	
AND FOR APPROVAL OF AN ACCELERATED	)	
RELIABILITY ENHANCEMENT PROGRAM	)	
("2012 BASE RATE FILING")	)	

DIRECT TESTIMONY OF ROBERT J. HENKES ON BEHALF OF THE STATE OF NEW JERSEY DIVISION OF RATE COUNSEL

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FILED: JUNE 14, 2013

JERSEY CENTRAL POWER & LIGHT COMPANY
BPU DOCKET NO. ER12111052
OAL DOCKET NO. PUC16310-2012n
DIRECT TESTIMONY OF ROBERT J. HENKES

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

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

Q. WHAT IS YOUR PRESENT OCCUPATION?

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

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

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

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting I performed the same type of consulting services as I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial

Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

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

II. SCOPE AND PURPOSE OF TESTIMONY

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

A. I was engaged by the New Jersey Division of Rate Counsel ("Rate Counsel") to conduct a review and analysis and present testimony in the matter of the Petition of Jersey Central Power & Light Company ("JCP&L" or "the Company") for an increase in its electric distribution base rates.

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

- Matt Kahal, concerning the appropriate capital structure, capital cost rates and overall rate of return of JCP&L in this proceeding;
- Andrea Crane, concerning JCP&L's appropriate consolidated income tax benefits;
- Dave Peterson, concerning JCP&L's appropriate cash working capital; and
- Mitchell Serota, concerning JCP&L's appropriate pension and other post-employment benefit expenses.

In developing this testimony, I have reviewed and analyzed JCP&L's original November 28, 2012 filing; supporting testimonies, exhibits and workpapers; the February 22, 2013 supplemental testimonies and exhibits; JCP&L's responses to initial and follow-up data requests by Rate Counsel and BPU Staff; and other relevant financial documents and data.

III. CASE OVERVIEW AND SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE DESCRIBE THE COMPANY'S RATE INCREASE REQUEST IN ITS ORIGINAL FILING.

A. In its original November 28, 2012 filing, the Company requested a base rate increase of $31.471 million. In paragraph 12 of its Petition, the Company states that this base rate increase represents approximately a 1.4% increase over its projected pro forma present rate revenues.

Q. DOES THE REQUESTED RATE INCREASE OF $31.471 MILLION REPRESENT A *DISTRIBUTION BASE RATE* INCREASE OF 1.4%?

A. No. The requested electric distribution base rate increase in this case is approximately 5.5%. This base rate increase percentage of 5.5% can be derived by dividing the requested electric distribution base rate increase of $31,470,596 into the Company's proposed projected pro forma present electric distribution base rate revenues of $576,804,153.[1] As shown it its response to RCR-A-3, in calculating its claimed rate increase number of 1.4%, the Company has divided the requested electric distribution base rate increase of $31,470,596 into its unadjusted test year *total electric revenues* of $2,219,023,444, consisting not only of distribution base rate revenues, but also of transmission revenues and a variety of non-base rate revenues. Thus, the Company's claim that the requested electric distribution base rate increase of $31.471 million represents only a 1.4% rate increase is somewhat confusing and may be misconstrued as the true increase in the Company's electric distribution base rates is approximately 5.5%

[1] This information can be found on Schedule RJH-7, line 1.

Q. DID THE COMPANY SUBMIT A SUPPLEMENTAL FILING SUBSEQUENT TO ITS ORIGINAL NOVEMBER 28, 2012 FILING?

A. Yes. On February 22, 2013, JCP&L submitted a supplemental filing which had as its purpose to update its original November 2012 base rate filing to include the costs, revenue requirement, and rate increase associated with Hurricane Sandy and the November 2012 Nor'easter. The proposed new rates from this supplemental filing would yield an overall rate increase of $112,324,536, or an additional base rate increase of $80,853,940 over and above the base rate increase of $31,470,596 requested in the original November 2012 filing.

Q. HAVE YOU USED THE UPDATED FILING RESULTS FROM THE FEBRUARY 2013 SUPPLEMENTAL FILING AS THE STARTING POINT FROM WHICH YOU HAVE MADE ADJUSTMENTS IN THIS TESTIMONY TO ARRIVE AT YOUR RECOMMENDED REVENUE REQUIREMENT AND RATE DECREASE NUMBERS?

A. No. As will be discussed in more detail later in this testimony, the costs and associated revenue requirements of the major 2012 storms that are included in the supplemental filing have been removed from this base rate proceeding and will first be subjected to a prudency review in the Generic Storm Costs Proceeding[2] prior to future base rate recovery consideration. Therefore, I have used the Company's original November 2012 filing results as the starting point from which I have made adjustments in this testimony in order to determine Rate Counsel's recommended revenue requirement and rate decrease numbers.

[2] Established by the Board on March 20, 2013.

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

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

1. The appropriate distribution rate base amounts to $1,224,170,198 which is $816,155,890 lower than JCP&L's proposed distribution rate base of $2,040,326,088. Schedules RJH-1, line 1 and RJH-3.

2. The appropriate pro forma distribution operating income amounts to $214,867,005 which is $52,111,360 higher than JCP&L's proposed pro forma distribution operating income of $162,755,645. Schedules RJH-1, line 4 and RJH-7.

3. The appropriate overall rate of return on rate base, as recommended by Rate Counsel witness Matt Kahal, is 7.76%, incorporating a recommended return on equity of 9.25%. This compares to JCP&L's proposed overall rate of return on rate base of 8.89%, including a requested return on equity rate of 11.53%. Schedules RJH-1, line 2 and RJH-2.

4. The appropriate Revenue Conversion Factor to be used for ratemaking purposes in this case is 1.69061. Schedule RJH-1, line 6.

5. The recommended ratemaking components outlined above indicate the need for an electric distribution base rate decrease of $202,759,263 (-35.10%). This recommended

rate decrease is $234,229,859 lower than JCP&L's proposed electric distribution base rate increase of $31,470,596 (+5.46%). Schedule RJH-1, lines 7 and 8. Schedule RJH-17 attached to this testimony summarizes the revenue requirement impacts of each of Rate Counsel's recommended adjustments to the Company's filing results that produce Rate Counsel's recommended rate decrease of $202,759,263.

It should be noted that the recommended rate decrease of $202,759,263 excludes the revenue requirement of $45,954,000 associated with the Company's claimed 2011 storm damage costs associated with Hurricane Irene, the October 2011 Snowstorm, and the July 2011 Heat Wave as a result of the temporary transfer of these costs from this rate case to the Generic Storm Costs Proceeding. The prudency of these storm damage costs will first be determined in this latter proceeding, after which the costs deemed to be prudent will be moved back into this base rate case for base rate recovery. The recommended rate decrease of $202,759,263 also excludes the revenue requirement associated with the post-test year 2012 storm damage costs related to Hurricane Sandy and the November 2012 Nor'easter the prudency of which will also be determined in the Generic Storm Costs Proceeding.

IV. REVENUE REQUIREMENT ISSUES

A. TEST YEAR AND POST-TEST YEAR ADJUSTMENTS

Q. DOES THE BOARD HAVE A LONG-STANDING AND WELL-ESTABLISHED RATEMAKING POLICY WITH REGARD TO THE TEST YEAR AND POST-TEST YEAR ADJUSTMENTS ALLOWED FOR RATEMAKING PURPOSES IN THE STATE OF NEW JERSEY?

A. Yes. In the 1985 Elizabethtown Water Company rate case, Docket No. WR8504330, the Board established ratemaking policies for the determination of a test year and the appropriate time period for post-test year adjustments.

The first test year ratemaking policy was that a utility in a base rate case must file a test year that has, at a minimum, 5 months of actual data and 7 months of projected data which must be updated to 12-month of actual data prior to the Board's decision in that case.

The Board also established "known and measurable" standards that must be applied to any out-of-period adjustments. Specifically, the Board ruled that 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.

Furthermore, the Board ruled that a utility in a base rate proceeding may consider (a) known and measurable changes regarding income and expense items for a period of nine months beyond the end of the test year; (b) changes to rate base for a period of six months beyond the end of the test year provided there is a clear likelihood that such proposed rate base additions shall be in service by the end of said six-month period, that such rate base additions are major in nature and consequence, and that such additions be substantiated with very reliable data; and (c) changes to capitalization for a period of three months past the end of the test year, provided that the results of said proposed financing are actual prior to the Board's decision in the rate case.

Q. HAS THE COMPANY FILED THE INSTANT BASE RATE CASE IN ACCORDANCE WITH THESE BOARD RATEMAKING PRINCIPLES?

A. No. While the 2011 test year in this case includes a full 12 months worth of actual data, and while the Company has appropriately proposed to reflect actual rate base balances as of June 30, 2012, a point in time six months beyond the end of the test year, JCP&L has violated the Board's post-test year ratemaking policies in various other respects, including:

1) The Company has adjusted its capital structure for a planned debt issue that is not scheduled to take place until sometime in 2013;
2) The Company has proposed to reflect a pro forma expense adjustment to replace its test year tree trimming expenses with the projected tree trimming expenses included in its 2013 Operating Budget; and
3) In its supplemental filing, the Company has proposed to reflect rate recovery for the deferred storm damage costs associated with major 2012 storms such as Hurricane Sandy and the November 2012 Nor'easter.

Q. WHAT POSITIONS HAVE YOU TAKEN IN THIS CASE WITH REGARD TO KNOWN AND MEASURABLE POST-TEST YEAR CHANGES?

A. I have only reflected known and measurable post-test year positions that are in compliance with the previously outlined Board post-test year ratemaking standards and policies. Specifically, Mr. Kahal and I have rejected the Company's proposal to reflect in the capital structure a planned $500 million debt issue not scheduled to be issued until sometime in 2013. This recommended position, in fact, increases the revenue requirement in this case as it increases Mr. Kahal's recommended cost of long-term debt. I have also rejected the Company's proposal to reflect fully-projected tree trimming expenses from JCP&L's 2013 Operating Budget. Both of these JCP&L-proposed adjustments represent post-test year items that are too far removed from the end of the 2011 test year to qualify as allowable post-test year adjustments under the Board's post-test year ratemaking standards and policies. The deferred storm damage costs associated with Hurricane Sandy and the November 2012 Nor'easter are not reflected in my recommended revenue requirement determination in this testimony not only because these events took place approximately 11-12 months after the end of the test year, but also because these costs were removed from this case to be placed in the Board's Generic Storm Costs Proceeding for prudency evaluation.

Q. ARE THERE OTHER ADJUSTMENTS YOU HAVE NOT MADE IN ORDER TO BE IN COMPLIANCE WITH THE BOARD'S POST-TEST YEAR RATEMAKING PRINCIPLES?

A. Yes. The test year includes $3.3 million for certain Other Post-Employment Benefit (OPEB) amortization expenses which expired on December 31, 2012 and $563,000 worth of Werner CT plant amortization expenses which expired in April 2013. While these expenses are no longer incurred by the Company and represent known and measurable expense changes, I have not removed them from the test year because both changes occurred more than 12 months after the end of the test year and therefore do not qualify as allowable post-test year adjustments under the Board's post-test year ratemaking policies. It should be noted that my recommended position increases the Company's revenue requirement in this case. In addition, as shown on Schedule RJH-3, line 16, I have reflected in rate base $19.7 million worth of deferred taxes associated with the Company's TMI-2 non-qualified decommissioning trust which deferred tax balance will be fully depleted in 2013 and, therefore, will no longer exist on the Company's books at the time the rates from this case become effective. This recommended position also increases the revenue requirement in this case.

B. RATEMAKING TREATMENT OF DEFERRED MAJOR STORM DAMAGE COSTS

Q. PLEASE BRIEFLY OUTLINE THE RATEMAKING TREATMENT OF JCP&L'S DEFERRED STORM DAMAGE COSTS ASSOCIATED WITH MAJOR STORM EVENTS IN 2011 AND 2012, AS CURRENTLY REFLECTED IN THIS TESTIMONY AND AS EVENTUALLY ENVISIONED BY THE BOARD IN ITS MAY 31, 2013 ORDER REGARDING CLARIFICATION OF THE GENERIC STORM COSTS PROCEEDING.

A. The Company's original November 2012 filing includes the revenue requirement associated with the costs incurred during Hurricane Irene and the October 2011 Snowstorm. On February 22, 2013, JCP&L submitted a supplemental filing requesting rate recovery in the current base rate case for all deferred storm damage costs associated with Hurricane Sandy and the November 2012

Nor'easter. This additional rate recovery request increased the Company's revenue requirement and associated rate change by approximately $81 million.

By Order dated March 20, 2013, the Board initiated a generic proceeding ("Generic Storm Costs Proceeding") to review the prudency of all 2011-2012 Major Storm Event expenditures for which New Jersey utilities seek reimbursement from ratepayers. In addition, by letter dated April 4, 2013, the Board issued a clarification which directed that in those cases where a utility has already filed a petition for recovery or deferral of expenditures related to a qualifying Major Storm Event and the amount of the final allowed recovery has not yet been determined, the review of the prudency of those costs must be conducted within the generic proceeding. After JCP&L filed a Motion for Reconsideration and Clarification, the Board issued an Order Denying Motion for Reconsideration and Clarifying Original Order on May 31, 2013 in which the Board made the following ruling:

> The Major Storm Event costs incurred by JCP&L in 2011 and 2012 will be reviewed for prudency within the Generic Storm Costs Proceeding. Those costs incurred in 2011, during the base rate case test year, will be reviewed expeditiously and returned to the base rate case for consideration there with the goal of maintaining the schedule of the case already set by ALJ McGill. The recovery of prudent costs incurred in connection with the 2012 Major Storm Events will be considered through a Phase II in the existing base rate case or through another method found to be appropriate by the Board. That decision will be made by the Board at the conclusion of JCP&L's Generic Storm Costs Proceeding review.

