STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE HONORABLE IRENE JONES, ALJ

I/M/O THE VERIFIED PETITION OF	)	
ROCKLAND ELECTRIC COMPANY	)	
FOR APPROVAL OF CHANGES IN	)	
ELECTRIC RATES, ITS TARIFF FOR	)	**OAL DOCKET NO. PUC 17625-2013N**
ELECTRIC SERVICE, AND ITS	)	
DEPRECIATION RATES,	)	**BPU DOCKET NO. ER13111135**
TERMINATION OF THE SMART	)	
GRID SURCHARGE;	)	
ESTABLISHMENT OF A STORM	)	
HARDENING SURCHARGE; AND	)	
FOR OTHER RELIEF	)	

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

STEFANIE A. BRAND, ESQ.
DIRECTOR, DIVISION OF RATE COUNSEL

DIVISION OF RATE COUNSEL
140 East Front Street-4th Floor
P. O. Box 003
Trenton, New Jersey 08625
Phone: 609-984-1460
Email: njratepayer@rpa.state.nj.us

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 90 Grove Street, Suite 211, Ridgefield, Connecticut 06877. (Mailing Address: PO Box 810, Georgetown, Connecticut 06829.)

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

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in March 2008.

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

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

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 350 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved electric, gas, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony since January 2008 is included in Appendix A.

Q. What is your educational background?

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On January 28, 2014, Rockland Electric Company ("RECO" or "Company") filed a Petition with the State of New Jersey, Board of Public Utilities ("BPU" or "Board") seeking a base rate increase of $19.259 million, or approximately 7.6% on total revenue.[1] In addition, RECO proposed to eliminate its Smart Grid Surcharge and instead to recover the associated

1 All amounts referenced in this testimony exclude sales and use tax ("SUT") unless otherwise noted.

costs through base rates. The Company's case was based on a Test Year consisting of the twelve months ending March 31, 2014. As originally filed, RECO's revenue requirement reflected actual results for six months and projected results for the last six months of the test year (6+6). RECO subsequently updated its filing to reflect nine months of actual results (9+3 Update). In that update, the Company increased its electric base rate deficiency to $22.585 million. On April 23, 2014, the Company provided a further update based on twelve months of actual Test Year results (12+0 Update) claiming a revenue deficiency of $23.825 million.

The Columbia Group, Inc. was engaged by The New Jersey Division of Rate Counsel ("Rate Counsel") to review the Company's Petition and to provide recommendations to the BPU regarding the Company's revenue requirement claim. In developing my recommendations, I have relied upon the cost of capital and capital structure testimony of Rate Counsel witness Matthew I. Kahal and upon the depreciation expense and salvage value recommendations of Rate Counsel witness James Garren.

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

A. The most significant issues driving the rate increase request are the Company's claim for recovery of $25.6 million of deferred storm costs, which RECO is seeking to recover over three years, along with rate base treatment of the unamortized balance. In addition to recovery of these past storm-related costs, RECO has also included an increase of $2.3 million in the prospective rate allowance relating to storm costs. The Company's claims also include various adjustments of $4.5 million relating to net salvage, an increase in depreciation rates, post-test year salary and wage adjustments, and post-test year plant additions. RECO's claim is based on a cost of equity of 10.25%. The Company's last base rate case was resolved by BPU Order issued May 12, 2010. That case was based on a test year ending December 31, 2009.

III. SUMMARY OF CONCLUSIONS

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

A. Based on my analysis of the Company's filing, including its 12+0 Update, and other documentation in this case, my conclusions are as follows:

1. The twelve months ending March 31, 2014 is an acceptable Test Year to use in this case to evaluate the reasonableness of the Company's claims.
2. Based on the testimony of Mr. Kahal, the Company has an overall cost of capital for its electric operations of 7.46%.
3. RECO has pro forma rate base of $161.064 million (see Schedule ACC-3).[2]
4. The Company has pro forma electric operating income at present rates of $8.110 million (see Schedule ACC-12).
5. RECO should be permitted to recover its deferred storm damage costs over a period of six years. The unamortized balance of such costs should be excluded from rate

[2] Schedules ACC-1, ACC-31 and ACC-32 are summary schedules, ACC-2 is a cost of capital schedule, ACC-3 to ACC-11 are rate base schedules, and ACC-12 to ACC-30 are operating income schedules.

base.

6. RECO has a pro forma, electric base distribution revenue deficiency of $6.614 million (see Schedule ACC-1). This deficiency includes recovery of deferred storm damage costs. This is in contrast to the Company's claimed revenue deficiency of $23.825 million.

7. Since the Company's 12+0 Update was only received on April 23, 2014, we have not yet had the opportunity to review all of the underlying calculations and workpapers. In addition, some of our adjustments are based on data request responses that have not yet been updated to reflect actual results for the full twelve months of the Test Year. Therefore, the recommendations contained in this testimony may be updated based upon our review of the workpapers supporting the 12+0 Update and our review of updated data request responses.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

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

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

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	47.9%	6.02%	2.88%
Common Equity	52.1%	10.25%	5.34%
Total	100.00%		8.22%

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

A. As shown on Schedule MIK-1 of Mr. Kahal's testimony, Rate Counsel is recommending an overall cost of capital for RECO of 7.51% based on the following capital structure and cost rates:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	47.38%	5.89%	2.79%
Short Term Debt	2.26%	0.25%	0.01%
Common Equity	50.35%	9.25%	4.66%
Total	100.00%		7.46%

Mr. Kahal's recommendation reflects inclusion of short-term debt in the Company's capital structure and a reduction to the Company's claimed cost of equity. This is the overall cost of capital that I have used to determine the Company's pro forma required income, as shown on summary Schedule ACC-1, based on my recommended rate base. I then compared this required income to pro forma income at present rates to determine the Company's need for rate relief. As shown on Schedule ACC-1, my recommendations indicate that the Company currently has an electric base distribution revenue deficiency of $6.614 million.

V. RATE BASE ISSUES

A. Utility Plant-in-Service

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

A. The Company's rate base as quantified in the 12+0 Update includes actual utility plant-in-service at March 31, 2014, the end of the Test Year in this case. In addition, the Company included post-test year plant of $6.752 million, partially offset by post-test year retirements of $699,000. This resulted in a post-test year plant claim of $6.053 million. In addition, the Company is requesting a Phase II increase related to three projects – the new Summit Avenue Substation, Ringwood Mainline Undergrounding, and Harings Corner Three Way Switch Projects that are scheduled to be completed by December 31, 2015. RECO proposes to make a Phase II filing by June 1, 2015 to reflect the costs of these three projects. The Company proposes that the Phase II increase would be effective once these projects are completed and the final costs are known.

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

A. Yes, I am recommending that the BPU eliminate all post-test year plant additions from the Company's rate base.

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

A. The Company's claim for post-test year plant includes the following gross plant additions ($000):

Harings Corner Substation – New Underground Circuit Exits	$1,442.6
Smart Grid	$56.0
Other Distribution Reinforcement Projects under $500,000	$953.7
Various Blankets	$4,300.0
Total	$6,752.3

RECO also adjusted its rate base claim to reflect $699,000 in retirements associated with these post-test year plant additions.

Q. What is the basis for your recommendation to exclude these post-test year plant additions from rate base?

A. The Company's claim results in a mismatch among the components of the regulatory triad used to set rates in this case and is inconsistent with BPU precedent regarding the inclusion of post-test year plant additions in rate base. While the Company included post-test year plant additions through September 30, 2014, or six months after the end of the Test Year, it based its pro forma revenues on annualized customer counts as of the end of the Test Year. More importantly, the Company did not attempt to limit post-test year plant additions to projects that met the "major in nature and consequence" criteria of the BPU. In fact, the vast majority of the Company's claim for post-test year plant relates to blanket projects and small projects under $500,000.

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

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

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

It is clear that the Company has not met the criteria specified by the BPU for the inclusion of post-test year projects in rate base. RECO has not limited its post-test year plant-in-service claim to projects that are "major in nature and consequence." Instead, the Company has included its blanket projects and a combination of small projects in its post-test year claim. Clearly, such projects are not "major in nature and consequence" and do not meet the criteria spelled out in the Elizabethtown order for inclusion of post-test year projects in rate base. Accordingly, I recommend that the Company's claim for inclusion of post-test year plant additions be denied. My adjustment is shown in Schedule ACC-4.

Q. Do you support the Company's request for a Phase II proceeding to reflect additional costs associated with the Summit Avenue Substation, Ringwood Mainline Undergrounding, and Harings Corner Three Way Switch Projects?

A. No, I do not. It is my understanding that these projects were not started in the Test Year and in fact they are not anticipated to be completed until December 31, 2015. The Company is continuously adding to its plant in service and there is no reason to treat these projects differently than other plant additions that are made between base rate case proceedings. Moreover, there are many factors that impact on a Company's earnings in addition to plant additions. If the Company believes that these projects will jeopardize its financial integrity, it has the option of filing for a base rate case and beginning recovery from ratepayers once they are completed and placed into service. It would be premature for the BPU to authorize a Phase II at this time and I recommend that the Company's request be denied.

B. Plant Held For Future Use

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

A. Yes, the Company has included $2.256 million of plant held for future use in its rate base claim.

Q. What is plant held for future use?

A. Plant held for future use is plant that is not currently used in the provision of utility service to customers but which the Company claims has some potential to be used in the future to serve customers. One common example is land being held as a possible future site for a Company facility.

Q. Please describe the plant held for future use included in the Company's rate base claim.

A. The Company has included three components of plant held for future use in its rate base claim, as shown in the response to RCR-A-90. First, RECO has included $2.048 million related to land acquired in 2009 as the possible site for the Summit Avenue Substation. According to this response, RECO projects an in-service date for this site of 2015. Second, RECO has included $167,049 of land acquired for a possible Wyckoff Substation Site. Third, it has included $41,660 in costs for an easement at the Wyckoff Substation site. The Wyckoff land and easement have been included in plant held for future use since 1976. The Company is currently projecting an in-service date of 2017 for the Wyckoff site.

Q. Please describe your adjustment with regard to plant held for future use.

A. Plant held for future use is, by definition, not used and useful in providing utility service to current customers. In this case, the Company has included costs for two future possible substations, neither of which is in-service. The land acquired for the Wyckoff Substation has been included in plant held for future use for almost 40 years. Inclusion of this plant in rate base is surely speculative. It is unreasonable for ratepayers to continue to pay a return on this plant when it has never provided them with utility service. Accordingly, at this time I recommend that the Wyckoff Substation land and easement be excluded from rate base.

Similarly, I am recommending that the plant associated with the Summit Avenue Substation also be excluded from rate base. While the Company does have plans to develop this site over the next few years, substantial construction is not expected until the summer of 2014. The substation project is not expected to be completed until December 2015. It is inconsistent to reflect the cost of this land in rate base when the project is not in-service and when no other project costs are included in rates proposed for this case. Accordingly, I recommend that all plant held for future use be excluded from the Company's rate base claim in this case. My adjustment is shown in Schedule ACC-5.

C. Construction Work in Progress

Q. What is Construction Work In Progress ("CWIP")?

A. CWIP is plant that is being constructed but which has not yet been completed and placed into service. Once the plant is completed and serving customers, then the plant is booked to utility plant-in-service and the utility begins to take depreciation expense on the plant. Inclusion of CWIP in rate base creates a mismatch among the ratemaking components utilized for the Test Year, since it represents plant that was not actually serving customers during the Test Year. Thus, including CWIP in rate base overstates the plant necessary to provide service to those customers who were served during the Test Year and on whom the Company's revenue claim is based.

Q. What CWIP has the Company included in its rate base claim?

A. RECO included its March 31, 2014 CWIP balance of $3.936 million in its proposed rate base. As stated on page 15 of Mr. Kane's testimony, RECO's rate base claim includes "the twelve-month average of total electric non-interest bearing construction work in progress for the twelve months ending March 31, 2014."

Q. Should CWIP be included in rate base?

A. No, I do not believe that CWIP is an appropriate rate base element. CWIP does not represent facilities that are used or useful in the provision of utility service. In addition, including this plant in rate base violates the regulatory principle of intergenerational equity by requiring current ratepayers to pay a return on plant that is not providing them with utility service and which may never provide current ratepayers with utility service.

One of the basic principles of utility ratemaking is that shareholders are entitled to a return on, and to a return of, plant that is used and useful in the provision of safe and adequate utility service. By its definition, CWIP does not meet these criteria. The Company can accrue an allowance for funds used during construction ("AFUDC") on certain projects until such time as the project is completed and placed into service. Although the CWIP included in the Company's rate base claim is "non-interest bearing" and presumably does not accrue AFUDC, it still represents investment that is not in-service and that is not used or useful to ratepayers.

Moreover, allowing CWIP to be included in rate base forces today's ratepayers to pay for plant that may never provide them with any benefit. It also transfers the risk during project construction from shareholders, where it properly belongs, to ratepayers.

Q. What do you recommend?

A. I recommend that the Commission reject RECO's claim to include CWIP in rate base. My adjustment to eliminate CWIP is shown in Schedule ACC-6.

D. Accumulated Depreciation

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

A. The Company began with its projected balance for accumulated depreciation at March 31 2014. RECO then made adjustments to reflect a) additions to the reserve based on its claim for post-test year plant additions, and b) reductions to the reserve based on retirements, including the cost of removal.

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

A. Yes, I am recommending one adjustment. Consistent with my recommendation to eliminate post-test year plant additions from the Company's rate base claim, I also recommend that post-test year reserve additions and retirements related to this post-test year plant be eliminated from the reserve. This adjustment is shown in Schedule ACC-7.

E. Cash Working Capital

Q. What is cash working capital?

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

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

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

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

A. The Company has based its cash working capital claim on a lead-lag study. According to the testimony of Mr. Kane, he "calculated the lag days and applied them to the cost of service inputs for the test year ending March 31, 2014 in order to determine the cash working capital requirements of RECO that is reflected in rate base."[3] The Company used a revenue lag of 38.8 days in its analysis, consisting of a service lag of 15.2 days (365 days / 12/ 2), a billing lag of 1.5 days, and a collection lag of 22.1 days. Its average expense lag was 18.9 days, resulting in an average net lag of 19.9 days (38.8 days – 18.9 days).

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

A. Yes, I am recommending several adjustments to the Company's claim. First, I am recommending that cash working capital associated with purchased power expense be eliminated from the lead/lag study. Second, I am recommending adjustments to those cash working capital components for which RECO has claimed a zero day lag, including materials and supplies, pension expense, various expense amortizations, and deferred federal income taxes.[4] I also recommend that non-contractual costs, such as utility operating income, be excluded from the lead/lag study. I recommend that the lead/lag study be revised to include the lag on interest expense. This adjustment reflects the fact that revenues are collected in rates for interest expense on a monthly basis but debt payments are made semi-annually to the bondholders. Finally, I have revised the expense lag associated with Investment Tax Credits ("ITCs") from 0 days to37.5 days, which is the lag reflected by RECO for federal income taxes.