As a result of this most recent Board Order, all costs associated with the 2011 and 2012 major storms have been removed from the current rate case in this testimony.

C. RATE BASE

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

A. JCP&L's proposed pro forma adjusted rate base amounts to $2,040,326,088 and is shown by rate base component on Schedule RJH-3. All of JCP&L's proposed pro forma rate base balances except for cash working capital represent actual balances as of June 30, 2012, a point in time falling 6 months after the end of the 2011 test year. The proposed rate base balance for the cash working capital requirement has been determined through a detailed lead/lag study approach.

As summarized on Schedule RJH-3 and shown in more detail in subsequent RJH schedules, I have reflected numerous rate base adjustments that have the combined effect of reducing JCP&L's proposed rate base by $816,155,890. Each of these recommended rate base adjustments will be discussed in detail below.

- **Utility Plant in Service**

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED UTILITY PLANT IN SERVICE BALANCE SHOWN ON SCHEDULE RJH-3, LINE 1.

A. As previously discussed in this testimony,[3] the Board has ordered that all costs associated with major storms booked by JCP&L in 2011 and 2012 be removed from this base rate case. The

[3] "Ratemaking Treatment of Deferred Major Storm Damage Costs"

prudency of these costs will first have to be determined in the Board's Generic Storm Costs Proceeding before they can be considered for rate recovery. While the Company's proposed plant in service balance as of June 30, 2012 does not include any capitalized plant costs associated with the major storms in 2012, it does include capitalized plant costs associated with major storms in 2011. This is described on page 2 of the testimony of Company witness Pittavino:

> The plant in service amount was derived by using the distribution portion of plant in service, along with three distribution projects that were included in construction work in progress ("CWIP") as of December 31, 2011 in JCP&L's FERC Form 1. These CWIP projects were storm-related costs that were charged to plant in service in early 2012. The storm costs are known and measurable expenses that were necessary for JCP&L to restore service. In addition, I have included an additional adjustment for actual distribution plant that was placed in service in the first six months of 2012, exclusive of the storm-related costs that were already reflected in plant in service as of December 31, 2011, as discussed above.

S-JREV-1 Attachment, page 40 and page 216 of JCP&L's 2011 FERC Form 1 show that the distribution plant in service associated with these three major storms in 2011 that is included in the Company's proposed plant in service balance in rate base amounts to a total balance of $100,733,746, consisting of $2,661,736 for the July Heat Storm, $30,170,141 for Hurricane Irene, and $67,901,869 for the October Snowstorm. Accordingly, I have removed this total plant balance of $100,733,746 from the Company's proposed plant in service balance in rate base.

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

A. Yes. I have not similarly removed from rate base any deprecation reserve and accumulated deferred income tax balances associated with the major 2011 storm plant for the simple reason that I do not know, at this time, whether such balances actually exist as of June 30, 2012. If they do exist, such major 2011 storm cost related depreciation reserve and accumulated deferred income tax balances should be removed from the Company's proposed depreciation reserve and accumulated deferred income tax balances included in rate base.

- **Unamortized Net Losses on Reacquired Debt (Net of Tax)**

Q. WHAT IS THE ISSUE WITH REGARD TO THE UNAMORTIZED NET LOSSES ON REACQUIRED DEBT SHOWN ON SCHEDULE RJH-4?

A. There are two issues with regard to JCP&L's proposed unamortized net loss on reacquired debt rate base amount of $17,920,314. First, this amount represents the Company's total electric balance rather than just the distribution-related portion. In its response to RCR-A-102(c), the Company quantifies that the distribution portion of its total electric balance for the net loss on reacquired debt is 78.78%. As shown on Schedule RJH-4, lines 1-3, the application of this distribution allocator to the total electric balance results in a recommended distribution-related balance of $14,117,623.

Second, as confirmed in its response to RCR-A-18(a), there is an associated accumulated deferred income tax balance that offsets the net unamortized net loss on reacquired debt balance, but the Company has failed to recognize this deferred tax benefit in this case. As shown on Schedule RJH-4, lines 3-5, the offsetting tax benefit is calculated by applying the composite income tax rate of 40.85% to the distribution-related net loss on reacquired debt balance. The resultant recommended net-of-tax net loss on reacquired debt balance is $8,350,574 which is $9,569,740 lower than JCP&L's proposed balance of $17,920,314.

Q. IN ITS RESPONSE TO RCR-A-18(A), THE COMPANY ARGUES THAT IN ITS PRIOR 2002 RATE CASE, THE RATE BASE ADDITION FOR NET UNAMORTIZED LOSS ON REACQUIRED DEBT ALLOWED FOR RATEMAKING PURPOSES IN THAT CASE WAS EXCLUSIVE OF ANY OFFSETTING DEFERRED TAX BENEFITS AND THAT, THEREFORE, THE POSITION IT IS TAKING IN THE CURRENT CASE IS CONSISTENT WITH THE BOARD ORDER IN THE PRIOR CASE. COULD YOU COMMENT ON THAT?

A. I disagree with this argument. Even if something "slipped through the cracks" in the prior rate case, this does not mean that, therefore, the same error should be reflected in the current case. Two wrongs do not make a right. The fact is that the Company only incurs a carrying cost on the net-of-tax net loss on reacquired debt balance and it would be wrong to allow them a return on the gross balance while completely ignoring the offsetting accumulated deferred income tax balance as a rate base deduction. The Company's position is also inconsistent with the net-of-tax rate base balances it has proposed for its Customer Advances (RJH-3, line 4) and unamortized storm damage costs (RJH-3, line 8). The Company has appropriately recognized the offsetting accumulated deferred income taxes associated with both these two other rate base balances.

- **<u>Unamortized Storm Damage Cost (Net of Tax)</u>**

Q. PLEASE EXPLAIN THE UNAMORTIZED STORM DAMAGE COST ADJUSTMENT SHOWN ON SCHEDULE RJH-5, LINES 6-8.

A. This adjustment represents the recommended removal from this base rate case of the Company's proposed unamortized balance (net of deferred tax) of the deferred costs associated with the 2011 major storms, Hurricane Irene and the October Snowstorm. This adjustment has been addressed in detail earlier in this testimony.[4]

- **Excess Cost of Removal Reserve**

Q. WHAT IS THE ISSUE WITH REGARD TO THE COMPANY'S PROPOSED EXCESS COST OF REMOVAL RESERVE RATE BASE ADDITION SHOWN ON SCHEDULE RJH-3, LINE 9?

A. The Company's actual distribution-related depreciation reserve balance as of June 30, 2012 of $1,502,324,772 (RJH-3, line 2) that has been used as a rate base deduction includes a $107,158,582 balance for excess cost of removal reserve. In this case, the Company has proposed to remove this $107.2 million excess cost of removal reserve from its depreciation reserve. This proposal increases rate base by $107.2 million (RJH-3, line 9). The Company justifies this proposed rate base adjustment by arguing that the cost of removal expense is no longer included in the Company's depreciation rates but, rather, is being collected from the ratepayers through a separate charge.[5] This justification makes no sense whatsoever. As conceded by the Company in its response to RCR-A-15(e), the $107.2 million excess cost of removal reserve has been funded by ratepayers in the past and, in fact, is being returned to the ratepayers over an amortization period of 28.5 years at an annual amortization expense credit of about $3.8 million.[6] Thus, during the time that this excess cost of removal reserve is being returned to the ratepayers, the unamortized excess cost of removal reserve (which has been funded by, but not yet returned to, the

[4] "Ratemaking Treatment of Deferred Major Storm Damage Costs."
[5] Rather than being part of the Company's depreciation rates, since the 2002 rate case the cost of removal is being collected as a separate amortization charge based on a historic 5-year average.
[6] See Marano testimony, page 4, lines 22-23 and Normalization Adjustment No. 17.

ratepayers) must remain as a rate base deduction in order to provide the ratepayers with an appropriate return on their investment. Therefore, I recommend that the Company's proposal to treat the excess cost of removal reserve as a rate base addition in this case be rejected by the Board.

Q. HOW WAS THE EXCESS COST OF REMOVAL RESERVE TREATED IN THE PRIOR 2002 BASE RATE CASE?

A. As confirmed in the response to RCR-A-15(c), the entire excess cost of removal reserve balance was properly treated as a rate base deduction. The Company's argument in the current case that this rate base deduction treatment has been invalidated as a result of the change in rate recovery methodology for its cost of removal that was decided in the last case has no basis and is disingenuous and inappropriate.

- **Materials and Supplies**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENTS TO THE COMPANY'S PROPOSED MATERIALS AND SUPPLIES BALANCE IN RATE BASE.

A. The Company's proposed Materials & Supplies ("M&S") balance in rate base of $20,461,958 represents its actual M&S balance as of June 30, 2012. I recommend that two adjustments be made to this proposed rate base balance. First, in its response to RCR-A-14, the Company conceded that its proposed June 30, 2012 M&S balance of $20,461,958 contained an error and should be corrected to the lower balance of $16,699,010. Second, this corrected M&S balance represents a single-point-in-time balance as of June 30, 2012. As shown in the table below, the M&S balance can vary significantly during the year due to seasonality and/or other reasons:

	Distribution-Related M&S
June 2011	$13,137.244
July	11,966,691
Aug	12,022,056
Sept	16,824,205
Oct	16,991,514
Nov	17,094,196
Dec	15,849,530
Jan 2012	14,634,650
Feb	14,214,970
Mar	14,057,244
Apr	13,755,763
May	15,429,083
June	16,699,010
13-Month Average	$14,821,243

For this reason, it is much more appropriate to reflect a 13-month average M&S balance during the period ending June 30, 2012 rather than what the balance happens to be at June 30, 2012. As shown in the table above, the 13-month average M&S balance is $14,821,243 which is the balance I recommend to be recognized for ratemaking purposes in this case.

- **<u>Cash Working Capital</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED CASH WORKING CAPITAL ADJUSTMENT SHOWN ON SCHEDULE RJH-3, LINE 12.

A. This adjustment represents my adoption of the recommendation of Rate Counsel witness David Peterson to reduce the Company's proposed cash working capital requirement. The reasons for this recommended rate base adjustment are discussed in detail in the testimony of Mr. Peterson.

- **Consolidated Income Tax Benefits**

Q. PLEASE EXPLAIN YOUR RECOMMENDED RATE BASE DEDUCTION FOR CONSOLIDATED INCOME TAX BENEFITS SHOWN ON SCHEDULE RJH-3, LINE 13.

A. This rate base deduction adjustment represents my adoption of the consolidated income tax benefit recommendations contained in the testimony of Ms. Crane. The reasons for this rate base deduction are explained in detail in Ms. Crane's testimony.

- **Customer Refunds**

Q. PLEASE EXPLAIN THE RECOMMENDED CUSTOMER REFUNDS RATE BASE DEDUCTION SHOWN ON SCHEDULE RJH-3, LINE 14.

A. In its response to RCR-A-128, the Company confirms that it carries a certain level of customer refunds on its books on a consistent, recurring basis. For example, the 12-month average balances for the most recent three years from 2010 through 2012 were $939,557, $1,163,573, and $1,059,994, respectively. Since these balances represent ratepayer-supplied funds that are continually and consistently carried on the Company's books, I recommend that the 12-month average test year balance of $1,163,573 be treated as a rate base deduction in this case. After all, the ratepayers should not be forced into paying a return on funds that are supplied by them.

- **Operating Reserves (Net of Tax)**

Q. PLEASE EXPLAIN THE RECOMMENDED OPERATING RESERVES (NET OF TAX) RATE BASE DEDUCTION SHOWN ON SCHEDULE RJH-3, LINE 15.

A. While in its prior 2002 rate case, the Company proposed, and the Board accepted, a distribution-related rate base deduction for certain operating reserves (net of offsetting deferred income taxes), in the instant case the Company did not propose a similar rate base deduction. In its response to RCR-A-126, the Company has quantified that the same net-of-tax operating reserves rate base deduction balance as the one that was proposed by JCP&L and accepted by the Board in the 2002 rate case would be a balance of $4,237,102 in the current case. I therefore recommend that this net-of-tax balance be treated as a rate base deduction in this case. These operating reserves consist of accumulated funds that have been supplied by the ratepayers. Therefore, they should not be required to pay a return on them.

- **TMI-2 Non-Qualified Decommissioning Trust Fund Deferred Tax**

Q. PLEASE EXPLAIN THE COMPANY'S POSITION WITH REGARD TO THE DEFERRED TAXES RELATED TO THE TMI-2 NON-QUALIFIED DECOMMISSIONING TRUST FUND SHOWN ON SCHEDULE RJH-3, LINE 16.

A. While in its prior 2002 rate case, the Company proposed, and the Board accepted, a distribution-related rate base addition for this item, in the instant case the Company did not propose a similar rate base addition. The reason for this is explained in the Company's response to RCR-A-135:

> This balance was first adopted as a rate base addition by the Board in the Company's base rate case, Docket No. ER91121820J and subsequently adopted in the Company's

> "non-generation" 2002 base rate case, Docket No. ER02080506. **However, the Company is no longer proposing to treat this deferred tax asset balance as a rate base addition**. The IRS has approved tax rulings which allow for the transfer of non-qualified decommissioning funds into qualified funds to meet an allowed annual level of fund contributions. Due to the recent periodic transfers of non-qualified funds to the qualified trust, by the end of 2013 there will be minimal balances remaining in the non-qualified trust fund and the related deferred tax asset will be eliminated.

In short, the Company has not reflected this item as a rate base addition in this case because the asset will be eliminated by the end of 2013.

Q. DO YOU AGREE WITH THIS POSITION?

A. No. As explained in a prior section of this testimony ("Test Year and Post Test Year Adjustments"), removing this cost from the test year is inappropriate in light of the Board's post-test year ratemaking policy. The balance in this account is not eliminated until the end of 2013 which is too far removed from the end of the 2011 test year to be given rate recognition in this case.

Q. HAS THE COMPANY QUANTIFIED WHAT THE BALANCE OF THIS ITEM IS AS OF JUNE 30, 2012?

A. Yes. In its response to RCR-A-126, the Company has quantified that the balance as of June 30, 2012 is $19,663,455. As shown on Schedule RJH-3, line 16, I have reflected this balance as a rate base addition.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS MATTER?

A. Yes. If, for some reason, the Board were to allow post-test year adjustments for as far away as 2013, I recommend that this $19.7 million balance be removed from the test year rate base as it represents a rate base balance that will no longer be on the Company's books by the time the rates from this case become effective.

D. OPERATING INCOME

Q. PLEASE SUMMARIZE JCP&L'S PROPOSED PRO FORMA TEST YEAR OPERATING INCOME, THE METHOD EMPLOYED BY JCP&L TO DETERMINE ITS PRO FORMA TEST YEAR OPERATING INCOME, AND THE RECOMMENDED OPERATING INCOME ADJUSTMENTS.

A. JCP&L's proposed pro forma adjusted test year net operating income amounts to $162,755,645 and is shown by operating income component on Schedules RJH-7. In deriving this pro forma income level, JCP&L started out with its unadjusted 2011 test year per books revenues and expenses on a total electric basis. The Company then separated out the distribution-related unadjusted 2011 test year per books revenue and expenses which it then adjusted through numerous pro forma adjustments claimed to be known and measurable to reflect changes both within the test year and in the post-test year period stretching into 2013.

As summarized on Schedule RJH-7 and shown in detail on subsequent RJH schedules, I have recommended numerous operating income adjustments with the combined effect of increasing JCP&L's proposed pro forma adjusted test year net operating income by a total amount of $52,111,358. Each of the recommended operating income adjustments will be discussed in detail below.

- **<u>Electric Retail Sales Revenue Adjustment</u>**

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY JCP&L TO DETERMINE ITS PRO FORMA TEST YEAR ELECTRIC RETAIL SALES REVENUE ADJUSTMENT.

A. The Company's proposed pro forma test year electric sales revenues are based on 2011 test year sales data that have been weather-normalized based on 20-year average normal degree days with regard to residential and commercial sales. The Company states that it is Board practice to use weather-normalized sales in setting electric utility base rates. The BPU approved a weather-normalization adjustment in JCP&L's 2002 base rate case and in the Company's previous base rate proceedings. In its response to RCR-A-106, the Company confirmed that its proposed pro forma weather-normalized test year sales revenues are based on the average number of customers in existence during the 2011 test year.

Q. IS THERE AN ISSUE REGARDING THE COMPANY'S PROPOSED PRO FORMA TEST YEAR ELECTRIC SALES REVENUE?

A. Yes. While I agree that the Company's proposal to base its pro forma test year electric sales revenues on 20-year weather-normalized sales data is consistent with Board ratemaking policy, I do not agree with the proposal that the pro forma test year sales level be based on the average number of customers during the 2011 test year. In this case, the Company has proposed to re-state its rate base based on actual balances as of June 30, 2012, a point in time 6 months beyond the end of the 2011 test year. In addition, the Company's proposed depreciation expenses have been annualized based on the depreciable plant in service balances as of June 30, 2012. In order to provide for a proper matching with the Company's proposed rate base and depreciation expense approach, it would be appropriate to re-state the pro forma test year sales level based on the number of customers in existence as of June 30, 2012 rather than basing it on the average number of 2011 customers as the Company has done. This recommended approach would give proper recognition to any customer growth from the mid-point of the 2011 test year to June 30, 2012.

Q. HAVE YOU QUANTIFIED THE IMPACT ON THE COMPANY'S PROPOSED PRO FORMA TEST YEAR ELECTRIC SALES REVENUES FROM RE-STATING THE TEST YEAR SALES LEVEL BASED ON THE NUMBER OF CUSTOMERS AS OF JUNE 30, 2012?

A. Since the Company owns the electric sales model, I requested in RCR-A-106 that JCP&L make this determination. In response to this request, the Company quantified that annualizing the pro forma test year sales revenues based on the number of customers as of June 30, 2012 would increase its proposed pro forma test year sales revenues by $823,138.

Q. WHAT IS YOUR RECOMMENDATION BASED ON THE FOREGOING INFORMATION?

A. I recommend that the Company's proposed pro forma test year sales revenues be increased by $823,138 for ratemaking purposes in this case. My recommendation is shown on Schedule RJH-7, line 1.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH PREVIOUSLY ESTABLISHED BOARD POLICY?

A. Yes. In the Company's prior (2002) base rate case, Rate Counsel recommended a similar adjustment to re-state the test year sales revenues based on the test year-end number of customers. As noted on page 48 of the Board's Final Order in that case:[7]

> Staff notes that JCP&L used the year-end plant-in-service balance and annualized its depreciation expenses based on year-end plant. (JC-4 at 1-2). Staff asserts that in order to properly match revenue with test-year end rate base and annualized depreciation expenses based on year-end plant, revenue should reflect customer growth up to the end of the test year. (SIB at 50). Staff notes that the BPU has used this approach in previous base rate cases. (Ibid).
>
> Consistent with prior findings in other matters before the Board, the Board **HEREBY ADOPTS** the recommendation of Staff and the Ratepayer Advocate … The Board **HEREBY FINDS** the inclusion of revenues related to such growth is appropriate when matching revenues with the use of test-year end rate base and annualized depreciation expenses based on year-end plant….

- **O&M Expense – Summary**

Q. PLEASE SUMMARIZE THE OPERATION AND MAINTENANCE EXPENSES SHOWN ON SCHEDULE RJH-8.

A. As shown on Schedule RJH-8, line 1, the Company's proposed unadjusted per books test year distribution-related O&M expenses amount to $194,393,842. Next, the Company proposed 15 pro forma O&M expense adjustments which, together with the test year unadjusted per books O&M expenses, result in JCP&L's proposed pro forma O&M expense amount of $208,471,052.

While I have accepted the Company's proposed O&M expense adjustments on Schedule RJH-8 lines 2 – 4 and 10-11, I have made recommended adjustments to the Company's proposed O&M

[7] BPU Docket No. ER02080506.

expense adjustments that are shown on the remaining lines of the schedule. Each of these recommended O&M expense adjustments will be discussed below.

- **Amortization of Werner CT Costs**

Q. DOES THE TEST YEAR INCLUDE AMORTIZATION EXPENSES ASSOCIATED WITH THE WERNER CT UNIT?

A. Yes. The 2011 test year includes $562,500 worth of amortization expenses related to the Werner CT plant. This amount is recorded in FERC account 407.3 – Regulatory Debits.

Q. **IS THE COMPANY CURRENTLY STILL BOOKING THIS AMORTIZATION EXPENSE?**

A. No. As confirmed by JCP&L in its response to RCR-A-47, the amortization of $562,500 ceased in April 2013 when the regulatory asset was fully amortized.

Q. SINCE THIS COST IS NO LONGER BEING INCURRED BY THE COMPANY, HAVE YOU REMOVED IT FROM THE TEST YEAR FOR RATEMAKING PURPOSES IN THIS CASE?

A. No, I have not. As explained in a prior section of this testimony ("Test Year and Post Test Year Adjustments"), removing this cost from the test year is inappropriate in light of the Board's post-test year ratemaking policy. In short, the amortization cessation date of April 2013 is too far removed from the end of the 2011 test year to be given rate recognition in this case.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS MATTER?

A. Yes. If, for some reason, the Board were to allow post-test year adjustments for as far away as 2013, I recommend that this $562,500 amortization expense be removed from the test year as it represents a cost that is no longer incurred by the time the rates from this case become effective.

- **<u>Amortization of Net Loss on Reacquired Debt</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO JCP&L'S PROPOSED AMORTIZATION OF NET LOSS ON REACQUIRED DEBT SHOWN ON SCHEDULE RJH-8, LINE 5.

A. JCP&L's proposed amortization of net loss on reacquired debt is its actual test year amortization expense of $1,772,707. However, this test year amortization amount represents the Company's total electric amortization expenses rather than just the distribution-related amortization expense portion. In its response to RCR-A-102(c), the Company quantifies that the distribution portion of its total electric amortization expense for the net loss on reacquired debt is 78.78%. As shown on Schedule RJH-4, lines 6-8, the application of this distribution allocator to the total electric amortization expense results in a recommended distribution-related amortization expense of $1,396,538. This expense amount is $376,168 lower than the Company's proposed amortization expense amount of $1,772,707.

- **<u>BPU & Rate Counsel Assessments</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED BPU AND RATE COUNSEL ASSESSMENTS, AS SHOWN ON SCHEDULE RJH-8, LINE 6.

A. The recommended adjustment merely represents a "flow-through" adjustment as a direct result of my recommended revenue adjustment. As explained in footnote (2) of Schedule RJH-8, the recommended adjustment is calculated by applying the combined BU/RC assessment rate of 0.00221 to my recommended sales revenue adjustment reflected on Schedule RJH-7, line 1(c).

- **<u>Management Audit Fees</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED MANAGEMENT AUDIT FEE ADJUSTMENT SHOWN ON SCHEDULE RJH-8, LINE 7.

A. The recommended $33,791 expense adjustment merely restates the Company's proposed management audit fees to the correct expense level as confirmed by the Company in its response to RCR-A-113.

- **<u>Rate Case Expenses</u>**

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS TO THE COMPANY'S PROPOSED RATE CASE EXPENSES SHOWN ON SCHEDULE RJH-9.

A. The first rate case expense adjustment concerns the recommended removal of 50% of the total rate case expenses in order to reflect the 50/50 sharing of all rate case expenses between ratepayers and stockholders. This recommended adjustment is consistent with long-standing and well-established Board policy. JCP&L has completely ignored this Board policy and, instead, is proposing that 100% of all rate case expenses be funded by the ratepayers. The Board should summarily dismiss this proposal.

The second rate case expense adjustment concerns a recommended change in the Company's proposed amortization period. JCP&L has proposed an amortization period of 4 years. However, the rates from JCP&L's last base rate case in 2002 became effective August 1, 2003. Thus, by the time that rates from the instant proceeding become effective (assume early 2014), a period of over 10 years will have expired since the Company's 2002 base rate case. For that reason, I conservatively recommend a rate case expense amortization period of 6 years.

In summary, the two recommended adjustments I just discussed reduce the Company's proposed annual rate case expense amount of $587,000 by $391,333 to a recommended annual rate case expense amount of $195,667.

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

A. Yes. The appropriate rate case expense amount to be recognized for ratemaking purposes in this case should be the actual expense incurred through the completion of this case. This actual expense amount is not known and measurable at this time. The Company has assumed this expense amount to be $2,348,000, but this is merely an estimate made by JCP&L at the time it prepared this case. Therefore, while I have reflected the Company's current expense estimate of $2,348,000 at this time, I will update these estimated expenses for actual results later on in this proceeding when I file supplemental testimony schedules to include the depreciation recommendations of Rate Counsel witness Michael Majoros who will file his depreciation testimony in August 2013.

- **Cost to Achieve Merger Synergy Savings**

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL WITH REGARD TO COST TO ACHIEVE MERGER SYNERGY SAVINGS IN THIS CASE.

A. On February 25, 2011 the merger between FirstEnergy and Allegheny was completed. JCP&L was allocated an expense amount of $14,466,766 for the Costs to Achieve Merger Savings and is proposing to charge these costs to its ratepayers over a 3-year amortization period, resulting in an annual amortization expense amount of $4,822,255. The Company justifies this proposal by arguing that various large benefits resulting from this merger have already flowed to the ratepayers and will in the future flow to the ratepayers through the merger savings that are alleged to be incorporated in the 2011 test year. For these reasons, the Company claims that the ratepayers should share in the costs to achieve these merger savings. The Stipulation in the Allegheny merger case allowed JCP&L to make this proposal and an associated merger cost recovery request in the instant rate proceeding. It also allowed Rate Counsel and Staff to challenge any of such proposals.