3 Direct Testimony of Mr. Kane, page 19, lines 13-15.
4 The Company included 79.5 lag days for OPEB costs on Exhibit P-3, Schedule 6, page 2 but its actual calculation reflects a zero lag. In response to S-RCWC-1-3, the Company indicated that the zero lag was due to a formula error, and that the lag of 79.5 days should be applied.

Q. Why are you recommending that purchased power costs be excluded from the Company's cash working capital requirement?

A. I am recommending that these costs be excluded from the cash working capital calculation because purchased power costs are not distribution costs and should not be included in base rates for distribution service. Customers have the option of purchasing power from RECO through Basic Supply Service ("BGS") or from a third-party supplier. Customers that purchase from a third-party are presumably paying a price that recovers the cash working capital requirements of the third-party supplier. It is unreasonable to have these customers also fund cash working capital associated with power purchases for those customers that choose to receive BGS from the electric utility.

In addition, not only has RECO included a cash working capital requirement associated with BGS power purchases but it has also included a cash working capital requirement associated with its deferred Purchased Power Expense balance, which was reflected in the cash working capital study at a zero expense lag. As discussed below, the use of a zero lag has the effect of increasing the Company's cash working capital requirement. Moreover, a review of the Company's deferred balance during the last twelve months shows that RECO was over-recovered in six months and under-recovered in six months. Thus, in many months, ratepayers had actually overpaid for purchased power while in other months the Company had under-recovered its costs. But the Company is made whole for its purchases, over time, through the BGS mechanism. That mechanism is separate and distinct from the process used to set distribution base rates. In addition, I understand that the Company receives interest on any under-recovery of the BGS balance. Given that power supply costs are recovered from BGS customers through the BGS rider mechanism, I recommend that these costs be excluded from the Company's cash working capital claim in this case. My adjustment is shown in Schedule ACC-8.

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

A. In addition to deferred purchased power expense, RECO has claimed a zero day lag for several cash working capital components, including materials and supplies; pension expense; expense amortizations associated with storm reserves, rate case costs, BPU assessments, and regulatory deferrals; deferred federal income taxes; and investment tax credits. The inclusion of these items with a zero lag actually has a very significant impact on the cash working capital requirement because it reduces the average number of lag days for expenses. The reduction in the expense lags results in an increase in the overall cash working capital requirement net lag days, which has a very direct and significant impact on the calculation of the amount of cash working capital required by the Company.

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

A. In the response to S-RCWC-1-2, the Company indicated that "A zero lag was assigned to the amounts included in the cost of service for these items because the related assets are either non-cash or are included in rate base as separate components."[5]

Q. How do you propose to reflect those items for which RECO has reflected a zero day lag?

A. My recommendation depends upon the specific cash working capital component. For example, with regard to pension expense, these costs are typically paid monthly by the utility. Therefore, I am recommending that these costs be included in the cash working capital requirement with a lag of 30 days. I have eliminated the Company's claim for materials and supplies balance entirely from cash working capital because, as noted, the average materials and supplies is already included in the Company's rate base. Therefore, no further cash working capital allowance is necessary and in fact materials and supplies are not generally included in a lead/lag study.

With regard to BPU assessments, I have utilized the Company's proposed revenue lag, since BPU assessments are based on the level of revenue generated by each utility. With regard to investment tax credits, I have utilized the current federal income tax expense lag. RECO reflected an expense lag of 0 days for ITCs. However, RECO does not receive the reduction in taxes associated with ITCs on a daily basis, but only receives this reduction as it actually pays its taxes. Therefore, I recommend that the BPU utilize the same expense lag for ITCs as is used for current income taxes. Accordingly, I have made an adjustment to increase the expense lag for ITCs from 0 days to 37.5 days, is which the lag claimed by the Company for current taxes.

5 Response to S-RCWC-1-2.

I have excluded depreciation expense, the remaining amortizations, and deferred income taxes entirely from the Company's cash working capital calculation. My adjustments are shown in Schedule ACC-8.

Q. Why have you excluded depreciation and amortization expense and deferred income taxes from the Company's cash working capital claim?

A. It is inappropriate to include depreciation and amortization expense and deferred income taxes in a utility's cash working capital claim because these costs do not result in cash outflows by the utility. RECO does not make cash payments for depreciation, amortization, or deferred taxes on a specified date. The purpose of a lead/lag study is to match cash inflows, or revenues, with cash outflows, or expenses. Cash working capital reflects the need for investor-supplied funds to meet the day-to-day expenses of operations that arise from the timing differences between when RECO has to expend money to pay the expenses of operation and when revenues for utility service are received by the utility. Only items for which actual out-of-pocket cash expenditures should be made are included in a cash working capital allowance. Therefore, at Schedule ACC-8, I have made an adjustment to eliminate the cash working claims associated with depreciation and amortization expense and deferred taxes from RECO's cash working capital claim.

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

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

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

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

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

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

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

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

A. The lag in the payment of interest expense must be reflected in the cash working capital calculation so that ratepayers are compensated for providing a cost-free source of capital to RECO. In developing my adjustment, I included the interest expense at a lag of 91.25 days, which reflects semi-annual payments of interest.[6]

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

A. To summarize, I have eliminated all purchased power costs from the Company's cash working capital claim. I have revised the expense lag for pension costs, from the zero days reflected by RECO to 30 days. I have revised the lag for investment tax credits to be consistent with the lag for current federal income taxes. I have eliminated depreciation and amortizations included by the Company at a zero lag. I have also eliminated return on invested capital and included the lag in the payment of interest expense. My adjustments result in a cash working capital allowance $5.17 million, as shown in Schedule ACC-8, instead of the $8.88 million included in the Company's claim.

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

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

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

F. Deferred Regulatory Balances

Q. Has the Company included deferred regulatory balances in its rate base claim?

A. Yes, it has. As shown on Exhibit P-3, Schedule 7, the Company included $26.762 million of deferred regulatory balances in its rate base claim, partially offset by deferred income taxes of $10.933 million, for a net deferred regulatory balance of $15.829 million. The vast majority of these net deferrals ($15.173 million) relate to storm deferrals. The remaining deferrals relate to other amortizations authorized in the Company's last base rate case, such as various audit costs, the transformer installation refund, property tax refunds, deferred pension and OPEB costs, costs of removal, and smart grid costs.

Q. In its last case, was the Company authorized to collect carrying costs on its regulatory amortizations?

A. No, it was not. There is nothing in the Order or Stipulation in the last case authorizing carrying costs on these deferrals. While the amount and time period for recovery of these deferred costs is discussed on page 4 of the Order in BPU Docket No. ER09080668, the regulatory treatment reflected in the Order does not include carrying costs.

Q. Do you believe that carrying costs are appropriate?

A. No, I do not. The Company is already being given extraordinary rate treatment by being able to recover these costs on a dollar-for-dollar basis from ratepayers. It is shareholders, and not ratepayers, who are generally responsible for variations in costs between base rate case filings. To the extent that actual costs vary from the level reflected in current rates, shareholders generally must absorb any shortfall. Alternatively, shareholders also benefit from variations when actual costs are less than projected or when revenues exceed the level adopted in the last base rate case.

With regard to regulatory deferrals, the risk of cost fluctuations is being transferred from shareholders to ratepayers. This is especially true with regard to storm damage costs, which account for the majority of the regulatory deferral in this case. As discussed later in this testimony, Rate Counsel is recommending that the level of storm damage costs approved in BPU Docket No. AX13030196/EO13070611 be recovered from ratepayers. However, we are not recommending carrying charges on these costs. Carrying charges have not generally been utilized in New Jersey for regulatory deferrals. Given that the Company is being made whole for these costs by being permitted to defer and recover them from future ratepayers, I do not believe that it would be appropriate to also require ratepayers to provide a return on these past costs. Accordingly, at Schedule ACC-9, I have made an adjustment to eliminate from rate base the Company's claim for carrying costs on regulatory deferrals.

G. Accumulated Deferred Income Taxes

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

Q. Yes, I am recommending one adjustment, resulting from my recommendation to utilize actual balances at March 31, 2014 for utility plant-in-service. As stated on page 18 of Mr. Kane's testimony, RECO included a post-test year deferred income tax reserve adjustment to reflect "the tax effects of various plant additions and amortizations, including post test year adjustments." Since I am recommending that utility plant be limited to actual plant balances at the end of the Test Year, I eliminated the Company's post-test year deferred income tax reserve adjustment. My adjustment is shown in Schedule ACC-10.

H. Consolidated Income Taxes

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

A. Yes, it did. On page 18 of Mr. Kane's testimony, he states that the Company included "the consolidated tax adjustment first imputed as an adjustment to RECO's Rate Base in BPU Docket No. ER06060483." RECO's adjustment is based on cumulative tax benefits for the period 1991-2012. The Company stated that "[i]nformation to calculate the 2013 adjustment is currently not available and amounts reflected for calendar year 2012 have not been finalized." [7]

Q. How does the BPU calculate consolidated income tax adjustments for ratemaking purposes?

A. The last litigated rate case in which the BPU addressed the methodology for calculating consolidated income tax adjustments was BPU Docket No. ER02100724, a base rate case proceeding involving RECO. In that proceeding, the BPU allocated tax losses to all members of the consolidated income tax group that had cumulative positive taxable income. Pursuant to the BPU's methodology employed in that case, the first step is to determine if each company included in the consolidated group had cumulative taxable income or a cumulative tax loss for the period 1991 to the present, which I will refer to as the Review Period. This analysis results in two groups of companies, those with cumulative taxable income over the Review Period and those with cumulative tax losses.

The second step is to calculate the tax loss, by year, for those companies that had a cumulative tax loss for the Review Period. The tax loss for each company in the group is then accumulated, by year, in order to determine the total annual loss for the consolidated group by year. The total annual loss, by year, is then multiplied by that year's annual federal income tax rate, in order to determine the tax loss benefit for the consolidated group by year. Adjustments are also made to reflect any alternative minimum tax ("AMT") payments made

7 RECO also noted that the BPU has initiated a generic investigation into the issue of consolidated income tax adjustments (BPU Docket No. EO12121072). The Company reserved its right to adjust or eliminate the consolidated income tax adjustment based upon the outcome of that proceeding.

by the group. The annual tax loss benefits, net of AMT, are then accumulated for the entire Review Period, to determine the total tax loss benefit that is subject to allocation.

In step three, the accumulated tax loss benefit is then allocated to each company that had positive taxable income on a cumulative basis during the Review Period. The accumulated tax loss benefit is allocated based on the percentage share of each entity's positive taxable income to the total accumulated positive taxable income of the group. This resulted in an allocation of 13.42% of the tax benefit being allocated to RECO prior to the Consolidated Edison merger and 2.39% being allocated to RECO subsequent to the merger.

Q. Did RECO utilize this methodology in calculating its adjustment?

A. RECO made two significant changes in its calculation. First, in calculating its proposed consolidated income tax adjustment, the Company eliminated tax losses incurred by companies that have since left the consolidated income tax group. Second, the Company included only 88.62% of its adjustment in rate base, claiming that the adjustment should reflect only its distribution allocation.

Q. Prior to allocating any income tax benefit to the utility, should the benefits resulting from tax losses incurred by companies that are no longer part of the consolidated income tax group be eliminated?

A. No. The rate base method of calculating consolidated income taxes is based on the theory that the companies with cumulative positive taxable income over the period provided a "loan" to the companies with cumulative tax losses. Moreover, the methodology adopted in New Jersey, i.e., calculating a rate base offset for the cost-free capital provided by the consolidated income tax filing, means that ratepayers are only benefiting by earning a carrying charge on the excess taxes reflected in rates. Even under the BPU-approved methodology, ratepayers are not compensated for the actual excess of income taxes that they pay in rates relative to the Company's allocated share of the actual taxes paid. Hence the rate base adjustment can be viewed as the ratepayers "loaning" the Company a sum equal to the difference between the statutory tax expense paid by RECO to its parent, and RECO's allocable share of the lower taxes actually paid by the consolidated group to the IRS.

Ratepayers receive the benefit of the consolidated income tax adjustment as long as a member of the consolidated group has a cumulative tax loss. Once that member has cumulative positive taxable income, that member's tax losses are no longer included in the calculation. The problem with excluding past members that are no longer part of the consolidated income tax group is that such an exclusion would mean that ratepayers would never be compensated for the loan provided to the entity that left the group. Until (and unless) the utility is repaid for its "loan", then the consolidated income tax adjustment should compensate ratepayers for these funds. There is nothing in the methodology adopted by the BPU in Docket No. ER02100724 to suggest that ratepayers should permanently fund any loans to entities that have departed from the consolidated income tax group. Instead, shareholders should fund these loans by continuing to provide a consolidated income tax adjustment to the utility's ratepayers. Therefore, the companies that have left the consolidated group should continue to be included in the consolidated income tax calculation for those years during which they were part of the group. My adjustment is shown in Schedule ACC-11.

Q. In the last litigated case, did the BPU allocate any amounts to non-distribution services?

A. No, it did not. All of the adjustment quantified in the 2002 case was allocated to the distribution function. Therefore, in calculating my consolidated income tax adjustment shown in Schedule ACC-11, I also allocated 100% of the RECO tax benefit to distribution services.

Q. Have you made any other adjustment to the Company's consolidated income tax calculation?

A. Yes, I have made one additional adjustment. The Company did not include data for 2013 in its calculation. I have updated RECO's calculation to include an adjustment for 2013. As a proxy, I used the average annual tax loss over the last five years (2008-2012) to estimate the 2013 loss that should be allocated among the companies with positive taxable income. This adjustment is also included in Schedule ACC-11.

Q. Hasn't the BPU initiated a generic proceeding to investigate the issue of consolidated income tax adjustments?

A. Yes, it has. The BPU issued an order on January 23, 2013 in BPU Docket No. EO12121072, establishing a generic proceeding on the issue of consolidated income taxes. In that Order, the BPU stated that "until such time as the Board makes a final determination on the consolidated tax adjustment issues, the current consolidated tax savings policy shall apply." Thus, the BPU was very clear that until the generic proceeding is concluded, its current policy with regard to consolidated income tax adjustments should be followed. That is the policy that I have reflected in my consolidated income tax adjustment.

I. Summary of Rate Base Issues

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

A. My recommended adjustments reduce the Company's rate base from $194.587 million, as reflected in the 12+0 Update, to $161.064 million, as summarized on Schedule ACC-3.

VI. OPERATING INCOME ISSUES

A. Pro Forma Revenues

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

A. RECO began with its actual test year revenues, as reflected in the 12+0 Update. The Company then eliminated revenues associated with the Smart Grid surcharge (which is being rolled into base rates), normalized its Test Year sales for normal weather, and annualized revenues for changes in the number of customers during the Test Year. RECO also included an adjustment to reflect a three-year average of miscellaneous revenue.