Q. DID THE COMPANY CALCULATE COST SAVINGS FOR JCP&L THAT ALLEGEDLY ARE INCORPORATED IN THE 2011 TEST YEAR THAT ARE CLAIMED TO BE ATTRIBUTABLE TO THE REDUCTION IN A&G COSTS DUE TO THE MERGER?

A. Yes. As described on page 14 of the testimony of Mr. Mader, JCP&L claims that, as a result of the merger, the Company's pre-merger JCP&L Indirect Cost Allocator of 16.40% in 2010 was reduced to 14.83% in 2011, representing a savings of 1.57% which savings the Company has equated to $6.4 million in dollar cost savings.

Q. DO YOU BELIEVE THAT THIS REPRESENTS CONVINCING AND RELIABLE PROOF THAT THE INDIRECT COST ALLOCATOR REDUCTION IS A DIRECT RESULT OF THE ALLEGHENY MERGER?

A. No. There are numerous other factors that could have caused this indirect cost allocator reduction. In fact, Mr. Mader himself concedes this when he acknowledges on pages 14-15 of his testimony that his Indirect Cost Allocator reduction calculations "capture variances to indirect corporate cost allocations from initiatives not related to merger activities." However, he then makes the bold but unsupported assumption that "it is reasonable to conclude that any initiatives that were not merger related likely would not contribute materially to the variation." The table below shows the actual JCP&L Indirect Cost Allocator percentages experienced by JCP&L from 2005 through 2011:[8]

2005	20.15%
2006	18.13
2007	18.32
2008	16.88
2009	17.62
2010	16.40
2011 TY	14.83

[8] Sources: Mader testimony page 14 and response to RCR-A-74.

What this table shows is that JCP&L in the past has experienced similar reductions in its Indirect Cost Allocators, for example, a reduction of 2.02% from 2005 to 2006, 1.44% from 2007 to 2008, and 1.22% from 2009 to 2010. Since no mergers occurred during those years, it is clear that non-merger factors can significantly influence the Company's Indirect Cost Allocator. The assumption that JCP&L has made, that the 1.57% Indirect Cost Allocator reduction from 2010 to 2011 is solely or predominantly caused by the Allegheny merger, not by non-merger factors, is therefore completely unsupported and unreliable.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THE COMPANY'S PROPOSAL WITH REGARD TO THIS COST TO ACHIEVE MERGER SYNERGY SAVINGS ISSUE?

A. I recommend that the Board reject the Company's proposal with regard to this issue. My recommendation is shown on Schedule RJH-8, line 9. I already discussed the fact that, in my opinion, the Company has not proven that there are any merger-attributable JCP&L Indirect Cost Allocation cost savings incorporated in the 2011 test year. However, there are other reasons why the Company's proposal should be rejected. First, since the merger was not completed until the end of February 2011, and since it generally takes time for any merger savings to gradually ramp up into the operating results of JCP&L, any savings from this merger are only partially included in the 2011 test year and may be very little, if any. Second, the Company ignores the fact that the merger also resulted in a detriment to the ratepayers. The Board's Decision and Order in this merger proceeding, Docket No. EM11010012 states at the bottom of pages 2 and 3:

> Shortly after the announcement of the Agreement, on February 17, 2010, JCP&L notified the Board that on February 11, 2010, Standard & Poors ("S&P") lowered its corporate credit rating on JCP&L's parent holding company FirstEnergy from BBB to BBB- and its senior unsecured credit rating on FirstEnergy from BBB- to BB+. In

> addition, S&P lowered JCP&L's corporate credit rating and senior unsecured debt from BBB to BBB-…..
>
> While the Board determined it did not have to take additional measures with regard to impacts to BGS, <u>the credit downgrade occurred as a direct result of the announcement of the Agreement and demonstrated that the Transaction had an effect on the underlying financial integrity of JCP&L.</u> [emphasis supplied]

Thus, the future benefits from the merger that are claimed by the Company may be wholly or partially offset by the future increased capital costs of JCP&L as a result of the merger-attributable credit downgrade. Third, as confirmed in the response to RCR-A-121, the $14.5 million Cost to Achieve Merger Savings allocated to JCP&L has already been flowed through the Company's income statement and is no longer on the Company's books.

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

A. Yes. If the Board decides that the $14.5 million Cost to Achieve Merger Savings can be considered for rate recovery, I recommend the use of a 6-year amortization period, rather than the 3-year amortization period proposed by JCP&L. I am making this recommendation for the same reasons as my recommended 6-year amortization period for the Company's rate case expenses that was discussed in the prior section of this testimony. In addition, I believe it more reasonable to use a longer amortization period than 3 years because if the Company's rates stay in effect for more than 3 years, as was the case in the Company's prior base rate proceeding, JCP&L would inappropriately over-collect the annual amortization expense of $4.8 million after the 3rd rate effective year.

- **Normalize Forestry Maintenance Expenses**

Q. WHAT IS THE ISSUE WITH REGARD TO THE COMPANY'S PROPOSED FORESTRY MAINTAINANCE EXPENSES IN THIS CASE?

A. The Company has proposed to adjust its per books 2011 test year forestry maintenance (tree trimming) expense level to bring it up to the tree trimming expense level that is projected in the Company's 2013 Operating Budget. Filing exhibit JC-3, Schedule SDM-2, page 13 shows that the projected 2013 tree trimming expenses amount to $14.4 million as compared to the actual 2011 test year expense level of $9.3 million, so the Company's proposal results in a pro forma expense increase of $5.1 million. This proposal should be rejected by the Board for various reasons.

First, as previously discussed in this testimony,[9] this concerns an expense adjustment based on data for calendar year 2013 which represents a time period falling 2 years beyond the end of the 2011 test year and, therefore, would violate the Board's post-test year ratemaking policy that only expense changes occurring within 9 months after the end of the test year be recognized for ratemaking purposes.

Second, the proposed adjustment is based on fully projected financial numbers from the Company's 2013 Operating Budget that cannot be considered "known and measurable changes" to the test year that are "carefully quantified through proofs which manifest convincingly reliable data." After all, it is difficult to determine the accuracy of these projected tree trimming expenses at this time since they are discretionary costs which can be significantly influenced by factors such as, for example, the financial condition of the Company, the economy, and the weather.

[9] "Test Year and Post-Test Year Adjustments."

My recommended adjustment is shown on Schedule RJH-8, line 12.

Q. HOW DO THE TEST YEAR TREE TRIMMING EXPENSES COMPARE TO THE ACTUAL EQUIVALENT DISTRIBUTION TREE TRIMMING EXPENSES IN THE PRIOR FOUR YEARS AND 2012?

A. These actual expenses are shown in the table below:[10]

2007	$12.1 million
2008	13.8
2009	3.0
2010	5.3
2011 TY	9.3
2012	10.9

The 5-year average (2007-2011) expense level is $8.7 million and the 6-year average is $9.1 million. Thus, the actual 2011 test year expenses of $9.3 million are very much in line with the Company's average experience during the last 6 years.

- **Account 935 – Maintenance of General Plant Expense Normalization**

Q. PLEASE EXPLAIN THE RECOMMENDED ADJUSTMENT WITH REGARD TO THE ACCOUNT 935 EXPENSES FOR MAINTENANCE ON GENERAL PLANT SHOWN ON SCHEDULE RJH-10.

A. As shown on Schedule RJH-10, the Company's actual Account 935 expenses for the 5-year period 2007 through the 2011 test year have been approximately $1.55 million (2007), $1.50 million (2008), $1.56 million (2009), $1.27 million (2010) and $2.74 million (2011 test year). The 5-year

[10] Source: response to RCR-A-92.

average expense level is approximately $1.72 million. The actual test year expense level of $2.74 million would appear to be abnormally high when compared to the expense levels in the recent prior years. For that reason, I believe that the 5-year historic average expense level of $1.72 million represents a more appropriate normalized Account 935 expense level to be recognized for ratemaking purposes in this case.

Schedule RJH-10, line 2 shows that my recommendation reduces the Company's test year Account 935 expenses by $1,018,802.

- **Incentive Compensation Expenses**

Q. WHAT IS THE COMPANY'S PROPOSAL IN THIS CASE WITH REGARD TO INCENTIVE COMPENSATION EXPENSES?

A. RCR-A-57 Attachments 3 and 4 show that the test year distribution-related O&M expenses include total incentive compensation expenses amounting to $8,418,907, consisting of $6,657,938 for the Short Term Incentive Plan ("STIP") and $1,760,969 for the Long Term Incentive Plan ("LTIP"). These numbers represent incentive compensation expenses included in the test year distribution O&M expenses for both the JCP&L Direct charges and the incentive compensation charges allocated to JCP&L from the Service Company. JCP&L is proposing to charge 100% of these incentive compensation expenses to its ratepayers.

Q. PLEASE GENERALLY DESCRIBE THE WORKINGS AND AWARD CRITERIA OF THE STIP.

A. As described on RCR-A-57 Attachments 1 and 2, the STIP provides annual cash incentive awards to employees whose contributions support the successful achievement of FirstEnergy's financial and operational Key Performance Indicators ("KPIs") The program supports FirstEnergy's compensation philosophy by linking awards directly to annual performance results in relation to company and business unit objectives key to FirstEnergy's success. Forty percent (40%) of the incentive awards paid out under the STIP are tied to the achievement of certain FirstEnergy corporate financial criteria (Earnings per share and Debt-to-Capitalization ratio), while sixty percent (60%) of the awards paid out are dependent on the achievement of certain FirstEnergy operational goals. It is important to note, though, that the STIP also has the following overriding provision:[11]

> Payment of any short-term incentive [STIP] award is contingent upon the Company [FirstEnergy] achieving the Earnings Per Share threshold level, after accounting for the cost of the payout.

Thus, if the minimum FirstEnergy EPS threshold is not reached or exceeded in the award year, no STIP incentive compensation will be paid out, whether they are based on corporate financial or operational performance criteria. *This overriding provision makes 100% of the STIP incentive compensation tied to and dependent upon FirstEnergy's corporate financial performance during the award year.*

[11] See top of page 2 of RCR-A-57 Attachment 1 and bottom of page 3 of RCR-A-57 Attachment 2.

Q. PLEASE GENERALLY DESCRIBE THE WORKINGS AND AWARD CRITERIA OF THE LTIP.

A. As described on RCR-A-57 Attachment 2, page 6, the LTIP is an equity-based program designed to reward executives for achievement of FirstEnergy goals that are intended to increase shareholder value. The LTIP consists of two components: 1) the Performance Share Program, and 2) the Performance-Adjusted Restricted Stock Unit (RSU) Program.

The Performance Share Program is 100% tied to the achievement of FirstEnergy's Total Shareholder Return (TSR). The incentive compensation paid out under the RSU Program is dependent upon the achievement of three performance criteria: 1) Earnings Per Share; 2) Safety; and 3) Operational Performance. Thus, the RSU Program is tied partially to corporate financial performance measures and partially to operational performance measures. The LTIP award program is for executives only.

Q. WHAT IS THE HISTORY OF THE BOARD'S RATEMAKING POLICY WITH REGARD TO INCENTIVE COMPENSATION IN JCP&L'S PRIOR BASE RATE PROCEEDINGS?

A. In its 1993 Final Decision and Order in JCP&L's 1991 rate case, Docket No. 91121820J, the Board disallowed 100% of the Company's incentive compensation expenses. In so doing, the Board noted that the incentive compensation "bonus" expenses should not be funded by the ratepayers as these expenses were significantly impacted by the Company achieving financial performance goals.

While in JCP&L's most recent 2002 base rate case, the Board allowed a portion of JCP&L's incentive compensation expenses, that portion allowed in rates was tied to an incentive compensation plan available to a wider array of employees, including union members, with specific operational measures that have been specifically negotiated between the union and management. As stated before, the LTIP is not offered to the Company's bargaining employees, rather it is available to executives only.

Q. BASED ON THE FOREGOING FACTS, WHAT IS YOUR RECOMMENDATION IN THE CURRENT CASE WITH REGARD TO JCP&L'S INCENTIVE COMPENSATION EXPENSES?

A. I have always taken the position that 100% of a utility's incentive compensation expenses should be disallowed for ratemaking purposes, and I am still of this opinion. My recommendation regarding JCP&L's incentive compensation expenses in the current case is therefore that 100% of the Company's test year incentive compensation expenses be removed from this case. As I show on Schedule RJH-11, my recommendation reduces the Company's test year distribution-related O&M expenses by $8,418,907. I believe that this recommendation reflects a ratemaking position that is consistent with the Board's rulings regarding JCP&L's incentive compensation expenses in the Company's prior base rate cases.

Q. OTHER THAN BEING CONSISTENT WITH THE BOARD'S TREATMENT OF JCP&L'S INCENTIVE COMPENSATION IN THE COMPANY'S PRIOR RATE CASES, ARE THERE ADDITIONAL REASONS WHY SUCH EXPENSES ARE NOT APPROPRIATE FOR RATE INCLUSION?

A. Yes. The incentive compensation expenses recommended to be removed from this case are either wholly or significantly dependent upon the achievement of FirstEnergy's improvements in EPS and TSR. FirstEnergy's shareholders are the primary beneficiaries of such corporate financial performance improvements by virtue of the resulting increases in their stock value or dividend receipts. For that reason, JCP&L's stockholders should be made responsible for these discretionary costs.

Second, the Company's proposed incentive compensation expenses are not known and certain. They are dependent on FirstEnergy's achievement of certain pre-determined financial thresholds and in determining its proposed pro forma incentive compensation awards, the Company has assumed that these financial thresholds will be achieved. However, if these financial thresholds are not reached, the incentive compensation could be substantially different from what the Company has assumed in this case.

Third, during a time that employees in other industries, including many in New Jersey's state government, have not had wage/salary increases as a result of the Great Recession and the associated budget crises, JCP&L's employees that are eligible for incentive compensation have continued to receive base salary increases and will continue to receive annual salary increases of at least 3% as reflected on an annualized basis for 2012 on a pro forma basis in this case. Given these facts, I do not believe it reasonable and appropriate to saddle the ratepayers with an additional amount in excess of $8.4 million for bonus awards to be paid out under the Company's incentive compensation programs.

Fourth, the Company has not presented any evidence in this case showing the specific benefits that are accruing to the ratepayers as opposed to JCP&L's shareholders as a result of the incentive compensation plans for which these same ratepayers are asked to pay 100% of the costs. Neither has JCP&L presented any evidence in this case showing that there is any appreciable difference in the productivity level of JCP&L and JCP&L's employees or that the ratepayers are receiving more efficient service at reduced overall costs as a direct result of the Company's incentive compensation programs.

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

Finally, I find the Company's request for rate recovery of approximately $8.4 million in bonus compensation on top of regular compensation particularly objectionable because this proposal is being made during a time when the effects of the Great Recession are still lingering, and where ratepayers are faced with job losses and reduced home values. It is especially during these difficult economic conditions that ratepayers need relief from these discretionary costs.

- **Supplemental Executive Retirement Plan (SERP) Expenses**

Q. PLEASE DESCRIBE THE SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN (SERP) EXPENSES PROPOSED TO BE INCLUDED IN THE TEST YEAR BY THE COMPANY.

A. SERP costs represent supplemental retirement benefits for top executives of JCP&L and the Service Company that are in addition to the normal retirement programs offered by JCP&L. These programs generally exceed various limits imposed on retirement programs by the IRS and are therefore referred to as "non-qualified" plans. The response to RCR-A-110 states with regard to the SERP program:

> In addition to the qualified and nonqualified plans, certain executives are eligible to receive an additional nonqualified benefit from the SERP. Historically, participation in the SERP has been provided to certain key executives as part of the integrated compensation program intended to attract, motivate, and retain top executives who are in a position to make significant contributions to our operations and profitability for the benefit of our customers and shareholders.
>
> In the 2011 test year, only nine active employees were eligible for a SERP benefit upon retirement: 1) CEO, 2) SVP – HR, 3) EVP – Finance & Strategy, 4) President Ohio Operations, 5) President PA Operations, 6) SVP & Pres FEU, 7) EVP & General Counsel, 8) VP Controller & CAO, and 9) VP Compliance and Regulated Services.

As shown on Schedule RJH-12, the test year includes $408,576 worth of SERP expenses of which $193,230 represents the utility's share and $215,346 represents allocated SERP expenses from the Service Company.

Q. DO YOU BELIEVE THAT THESE SERP EXPENSES SHOULD BE ALLOWED FOR RATEMAKING PURPOSES IN THIS CASE?

A. No. The ratepayers are already paying for the regular retirement benefits of these top executives and should not be forced to also fund these SERP perks. If the Company wants to provide additional retirement benefits to these key employees, then shareholders rather than ratepayers should be picking up the tab for that. In summary, I recommend that all of the SERP expenses included in the test year be disallowed for ratemaking purposes. My recommendation reduces the Company's distribution-related test year expenses by $408,576.

- **<u>Pension Expenses</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED PENSION EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-8, LINE 16.

A. This adjustment represents my adoption of the recommendation of Rate Counsel witness Dr. Mitchell Serota to reduce the Company's test year pension expenses. The reasons for this recommended pension expense adjustment are discussed in detail in the testimony of Dr. Serota.

- **<u>OPEB Expenses</u>**

Q. PLEASE EXPLAIN THE RECOMMENDED OTHER POST EMPLOYMENT BENEFITS ("OPEB") EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-8, LINE 17.

A. This adjustment represents my adoption of the recommendation of Rate Counsel witness Dr. Mitchell Serota to reduce the Company's test year OPEB expenses. The reasons for this recommended OPEB expense adjustment are discussed in detail in the testimony of Dr. Serota.

- **<u>Deferred OPEB Amortization Expenses</u>**

Q. DOES THE TEST YEAR INCLUDE AMORTIZATION EXPENSES ASSOCIATED WITH THE COMPANY'S OTHER POST-EMPLOYMENT BENEFITS?

A. Yes. The 2011 test year includes $3,320,472 worth of amortization expenses related to certain deferred OPEB costs.

Q. **IS THE COMPANY CURRENTLY STILL BOOKING THESE AMORTIZATION EXPENSES?**

A. No. As confirmed by JCP&L in its response to RCR-A-63, the amortization of $3,242,100 ceased on December 31, 2012 when the deferred asset was fully amortized.

Q. SINCE THIS COST IS NO LONGER BEING INCURRED BY THE COMPANY, HAVE YOU REMOVED IT FROM THE TEST YEAR FOR RATEMAKING PURPOSES IN THIS CASE?

A. No, I have not. As explained in a prior section of this testimony,[12] removing this cost from the test year is inappropriate in light of the Board's post-test year ratemaking policy. In short, the amortization cessation date of December 31, 2012 is too far removed from the end of the 2011 test year to be given rate recognition in this case.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS MATTER?

A. Yes. If, for some reason, the Board were to allow post-test year adjustments for as far away as December 31, 2012, I recommend that this $3,242,100 amortization expense be removed from the test year as it represents a cost that is no longer incurred by the time the rates from this case become effective.

[12] "Test Year and Post-Test Year Adjustments."

- **Miscellaneous O&M Expense Adjustments**

Q. **PLEASE DESCRIBE EACH OF THE MISCELLANEOUS EXPENSES LISTED ON SCHEDULE RJH-13 THAT YOU RECOMMEND BE REMOVED FOR RATEMAKING PURPOSES IN THIS CASE.**

A. The Employee Clubs expense of $1,387 represents JCP&L's matching contribution for employees who are in employee retiree clubs. The objectives of such clubs are to promote and carry out a variety of social, recreational and educational activities that appeal to the interests of its members (response to RCR-A-132).

The "Celebrate Success" expenses of $5,707 and the service award expenses of $37,875 represent expenses for employee awards, parties, outings and gifts that are incurred by JCP&L direct, as well as allocated to JCP&L from the Service Company.

The institutional and goodwill advertising expenses of $8,140 represent advertising expenses to enhance the image and goodwill of JCP&L.

The civic membership expenses of $25,295 represent dues paid by JCP&L to a number of chambers of commerce, mayor associations, area associations, Jersey shore partnership association, and economic development associations.

Finally, the private club expenses of $854 represent expenses for a private club membership.

I believe that the miscellaneous expenses I just discussed have nothing to do with the provision of safe, adequate and reliable electric service to JCP&L's distribution ratepayers and, for that reason, should be funded by the Company's shareholders rather than its captive ratepayers. I therefore recommend that these expenses, totaling $79,258, be removed from the test year expenses. I also believe that my recommendation is consistent with Board ratemaking policy to exclude these types of expenses for ratemaking purposes.

- **Depreciation Expenses**

Q. PLEASE EXPLAIN THE DERIVATION OF THE RECOMMENDED PRO FORMA DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-14.

A. At this time, I have reflected two depreciation expense adjustments on Schedule RJH-14. The first depreciation expense adjustment removes the Company's proposed depreciation expenses associated with the 12/31/2011 plant in service balances associated with 3 major storms that occurred in the 2011 test year, i.e., the July 2011 Heat Storm, Hurricane Irene and the October Snowstorm. The prudency of these depreciation expenses will first be determined in the Board's Generic Storm Costs Proceeding before they can be considered for ratemaking purposes in this base rate case. The second depreciation expense adjustment corrects the Company's proposed distribution-allocated Intangible Plant depreciation expense from $6,275,094 to $3,364,830. This required expense correction was conceded by the Company in its response to RCR-A-34. As shown on Schedule RJH-14, line 8, these two recommended depreciation expense adjustments reduce the Company's proposed total distribution depreciation expense of $92,746,142 by $5,102,293 to a recommended expense level of $87,643,849.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE COMPANY'S DEPRECIATION EXPENSES?

A. Yes. The Rate Counsel-recommended depreciation expenses on Schedule RJH-14, lines 1 and 2 will be updated to reflect the depreciation rates and associated depreciation expenses included in the testimony of Rate Counsel witness Michael Majoros, which testimony is scheduled to be filed on August 7, 2013. At that time, I will update my testimony schedules to reflect the impact of Mr. Majoros' depreciation expense recommendations on the Company's revenue requirement.

- **Amortization Expenses – Summary**

Q. PLEASE SUMMARIZE THE AMORTIZATION EXPENSES SHOWN ON SCHEDULE RJH-15.

A. As shown on Schedule RJH-15, line 1, the per books test year distribution-related amortization expenses amount to $3,912,364. This balance consists of deferred OPEB amortization and Werner CT amortization expenses, which amortizations have expired in December 2012 and April 2013, respectively. However, to be consistent with BPU post-test year ratemaking policy, I have not removed these amortization expenses from the test year. Next, the Company proposed 8 pro forma amortization expense adjustments which, together with the test year per books amortization expenses, result in JCP&L's proposed pro forma amortization expense amount of $38,354,159.

While I have accepted the Company's proposed amortization expense adjustments on Schedule RJH-15 lines 4 – 7 and 9, I have made recommended adjustments to the Company's proposed amortization expense adjustments that are shown on lines 2, 3 and 8. Each of these recommended amortization expense adjustments will be discussed below.

- **Storm Damage Cost Amortization**

Q. PLEASE EXPLAIN THE STORM DAMAGE COST AMORTIZATION ADJUSTMENT SHOWN ON SCHEDULE RJH-15, LINE 2.

A. As shown in more detail on Schedule RJH-5, line 3, this adjustment represents the recommended removal from this base rate case of the Company's proposed 3-year amortization of the deferred costs associated with the 2011 major storms, Hurricane Irene and the October 2011 Snowstorm. The prudency of these deferred costs will first be determined in the Board's Generic Storm Costs Proceeding before they can be considered for ratemaking purposes in this base rate case. This adjustment has been addressed in detail earlier in this testimony.[13]

- **Net Salvage and Cost of Removal Costs**

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL WITH REGARD TO ITS NET SALVAGE AND COST OF REMOVAL COST LEVEL IN THIS PROCEEDING.

A. In the Company's prior (2002) rate case, the Board adopted a recommendation to remove the net salvage and cost of removal costs from JCP&L's depreciation rates and, instead, allow a separate recovery of such costs based on a 5-year historical average of actual net salvage and removal costs. As shown in the response to RCR-A-35, the 5-year historical average of actual net salvage and removal costs for the most recent period 2007 – 2011 is approximately $2.4 million. However, the Company in this case has proposed to change to a 2-year historical average for the years 2010-

[13] "Ratemaking Treatment of Deferred Major Storm Damage Costs."

2011. Not surprisingly, this produces an average net salvage and removal cost of approximately $4.8 million, or twice the annual cost based on the traditional 5-year historical average. I recommend that the Company's proposal to switch from a 5-year to a 2-year historical average be rejected by the Board for the following reasons: 1) it is my understanding that the 5-year average has historically been ordered by the Board, not only for JCP&L but for all other NJ utilities in which the Board ordered to remove the net salvage and cost of removal from their depreciation rates; I see no pressing need to now abandon this traditional 5-year historic average methodology; 2) a 2-year average is not a long enough time span to derive a reliable normalized net cost level; and 3) similar to the argument I make regarding the next issue I discuss in this testimony ("Production-Related RA Amortization"), it would be inappropriate to implement this change without re-evaluating all of the other issues decided by the Board in the prior 2002 base rate case where the 5-year historic average method was approved, as this could upset the balance struck between the competing interests of ratepayers and shareholders.

Please note that this issue will also be addressed by Rate Counsel's depreciation expert Mike Majoros who recommended the 5-year historical ratemaking treatment in JCP&L's prior rate case.

- **<u>Production-Related RA Amortization</u>**

Q. PLEASE EXPLAIN THE PRODUCTION-RELATED REGULATORY ASSET AMORTIZATION ADJUSTMENT SHOWN ON SCHEDULE RJH-15, LINE 8.

A. The test year includes $109,008 worth of amortization expenses for two Regulatory Assets ("RA") involving Oyster Creek and TMI-1 design basis documentation studies. The amortization periods underlying this test year amortization expense is equal to the operating license lives of these two facilities. In JCP&L's prior (2002) base rate case, the Board found these amortization periods and the associated amortization expenses of $109,008 to be reasonable and appropriate based on prior JCP&L proceedings. In the instant proceeding, the Company has proposed to accelerate the amortization period for these two RAs from the length of the operating licenses to 3 years. This results in a pro forma annual amortization expense of $1,629,650, which is $1,520,642 higher than the per books test year amortization expense of $109,008. As stated on page 12 of Ms. Marano's testimony, the reason for the proposed amortization acceleration is that …"JCP&L no longer owns these production facilities and, except for the Yards Creek pumped storage hydroelectric facility, is no longer in the generation business."