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

A. Yes, I am recommending one adjustment, relating to the annualization of Test Year customers. In addition, I have concerns about the weather normalization adjustment provided in the 12+0 Update. Given the fact that this update was not provided until shortly before this testimony was filed, I have not had the opportunity to receive or analyze the Company's supporting documentation for this adjustment. Therefore, I may propose an additional adjustment to the Company's weather normalization claim after I have received and reviewed the underlying support.

Q. Please explain your adjustment relating to annualization of Test Year customers.

A. In its filing, RECO included an adjustment to reflect increases in customer counts through March 31, 2014. The Company then offset this additional revenue by incremental customer costs associated with serving these customers. RECO used an annual customer cost of $283.56 for residential customers and an annual customer cost of $705.60 for non-residential customers.

I believe that the incremental costs used by the Company in its adjustment are excessive. The customer costs provided by the Company included costs in Accounts 361-386, which contain distribution plant that would not necessarily change with increases in customer counts, especially the relatively modest increases (52 residential customers and 22 non-residential customers) contained in the filing. In RCR-RD-10, the Company provided its estimated per customer costs excluding Accounts 361-368. This response shows customer costs of $202.20 for residential customers and of $422.64 for commercial and industrial ("C&I") customers. These are the costs that I have used to offset the incremental revenue resulting from the Company's customer annualization adjustment. My adjustment is shown in Schedule ACC-13.

Q. Please describe you concerns relating to the Company's weather normalization adjustment.

A. In its original filing, RECO projected Test Year revenue (net of purchased power supply costs) of $72.068 million. In its 9+3 Update, the Company projected weather normalized sales (net of purchased power supply costs) of $72.618 million. Both of these scenarios included a customer annualization adjustment of $262,000. However, in its 12+0 Update, RECO is now claiming weather normalized Test Year revenue of only $69.244 million. It has revised its customer annualization adjustment downward to $111,003, so that accounts for approximately $150,000 of the difference. However, that still leaves a significant difference of over $3.2 million or approximately 4.5% of revenue.

Since the Company's filings have all been weather normalized, then this difference cannot be explained by actual results alone. Instead, either the Company changed its weather normalization methodology between the filing of its 9+3 Update and the filing of its 12+0 Update or it made other changes that effectively lowered its pro forma revenue at present rates by $3.2 million.

Unfortunately, the 12+0 Update was not provided until April 23, 2014, which did not provide sufficient time to investigate the significant drop in Test Year revenue. I am continuing to investigate this decline and may recommend an additional adjustment to pro forma revenue at present rates once the Company provides workpapers supporting the weather normalization adjustment reflected in the 12+0 Update and explaining the rationale for the significant decline in pro forma revenue.

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

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

A. The Company made four adjustments to its actual Test Year salary and wage costs reflected in its 12+0 Update. First, it annualized a wage increase for weekly employees that was effective June 1, 2013. Second, it included an additional wage increase for weekly employees effective June 1, 2014. Third, it included a salary increase effective April 1, 2014 for monthly employees. Finally, it annualized costs for five employees added during the Test Year.[8]

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

A. Yes, I am recommending that the Company's adjustments relating to post-test year salary and

8 It should be noted that the increases included in the Company's 12+0 Update do not agree with the description of the increases included in Mr. Kosior's testimony at pages 5 and 6.

wage increases be excluded from the Company's revenue requirement. Therefore, I have excluded the Company's adjustments relating to the April 1, 2014 increase and the June 1, 2014 increase. I have also eliminated the portion of RECO's adjustment related to employee positions added during the Test Year that reflected the post-test year increase for these employees.

Q. What is the basis for your adjustment?

A. My adjustment is based on the maintaining the integrity of the Test Year matching principle, matching the Test Year revenues, expenses and investment. The actual salary and wage expense incurred by the Company can vary depending upon the level of employees at any given time, the extent to which costs are allocated to RECO relative to other affiliates, capitalization ratios, and other factors. Therefore, while I have accepted the Company's adjustments that annualize salary and wage increases that took place during the Test Year, I have not included those adjustments that result from post-test year increases. My adjustment is shown in Schedule ACC-14.

Q. How did you quantify your adjustment?

A. To determine the adjustments relating to the June 1, 2014 and April 1, 2014 salary and wage increases, I simply reversed the Company's adjustments. With regard to the adjustment relating to employees added during the Test Year, the adjustment was more complex.

To determine the amount of pro forma salary and wage expense for these employees, I first annualized payroll costs for these employees based on actual costs in March 2014, the last month of the Test Year, based on the response to RCR-A-16. This resulted in pro forma costs of $162,012. That same response shows that $68,522 of payroll costs is already reflected in the Test Year. Therefore, it is necessary to make an adjustment of $93,490 ($162,012 - $68,522) to reflect the annualization of payroll costs for these employees. Since the Company included an adjustment of $135,000 in its 12+0 Update, my recommendation results in a reduction of $41,610 to the Company's claim. This adjustment is also shown in Schedule ACC-14.

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

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

A. RECO has two incentive compensation programs for its management employees, the Annual Team Incentive Plan ("ATIP") and the Long-Term Incentive Plan ("LTIP"). ATIP awards are based on three performance metrics: 50% on customer service metrics, 25% on earnings metrics, and 25% on operating budget metrics. In addition, 60% of the ATIP award is based on team performance and 40% on individual performance.

The LTIP consists of restricted stock awards and equity grants for management employees. The specific LTIP award parameters depend upon the employee's level of management. Employees in Bands 1 and 2 are granted restricted stock awards tied to a continued employment of three years before the stock is vested. Employees in Bands 3 and 4 are awarded equity grants, tied to two measures: 50% of the award is based on the 3-year total shareholder return relative to a peer group of companies while the remaining 50% is tied to the 3-year corporate average of the ATIP award fund. According to the Supplemental Response to RCR-A-37, RECO included ATIP costs of $889,900 and LTIP costs of $247,800 in its filing for management awards.

Q. Did the Company include officers incentive program costs in its revenue requirement claim as well?

A. Yes, it did. The LTIP discussed above is also provided to all officers while the ATIP is provided to all officers except for the President and Chief Executive Officer ("CEO"). The President and CEO participate in an Executive Incentive Plan ("EIP"). According to the response to RCR-A-38, the EIP incorporates the ATIP goals for customer service (weighted at 30%) and the operating budget (weighted at 20%). The remaining 50% of the EIP is based on a net income goal. The Company has not yet identified how much was included in its 12+0 Update for officer incentive award payment. In 2013, it incurred ATIP costs of $131,600 and LTIP costs of $336,300 for officers.

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

A. No, I do not. I have several concerns about these types of programs, especially as designed and implemented by RECO. The Company's incentive plans are heavily weighted toward financial objectives. Providing employees with a direct financial interest in the profitability of the Company is an objective that would benefit shareholders, but it does not benefit ratepayers.

Incentive compensation awards that are based at least partially on earnings criteria may violate the principle that a utility should provide safe and reliable utility service at the lowest possible cost. This is because these plans require ratepayers to pay higher compensation costs as a consequence of high corporate earrings, a spiral that does not directly benefit ratepayers, but does benefit shareholders and the management to whom such awards are granted.

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

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

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

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

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

A. Yes, they are. Over the last five years, management employees have consistently been awarded annual payroll increases of 2%-3%. According to Mr. Kosior's testimony on pages 5-6, annual union increases have also averaged approximately 3.0% over the past few years. There is no indication that the employees of RECO are underpaid or that the Company would have difficulty attracting qualified employees in the absence of these programs.

Q. Has the BPU previously addressed this issue?

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

> Staff is persuaded by the arguments of the RPA that, at this time, the incentive compensation expenses should be not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also

> indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.[9]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be permitted to recover 50% of its incentive compensation costs in rates. However, the BPU rejected the ALJ's recommendation and instead ordered that 100% of these costs be disallowed.[10]

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

> We are persuaded by the arguments of Staff and Rate Counsel that, at this time, the incentive compensation or "bonus" expenses should not be recovered from ratepayers. The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills and otherwise remaining profitable. These circumstances, as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.[11]

During this time, the Company has not only sought three rate increases but it has also provided annual salary increases to its employees. During this period, ratepayers have faced

9 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Staff Initial Brief, page 37.
10 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part Initial Decision at 25-26 (June 6, 2001).
11 I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, BRC Docket No. ER91121820J, Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision at 4 (June 15, 1993).

difficult economic conditions, compounded by several major storms that have put a significant financial burden on some residents. Thus, the BPU's reasoning for disallowing these costs is just as relevant today as it was in 1993. The BPU's findings on this issue therefore support my recommendation that all such costs be excluded from the Company's revenue requirement.

Q. Aren't the Company's compensation policies, at least for executives, tied to industry benchmarks?

A. Yes, they are. However, the Company's methodology that ties executive compensation to industry benchmarks results in ever-increasing compensation costs. This is because the Company targets compensation at the 50^{th} percentile for its peer group, which is fairly common practice. Unfortunately, the result of this policy is that companies that are under the 50^{th} percentile increase compensation in an attempt to reach the 50^{th} percentile, thereby raising the 50^{th} percentile even higher and putting additional companies below the 50^{th} percentile threshold. Thus, while the use of industry benchmarks is a popular method for determining executive compensation, the result is continually increasing compensation levels.

As shown in the 2013 Proxy Report, executives are well paid. Annual salaries for the Named Executive Officers ranged from $405,959 to $1,244,063 in 2013. In addition, non-equity incentive plan compensation ranged from $422,300 to $1,618,800, while stock awards ranged from $946,800 to $4,870,760. The issue for the BPU should be what is an appropriate amount of incentive compensation to recover from ratepayers.

Q. What do you recommend?

A. I recommend that the BPU exclude 50% of the Company's incentive compensation costs for employees from utility rates. This recommendation recognizes that employees' incentive compensation costs are heavily impacted by financial metrics. In addition, it recognizes the fact that the impact of individual performance on the ATIP award is limited. In addition, I recommend that 100% of incentive compensation costs for officers be excluded from the Company's revenue requirement. Officers are already well-compensated. Permitting these costs to be recovered from ratepayers eliminates the Company's incentive to control officer compensation costs. If the Company chooses to award officers with incentive compensation, these costs should be funded by shareholders instead of the Company's ratepayers. My adjustments to incentive compensation are shown in Schedule ACC-15.

D. Payroll Tax Expense

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

A. Since I am recommending adjustments to the Company's claims for salaries and wages and incentive compensation costs that result in a net expense reduction, it is necessary to make a corresponding adjustment to eliminate certain payroll taxes from the Company's revenue requirement claim. At Schedule ACC-16, I have eliminated payroll taxes associated with my recommended salary and wage adjustments and with my incentive compensation plan adjustment. To quantify my payroll tax adjustment, I utilized the pro forma payroll tax rate of 7.47%, which was reflected in the Company's filing, and applied it to my recommended adjustments for salaries and wages and for incentive compensation program costs.

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

Q. What are SERP costs?

A. These costs relate to supplemental retirement benefits for key executives that are in addition to the normal retirement programs provided by the Company. These programs generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. As stated in the 2013 Proxy Statement, "[t[he supplemental retirement income plan provides certain highly compensated employees (including the Name Executive Officers) whose benefits are limited by the Internal Revenue Code with that portion of their retirement benefit that represents the difference between (i) the amount they would have received under the retirement plan absent IRS limitations on the amount of final average salary that may be considered in calculating pension benefits, and the amount of pension benefits paid and (ii) the amount actually paid from the retirement plan."

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

A. As shown in the Supplemental Response to RCR-A-41, the Company incurred SERP expense of $435,471 in the Test Year.

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

A. No, I do not. The officers of the Company are already well compensated. In 2013, total compensation for the Named Executive Officers ("NEOs") ranged from $1.869 million for the President and Chief Executive Officer ("CEO") to $7.933 million for the former President and CEO. Moreover, the officers that receive SERP benefits are also included in the normal retirement plans of the Company, so ratepayers are already paying retirement costs for these executives. If RECO wants to provide further retirement benefits to select officers and executives then shareholders, not ratepayers, should fund these excess benefits. Therefore, I recommend that the Company's claim for SERP costs be disallowed. My adjustment is shown in Schedule ACC-17.

F. <u>Employee Benefit Expense</u>

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

A. RECO's claim is based on applying a medical benefit expense ratio of 22.15% to its claimed salary and wage adjustment. This ratio consists of 20.62% for employee health and group life insurance costs and of 1.52% for workers compensation and public liability costs. These percentages were derived from examining the 2013 fringe benefit rates.

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

A. Yes, since I am recommending adjustments to the salary and wage and incentive compensation claims, it is necessary to make a corresponding adjustment to reduce the employee benefit costs to eliminate the benefits associated with the payroll costs that I have disallowed. Therefore, at Schedule ACC-18, I have made an adjustment to employee benefit expense. I have quantified my adjustment based on the Company's proposed percentage of 22.15% applied to my recommended salary and wage and incentive compensation adjustments.

G. Rate Case Expense

Q. How did the Company develop its claim for rate case costs relating to this case?

A. RECO's rate case expense claim is based on total estimated costs for the current rate case of $600,000, as shown in the Supplemental Response to RCR-A-71. This includes $500,000 in external legal costs; $70,000 for cost of capital services, and $30,000 for printing and other miscellaneous expenses. The Company is proposing to amortize these costs over three years, for an annual amortization expense of $200,000.

Q. Did the Company solicit competitive bids for rate case services relating to this case?

A. No, it did not. According to the response to RCR-A-73, the Company did not issue any Requests for Proposal for services associated with this rate case.

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

A. Yes, I am recommending two adjustments. First, I am recommending a reduction in the pro forma costs projected for this case, since I believe that the Company's claim is excessive.

The estimated costs for the current case are significantly higher than the actual costs incurred in the last three base rate case proceedings, as shown below:[12]

	Rate Case Expense
2002 Case	$513,998
2006 Case	$309,494
2009 Case	$216,193
Average	$346,561

In order to determine a normalized level of rate case costs, I recommend that the BPU utilize an average of RECO's costs in its last three base rate proceedings. The 2002 rate case was a litigated case, that included a Phase 2 proceeding.[13] The 2006 and 2009 cases were settled. These three cases therefore represent a good mix of regulatory activities. My recommendation results in a pro forma cost of $346,561 for the current case. In addition, I have accepted the Company's proposal to use a three-year amortization period for rate case costs associated with the current proceeding. Accordingly, at Schedule ACC-19, I have made an adjustment to reflect prospective annual costs of $346,561, based on the average costs over the last three rate cases, and a three-year amortization period.

Q. What is your second adjustment?

A. The BPU has a long-standing policy of requiring a 50/50 sharing of rate case costs between shareholders and ratepayers. This policy is based on the assumption that base rate case filings provide benefits to both shareholders and ratepayers, and therefore should be allocated

12 Per the response to RCR-A-70.
13 The Phase 2 in BPU Docket No. ER02100724 was settled.

equally between the two groups. The Company has not reflected any sharing of rate case costs in its filing. Accordingly, at Schedule ACC-19, I have also made an adjustment to allocate 50% of the Company's pro forma annual rate case costs to shareholders.