I recommend the continuation of the current amortization period. There is no compelling reason in this case to change the amortization period that was deemed to be appropriate in all of the Company's prior rate cases since 1989. As confirmed in the Company's response to RCR-A-51(e), Oyster Creek and TMI-1 were sold in 2000 and 1999, respectively. Therefore, even in its last (2002) rate case, JCP&L no longer owned these production facilities and, except for Yards Creek, was no longer in the generation business. Yet, despite this fact, the Board found it appropriate to continue the existing amortization period in the Company's last rate case. Nothing has changed in the current case since the last case regarding this matter, so there really is no justification to now make such a drastic change in the amortization period. It should also be noted that JCP&L, in its prior base rate case, made a similar proposal to accelerate the amortization of certain production-related RAs. In ruling against this proposal, the Board stated on page 61 of its Final Order in that case (Docket No. ER02080506):

> The Board **HEREBY FINDS**, consistent with the positions of Staff and the RPA, an alteration of the amortization of these assets as proposed by the Company is inappropriate. The Board agrees that without re-evaluating the issues previously decided by the Board in the prior proceedings where these amortization periods were approved, the delicate balance struck between the competing interests of ratepayers and shareholders might be upset.

The same can be said with regard to the Company's proposal in the current case. It would be inappropriate to implement this drastic amortization change without re-evaluating all of the other issues decided by the Board in the prior 2002 base rate case where the existing amortization periods were approved, as this could upset the balance struck between the competing interests of ratepayers and shareholders. My recommendation reduces the Company's test year expense by $1,520,642.

- **<u>Taxes Other Than Income Taxes</u>**

Q. PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO JCP&L'S PROPOSED TAXES OTHER THAN INCOME TAXES SHOWN ON SCHEDULE RJH-7, LINE 6.

A. This recommended tax adjustment reflects the payroll tax impact of my recommended incentive compensation expense adjustment. I have calculated this tax adjustment by applying a conservatively estimated composite payroll tax ratio of approximately 7% to my recommended incentive compensation expense adjustment shown on Schedule RJH-8, line 14.

- **<u>Income Taxes</u>**

Q. HOW DID YOU DETERMINE THE RECOMMENDED PRO FORMA INCOME TAX CALCULATIONS SHOWN ON SCHEDULE RJH-16?

A. As shown on the above-referenced schedule, I have used the same calculation method and calculation components as used by JCP&L to determine the recommended pro forma income tax amounts for JCP&L in this case. The difference between the recommended pro forma income taxes and JCP&L's proposed pro forma income taxes is caused by (1) the "flow-through" effect of the recommended adjustments made by me to JCP&L's proposed pre-tax operating income and pro forma interest deduction; and (2) JCP&L's failure to reflect the annual Investment Tax Credit ("ITC") amortization as an income tax reduction. As confirmed in the Company's response to RCR-A-138, the Company's pro forma income tax calculation does not, but should, reflect the annual distribution related ITC amortization tax credit of $102,860.

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

A. Yes, it does.

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

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

DELAWARE

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

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

Gas Base Rate Proceeding*		
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004
United Water Delaware Water Base Rate Proceeding*	Docket No. 06-174	10/2006
United Water Delaware Water Base Rate Proceeding*	Docket No. 09-60	06/2009
United Water Delaware Water Base Rate Proceeding*	Docket No. 10-421	05/2011
Tidewater Environmental Services, Inc. Wastewater Base Rate Proceeding*	Docket No. 11-329WW	03/2012
TESI/Holland Mills Wastewater Base Rate Proceeding*	Docket No. 11-419WW	05/2012

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991

Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company Base Rate Proceeding	Docket 3465-U	08/1984
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994

Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005
Georgia Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 25060-U	10/2007
Georgia Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 31958	10/2010

<u>FERC</u>

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

<u>KENTUCKY</u>

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983

Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002

Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005
Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005
Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006
Duke Energy Kentucky Electric Base Rate Proceeding*	Case No. 2006-00172	09/2006
Atmos Energy Corporation Gas Show Cause Proceeding*	Case No. 2005-00057	09/2006
Inter County Electric Cooperative Electric Base Rate Proceeding	Case No. 2006-00415	04/2007
Atmos Energy Corporation Gas Base Rate Proceeding*	Case No. 2006-00464	04/2007
Columbia Gas of Kentucky	Case No. 2007-00008	06/2007

Gas Base Rate Proceeding*		
Delta Natural Gas Company Gas Base Rate Proceeding – Alternative Rate Mechanism*	Case No. 2007-00089	08/2007
Nolin Rural Electric Cooperative Corporation Electric Rate Proceeding	Case No. 2006-00466	09/2007
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2006-00022	10/2007
Jasckson Energy Cooperative Electric Base Rate Proceeding	Case No. 2007-00333	03/2008
Jackson Purchase Energy Corporation Electric Base Rate Proceeding	Case No. 2007-00116	04/2008
Blue Grass Energy Cooperative Electric Base Rate Proceeding	Case No. 2008-00011	7/2008
Louisville Gas & Electric Company Electric and Gas Base Rate Proceedings*	Case No. 2008-00252	10/2008
Kentucky Utilities Company Electric Base Rate Proceeding*	Case No. 2008-00251	10/2008
Owen Electric Cooperative Corporation Electric Base Rate Proceeding	Case No. 2008-00154	12/2008
Kenergy Corporation Electric Base Rate Proceeding	Case No. 2008-00323	12/2008
Kentucky-American Water Company Water Base Rate Proceeding*	Case No. 2008-00427	04/2009
Grayson Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2008-00254	04/2009
Farmers Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2008-00030	04/2009
Big Sandy Electric Cooperative Electric Base Rate Proceeding	Case No. 2008-oo401	04/2009
Columbia Gas Company	Case No. 2009-00141	09/2009

Gas Base Rate Proceeding*		
Duke Energy Kentucky Gas Base Rate Proceeding*	Case No. 2009-00202	10/2009
Licking Valley Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2009-00016	10/2009
Atmos Energy – Kentucky Electric Base Rate Proceeding	Case No. 2009-00354	03/2010

<u>MAINE</u>

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

<u>MARYLAND</u>

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7591	12/1981

Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

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

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976

Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984
Rockland Electric Company	Docket 849-1014	11/1984

Electric Fuel Clause Proceeding*		
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER92090900J	12/1992

Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey Base Rate Proceeding*	Docket WR95070303	01/1996

Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997

South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999
Applied Wastewater Management, Inc.	Docket No.WM99020090	10/1999

Merger with Homestead Treatment Utility

Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No.GR99070509	03/2000
DSM Adjustment Clause Proceeding	Docket No. GR99070510	03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies	Docket Nos. WO99040259	06/2000
Computer and Billing Services Contracts	WO9904260	06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000

Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001
SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001
Consumers New Jersey Water Company	Docket No. WF01080523	01/2002

Stock Transfer/Change in Control Proceeding

Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding*	Docket No. WM01120833	07/2002
Borough of Haledon – Water Department Water Base Rate Proceeding*	Docket No. WR01080532	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding	Docket No. WM02020072	09/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02050303	10/2002
United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002
United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Minimum Pension Liability Proceeding	Docket No. EO02110853	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Electric Deferred Balance Proceeding Direct Testimony*	Docket No. ER02050303	01/2003
Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003

Public Service Electric & Gas Company Supplemental Direct Testimony*	Docket No. ER02050303	02/2003
Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004

United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004
Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET05040313	08/2005
Public Service Electric & Gas Company Buried Underground Distribution Tariff Proceeding	Docket No. ET05010053	08/2005
Aqua New Jersey Acquisition of Berkeley Water Co. Water Merger Proceeding	Docket No. WM04121767	08/2005
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR05050451	10/2005
Public Service Electric & Gas Company Land Sale Proceeding	Docket No. EM05070650	10/2005
Public Service Electric & Gas Company Merger of PSEG and Exelon Corporation Direct Testimony	Docket No. EM05020106	11/2005
Public Service Electric & Gas Company* Merger of PSEG and Exelon Corporation Surrebuttal Testimony	Docket No. EM05020106	12/2005
Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005
Rockland Electric Company	Docket No. EA02020098	12/2005

Competitive Services Audit		
Public Service Electric & Gas Company Customer Accounting System Cost Recovery	Docket No. EE04070718	01/2006
Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755	01/2006
Public Service Electric & Gas Company Competitive Services Audit	Docket No. EA02020097	02/2006
Wildwood Water Company Water Base Rate Proceeding	Docket No. WR05070613	03/2006
Pinelands Water Company Water Base Rate Proceeding*	Docket No. WR05080681	03/2006
Pinelands Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR05080680	03/2006
Aqua New Jersey Water Company Water Base Rate Proceeding*	Docket No. WR05121022	06/2006
Public Service Electric & Gas Company Gas Base Rate Proceeding*	Docket No. GR05100845	07/2006
New Jersey American Company Consolidated Water Base Rate Proceeding,* New Jersey American Water Company, Elizabethtown Water Company, and Mount Holly Water Company	Docket No. WR06030257	10/2006
Roxiticus Water Company Water Base Rate Proceeding	Docket No. WR06120884	04/2007
United Water Company of New Jersey Change of Control Proceeding	Docket No. WM06110767	05/2007
United Water Company of New Jersey Water Base Rate Proceeding*	Docket No. WR07020135	09/2007
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR07040275	09/2007
Maxim Wastewater Company Purchased Sewerage Treatment Adjustment Clause	Docket No. WR07080632	11/2007

Fayson Lake Water Company Financing Case	Docket No. WF07080593	12/2007
Atlantic City Electric Company Sales of Utility Properties	Docket No. EM07100800	12/2007
Atlantic City Sewerage Company Base Rate and Purchased Sewerage Treatment Clause Proceedings	Docket No. WR07110866	04/2008
SB Water Company Water Base Rate Proceeding	Docket No. WR07110840	04/2008
Aqua New Jersey Water Company Water Base Rate Proceeding	Docket No. WR07120955	06/2008
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR07090715	06/2008
Middlesex Water Company Financing Case	Docket No. WF08040213	07/2008
Aqua New Jersey Water Company Franchise Case	Docket No. WE08040230	07/2008
Aqua New Jersey Water Company Financing Case	Docket No. WF08040216	07/2008
New Jersey American Water Company Water Base Rate Proceeding*	Docket No. WR08010020	07/2008
United Water Toms River, Inc. Water Base Rate Proceeding	Docket No. WR08030139	08/2008
New Jersey American Water Company Purchased Water and Purchased Sewer Treatment Adjustment Clauses	Docket No. WR08050371	10/2008
Pinelands Water Company Water Base Rate Proceeding	Docket No. WR08040282	12/2008
Pinelands Wastewater Company Wastewater Base Rate Proceeding	Docket No. WR08040283	12/2008
Applied Wastewater Management, Inc.	Docket No. WR08080550	03/2009

Wastewater Base Rate Proceeding		
New Jersey-American Water Company Implementation of Distribution System Improvement Charge (DSIC)*	Docket No. WO08050358	04/2009
United Water New Jersey Water Base Rate Proceeding	Docket No. WR08090710	04/2009
United Water Arlington Hills Sewerage Company Wastewater Base Rate Proceeding	Docket No. WR08100929	04/2009
United Water West Milford Inc. Water Base Rate Proceeding	Docket No. WR08100928	04/2009
Middlesex Water Company Purchased Water Adjustment Clause	Docket No. WR09010036	05/2009
Atlantic City Sewerage Company Purchased Sewerage Treatment Adjustment Clause	Docket No. WR09030201	05/2009
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR09020156	05/2009
Lawrenceville Water Company Change of Control Proceeding	Docket No. WM08110984	06/2009
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR09010090	07/2009
Fayson Lake Water Company Financing Proceeding	Docket No. WF09080660	10/2009
Elizabethtown Gas Gas Base Rate Proceeding*	Docket No. GR09030195	10/2009
Andover Utility Company Wastewater Base Rate Proceeding*	Docket No. WR09050413	11/2009
Public Service Electric & Gas Company Electric Base Rate Proceeding*	Docket No. GR09050422	11/2009
Environmental Disposal Corporation Financing Proceeding	Docket No. WR07090715	12/2009
New Jersey American Water Company	Docket No. WM09110877	01/2010

Financing Proceeding

Middlesex Water Company Water Base Rate Proceeding	Docket No. WR09080666	02/2010
Shore Water Company Water Base Rate Proceeding	Docket No. WR09070575	02/2010
Rockland Electric Company Electric Base Rate Proceeding*	Docket No. ER09080668	03/2010
Lake Lenape Water Company Water Base Rate Proceeding	Docket No. WR09090766	04/2010
Atlantic City Electric Company Electric Base Rate Proceeding*	Docket No. ER09080664	04/2010
United Water Toms River Company Water Base Rate Proceeding	Docket No. WR09110934	04/30/10
South Jersey Gas Company Gas Base Rate Proceeding*	Docket No. GR10010035	05/28/10
United Water New Jersey Water Base Rate Proceeding*	Docket No. WR09120987	06/08/10
New Jersey American Water Company Water Base Rate Proceeding	Docket No. WR10040260	10/2010
Maxim Wastewater Company Purchased Sewer Treatment Adjustment Clause	Docket No. WR10070464	11/2010
Middlesex Water Company Proposed Merger with Montague Water Company	Docket No. WM10060432	11/2010
Lawrenceville Water Company Purchased Water Adjustment Clause	Docket No. WR10060420	02/2011
New Jersey Natural Gas Company Gas Infrastructure Investment Program	Docket No. GR10100793	03/2011
United Water Great Gorge/Vernon Valley Sewer Base Rate Proceeding	Docket No. WR10100785	04/2011
South Jersey Gas Company Gas Infrastructure Investment Program	Docket No. GR10100765	04/2011

Elizabethtown Gas Company Gas Infrastructure Investment Program	Docket No. GO10120969	05/2011
Public Service Electric & Gas Company Energy Efficiency Programs Proceeding*	Docket No. EO11010030	06/2011
Roxiticus Water Company Water Base Rate Proceeding	Docket No. WR11020051	06/2011
Middlesex Water Company Purchased Water Adjustment Clause	Docket No. WR11010038	07/2011
New Jersey American Water Company Purchased Water Adjustment Clause and Purchased Sewerage Treatment Adjustment Clause	Docket No. WR11030131	08/2011
SB Water Company Purchased Water Adjustment Clause	Docket No. WR11050283	10/2011
United Water New Jersey Water Company Land Sale and Associated Regulatory Treatment	Docket No. WR11030147	10/2011
Maxim Wastewater Company Purchased Sewerage Treatment Adjustment Clause	Docket No. WR11080472	11/2011
New Jersey Natural Gas Company Energy Efficiency Program Proceeding*	Docket No. GR11070425	11/2011
Elizabethtown Gas Company Energy Efficiency Program Proceeding*	Docket No. GO11070399	12/2011
New Jersey American Water Company* Water Base Rate Proceeding	Docket No. WR11070460	01/2012
New Jersey Distribution System Investment Clause Implementation of DSIC Rulemaking	Docket No. WO10090655	02/2012
Shorelands Water Company Purchased Water Adjustment Clause	Docket No. WR11120899	04/2012
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR12010027	06/2012
Aqua New Jersey Water Company Acquisition of Tranquility Springs Water Company	Docket No. WM11120886	08/2012

New Jersey Natural Gas Company Accelerated Infrastructure Investment Program	Docket No. GO12030255	09/2012
Jersey Central Power & Light Company Electric Operations Earnings Review	Docket No. EO11090528	09/2012
South Jersey Gas Company Accelerate Infrastructure Investment Proceeding	Docket No. GR11060334	10/2012
New Jersey Natural Gas Company Accelerated Infrastructure Investment Proceeding	Docket No. GR11060332	10/2012
South Jersey Gas Company Energy Efficiency Program	Docket No. GR11060336	10/2012
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR12060509	11/2012
Maxim Sewerage Company Purchased Sewerage Treatment Adjustment Clause	Docket No. WR12070686	12/2012
Elizabethtown Gas Company Energy Efficiency Program Proceeding	Docket No. GR12100946	12/2012
Public Service Electric & Gas Company Weather Normalization Clause Proceeding	Docket No. GR12060583	12/2012
South Jersey Gas Company Accelerated Infrastructure Replacement Program	Docket No. GO12070670	02/2013
Pinelands Water Company Base Rate Proceeding	Docket No. WR12080734	02/2013
Pinelands Wastewater Company Base Rate Proceeding	Docket No. WR12080735	02/2013
New Jersey-American Water Company PWAC & PSTAC Proceeding	Docket No. WR12111019	03/2013
Gordon’s Corner Water Company Base Rate Proceeding	Docket No. WR12090807	03/2013
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket No. WR12090881	03/2013

Elizabethtown Gas Company BGSS Proceeding	Docket No. GR12060474	03/2013
United Water Tom's River Base Rate Proceeding	Docket No. WR12090830	04/2013
Montague Water & Sewer Companies Water & Sewer Base Rate Proceedings	Docket No. WR12110983	04/2013
South Jersey Gas Company Energy Efficiency Extension Proceeding	Docket No. GO12050363	06/2013
South Jersey Gas Company Energy Efficiency Reconciliation Proceeding	Docket No. GR12060473	06/2013
Elizabethtown Gas Company Energy Efficiency Reconciliation Proceeding	Docket No. GR12080729	06/2013
Elizabethtown Gas Company Remediation Adjustment Clause Proceeding	Docket No. GR12100936	06/2013

<u>NEW MEXICO</u>

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico Phase-In Plan*	Case 2146/Phase II	10/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989

Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990
El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

<u>OHIO</u>

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

<u>PENNSYLVANIA</u>

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984
National Fuel Gas Distribution Company Gas Base Rate Proceeding*	Docket R-870719	12/1987

<u>RHODE ISLAND</u>

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	
Newport Electric Company Report on Emergency Relief		

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126	

SCHEDULES RJH-1 THROUGH RJH-17

JERSEY CENTRAL POWER AND LIGHT COMPANY
REVENUE REQUIREMENT

		JCP&L (1)	Adjustments	RC	
1.	Pro Forma Rate Base	$ 2,040,326,088	$ (816,155,890)	$ 1,224,170,198	RJH-3
2.	Rate of Return	8.89%		7.76%	RJH-2
3.	Income Requirement	181,370,503	(86,436,104)	94,934,399	
4.	Pro Forma Income	162,755,645	52,111,360	214,867,005	RJH-7
5.	Income Deficiency	18,614,858	(138,547,464)	(119,932,606)	
6.	Revenue Conversion Factor	1.69061	1.69061	1.69061	
7.	Rate Increase	$ 31,470,596	$ (234,229,859)	$ (202,759,263)	
8.	Rate Increase Percentage	5.46%		-35.10%	(2)

(1) Exhibit JC-3, Schedule SDM-1
(2) Rate increase on line 7 above divided by pro forma test year electric sales revenues on Schedule RJH-7, line 1.

JERSEY CENTRAL POWER AND LIGHT COMPANY
RATE OF RETURN

JCP&L PROPOSAL:	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)
Long Term Debt	46.20%	5.82%	2.69%
Common Equity	53.80%	11.53%	6.20%
Total Cost of Capital	100.00%		8.89%

RCRECOMMENDATION:	Ratios	Cost Rates	Weighted Cost Rates
	(2)	(2)	(2)
Long Term Debt	50.00%	6.26%	3.13%
Common Equity	50.00%	9.25%	4.63%
Total Cost of Capital	100.00%		7.76%

(1) Schedule SRS-4
(2) Testimony of Matthew Kahal, Schedule MIK-1, page 1

JERSEY CENTRAL POWER AND LIGHT COMPANY
DISTRIBUTION RATE BASE

	JCP&L (1)	Adjustments		RC	
1. Utility Plant in Service	$ 3,948,975,061	$ (100,733,746)	(2)	$ 3,848,241,315	
Deductions:					
2. Reserve for Depreciation	(1,502,324,772)			(1,502,324,772)	
3. Accumulated Deferred Income Tax	(687,624,687)			(687,624,687)	
4. Customer Advances (Net of Tax)	(13,264,190)			(13,264,190)	
5. Customer Deposits	(23,745,666)			(23,745,666)	
6. Total Deductions	(2,226,959,315)			(2,226,959,315)	
Additions:					
7. Unamort. Net Loss on Reacq. Debt	17,920,314	(9,569,740)		8,350,574	RJH-4, L5
8. Unamort. Storm Cost (Net of Tax)	26,470,956	(26,470,956)		-	RJH-5, L8
9. Excess Cost of Removal Reserve	107,158,582	(107,158,582)		-	(3)
10. Total Additions	151,549,852	(143,199,278)		8,350,574	
Other Rate Base Components:					
11. Materials & Supplies	20,461,958	(5,640,715)		14,821,243	RJH-6
12. Cash Working Capital	146,298,532	(69,814,503)		76,484,029	(4)
13. Consolidated Income Tax Benefits	-	(511,030,428)		(511,030,428)	(5)
14. Customer Refunds	-	(1,163,573)		(1,163,573)	(6)
15. Operating Reserves (Net of Tax)	-	(4,237,102)		(4,237,102)	(7)
16. Deferred Taxes - TMI-2 Non-Qual. Decommisioning Trust Fund	-	19,663,455		19,663,455	(7)
17. Total Other Rate Base Components	166,760,490	(572,222,866)		(405,462,376)	
18. TOTAL NET RATE BASE	$ 2,040,326,088	$ (816,155,890)		$ 1,224,170,198	

(1) Exhibit JC-3, Schedule SDM-5

(2) Remove the following major storm balances included in the actual 6/30/12 plant in service balance, as per S-REV-1 Attachment, page 40 and Pittavino testimony, page 2, lines 14-23:

- July 2011 Heat Storm	$ 2,661,736
- Hurricane Irene	30,170,141
- October 2011 Snowstorm	67,901,869
- Total Major Storm Plant Cost	$ 100,733,746

(3) Testimony of Robert Henkes

(4) Testimony of Dave Peterson

(5) Testimony of Andrea Crane

(6) Average monthly 2011 test year balance as per RCR-A.128 Attachment

(7) Response to RCR-A-126

JERSEY CENTRAL POWER AND LIGHT COMPANY
UNAMORTIZED NET LOSS ON REACQUIRED DEBT (NET OF TAX)

	JCP&L	Adjustments	RC	
IMPACT ON RATE BASE:				
1. Total Electric Net Loss on Reacquired Debt	$ 17,920,314		$ 17,920,314	(1)
2. Distribution Allocation Factor	-		78.78%	(2)
3. Distribution Net Loss on Reacquired Debt	17,920,314		14,117,623	
4. Offsetting Deferred Tax Benefits @40.85%	-		(5,767,049)	(3)
5. Net-Of-Tax Distribution Net Loss on Reacquired Debt	$ 17,920,314	$ (9,569,740)	$ 8,350,574	
IMPACT ON EXPENSES:				
6. Total Electric Net Loss on Reacquired Debt Amortization Expenses	$ 1,772,706		$ 1,772,706	(4)
7. Distribution Allocation Factor	-		78.78%	(2)
8. Distribution Net Loss on Reacquired Debt Amortization Expense	$ 1,772,706	$ (376,168)	$ 1,396,538	

(1) Exhibit JC-3, Schedule SDM-5, line 7
(2) Response to RCR-A-102c
(3) Responses to RCR-A-12 and RCR-A-18(a)
(4) Exhibit JC-3, Schdule SDM-2, page 6 of 24

JERSEY CENTRAL POWER AND LIGHT COMPANY
STORM DAMAGE COSTS (NET OF TAX)

	JCP&L (1)	Adjustments	RC
IMPACT ON EXPENSES:			
1. Average Storm Damage Costs 2007-2011 Excluding Major Storms	$ 10,201,290		$ 10,201,290
2. 2011 Test Year Major Storms - 3 Yr. Amortization	29,834,833	(29,834,833)	-
3. Total Annual Storm Damage Costs	40,036,123	(29,834,833)	10,201,290
4. Less: Amortization Included in Test Year	(8,556,720)		(8,556,720)
5. Amortization Expense Adjustment	$ 31,479,403	$ (29,834,833)	$ 1,644,570
IMPACT ON RATE BASE:			
6. Average Unamortized Storm Damage Balance 2011 Test Year Major Storms - 3 Yr. Amortization	$ 44,752,250	(44,752,250)	$ -
7. Offsetting Deferred Tax Benefits @40.85%	(18,281,294)	18,281,294	-
8. Average Unamortized Balance Net Of Tax	$ 26,470,956	$ (26,470,956)	$ -

(1) Exhibit JC-3, Schedule SDM-2, page 17 of 24

JERSEY CENTRAL POWER AND LIGHT COMPANY
MATERIALS AND SUPPLIES

1.	Distribution M&S Balance at 6/30/12 Proposed By JCP&L	$ 20,461,958	(1)
2.	Required Correction to Distribution M&S Balance at 6/30/12	(3,762,948)	
3.	Corrected Distribution M&S Balance at 6/30/12	16,699,010	(2)
4.	Adjustment to Reflect 13-Month Average Corrected Distribution M&S Balance for 13 Months Ended 6/30/12	(1,877,767)	(2)
5.	13-Month Average Corrected Distribution M&S Balance	$ 14,821,243	

(1) Exhibit JC-3, Schedule SDM-2, page 17 of 24
(2) RCR-A-14 Attachment

JERSEY CENTRAL POWER AND LIGHT COMPANY
OPERATING INCOME

	JCP&L (1)	Adjustments		RC	
1. Operating Revenues					
a. Electric Retail Sales	$ 576,804,153	$ 823,138		$ 577,627,291	(2)
b. Other Operating Revenues	16,736,984			16,736,984	
c. Total Operating Revenues	593,541,137	823,138		594,364,275	
2. Operating Expenses:					
3. O&M Expenses	208,471,052	(59,135,560)		149,335,492	RJH-8
4. Depreciation Expense	92,746,142	(5,102,293)		87,643,849	RJH-14
5. Amortization Expense	38,354,159	(33,702,108)		4,652,051	RJH-15
6. Taxes o/t Income Taxes	16,700,324	(589,323)	(3)	16,111,001	
7. Total Operating Expenses	356,271,677	(98,529,284)		257,742,393	
8. Operating Income Before FIT	237,269,460	99,352,422		336,621,882	
9. Income Taxes	74,513,813	47,241,064		121,754,878	RJH-16
10. Net Utility Operating Income	$ 162,755,645	$ 52,111,358		$ 214,867,005	