H. Storm Damage Expense

Q. How did the Company develop its claim for storm damage expense in this filing?

A. The Company's 12+0 Update includes a deferred storm damage balance at March 31, 2014 of $25,652,364. The Company proposed to amortize these costs over three years. In addition to the amortization expense associated with the deferred storm damage expense balance, the Company also proposed to increase its current storm damage rate allowance from $375,799 to $2,668,832. The claim of $2,668,832 reflects actual storm damage costs over the past five years, excluding costs for Superstorm Sandy. In addition, the Company proposed that an unamortized balance of $26,762,000 be included in rate base, net of deferred income taxes. RECO's proposed rate base adjustment was discussed earlier in this testimony.

Q. Has the BPU taken any independent action on storm damage costs?

A. Yes, it has. On March 20, 2013, the BPU initiated a generic proceeding to examine the costs incurred by New Jersey utilities relating to major storm events in 2011 and 2012.[14] The BPU ordered that utilities seeking recovery of unreimbursed costs related to these storms submit a comprehensive report by July 1, 2013, identifying and quantifying the costs for which they

14 In the Matter of the Board's Establishment of a Generic Proceeding to Review the Prudency of Costs Incurred by New Jersey Utility Companies in Response to Major Storm Events in 2011 and 2012, BPU Docket No. AX13030196.

are seeking recovery. RECO filed the required Report on July 1, 2013. On September 30, 2013, RECO made a subsequent filing in a RECO-specific sub-docket (EO13070611). In that Petition, RECO requested recovery of deferred operating and maintenance costs and capital costs relating to Hurricane Irene, the October Snowstorm, and Superstorm Sandy. Specifically, the Company included the following costs in its filing:

Event	Operating	Capital
Hurricane Irene	$2,986,588	$483,640
October 2011 Snowstorm	$5,544,120	$690,965
Hurricane Sandy	$16,843,156	$4,425,950
Total	$25,373,864	$5,600,555

I did not participate in the RECO-specific investigation into storm damage costs, but I have been informed by Rate Counsel that the parties have executed a Stipulation in that case. In that Stipulation, the parties agree to permit RECO to recover $25,645,780 in deferred O&M storm-related costs. The Stipulation stated that these costs would be "amortized over a period and at a carrying charge rate to be determined in the Base Rate Case."[15] It also stated that the "parties reserve the right to take whatever position each deems appropriate regarding

15 Stipulation in BPU Docket No. AX13030196 / EO13070611, page 6.

the length of the amortization period...and regarding the carrying charge to be applied to the unamortized balance..."[16]

Q. Given the BPU's investigation of storm damage costs in BPU Docket No. AX13031096 and EO13070611, are you recommending any adjustment to the storm expense claim proposed by RECO in its 12+0 Update?

A. I have accepted the Company's claim for recovery of deferred storm damage costs of $25,652,364. The Company's claim is based on the amount agreed upon by the parties in the generic proceeding, as well as a small amount ($6,584) for storms that were not included in the generic investigation. However, I am proposing a six-year amortization instead of the three-year period requested by RECO. In addition, as discussed earlier, I have not included the unamortized balance of deferred storm costs in my recommended rate base.

Finally, I am recommending that the Company's proposal to increase its prospective rate allowance be denied.

Q. Why are you recommending a six-year amortization period instead of the three-year period proposed by the Company?

A. The Company's requested increase corresponds to a 41.8% increase on distribution rates. Even though we are recommending a significantly lower rate increase than the increase proposed by RECO, our recommendation still results in a distribution base rate increase of

16 Id.

approximately 11.6%. Given the magnitude of this increase, I believe that a six-year recovery period is more appropriate than the three-year period proposed by RECO. Another factor to consider when evaluating an appropriate recovery period is the fact that the current deferred storm costs reflect the three most severe storms in the Company's history. Therefore, each of these storms was historic on an individual basis. When considered together, these storms constitute an unprecedented cost for RECO ratepayers. While Rate Counsel has agreed to permit the Company to recover these costs through utility rates, the magnitude of the costs and the historic nature of the storms suggest that a three-year recovery period is too short. Furthermore, a six-year amortization period is also reasonable when one considers the fact that in its last base rate case, RECO was permitted to recover its storm reserve deficiency, which was significantly smaller than the current deficiency, over five years. For all these reasons, I have reflected a six-year amortization period for storm damage costs at Schedule ACC-20.

Q. What is the basis for your adjustment relating to the prospective rate allowance?

A. The past five years was not a normal period for purposes of calculating ongoing prospective storm damage costs. Even though the Company has removed the impact of Superstorm Sandy from its calculation, actual costs over the past five years still reflect several extraordinary storms, such as Hurricane Irene and the 2011 Snowstorm. These two storms constitute the worst storms in the Company's history, except for Superstorm Sandy. Therefore, using actual costs over this five-year period does not necessarily result in a representative normalized cost for ratemaking purposes.

In addition, RECO has historically been permitted to recover its actual storm damage costs, regardless of the annual rate allowance. The entire purpose of a rate allowance is to determine a normalized level of costs to include in prospective rates. Utilities are not generally permitted to true-up actual storm damage costs that exceed this allowance, unless there is an extraordinary event and the Company receives authorization from the BPU for a cost deferral.

If the BPU decides to continue to include any prospective rate allowance in rates, then I recommend that it continue the allowance approved in the last case. Therefore, at Schedule ACC-20, I have made an adjustment to reflect a prospective rate allowance of $375,799. Alternatively, if the BPU intends to permit the Company to true-up all future storm damage costs, then it may decide to eliminate any prospective storm damage rate allowance from the Company's prospective rates.

I. Advertising Expense

Q. Has the Company included any costs in its claim related to institutional advertising and public relations?

A. Yes, as shown in the response to S-RREV-1-30, RECO has included $116,408 of costs related to institutional advertising and public relations in its revenue requirement claim.[17] The Company identified these costs in response to a question from Staff specifically

17 Based on a distribution allocation of 89.96%.

requesting the quantification of costs related to "corporate branding or promoting the Company's goodwill."

Q. Are you recommending any adjustment to these advertising costs?

A. Yes, I am recommending that these institutional advertising and public relations costs be disallowed. Costs related to corporate branding and promoting the corporate goodwill are not necessary for the provision of safe and reliable electric service and do not provide a direct benefit to ratepayers. These costs are generally incurred in order to benefit the corporate image of the utility. Therefore, to the extent such costs are incurred, they should be absorbed by the Company's shareholders instead of being passed through to ratepayers. Accordingly, I am recommending that the institutional advertising and public relations costs identified in the response to S-RREV-1-30 be disallowed. My adjustment is shown in Schedule ACC-21.

J. <u>Community Affairs – Public Relations Expense</u>

Q. **Do you have similar concerns about the Community Affairs and Public Relations costs included in the Company's claim?**

A. Yes, I do. In the response to S-RREV-1-31, RECO identified $208,700 of community affairs and public relations costs that were incurred in the Test Year, approximately 89.96% of which were allocated to distribution. Most of these costs relate to management payroll costs. I am recommending that these Community Affairs and Public Relations costs also be disallowed. The Company has not demonstrated that these costs are necessary for the provision of safe and reliable utility service. Such costs are often incurred in order to promote the corporate impact of the utility among the community. Therefore, similar to the advertising adjustment discussed above, I am also recommending that these Community Affairs and Public Relations costs be disallowed. My adjustment is shown in Schedule ACC-22.

K. Membership Dues Expense

Q. What membership dues has the Company included in its revenue requirement claim?

A. In its Supplemental Response to RCR-A-78, the Company identified the membership dues included in the filing. The Company's claim includes $50,551 in dues to the Edison Electric Institute ("EEI"), $60,004 in dues to the New Jersey Utilities Association, Inc. ("NJUA"), and $6,080 in dues to other organizations.

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

A. Yes, I am recommending that 50% of the dues to the NJUA and the $6,080 to multiple other organizations be disallowed. I am not recommending any adjustment to the Company's claim for membership dues to the EEI. In its original filing, RECO eliminated $8,148 in EEI costs on the basis that such costs constituted lobbying and should not be passed through to ratepayers. In response to RCR-A-79, RECO indicated that it should have eliminated $11,049 of these costs. This revision was included in the Company's 12+0 Update. Therefore, I am not recommending any further revision to the Company's claim for EEI costs.

With regard to the NJUA, it is my understanding that this organization engages in extensive lobbying activities and in other activities that do not necessarily benefit ratepayers, such as public affairs, media relations, and other advocacy initiatives. Therefore, I am recommending that membership dues to the NJUA be allocated equally between ratepayers and shareholders. Accordingly on Schedule ACC-23, I have made an adjustment to remove 50% of the Company's claim.

With regard to the other organizations included in the response to RCR-A-78, I am recommending that membership dues to these organizations be disallowed. The Company has not demonstrated why payments to such organizations as the Mahwah Chamber of Commerce, New Jersey Alliance for Action, and the State of New Jersey Election Law Enforcement Commission are necessary for the provision of utility service or why such costs should be recovered from ratepayers. Therefore, at Schedule ACC-23, I have eliminated the $6,630 in membership dues to these other organizations from the Company's claim.

L. Research and Development Expense

Q. Has the Company included any costs relating to Research and Development activities in its revenue requirement claim?

A. Yes, it has. In the Supplemental Response to RCR-A-74, RECO identified $202,021 of research and development costs that have been included in its rate filing. These costs include $94,899 related to automation and incorporation of the Smart Grid Distribution Management software, $6,708 of travel and administrative costs, and $100,513 of allocated costs related to "the shared services portion of CECONY's R&D salaries and the EPRI monthly program funding."

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

A. Yes, I am recommending that the $100,513 of research and development costs allocated from Consolidated Edison be denied. RECO has not shown that projects undertaken by Consolidated Edison and/or EPRI are necessary to the provision of distribution electric service in New Jersey. It has not shown that there is any ratepayer benefit related to these project costs. In the absence of additional supporting documentation from RECO, I recommend that these costs be disallowed. My adjustment is shown in Schedule ACC-24.

M. <u>Depreciation Expense</u>

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

A. Yes, I have made three adjustments. First, since I am recommending that post-test year plant additions be excluded from rate base, it is necessary to make a corresponding adjustment to eliminate the associated depreciation expense. At Schedule ACC-25, I have made an adjustment to eliminate depreciation expense associated with the utility plant that I recommend be excluded from rate base.

Second, Rate Counsel witness James Garren is proposing adjustments to the depreciation rates being proposed by RECO in this case. Rate Counsel is recommending a composite depreciation rate of 1.65% instead of the composite rate of 2.106% proposed by the Company. The current composite rate is 2.025%. Therefore, Rate Counsel's depreciation rate recommendations will result in a reduction to depreciation expense relative to depreciation expense based on currently depreciation rates. At Schedule ACC-26, I have made an adjustment to reflect an adjustment to the Test Year annualized depreciation expense, based on the composite depreciation rate of 1.65% recommended by Mr. Garren.

Third, the Company is also proposing an increase to the net salvage allowance reflected in utility rates. According to Schedule 17 of Exhibit P-2, RECO's current net salvage of $441,133 was authorized in BPU Docket No. ER02100724. Rate Counsel witness James Garren is recommending that the Company's proposed increase be disallowed, and the currently-approved net salvage allowance of $441,133 be retained. Therefore, at Schedule ACC-27, I have eliminated the increase to the net salvage allowance proposed by the Company.

N. <u>Interest Synchronization</u>

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

A. Yes, I have made this adjustment at Schedule ACC-28. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Kahal. Our recommendations result in a lower rate base and lower interest expense than the rate base and interest expense included in the Company's filing.

This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under Rate Counsel's recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

O. Income Taxes and Revenue Multiplier

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

A. As shown on Schedule ACC-29, I have used a composite income tax factor of 40.85%, which includes a corporate business tax rate of 9.0% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing.

My revenue multiplier, which is shown in Schedule ACC-30, incorporates these tax rates. In addition, the revenue multiplier also includes the uncollectible rate of 0.18% included in the Company's 12+0 Update.

VII. REVENUE REQUIREMENT SUMMARY

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

A. My adjustments indicate a revenue deficiency at present rates of $6.614 million, as summarized on Schedule ACC-1. This recommendation reflects revenue requirement adjustments of $17.211 million to the Company's requested revenue increase of $23.825

million.

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

A. Yes, at Schedule ACC-31, I have quantified the revenue requirement impact of the rate of return, rate base, revenue and expense recommendations contained in this testimony.

Q. Have you developed an income statement showing the result of your recommendations?

A. Yes, at Schedule ACC-32, I have provided an income statement showing the Company's pro forma income at present rates as claimed by RECO, the income impact of Rate Counsel's recommended adjustments, and pro forma income resulting from Rate Counsel's proposed rate increase. As shown in that schedule, our recommended rate increase of $6.614 million will result in an overall return of 7.46%, as recommended by Mr. Kahal.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

List of Prior Testimonies

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

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Rockland Electric Company	E	New Jersey	ER13111135	5/14	Revenue Requirements	Division of Rate Counsel
Kansas City Power and Light Company	E	Kansas	14-KCPE-272-RTS	4/14	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR13100885-906	3/14	Cable Rates	Division of Rate Counsel
New Mexico Gas Company	G	New Mexico	13-00231-UT	2/14	Merger Policy	Office of Attorney General
Water Service Corporation (Kentucky)	W	Kentucky	2013-00237	2/14	Revenue Requirements	Office of Attorney General
Oneok, Inc. and Kansas Gas Service	G	Kansas	14-KGSG-100-MIS	12/13	Plan of Reorganization	Citizens' Utility Ratepayer Board
Public Service Electric & Gas Company	E/G	New Jersey	EO13020155 GO13020156	10/13	Energy Strong Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	12-00350-UT	8/13	Cost of Capital, RPS Rider, Gain on Sale, Allocations	New Mexico Office of Attorney General
Westar Energy, Inc.	E	Kansas	13-WSEE-629-RTS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	13-115	8/13	Revenue Requirements	Division of the Public Advocate
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-447-MIS	8/13	Abbreviated Rate Filing	Citizens' Utility Ratepayer Board
Jersey Central Power & Light Company	E	New Jersey	ER12111052	6/13	Reliability Cost Recovery Consolidated Income Taxes	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	13-MKEE-447-MIS	5/13	Transfer of Certificate Regulatory Policy	Citizens' Utility Ratepayer Board
Mid-Kansas Electric Company (Southern Pioneer)	E	Kansas	13-MKEE-452-MIS	5/13	Formula Rates	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	12-450F	3/13	Gas Sales Rates	Attorney General
Public Service Electric and Gas Co.	E	New Jersey	EO12080721	1/13	Solar 4 All - Extension Program	Division of Rate Counsel
Public Service Electric and Gas Co.	E	New Jersey	EO12080726	1/13	Solar Loan III Program	Division of Rate Counsel
Lane Scott Electric Cooperative	E	Kansas	12-MKEE-410-RTS	11/12	Acquisition Premium, Policy Issues	Citizens' Utility Ratepayer Board
Kansas Gas Service	G	Kansas	12-KGSG-835-RTS	9/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	12-KCPE-764-RTS	8/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Woonsocket Water Division	W	Rhode Island	4320	7/12	Revenue Requirements	Division of Public Utilities and Carriers
Atmos Energy Company	G	Kansas	12-ATMG-564-RTS	6/12	Revenue Requirements	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	110258	5/12	Cost of Capital	Division of the Public Advocate
Mid-Kansas Electric Company (Western)	E	Kansas	12-MKEE-491-RTS	5/12	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER11080469	4/12	Revenue Requirements	Division of Rate Counsel