(1) Exhibit JC-3, Schedule SDM-1
(2) RCR-A-106 Attachment
(3) Incentive compensation expense adjustment on Schedule RJH-11 x estimated payroll tax ratio of 7%

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JERSEY CENTRAL POWER AND LIGHT COMPANY
OPERATION AND MAINTENANCE EXPENSES

	JCP&L (1)	Adjustments		RC	
1. Unadjusted Test Year O&M Expenses	$ 194,393,842			$ 194,393,842	
Pro Forma O&M Expense Adjustments:					
2. Reclassify SNFD & PDMS RA Amort.	(1,819,000)			(1,819,000)	
3. Interest on Customer Deposits	30,912			30,912	
4. Annualize Wage Increases at 3%	3,392,898			3,392,898	
5. Amortization of Net Loss on Reacq. Debt	1,772,706	(376,168)		1,396,538	RJH-4, L8
6. BPU & RC Assessments	(94,855)	1,819	(2)	(93,036)	
7. Management Audit Fees	148,750	(33,791)	(3)	114,959	
8. Rate Case Expenses	587,000	(391,333)		195,667	RJH-9
9. Cost to Achieve Merger Synergy Savings	4,822,255	(4,822,255)		-	(4)
10. Reclassify Deferred USF Admin Costs	51,923			51,923	
11. Incremental BGS Meter Costs	75,655			75,655	
12. Normalize Forestry Maintenance Exp.	5,108,966	(5,108,966)		-	(4)
13. Acct. 935 Expense Normalization	-	(1,018,802)		(1,018,802)	RJH-10
14. Remove Incentive Compensation Exp.	-	(8,418,907)		(8,418,907)	RJH-11
15. Remove SERP Expenses	-	(408,576)		(408,576)	RJH-12
16. Pension Expense Adjustment	-	(37,664,418)		(37,664,418)	(5)
17. OPEB Expense Adjustment	-	(814,905)		(814,905)	(5)
18. Miscellaneous Expense Adjustments	-	(79,258)		(79,258)	RJH-13
19. Total O&M Expense Adjustments	14,077,210	(59,135,560)		(45,058,350)	
20. Total Adjusted Test Year O&M Expenses	$ 208,471,052	$ (59,135,560)		$ 149,335,492	

(1) Exhibit JC-3, Schedules SDM-1 and SDM-2, page 1 of 24
(2) Recommended revenue adjustment on RJH-7, L1(c) x assessment rate of 0.00221
(3) Response to RCR-A-113
(4) Testimony of Robert Henkes
(5) Testimony of Dr. Mitchell Serota

JERSEY CENTRAL POWER AND LIGHT COMPANY
RATE CASE EXPENSES

	JCP&L (1)	Adjustments	RC	
1. Estimated Rate Case Expenses				
a. Legal	$ 2,000,000			
b. Consultant Fees and Expenses	240,000			
c. Court Reporter Fees, Publ. Notices, Postage	108,000			
d. Total	2,348,000	-	2,348,000	
2. Less: Stockholder Sharing @ 50%	-	(1,174,000)	(1,174,000)	(2)
3. Ratepayer Expense Portion	2,348,000	(1,174,000)	1,174,000	
4. Amortization Period (Yrs)	4		6	(2)
5. Annual Amortization Expense	$ 587,000	$ (391,333)	$ 195,667	

(1) Schedule CP-7
(2) Testimony of Robert Henkes

JERSEY CENTRAL POWER AND LIGHT COMPANY
ACCOUNT 935 - MAINTENANCE GENERAL PLANT EXPENSE NORMALIZATION

1. Actual Account 935 Expenses - Distribution Related Only:

		(1)	
	2007	$ 1,552,757	
	2008	1,495,386	
	2009	1,564,891	
	2010	1,265,905	
	2011	2,743,237	
	5-Yr. Average	1,724,435	Normalized
2. Difference Between 2011 Test Year and Normalized Expenses		$ (1,018,802)	Recommended

(1) RCR-A-86 Attachment, page 2

JERSEY CENTRAL POWER AND LIGHT COMPANY
INCENTIVE COMPENSATION EXPENSE ADJUSTMENT

1. Total Short Term Incentive Plan (STIP) Expenses Included in Distribution Related 2011 Test Year Expense	$ 6,657,938	(1)
2. Total Long Term Incentive Plan (LTIP) Expenses Included in Distribution Related 2011 Test Year Expense	$ 1,760,969	(2)
3. Test Year Distribution STIP and LTIP Expenses	$ 8,418,907	

(1) RCR-A-57 Attachment 3
(2) RCR-A-57 Attachment 4 ($420,208 + $1,340,761)

JERSEY CENTRAL POWER AND LIGHT COMPANY
REMOVAL OF SUPPLEMENTAL EXECUTIVE RETIREMENT PLANT (SERP) EXPENSES

1. Direct JCP&L SERP Expenses in Test Year:			
a. Total Electric Expense	$ 207,417.0		
b. Distribution Allocation Factor	93.16%		
c. Distribution Related Expense		$ 193,230	(1)
2. SERP Expense Allocated from Service Company to JCP&L's Distribution Related Expense		215,346	(2)
3. Total Distribution Related SERP Expenses to be Removed from Test Year		$ 408,576	

(1) Response to RCR-A-64 Supplemental
(2) Response to RCR-A-110c

JERSEY CENTRAL POWER AND LIGHT COMPANY
MISCELLANOUS EXPENSE ADJUSTMENTS

1.	Remove Employee Clubs Expense	$	(1,387)	(1)
2.	Remove "Celebrate Success" Expenses		(5,707)	(2)
3.	Remove Service Award Expenses		(37,875)	(2)
4.	Remove Institutional/Goodwill Advertising Expense		(8,140)	(3)
5.	Remove Civic Membership Expenses		(25,295)	(4)
6.	Remove Private Club Expenses		(854)	(5)
7.	Total Miscellaneous Expense Adjustments	$	(79,258)	

(1) Response to RCR-A-132
(2) Response to RCR-A-87(d)
(3) RCR-A-85 Attachment 2
(4) RCR-A-119 Supplemental, page 2
(5) Response to RCR-A-87(h)

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Sch. RJH-14

JERSEY CENTRAL POWER AND LIGHT COMPANY
DEPRECIATION EXPENSES

	JCP&L (1)	Adjustments		RC	
1. Depreciation on Depreciable Distribution Plant at 12/31/11	$ 77,531,868	$ (2,192,029)	(2)	$ 75,339,839	(3)
2. Depreciation on Post-Test Year Distribution Plant Additions from 12/31/11 - 6/30/12	1,548,268			1,548,268	(3)
3. Total Distribution Plant Depreciation Expense	79,080,136	(2,192,029)		76,888,107	
4. Allocated General Plant Depreciation Expense	7,378,169			7,378,169	
5. Allocated Intangible Plant Depreciation Expense	6,275,094	(2,910,264)		3,364,830	(4)
7. BGS Metering Depreciation (Normalization Adj. 11)	12,743			12,743	(5)
8. Total Pro Forma Depreciation Expense	$ 92,746,142	$ (5,102,293)		$ 87,643,849	

(1) Schedule CP-2
(2) Depreciation expense associated with the removal of 12/31/11 distribution plant in service for major storms in 2011:
See Schedule RJH-3, footnote (2): $ 100,733,746 x 2.176062% = $ 2,192,029
(3) The recommended depreciation expenses will be based on the recommended depreciation rates and associated depreciation expenses included in the testimony of Rate Counsel witness Michael Majoros that will be filed on August 7, 2013. At that time, Mr. Henkes will update his testimony schedules to reflect the impact of the recommended depreciation expenses on JCP&L's revenue requirement.
(4) RCR-A-34 Attachment 2
(5) Exhibit JC-3, Schedule SDM-2, page 12 of 24

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Sch. RJH-15

JERSEY CENTRAL POWER AND LIGHT COMPANY
AMORTIZATION EXPENSES

	JCP&L	Adjustments	RC	
1. Unadjusted Test Year Amortization Exp.	$ 3,912,364		$ 3,912,364	(1)
2. Storm Damage Cost Amortization	31,479,403	(29,834,833)	1,644,570	RJH-5,L6
3. Net Cost Of Removal Amortization	4,762,102	(2,346,633)	2,415,469	(2)
4. Excess Cost of Removal Amortization	(3,758,513)		(3,758,513)	(3)
5. Gain on Sale of Property Amortization	(420,786)		(420,786)	(4)
6. Eliminate DOE SNFD Fees Amortization	(1,569,000)		(1,569,000)	(5)
7. TMI-2 PDMS Amortization	608,947		608,947	(6)
8. Production-Related RA Amortization Acceleration	1,520,642	(1,520,642)	-	(7)
9. Reclassify SNFD & PDMS RA Amort.	1,819,000		1,819,000	(8)
10. Total Amortization Expenses	$ 38,354,159	$ (33,702,108)	$ 4,652,051	

(1) See response to RCR-A-82. This balance consists of the test year deferred OPEB amortization and the Werner CT amortization which amortization expenses have expired in December 2012 (RCR-A-63) and April 2013 (RCR-A-47), respectively. To be consistent with BPU post-test year ratemaking policy, Rate Counsel has not removed these amortization expenses from the test year.
(2) See Exhibit JC-3, Schedule SDM-2, p. 16 and RCR-A-35 Attachment: JCP&L's proposed net COR amortization is based on the 2-yr. average net COR expenses for 2010 - 2011 and Rate Counsel's recommended net COR amortization is based on the traditionally allowed 5-yr. average net COR expenses for 2007 - 2011.
(3) Normalization Adjustment No. 17
(4) Normalization Adjustment No. 18
(5) Normalization Adjustment No. 19
(6) Normalization Adjustment No. 20
(7) See Exhibit JC-3, Schedule SDM-2, p. 22: JCP&L proposes to accelerate the test year amortization period to 3 years, whereas Rate Counsel rejects this proposal
(8) Normalization Adjustment No. 2

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Test Year 2011

Sch. RJH-16

JERSEY CENTRAL POWER AND LIGHT COMPANY
PRO FORMA INCOME TAX

	JCP&L	Adjustments	RC	
1. Net Revenues Before FIT	$ 237,269,460	$ 99,352,422	$ 336,621,882	RJH-7, L8
2. Pro Forma Interest	(54,861,104)	16,544,577	(38,316,527)	(2)
3. Taxable Income	182,408,356	115,896,999	298,305,355	
4. FIT and SIT @ 40.85%	74,513,813	47,343,924	121,857,738	
5. ITC Amortization	-	(102,860)	(102,860)	(3)
6. Net Pro Forma Income Taxes	$ 74,513,813	$ 47,241,064	$ 121,754,878	

(1) Response to RCR-A-138

(2) Rate Base	$ 2,040,326,088	$ 1,224,170,198	Sch. RJH-3
Weighted Cost of Debt	2.69%	3.13%	Sch. RJH-2
Pro Forma Interest	$ 54,861,104	$ 38,316,527	

(3) Response to RCR-A-138

JERSEY CENTRAL POWER AND LIGHT COMPANY
REVENUE REQUIREMENT IMPACT OF RATE COUSEL ADJUSTMENTS
$000's

	Rev Req. Impact of Adjustment
- JCP&L's Original Rate Increase Request	$ 31,471
RC-Recommended Adjustments:	
Rate of Return:	
- ROE @ 9.25% vs. 11.53% (*Kahal)*	(42,220)
- LT debt rate 6.26% vs. 5.82% *(Kahal)*	4,148
- Cap structure 50/50 Debt/Equity *(Kahal)*	(7,271)
Rate Base:	
- Remove excess COR reserve rate base addition	(11,733)
- Materials and supplies adjustment	(618)
- Cash working capital *(Peterson)*	(7,644)
- Consolidated income tax rate base deduction *(Crane)*	(55,953)
- Customer refunds	(127)
- Operating reserves + decomm. fund def. taxes	1,689
Rate Base & Amortization:	
- Unamort net loss on reacquired debt adjustment	(1,424)
- Remove all 2011 major storm damage costs	(45,954)
Operating Income:	
- Year-end customer revenue adjustment	(821)
- Management audit fee adjustment	(34)
- Rate case expense adjustment	(391)
- Remove costs to achieve merger savings adjustment	(4,822)
- Normalize tree trimming expense adjustment	(5,109)
- Remove incentive compensation expenses	(9,008)
- Acct 935 expense normalization adjustment	(1,019)
- Remove SERP expenses	(409)
- Pension expense adjustment *(Serota)*	(37,664)
- OPEB expense adjustment *(Serota)*	(815)
- Miscellaneous expense adjustments	(79)
- Depreciation expense error correction	(2,910)
- Cost of removal amortization exp adjustment	(2,347)
- Production RA amortization adjustment	(1,521)
- Reflect ITC tax credit amortization	(174)
- RC-recommended rate decrease	$ (202,759)
- Rate increase percentage	-35.10%