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

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

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

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Atmos Energy Corp.	G	Kansas	10-ATMG-495-RTS	6/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	10-EPDE-314-RTS	3/10	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Delmarva Power and Light Company	E	Delaware	09-414 and 09-276T	2/10	Cost of Capital Rate Design Policy Issues	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	09-385F	2/10	Gas Cost Rates	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	09-398F	1/10	Gas Service Rates	Division of the Public Advocate
Public Service Electric and Gas Company	E	New Jersey	ER09020113	11/09	Societal Benefit Charge Non-Utility Generation Charge	Division of Rate Counsel
Delmarva Power and Light Company	G	Delaware	09-277T	11/09	Rate Design	Division of the Public Advocate
Public Service Electric and Gas Company	E/G	New Jersey	GR09050422	11/09	Revenue Requirements	Division of Rate Counsel
Mid-Kansas Electric Company	E	Kansas	09-MKEE-969-RTS	10/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy, Inc.	E	Kansas	09-WSEE-925-RTS	9/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08050326 EO08080542	8/09	Demand Response Programs	Division of Rate Counsel
Public Service Electric and Gas Company	E	New Jersey	EO09030249	7/09	Solar Loan II Program	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	09-MDWE-792-RTS	7/09	Revenue Requirements	Citizens' Utility Ratepayer Board
Westar Energy and KG&E	E	Kansas	09-WSEE-641-GIE	6/09	Rate Consolidation	Citizens' Utility Ratepayer Board
United Water Delaware, Inc.	W	Delaware	09-60	6/09	Cost of Capital	Division of the Public Advocate
Rockland Electric Company	E	New Jersey	GO09020097	6/09	SREC-Based Financing Program	Division of Rate Counsel
Tidewater Utilities, Inc.	W	Delaware	09-29	6/09	Revenue Requirements Cost of Capital	Division of the Public Advocate
Chesapeake Utilities Corporation	G	Delaware	08-269F	3/09	Gas Service Rates	Division of the Public Advocate
Delmarva Power and Light Company	G	Delaware	08-266F	2/09	Gas Cost Rates	Division of the Public Advocate
Kansas City Power & Light Company	E	Kansas	09-KCPE-246-RTS	2/09	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Jersey Central Power and Light Co.	E	New Jersey	EO08090840	1/09	Solar Financing Program	Division of Rate Counsel
Atlantic City Electric Company	E	New Jersey	EO06100744 EO08100875	1/09	Solar Financing Program	Division of Rate Counsel
West Virginia-American Water Company	W	West Virginia	08-0900-W-42T	11/08	Revenue Requirements	The Consumer Advocate Division of the PSC

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

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Westar Energy, Inc.	E	Kansas	08-WSEE-1041-RTS	9/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Artesian Water Company	W	Delaware	08-96	9/08	Cost of Capital, Revenue, New Headquarters	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR08020113	9/08	Form 1205 Equipment & Installation Rates	Division of Rate Counsel
Pawtucket Water Supply Board	W	Rhode Island	3945	7/08	Revenue Requirements	Division of Public Utilities and Carriers
New Jersey American Water Co.	W/WW	New Jersey	WR08010020	7/08	Consolidated Income Taxes	Division of Rate Counsel
New Jersey Natural Gas Company	G	New Jersey	GR07110889	5/08	Revenue Requirements	Division of Rate Counsel
Kansas Electric Power Cooperative, Inc.	E	Kansas	08-KEPE-597-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Company	E	New Jersey	EX02060363 EA02060366	5/08	Deferred Balances Audit	Division of Rate Counsel
Cablevision Systems Corporation	C	New Jersey	CR07110894, et al..	5/08	Forms 1240 and 1205	Division of Rate Counsel
Midwest Energy, Inc.	E	Kansas	08-MDWE-594-RTS	5/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board
Chesapeake Utilities Corporation	G	Delaware	07-246F	4/08	Gas Service Rates	Division of the Public Advocate
Comcast Cable	C	New Jersey	CR07100717-946	3/08	Form 1240	Division of Rate Counsel
Generic Commission Investigation	G	New Mexico	07-00340-UT	3/08	Weather Normalization	New Mexico Office of Attorney General
Southwestern Public Service Company	E	New Mexico	07-00319-UT	3/08	Revenue Requirements Cost of Capital	New Mexico Office of Attorney General
Delmarva Power and Light Company	G	Delaware	07-239F	2/08	Gas Cost Rates	Division of the Public Advocate
Atmos Energy Corp.	G	Kansas	08-ATMG-280-RTS	1/08	Revenue Requirements Cost of Capital	Citizens' Utility Ratepayer Board

APPENDIX B

Supporting Schedules

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim (A)	Recommended Adjustment	Recommended Position	
1. Pro Forma Rate Base	$194,587	($33,523)	$161,064	(B)
2. Required Cost of Capital	8.23%	-0.77%	7.46%	(C)
3. Required Return	$16,015	($4,000)	$12,015	
4. Operating Income @ Present Rates	1,948	6,162	8,110	(D)
5. Operating Income Deficiency	$14,067	($10,162)	$3,905	
6. Revenue Multiplier	1.6937		1.6937	(E)
7. Revenue Increase	**$23,825**	**($17,211)**	**$6,614**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-2., Summary Page 3.
(B) Schedule ACC-3.
(C) Schedule ACC-2.
(D) Schedule ACC-12.
(E) Schedule ACC-30.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
REQUIRED COST OF CAPITAL

	Capital Structure (%) (A)	Cost Rate (%) (A)	Weighted Cost (%)
1. Long Term Debt	47.38%	5.89%	2.79%
2. Short-Term Debt	2.26%	0.25%	0.01%
3. Common Equity	50.35%	9.25%	4.66%
4. Total Cost of Capital	100.00%		**7.46%**

Sources:

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

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
RATE BASE SUMMARY ($000)

	Company Claim (A)	Recommended Adjustment		Recommended Position
1. Electric Plant in Service	$275,717	($6,053)	(B)	$269,664
2. Electric Plant Held for Future Use	2,256	(2,256)	(C)	0
3. CWIP	3,936	(3,936)	(D)	0
4 Total Utility Plant	$281,909	($12,245)		$269,664
5. Acc. Provision for Depreciation	(64,626)	2,024	(E)	(62,602)
6. Net Utility Plant	$217,283	-$10,221		$207,062
Plus:				
7. Cash Working Capital	$8,886	($3,708)	(F)	$5,178
8. Prepayments	2,736	0		2,736
9. Materials and Supplies	2,646	0		2,646
10. Deferred Regulatory Balances	15,829	(15,829)	(G)	0
Less:				
11. Net Pension/OPEB Liability	$0	$0		$0
12. Customer Deposits	($2,858)	0		($2,858)
13. Customer Advances	(361)	0		(361)
14. Acc. Def. Federal Income Tax	(45,393)	480	(H)	(44,913)
15. Consolidated Tax Adj.	(4,181)	(4,245)	(I)	(8,426)
16. Total Rate Base	**$194,587**	**($33,523)**		**$161,064**

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-3, Summary and Exhibit P-3, Schedule 6.
(B) Schedule ACC-4.
(C) Schedule ACC-5.
(D) Schedule ACC-6.
(E) Schedule ACC-7.
(F) Schedule ACC-8.
(G) Schedule ACC-9.
(H) Schedule ACC-10.
(I) Schedule ACC-11.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
ELECTRIC PLANT IN SERVICE ($000)

1	Post Test Year Plant Additions	($6,752)	(A)
2.	Post Test Year Plant Retirements	699	(A)
3.	Recommended Adjustment	**($6,053)**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-3, Schedule 1.

Schedule ACC-5

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
PLANT HELD FOR FUTURE USE ($000)

1	Company Claim	$2,256	(A)
2.	Recommended Adjustment	**($2,256)**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-3, Schedule 2.

Schedule ACC-6

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
CONSTRUCTION WORK IN PROGRESS ($000)

1. Company Claim	$3,936	(A)
2. Recommended Adjustment	**($3,936)**	

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

Schedule ACC-7

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
ACCUMULATED PROVISION FOR DEPRECIATION ($000)

1	Post Test Year Additions	$3,057	(A)
2.	Post Test Year Retirements	(1,033)	
3.	Net Adjustment	**$2,024**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-3, Schedule 4.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
CASH WORKING CAPITAL

		Amount (A)	Expense Lead/Lag Days	Revenue Lag	
1.	Revenue Recovery	$155,047,222	38.80	$6,015,832,214	
2.	Sales Tax	9,302,833	38.80	360,949,920	
3	Total Revenue	$164,350,055	38.80	$6,376,782,134	
	Purchased Power Expense:				
4.	BGS	$0	35.10	$0	(B)
5.	O&R	0	45.00	0	(B)
6.	Deferred Purchased Power Expens	0	0.00	0	(B)
7.	Salaries and Wages	10,100,194	8.10	81,886,140	
8.	Pensions	5,224,425	30.00	156,732,750	(C)
9.	OPEBs	640,000	79.50	50,880,000	(D)
10.	Employee Welfare Expenses	2,410,433	2.90	7,019,367	
11.	Joint Operating Expenses	4,769,527	45.00	214,628,736	
12.	Uncollectible Accounts Accrual	311,489	38.80	12,085,773	
13.	Material and Supplies Issues	0	0.00	0	(E)
14.	Other O&M	22,638,111	23.40	529,200,964	
	Amortizations:				
15.	Storm Reserve	0	0.00	0	(E)
16.	Rate Case Costs	0	0.00	0	(E)
17.	BPU Assessment	506,825	38.80	19,664,810	(E)
18.	Regulatory Deferrals	0	0.00	0	(E)
19.	Depreciation and Amortization	0	0.00	0	(E)
20.	Taxes Other than Income Taxes	4,300,736	(37.10)	(159,763,571)	
21.	New Jersey Sales Tax (UTUA)	9,302,833	51.20	(475,994,971)	
	Income Taxes:				
22.	Federal Income Tax	(4,658,000)	37.50	(174,675,000)	
23.	Defered Federal Income Tax	0	0.00	0	(E)
24.	Investment Tax Credit	(398,908)	37.50	(14,959,050)	(F)
25.	Corporate Business Tax (State)	(37,633)	(46.80)	1,759,350	
26.	Return on Invested Capital	0	0.00	0	(E)
27.	Interest Expense	4,503,871	91.25	410,978,270	(G)
28.	Total Requirement	$55,110,032	4.51	$248,465,298	
29.	Net Lag		34.29		
30.	Daily Requirement		$150,986		
31.	Annual Requirement		$5,177,545		
32.	Company Claim		8,885,462		
33.	Recommended Adjustment		**($3,707,917)**		

Sources:
(A) Company Workpapers, 12+0 Update, Exhibit P-3, Schedule 6, Page 2.
(B) Reflects eliminiation of non-distribution costs.
(C) Reflects monthly payment.
(D) Response to S-RCWC-1-3.
(E) Reflects elimination of items with zero lag.
(F) Reflects lag for current federal income taxes.
(G) Interest Expense per Schedule ACC-28.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
DEFERRED REGULATORY BALANCE ($000)
(NET OF ACCUMULATED DEFERRED TAXES)

1. Company Claim	$15,829	(A)
2. Recommended Adjustment	**($15,829)**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-3, Schedule 7.

Schedule ACC-10

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
ACCUMULATED DEFERRED INCOME TAX ($000)

1	Post Test Year Adjustments	$480	(A)
2.	Recommended Adjustment	**$480**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-3, Schedule 10.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
CONSOLIDATED INCOME TAXES ($000)

1. CIT Adjustment for RECO	($8,426)	(A)
2. Company Claim	(4,181)	(B)
3. Recommended Adjustment	**(4,245)**	

Sources:
(A) Derived from response to RCR-A-117.
(B) Company Filing, 12+0 Update, Exhibit P-3, Schedule 11.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
OPERATING INCOME SUMMARY ($000)

		Schedule No.
1. Company Claim	$1,948	1
Recommended Adjustments:		
2. Incremental Customer Expense	7	13
3. PTY Salary and Wage Expense for Increases	204	14
4. Incentive Compensation Program Expense	617	15
5. Payroll Tax Expense	61	16
6. Supplemental Executive Retirement Plan Expense	258	17
7. Medical Benefit Expense	45	18
8. Rate Case Expense	84	19
9. Storm Damage Expense	3,885	20
10. Advertising Expense	69	21
11. Community Affairs	111	22
12. Membership Dues Expense	19	23
13. Research and Development	53	24
14. Depreciation Expense - Post Test Year Plant	75	25
15. Depreciation Expense - Proposed Rates	727	26
16. Depreciation Expense - Net Salvage Allowance	449	27
17. Interest Synchronization	(505)	28
18. Operating Income	**$8,110**	

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
PRO FORMA REVENUE - CUSTOMER COUNTS @ MARCH 31, 2014

		Residential	Secondary	
1. Incremental Customers		52	22	(A)
2. Annual Incremental Costs		$202.20	$422.64	(B)
3. Total Incremental Costs Per Class		$10,514	$9,298	
4. Total Incremental Costs			$18,596	
5. Company Claim			30,268	(A)
6. Recommended Adjustment			$11,672	
7. Income taxes @	40.85%		4,768	
8. Operating Income			**$6,904**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-2, Schedule 2.
(B) Response to RCR-RD-10.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
SALARY AND WAGES ADJ. - POST TEST YEAR INCREASES

1. Increase Effective April 1, 2014		$138,700	(A)
2. Increase Effective June 1, 2014		165,297	(A)
3. New Positions - Annualized		41,510	(B)
4. Recommended Adjustment		$345,507	
5. Income Taxes @	40.85%	141,140	
6. Operating Income Impact		**$204,367**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-2, Schedule 4, page 1.
(B) Reflects the adjustment that should have been made to annualize positions ($93,490) and the adjustment that was made by the Company ($135,000). $93,490 reflects the difference between the actual test year costs of $68,522 and the annualized costs costs of $162,012 ($13,501 X12) per the response to RCR-A-16.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
INCENTIVE COMPENSATION PROGRAM EXPENSE

1.	Non-Executive ATIP Expense		$889,000	(A)
2.	Recommended Disallowance		50.00%	(B)
3.	Recommended Expense Adjustment		$444,500	
4.	Long Term Incentive Plan Award		247,800	(A)
5.	Officer Incentive Compensation		467,900	(C)
6.	Total Recommended Adjustment		$1,160,200	
7.	Distribution Allocation		89.96%	(D)
8.	Distribution Adjustment		$1,043,716	
9.	Income Taxes @	40.85%	426,358	
10.	Operating Income Impact		**$617,358**	

Sources:
(A) Response to RCR-A-37.
(B) Recommendation of Ms. Crane.
(C) Response to RCR-A-40 (2013 Costs).
(D) Distribution Percentage per Company Filing, 12+0 Update, Exhibit P-2, Schedule 6.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
PAYROLL TAX EXPENSE

1. Salary and Wage Expense Adjustment		$345,507	(A)
2. Incentive Compensation Expense Adjustment		1,043,716	(B)
3. Total Recommended Adjustments		$1,389,223	
4. Statutory Tax Rate		7.47%	(C)
5. Recommended Payroll Tax Adjustment		$103,775	
6. Income Taxes @	40.85%	42,392	
7. Operating Income Impact		**$61,383**	

Sources:
(A) Schedule ACC-14.
(B) Schedule ACC-15.
(C) Company Filing, 12+0 Update, Exhibit P-2, Schedule 18.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN EXPENSE

1. Recommended Expense Adjustment		$435,471	(A)
2. Income Taxes @	40.85%	177,890	
3. Operating Income Impact		**$257,581**	

Sources:
(A) Supplemental response to RCR-A-41.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
EMPLOYEE BENEFIT EXPENSE

1.	Salary and Wage Expense Adjustment	$345,507	(A)
2.	Incentive Compensation Expense Adjustment	1,043,716	(B)
3.	Total Recommended Adjustments	$1,389,223	
4.	Benefits Ratio	22.15%	(C)
5.	Recommended Benefits Adjustment	$76,530	
6.	Income Taxes @ 40.85%	31,262	
7.	Operating Income Impact	**$45,267**	

Sources:
(A) Schedule ACC-14.
(B) Schedule ACC-15.
(C) Company Filing, 12+0 Update, Exhibit P-2, Schedule 5.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
RATE CASE EXPENSE

1. Pro Forma Cost		$346,561	(A)
2. Recommended Amortization Period		3	(B)
3. Annual Amortization		$115,520	
4. Sharing with Shareholders		50.00%	(C)
5. Allocation to Ratepayers ($)		$57,760	
6. Company Claim		200,000	(B)
7. Recommended Adjustment		$142,240	
8. Income Taxes @	40.85%	58,105	
9. Operating Income Impact		**$84,135**	

Sources:
(A) Average of last three cases per response to RCR-A-70.
(B) Company Filing, 12+0 Update, Exhibit P-2, Schedule 9.
(C) Reflects BPU precedent.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
STORM DAMAGE COSTS

1. Deferred Storm Damage Costs		$25,652,364	(A)
2. Amortization Period (Yrs.)		6	(B)
3. Annual Amortization ($)		$4,275,394	
4. Recommended Prospective Costs		375,799	(C)
5. Total Annual Pro Forma Costs		$4,651,193	
6. Company Claim		11,219,620	(A)
7. Recommended Adjustment		$6,568,427	
8. Income Taxes @	40.85%	2,683,202	
9. Operating Income Impact		**$3,885,225**	

Sources:

(A) Company Filing, 12+0 Update, Exhibit P-2, Schedule 13.
(B) Recommendation of Ms. Crane.
(C) Testimony of Mr. Kosier, page 24, line 14.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
ADVERTISING ($000)

1. Recommended Disallowance		$129,400	(A)
2. Distribution Allocation		89.96%	(B)
3. Distribution Adjustment		$116,408	
4. Income Taxes @	40.85%	47,553	
5. Operating Income Impact		**$68,855**	

Sources:
(A) Response to S-RREV-1-30.
(B) Distribution Percentage per Company Filing, 12+0 Update, Exhibit P-2, Schedule 6.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
COMMUNITY AFFAIRS - PUBLIC RELATIONS

1. Recommended Adjustment		$209	(A)
2. Distribution Allocation		89.96%	(B)
3. Distribution Adjustment		$188	
4. Income Taxes @	40.85%	77	
5. Operating Income Impact		**$111**	

Sources:
(A) Response to S-RREV-1-31.
(B) Distribution Percentage per Company Filing, 12+0 Update, Exhibit P-2, Schedule 6.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
MEMBERSHIP DUES EXPENSE

1. Test Year Miscellaneous Membership Dues		$6,080	(A)
2. 50% of NJUA		30,002	(B)
3. Membership Dues Adjustment		$36,082	
4. Distribution Allocation		89.96%	(C)
5. Distribution Adjustment		$32,459	
6. Income Taxes @	40.85%	13,260	
7. Operating Income Impact		**$19,200**	

Sources:
(A) Supplemental Response to RCR-A-78, excluding NJUA and EEI.
(B) Recommendation of Ms. Crane.
(C) Distribution Percentage per Company Filing, 12+0 Update, Exhibit 2, Schedule 6.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
RESEARCH AND DEVELOPMENT

1. Recommended Adjustment		$100,513	(A)
2. Distribution Allocation		89.96%	(B)
3. Distribution Adjustment		90,421	
4. Income Taxes @	40.85%	36,937	
5. Operating Income Impact		**$53,484**	

Sources:
(A) Supplemental Response to RCR-A-74.
(B) Distribution Percentage per Company Filing, 12+0 Update, Exhibit 2, Schedule 6.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
DEPRECIATION EXPENSE - POST TEST YEAR PLANT

1. Depreciation Expense Adjustments		$127	(A)
2. Income Taxes @	40.85%	52	
3. Operating Income Impact		**$75**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-2, Schedule 16.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
DEPRECIATION EXPENSE - PROPOSED RATES

1. Recommended Composite Depreciation Rate		1.650%	(A)
2. Company Proposed Rate		2.106%	(B)
3. Recommended Adjustment		-0.46%	
4. Test Year Plant In Service		$269,664,000	(B)
5. Recommended Depreciation Expense Adjustment		$1,229,668	
6. Income Taxes @	40.85%	502,319	
7. Operating Income Impact		**$727,349**	

Sources:
(A) Testimony of Mr. Garren.
(B) Company Filing, 12+0 Update, Exhibit P-2, Schedule 15.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
DEPRECIATION EXPENSE - NET SALVAGE ALLOWANCE

1. Company Claim		$1,200,484	(A)
2. Rate Counsel Recommendation		441,133	(B)
3. Recommended Adjustment		$759,351	
4. Income Taxes @	40.85%	310,195	
5. Operating Income Impact		**$449,156**	

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-2, Schedule 17.
(B) Testimony of Mr. Garren.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
INTEREST SYNCHRONIZATION

1. Pro Forma Rate Base		$161,064	(A)
2. Weighted Cost of Debt		2.80%	(B)
3. Pro Forma Interest Expense		$4,504	
4. Company Claim		5,739	(C)
5. Recommended Adjustment		$1,235	
6. Increase in Income Taxes @	40.85%	505	
7. Operating Income Impact		**$505**	

Sources:
(A) Schedule ACC-3.
(B) Schedule ACC-2.
(C) Company Filing,12+0 Update, Exhibit P-2, Schedule 21.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
INCOME TAX RATE

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

Sources:
(A) Reflects current statutory rates.
(B) Line 1 - Line 5.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
REVENUE MULTIPLIER

1. Revenue		100.00%	
Less:			
2. Uncollectibles		0.18%	(A)
3. Taxable Income		99.82%	
4. State Income Taxes @	9.00%	8.98%	(B)
5. Federal Taxable Income		90.84%	
6. Income Taxes @	35.00%	31.79%	(B)
7. Operating Income		59.04%	
8. Revenue Multiplier		**1.6937**	(C)

Sources:
(A) Company Filing, 12+0 Update, Exhibit P-2, Summary, Page 3.
(B) Reflects statutory tax rates.
(C) Line 1 / Line 8.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1. Capital Structure/Cost of Capital	($2,538)
Rate Base Adjustments:	
2. Electric Plant in Service	($765)
3. Electric Plant Held for Future Use	(285)
4. CWIP	(497)
5. Acc. Provision for Depreciation	256
6. Cash Working Capital	(469)
7. Deferred Regulatory Balances	(2,000)
8. Acc. Def. Federal Income Tax	61
9. Consolidated Tax Adj.	(536)
Operating Income Adjustments	
10. Incremental Customer Expense	($12)
11. PTY Salary and Wage Expense for Increases	(346)
12. Incentive Compensation Program Expense	(1,046)
13. Payroll Tax Expense	(104)
14. Supplemental Executive Retirement Plan Expense	(436)
15. Medical Benefit Expense	(77)
16. Rate Case Expense	(142)
17. Storm Damage Expense	(6,580)
18. Advertising Expense	(117)
19. Community Affairs	(188)
20. Membership Dues Expense	(33)
21. Research and Development	(91)
22. Depreciation Expense - Post Test Year Plant	(127)
23. Depreciation Expense - Proposed Rates	(1,232)
24. Depreciation Expense - Net Salvage Allowance	(761)
25. Interest Synchronization	855
26. Total Adjustments	($17,211)
27. Company Claim	23,825
28. Recommended Deficiency	**$6,614**

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING MARCH 31, 2014
INCOME STATEMENT

	Pro Forma Company @ Present Rates	Rate Counsel Adjustments	Rate Counsel Pro Forma @ Present Rates	Rate Counsel Increase	Rate Counsel Pro Forma @ Proposed Rates
Operating Revenues:					
1. Sales of Electricity	$154,641	$0	$154,641	$6,614	$161,255
2. Other Operating Revenues	406	0	406		406
3. Total Operating Revenues	$155,047	$0	$155,047	$6,614	$161,661
Operating Expenses					
4. Purchased Power	$85,397	$0	$85,397		$85,397
5. Deferred Purchased Power	118	0	118		118
6. Other Operation and Maintenance Expense	$56,664	(9,051)	47,613	12	47,625
7. Total Operating Expenses	$142,179	($9,051)	$133,128	$12	$133,140
8. Depreciation and Amortization	8,949	-2,116	6,833		6,833
9. Taxes Other Than Income Taxes	4,301	-104	4,197		4,197
10. Operating Income Before Income Taxes	-$382	$11,271	$10,889	$6,602	$17,491
11. Interest Expense	5,739	-1,235	4,504	0	4,504
12. Taxable Income	($6,121)	$12,506	$6,385	$6,602	$12,987
13. State and Federal Income Taxes	($2,330)	5,109	2,779	2,697	5,476
14. Operating Income After Income Taxes	$1,948	$6,162	$8,110	$3,905	$12,015
15. Rate Base					$161,064
16. Required Return					7.46%

APPENDIX C

Referenced Data Requests

RCR-A-16 (partial)
RCR-A-37 (Original and Supplemental)
RCR-A-38
RCR-A-40
RCR-A-41 (Supplemental)
RCR-A-70
RCR-A-71 (Supplemental)
RCR-A-73
RCR-A-74 (Supplemental)
RCR-A-78 (Supplemental)
RCR-A-79
RCR-A-90
RCR-A-117

RCR-RD-10

S-RCWC-1-2 (partial)
S-RCWC-1-3
S-RREV-1-30 (partial)
S-RREV-1-31

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: 02/05/2014
Responding Witness:

Question No. : 16

Regarding Exhibit P-2, Schedule 4, page 2, please provide all assumptions, documentation and supporting calculations for the five additional employees and the RECO allocation of $134,594.

Response

Please see the attached worksheet (RECO RCR-A-16.xls)

ROCKLAND ELECTRIC COMPANY
To Distribution Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2013

Adjustment to O&M Expense to Reflect Increases in Wages and Salaries for Additional Employees:

Wage and Salary Increase:		
(A) Monthly Paid Employees		
Additional Labor Costs charged to RECO O&M expense:		
October 2013 - September 2014	$134,594	
	$134,594	
Adjustment		$134,594
Rounded		$135,000

CONSOLIDATED WAGE INCREASE SUMMARY
For Rockland Electric Company Rate Case

NEW EMPLOYEE Wage Increases Applicable To

		Monthly Paid			
		Straight Time	Overtime	Total	
Apr-13		2,894		2,894	
May-13		2,894		2,894	
Jun-13		2,894		2,894	
Jul-13		2,894		2,894	
Aug-13		2,894		2,894	
Sep-13	end of test year	2,894		2,894	
Oct-13		2,894		2,894	
Nov-13		2,894		2,894	
Dec-13		5,356		5,356	
Jan-14		13,012		13,012	
Feb-14		13,501		13,501	
Mar-14		13,501		13,501	
Apr-14		13,906		13,906	
May-14		13,906		13,906	
Jun-14		13,906		13,906	
Jul-14		13,906		13,906	
Aug-14		13,906		13,906	
Sep-14	end of reaching	13,906		13,906	134,594

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: 3/19/2014
Responding Witness: Ken Kosior

Question No. : 37

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

RESPONSE:

a) During the test year, the following incentive compensation programs existed for non-officer employees.

Annual Team Incentive Plan (ATIP) is a variable pay or pay-for-performance plan that links a portion of management employees' annual compensation to the achievement of various performance measures. ATIP is not available to non-management employees. A copy of the 2013 and 2014 ATIP plan was submitted as an attachment to the Company's response to RCR-A1-30.

Long Term Incentive Plan: Restricted stock awards are granted under the Long-Term Incentive Plan. Equity grants for employees in bands 1 and 2 are made in the form of time-based restricted stock. Time-based restricted stock is tied to a continued employment of three years before the stock is vested. Additionally, employees receiving time-based restricted stock awards must be on the active payroll at the time the stock vests in order to receive a payout.

Equity grants for employees in bands 3 and 4 are made in the form of performance based restricted stock. Performance based restricted stock, for bands 3 and 4 management employees, is tied to two performance measures. The first performance measure will be the 3-year total shareholder return relative to the Consolidated Edison, Inc. peer group. This will serve as the basis for 50 percent of the equity grant payout. The performance measure for the remaining 50% of the restricted stock grant will be the 3-year corporate average of the ATIP award fund.

b) The amount of the ATIP pay allocated to RECO during the test year (actual data for the nine months ended December 31, 2013 and forecast data for the period January 2014 through March 2014) is $889,900. Long Term Incentive Plan costs allocated to

RECO during the test year (actual data for the nine months ended December 31, 2013 and forecast data for the period January 2014 through March 2014) is $247,800.

c) The actual amount incurred in each of the past five years is as follows:

Year	ATIP	Long Term Incentive
2013	$769,000	$76,601
2012	$800,600	$52,872
2011	$781,500	$60,672
2010	$660,900	$77,136
2009	$663,100	$78,020

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to RATE COUNSEL Interrogatories – Set RCR-A1
Date of Response: March 12, 2014
Responding Witness: Ken Kosior

Question No. : 37-Supp

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

RESPONSE:

The Company supplements its initial response to this data request by providing this corrected response to subpart c)

The actual amount incurred in each of the past five years is as follows:

Year	ATIP	Long Term Incentive
2013	$769,000	$76,601
2012	$800,600	$52,872
2011	$781,500	$60,672
2010	$660,900	$77,136
2009	$663,100	$78,020

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: April 30, 2014
Responding Witness: Kenneth Kosior

Question No. : 38

Please provide a description of all incentive compensation programs provided to officers. For each program, please provide a. a description of the program, b. the performance criteria factors used to determine awards, c. the amount included in the Company's claim, d. the actual amount incurred in each of the past five years, and e. by title, a list of all officers eligible to participate.

RESPONSE:

a. The Company's compensation program is designed to assist in attracting and retaining officers critical to the Company's long-term success, and to motivate these officers to create value for its stockholders and to provide safe, reliable, and efficient service for its customers. The compensation program includes base salary, and performance-based variable compensation, including annual cash incentive compensation and long-term equity-based incentive compensation, that aligns pay to performance. A significant portion of each officer's total direct compensation (the sum of base salary plus annual cash incentive plus long-term equity-based incentive compensation) is performance based variable compensation to motivate strong annual and multi-year Company performance.

   RECO has no operating employees. RECO is allocated a portion of the performance based variable compensation paid to Orange and Rockland Utilities, Inc.'s ("O&R") officers. O&R's officers participate in the following incentive programs: Consolidated Edison Company of New York, Inc.'s ("CECONY") Executive Incentive Plan ("EIP"); O&R's Annual Team incentive Plan ("ATIP") and the Consolidated Edison, Inc.'s Long Term Incentive Plan ("LTIP").

   The EIP, which is the annual incentive plan that the President and CEO participates in, and the ATIP, which is the annual incentive plan that the two other O&R officers (i.e., Vice President – Operations, Vice President – Customer Service) participate in, are directly related to the Company's financial and operating performance. Each officer's annual incentive is based on a targeted percentage of the officer's annual base salary. The target percentages are: 80 percent for the President and CEO; and 35 percent for each of the Vice Presidents.

The annual incentive earned varies based on the achievement of performance goals established at the beginning of the performance period.

The performance goals must be earned each year. In linking a portion of annual compensation to defined and measurable performance criteria, the Company's compensation philosophy strives to reward employees for the achievement of predefined operating, customer service, and financial performance goals.

The long-term equity-based incentive compensation is provided under the LTIP which measures achievement, over a three-year period, of financial and operating objectives and Consolidated Edison, Inc.'s total shareholder return relative to its compensation peer group. Each officer's long term incentive is based on a targeted percentage of the officer's annual base salary. The target percentages are: 200 percent for the President and CEO; and 60 percent for each of the Vice Presidents.

b. As noted in the Company's response to subpart a. above, the Vice President – Operations and Vice President – Customer Service participate in the ATIP, while the President and CEO participates in the EIP. The ATIP goals include Customer Service (weighted at 50%), Operating Budget (weighted at 25%), and Net Income (weighted at 25%). The 2013 ATIP targets and performance payout was as follows:

Target	% of award earned
Customer Service	55.0%
Operating Budget	29.8%
Net Income	30.0%
Total 2013 Award	114.8%

The EIP goals applicable to the President and CEO incorporate the ATIP goals for Customer Service (weighted at 30%) and Operating Budget (weighted at 20%). The EIP Net Income goal (weighted at 50%) applicable to the President and CEO, however, is based on 70 percent of O&R's performance and 30 percent of CECONY's results.

The LTIP results are equally weighted between the three-year average of the ATIP performance results and Consolidated Edison Inc.'s total shareholder return relative to its compensation peer group. For the three-year period ended December 31, 2013 the results are as follows:

<u>Three-year of ATIP percentage – 50% of award</u>

2011 performance – 115%
2012 performance – 120%
2013 performance – 114.8%
Three-year average – 116.6%

50% of award @ 116.6%= 58.3 percent

plus

Total Shareholder Return - 50% of grant

Percentile Ranking 37th

Percent of units to be distributed based on ranking 61%

50% of award @ 61% = 30.5 percent

Total payout percent 88.8% (58.3% plus 30.5% = **88.8%**)

c. Please see the 2013 activity in the Company's response to RCR-A-40.

d. Please see the Company's response to RCR-A-40, for the past three years.

e. Please see table below for list of officers and incentive plans they participate in indicated by an "X".

Title	**EIP**	**ATIP**	**LTIP**
President and CEO	X		X
Vice President, Operations		X	X
Vice President, Customer Service		X	X

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: April 23, 2014
Responding Witness: Kenneth Kosior

Question No. : 40

Identify and quantify all officer compensation by component, including incentive awards and bonuses, paid in each of the past three years and indicate the portion of each component that is included in the Company's proposed revenue requirement. Please also identify, by title, the officers whose compensation is included in this response.

RESPONSE:

Officer incentive award and bonus expenses allocated to Rockland Electric Company for the past three years are as follows:

Year	ATIP	Long Term Incentive
2013	$131,600	$336,300
2012	$183,900	$310,900
2011	$147,200	$388,200

The amounts listed above relate to compensation provided to the following three officers of the Company:

- President;
- Vice President - Operations; and
- Vice President - Customer Service.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: April 28, 2014
Responding Witness: Richard Kane

Question No. : 41-Supp

Fully describe any SERP benefits. Quantify any SERP costs included in the Company's filing, and describe how the Company's claim for SERP costs was determined.

RESPONSE:

This response supplements the original response submitted on January 17, 2014 to update the information for the Company's 12+0 filing.

RECO's portion of SERP costs for the historic period of 12 months ended March 2014 was $484,082.

Allocation of SERP Costs:

Distribution (89.96%)	$ 435,471
Transmission (10.04%)	48,611
	$ 484,082

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: January 17, 2014
Responding Witness: Richard Kane

Question No. : 70

For each of the past three rate case filings, provide: a. the amount of the increase requested, b. the percentage increase requested, c. the amount of increase granted, d. whether the case was litigated or settled, e. the total rate case costs incurred. and f. the effective date of new rates.

RESPONSE:

Case ER090806668:

a. the amount of the increase requested - $9.8 million
b. the percentage increase requested – 3.8%
c. the amount of increase granted - $9.8 million
d. the case was settled
e. the total rate case costs incurred - $216,193
f. the effective date of new rates – May 17, 2010

Case ER06060483:

a. the amount of the increase requested - $13.2 million
b. the percentage increase requested – 7.5%
c. the amount of increase granted - $6.4 million
d. the case was settled
e. the total rate case costs incurred - $309,494
f. the effective date of new rates – April 1, 2007

Case ER02100724:
Please note that, as indicated below, this rate case included a Phase 2.

a. the amount of the increase requested - $7.3 million ($3.1 million in Phase 2)
b. the percentage increase requested – 5.5% (2.0% in Phase 2)
c. the amount of increase granted - $7.2 million decrease ($2.7 million in Phase 2)
d. the case was litigated (Phase 2 was settled)
e. the total rate case costs incurred - $513,998
f. the effective date of new rates – August 1, 2003 (August 1, 2004 for Phase 2)

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to Rate Counsel Interrogatories – Set RCR-A1
Date of Response: March 25, 2014
Responding Witness: Richard Kane

Question No. : 71 Supp

Regarding Exhibit P-2, Schedule 9, please itemize the estimated rate case costs of $600,000 for the current filing.

RESPONSE:

The Company supplements its response to RCR-A1-71, by noting that the estimated rate case costs of $600,000 for this proceeding include the following components:

- Riker Danzig Scherer Hyland & Perretti LLP (legal services) - $500.000
- Sussex Economic Advisors, LLC (Cost of Capital advice & testimony) - $70.000
- Printing and other miscellaneous expenses - $30.000

The Company would note that the above-referenced amount for Sussex Economic Advisors, LLC represents its fees for providing expert testimony only for Rockland Electric Company and only in this proceeding; there is no allocation of costs for any other company or matter.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: January 24, 2014
Responding Witness: Richard Kane

Question No. : 73

Please provide copies of all Requests for Proposal issued by or on behalf of RECO with regard to the provision of rate case services in this case.

RESPONSE:

The Company objects to this interrogatory to the extent that it seeks information that is: subject to the attorney client privilege, attorney work product privilege and trial preparation privilege, neither relevant nor reasonably calculated to lead to the discovery of admissible evidence, and highly confidential and proprietary. Subject to and without waiver of the foregoing objection, RECO has not issued any such Requests for Proposals in this case.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: April 28, 2014
Responding Witness: Richard kane

Question No. : 74-Supp

Provide the amount of research and development costs claimed in rates in this filing and provide a description of each project to be undertaken, the timing of the project and the organization that is expected to perform the research.

RESPONSE:

The total amount of research and development costs reflected in rates in this filing is $202,000. Please see Attachment RCR-A-74-Suppa for the description of each project to be undertaken, the timing of the project and the organization that is expected to perform the research.

RECO Rate Case 2013
Case # ER13111135
Research & Development Expense

Type of Project	Description	Timing	Organization	Total Orange & Utilities Inc.	Allocated to Rockland Electric (30%)
Travel and Administrative Expenses	This authorization is for all O&R R&D personnel, administrative and travel expenses associated with R&D activities	On going	All R&D electric organizations	$ 22,361	$ 6,708
Integrate System Analysis Capability Using Distribution Engineering Workstation (DEW) into O&R's Smart Grid Distribution Management Software	This R&D authorization is being used to automate and incorporate the analysis tools of Distribution Engineering Workstation (DEW) for use in conjunction with the Smart Grid Distribution Management Software. This project takes this process to the next level by automating the electrical analysis of proposed switching moves to insure that the designed distribution system capability is being optimally utilized.	will be completed by year end 2014	O&R Electric Engineering Smart Grid and Distribution Engineering organizations)	316,330	94,899
Monthly Shared Services R&D Allocation	This monthly allocations is the shared services portion of CECONY's R&D salaries and the EPRI monthly program funding.	On going	Shared Services Allocation	335,044	100,513
		Total amount of Research and Development cost Included in rate filing			$ 202,121

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: April 28, 2014
Responding Witness: Richard Kane

Question No. : 78-Supp

Provide the amount of expenses for memberships and dues included in the filing indicating the organization paid and the employees who participate (union, management, directors, etc.).

RESPONSE:

Expenses for memberships and dues including in the 12+0 filing are:

Organization	Amount	Participants
STATE OF NJ ELECTION LAW ENFORCEMENT COMMISSION	$ 425	Thomas L. Brizzolara, Director of Government Relations
STATE OF NJ ELECTION LAW ENFORCEMENT COMMISSION	425	John L. Carley, Assistant General Counsel
MAHWAH REGIONAL CHAMBER COMMERCE	580	General company membership
NJ ALLIANCE FOR ACTION	1,200	General company membership
NJR ENERGY SERVICES CO	3,450	General company membership
NJ UTILITIES ASSOCIATION INC	60,004	General company membership
EDISON ELECTRIC INSTITUTE	50,551	General company membership
	$ 116,635	

Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: 01/27/2014
Responding Witness: Richard Kane

Question No. : 79

For each entity for which dues and membership expenses are included in the filing, identify any portion of dues or membership fees that are directed toward lobbying activities by the organization.

Response:
Of the $49,243 in membership dues to Edison Electric Institute that was included in the Company's filing, $11,049 was directed toward lobbying activities. In its initial rate case filing, the Company eliminated $8,148 (i.e., the Company's initial calculation of the lobbying costs, as shown in Exhibit P-2, Schedule 12). The Company will update this exhibit in the 9+3 Update Filing to eliminate the entire $11,049. The Company is not seeking recovery of lobbying costs in its rate filing.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: January 27, 2014
Responding Witness: Ken Kosior

Question No. : 90

Regarding Exhibit P-3, Schedule 2, please identify the plant held for future use included in the Company's rate base claim. Please include a) a description of the plant, b) the date when the plant was acquired, c) the anticipated use of the plant, and d) and the expected date when the plant held for future use is expected to go into service.

RESPONSE:

Please see the Attachment for the information requested.

ROCKLAND ELECTRIC COMPANY
FUTURE USE DETAIL REPORT AS OF 12-31-2013

DESCRIPTION OF PLANT HELD FOR FUTURE USE	BOOK COST	TAX DISTRICT	YEAR Purchased	LAND S-B-L	LAND ACRES	PLANNED USE	YEAR PLACED IN PHFU	PROJECTED IN-SERVICE DATE
Future Wcykoff Substation site:								
Land - Deed 940-Peter, Marion, John & Louise Pulis	$ 167,049.29	Wyckoff	1975/1978	B202-L7:2	4.00	Distribution Substation	1976	2017
Easement - Deed 940-Peter, Marion, John & Louise Pulis - 50' wide	41,660.00	Wyckoff	1975	B202-L7:2		Distribution Substation	1976	2017
Future Land for Montvale Substation (Summit Ave Substation)	2,047,560.96	Montvale	2009	2.02	5.50	Distribution Substation	2009	2015
Total Held for Future Use	$ 2,256,270.25							

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set RCR-A1
Date of Response: January 27, 2014
Responding Witness: Rich Kane

Question No. : 117

Please provide all supporting assumptions, workpapers, and calculations for the consolidated income tax adjustment shown in Exhibit P-3, Schedule 11.

RESPONSE:

See Attachment RCR-A-117a for the calculation of the consolidated income tax adjustment for years 1991 – 1998 (pre-merger to Consolidated Edison Inc.).

See Attachment RCR-A-117b for the calculation of the consolidated income tax adjustment for years 1999 – 2012 (post-merger to Consolidated Edison Inc.).

ROCKLAND ELECTRIC COMPANY
CONSOLIDATED TAX DEDUCTION
TWELVE MONTHS ENDED MARCH 31, 2014
($000s)

EXHIBIT P-3
SCHEDULE 11

Consolidated Tax Losses Allocated to RECO				
1991 - 1998 Pre Merger (Orange & Rockland Utilities, Inc.)	$	(209)		
1999 - 2012 Post Merger (Consolidated Edison, Inc.)		(4,509)		
Total			$	(4,718)
Consolidated Tax Losses 2003				
Calendar Year 2013		tbd		
				-
Total Tax Losses				(4,718)
Portion Applicable to Delivery Service				88.62%
Net Consolidated Tax Deduction			$	(4,181)

Rockland Electric Company
Computation of Consolidated Tax Adjustment
1991 - 1998 (Pre Con Ed Merger)

Taxable Income	1991	1992	1993	1994	1995	1996	1997	1998	Cumulative	Percent
Orange and Rockland (Utility)	36,274,936	38,159,031	65,568,063	66,445,393	32,633,033	44,314,738	42,257,257	28,895,310	354,547,761	85.55%
Rockland Electric (Utility)	12,444,076	6,492,735	1,423,777	1,037,462	4,907,614	4,877,033	8,428,537	16,019,406	55,630,640	13.42%
Pike County Light & Power (Utility)	375,474	39,132	39,800	105,135	421,425	32,270	133,512	191,456	1,338,204	0.32%
Clove Dev. Corp	(1,678,732)	563,643	621,049	497,760	557,101	669,370	850,563	825,567	2,906,321	0.70%
Con Edison Energy	-	-	-	-	-	-	-	-	-	0.00%
Con Edison Solutions Inc.	-	-	-	-	-	-	-	-	-	0.00%
Con Edison Company of New York (Utility)	-	-	-	-	-	-	-	-	-	0.00%
Companies with Cumulative Income & Utilities	47,415,754	45,254,541	67,652,689	68,085,750	38,519,173	49,893,411	51,669,869	45,931,739	414,422,926	100.00%
O&R Energy Dev. (DISSOLVED)	63,178	54,500	(601)	(31,458)	46,575	9,595	8,091	21,939	171,819	
O&R Dev.	64,177	(695,530)	(673,352)	(478,130)	(515,705)	(453,552)	(382,720)	(1,336,380)	(4,471,192)	
ORIC (DISSOLVED)	372,657	(61,573)	-	-	-	-	-	-	311,084	
Saddle River Holding (DISSOLVED)	(120,743)	(23,006)	36,884	(568,182)	(321,519)	(307,786)	(285,193)	(1,118,794)	(2,708,339)	
Wickham Group (DISSOLVED)	(288,922)	(214,840)	-	-	-	-	-	-	(503,762)	
Atlantic Morris Broadcasting (DISSOLVED)	(1,100,352)	(1,092,275)	(903,756)	(406,261)	(26,943)	-	-	-	(3,529,587)	
Palisades Management Services (DISSOLVED)	5,938	-	-	-	-	-	-	-	5,938	
Norstar Holding Inc. (DISSOLVED)	4,028,233	2,281,764	1,314,041	782,598	(2,003,458)	(5,150,084)	(15,444,112)	(2,163,572)	(16,354,590)	
Norstar Management (ORE) (DISSOLVED)	-	-	-	-	(785,730)	405,299	115,732	(2,759)	(267,458)	
Millbrook Holding (DISSOLVED)	(15,706)	(48,753)	(37,326)	(37,510)	(34,812)	(57,786)	(52,274)	(51,996)	(336,163)	
Palisades Energy Services (DISSOLVED)	-	-	-	-	-	-	(704,547)	(880,845)	(1,585,392)	
Compass Resources Inc. (DISSOLVED)	-	-	-	-	-	-	(19,692)	(2,233)	(21,925)	
Enserve Holding (DISSOLVED)	-	-	-	-	-	-	(8,651)	(338,084)	(346,735)	
Con Edison Inc.	-	-	-	-	-	-	-	-	-	
Con Edison Development	-	-	-	-	-	-	-	-	-	
Con Edison Communications (DISSOLVED)	-	-	-	-	-	-	-	-	-	
Companies with Cumulative Losses / Dissolved	3,008,460	200,287	(264,110)	(738,943)	(3,641,592)	(5,554,314)	(16,773,366)	(5,872,724)	(29,636,302)	
Taxable Income	50,424,214	45,454,828	67,388,579	67,346,807	34,877,581	44,339,097	34,896,503	40,059,015	384,786,624	
Income Tax @ 34% - 35%	17,144,233	15,454,642	23,586,003	23,571,382	12,207,153	15,518,684	12,213,776	14,020,655	134,675,318	
Sum where cumulative is positive	47,857,527	45,247,468	67,652,088	68,054,292	38,565,748	49,903,006	51,677,960	45,953,678	414,911,767	
Less: Dissolved corporations where cum'l is positive	441,773	(7,073)	(601)	(31,458)	46,575	9,595	8,091	21,939	488,841	
Adjusted sum where cumulative is positive (1)	47,415,754	45,254,541	67,652,689	68,085,750	38,519,173	49,893,411	51,669,869	45,931,739	414,422,926	
sum where cumulative is negative	2,566,687	207,360	(263,509)	(707,485)	(3,688,167)	(5,563,909)	(16,781,457)	(5,894,663)	(30,125,143)	
Less: Dissolved corporations where cum'l is negative	2,502,510	902,890	409,843	(229,355)	(3,172,462)	(5,110,357)	(16,398,737)	(4,558,283)	(25,653,951)	
Adjusted sum where cumulative is negative (2)	64,177	(695,530)	(673,352)	(478,130)	(515,705)	(453,552)	(382,720)	(1,336,380)	(4,471,192)	

	1991	1992	1993	1994	1995	1996	1997	1998		
RECO Taxable Inc. ./ (loss)	12,444,076	6,492,735	1,423,777	1,037,462	4,907,614	4,877,033	8,428,537	16,019,406	55,630,640	13.42%
Total Positive - Affiliate Taxable Income (1)	47,415,754	45,254,541	67,652,689	68,085,750	38,519,173	49,893,411	51,669,869	45,931,739	414,422,926	100.00%
Total Negative - Affiliate Taxable Income (2)	64,177	(695,530)	(673,352)	(478,130)	(515,705)	(453,552)	(382,720)	(1,336,380)	(4,471,192)	
Statutory Tax Rate	34.00%	34.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%		
Consolidated Tax Savings	21,820	(236,480)	(235,673)	(167,346)	(180,497)	(158,743)	(133,952)	(467,733)		
Alternative Minimum Tax										
Total Net Savings	21,820	(236,480)	(235,673)	(167,346)	(180,497)	(158,743)	(133,952)	(467,733)	(1,558,604)	
RECO's Rounded % of Pos. Affl. Tax Income									13.42%	
Rate Base Adjustment allocated to RECO T&D									**(209,221)**	

Rockland Electric Company
Computation of Consolidated Tax Adjustment
1999 - 2012 (Post Con Ed Merger)

	Federal Taxable Income (Losses)															
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Cumulative	Percent
Taxable Income																
Orange and Rockland (Utility)	252,979,653	37,722,610	47,952,836	(11,425,718)	22,838,140	21,060,060	39,955,874	20,893,476	9,736,133	5,079,632	(40,691,137)	(6,921,578)	(116,102,466)	(27,598,707)	255,478,810	7.12%
Rockland Electric (Utility)	15,239,148	(9,922,708)	(13,766,456)	770,644	3,781,891	7,953,084	18,528,468	16,001,367	19,906,714	17,333,186	(397,928)	21,063,704	(7,675,226)	(2,957,165)	85,858,723	2.39%
Clove Dev Corp	1,087,581	4,799,920	906,450	641,523	278,545	333,274	593,340	976,475	1,016,521	439,771	64,240	63,551	68,824	82,412	11,372,427	0.32%
Con Edison Energy	1,257,160	5,272,163	6,374,729	2,408,566	3,300,684	(1,163,666)	(930,568)	3,929,401	(434,947)	14,055,522	(9,658,528)	(12,805,545)	(299,235)	7,671,689	19,156,427	0.53%
Con Edison Solutions Inc	(10,569,320)	(20,058,340)	1,898,014	29,035,921	29,865,640	(982,845)	6,625,602	44,214,714	25,864,162	(8,502,519)	68,665,378	77,179,984	54,193,811	32,325,693	333,145,085	9.28%
Con Edison Company of New York (Utility)	809,046,200	564,853,517	874,709,351	(37,419,662)	440,201,859	(205,002,324)	737,624,112	97,026,544	398,240,981	(27,818,709)	(602,274,054)	(179,144,206)	(393,782,202)	309,399,882	2,585,661,287	72.04%
Honeoye Storage Corporation												471,317	2,550,742	1,343,035	4,365,094	0.12%
Con Edison Deve Gene Holding									(2,108,522)	7,608,612					5,500,090	0.15%
Con Edison Energy Mass									11,730,645	1,900,802					13,631,447	0.38%
Con Edison Development (per books)	(14,124,646)	(46,367,171)	(56,261,951)	(80,528,978)	(113,454,582)	(101,618,631)	(191,511,092)	(21,891,023)	(1,696,383)	784,720,779	(41,259,345)	(46,735,738)	(152,285,871)	(191,810,435)	(275,155,267)	
Adjustment due to LILO Case Court Ruling	33,798,718	41,460,783	41,409,236	40,694,284	40,177,415	39,640,481	35,552,944	34,918,977	33,572,207	90,093,176	41,970,613	41,111,901	35,974,369	-	550,375,104	
Con Edison Development (Revised)	19,673,872	(4,906,388)	(14,852,715)	(39,834,694)	(73,277,167)	(61,978,150)	(156,258,148)	13,027,954	31,875,824	874,813,955	661,268	(5,623,837)	(116,311,502)	(191,810,435)	275,219,837	7.67%
Companies with Cumulative Income & Utilities	1,098,714,294	577,750,974	903,222,011	(55,823,420)	426,189,592	(239,800,567)	646,338,680	196,069,931	498,627,511	884,910,252	(782,590,759)	(105,517,612)	(577,358,054)	128,456,404	3,589,389,237	100.00%
O&R Energy Dev (DISSOLVED)	10,890	9,043	-	-	-	-	-	-	-	-					19,933	
O&R Dev	(749)	(594,515)	(1,276,449)	(499,056)	(95,852)	(119,157)	(57,856)	(134,137)	12,540	10,205	41,860	109,279	(705)	(787)	(2,605,359)	
ORIC (DISSOLVED)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Saddle River Holding (DISSOLVED)	(1,548,480)	110,167	20,267	-	-	-	-	-	-	-	-	-	-	-	(1,418,046)	
Wickham Group (DISSOLVED)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Atlantic Morris Broadcasting (DISSOLVED)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Palisades Management Services (DISSOLVED)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Norstar Holding Inc (DISSOLVED)	(226,646)	-	-	-	-	-	-	-	-	-	-	-	-	-	(226,646)	
Norstar Management (ORE) (DISSOLVED)	5,078	(67,259)	27,758	-	-	-	-	-	-	-	-	-	-	-	(34,422)	
Millbrook Holding (DISSOLVED)	(9,311)	(10,960)	(1,490,756)	-	-	-	-	-	-	-	-	-	-	-	(1,511,027)	
Palisades Energy Services (DISSOLVED)	(492,058)	(113,544)	-	-	-	-	-	-	-	-	-	-	-	-	(605,602)	
Compass Resources Inc (DISSOLVED)	(3,246)	(4,868)	-	-	-	-	-	-	-	-	-	-	-	-	(8,114)	
Enserve Holding (DISSOLVED)	(85,492)	(69,095)	(64,405)	3,400	6,548	-	-	-	-	-	-	-	-	-	(189,049)	
Con Edison Communications (DISSOLVED)	(909,131)	(7,641,191)	(19,343,960)	(55,378,743)	(67,100,805)	(29,562,940)	(52,565,122)	(5,351,601)	-	-	-	-	-	-	(237,853,493)	
Con Edison Dev Ada (DISSOLVED)									5,568,296	(6,209,842)					(641,546)	
Con Ed Leasing (DISSOLVED)									(16,521,860)	(17,865,941)					(34,387,821)	
Competitive Shared Services Inc											(362,472)	252,268	(197,500)		(307,704)	
Con Edison Inc	(156,514)	(38,500,203)	(21,225,640)	(12,671,641)	(26,042,835)	(40,549,137)	(146,940,703)	(111,633,375)	(72,924,066)	18,807,265	(23,646,282)	(14,582,612)	(17,702,276)	(23,844,195)	(532,054,654)	
Pike County Light & Power (Utility)	349,559	(829,632)	(463,042)	58,377	59,032	(916,655)	(574,419)	995,670	45,601	(807,519)	(678,421)	293,735	(329,880)	(2,237,979)	(5,234,383)	
BGA Inc									14,360	1,583,465	1,736,546	2,612,637	(729,209)	(6,184,866)	(965,038)	
Companies with Cumulative Losses / Dissolved	(3,089,100)	(47,707,057)	(43,816,528)	(68,687,863)	(93,172,914)	(71,149,589)	(200,138,100)	(116,123,443)	(83,804,889)	(4,482,347)	(23,309,749)	(11,314,703)	(18,959,561)	(32,267,827)	(818,019,970)	
Taxable Income	1,085,628,194	530,043,917	859,405,483	(124,511,283)	333,016,678	(310,950,456)	446,200,580	79,946,488	415,022,622	880,427,905	(805,899,506)	(116,832,315)	(596,317,615)	96,188,577	2,771,369,267	
Income Tax @ 34% - 35%	379,969,868	185,515,371	300,791,919	(43,578,949)	116,555,837	(108,832,660)	156,170,203	27,981,271	145,257,918	308,149,767	(282,064,828)	(40,891,310)	(208,711,165)	33,666,002	969,979,243	
Sum where cumulative is positive	1,069,074,743	577,760,017	903,222,011	(55,823,420)	426,189,592	(239,800,567)	646,338,680	196,069,931	504,410,167	886,493,737	(780,852,213)	(102,904,975)	(578,087,254)	128,456,404	3,589,409,170	
Less Dissolved corporations where cum'l is positive	10,890	9,043	-	-	-		-	-	5,568,296	-	-	-	-	-	19,933	
Adjusted sum where cumulative is positive (1)	1,069,063,853	577,750,974	903,222,011	(55,823,420)	426,189,592	(239,800,567)	646,338,680	196,069,931	498,841,871	886,493,737	(780,852,213)	(102,904,975)	(578,087,254)	128,456,404	3,589,389,237	
sum where cumulative is negative	(3,446,549)	(47,716,100)	(43,816,528)	(68,687,863)	(93,172,914)	(71,149,889)	(200,138,100)	(116,123,443)	(89,387,545)	(6,065,832)	(25,047,296)	(13,927,340)	(18,230,361)	(32,267,827)	(818,039,903)	
Less Dissolved corporations where cum'l is negative	(3,255,113)	(8,390,265)	(22,127,546)	(55,874,399)	(67,188,111)	(29,682,097)	(52,622,978)	(5,485,738)	(16,509,340)	(24,065,578)	41,880	109,279	(705)	(787)	(279,478,124)	
Adjusted sum where cumulative is negative (2)	(191,436)	(39,325,835)	(21,688,982)	(12,813,464)	(25,984,803)	(41,467,792)	(147,515,122)	(110,637,705)	(72,878,205)	17,999,746	(25,089,175)	(14,036,619)	(18,229,656)	(32,267,040)	(538,561,779)	

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		
RECO Taxable Inc / (Loss)	15,239,148	(9,922,708)	(13,766,456)	770,644	3,781,891	7,953,084	18,528,468	16,001,367	19,906,714	17,333,186	(397,928)	21,063,704	(7,675,226)	(2,957,165)	85,858,723	2.39%
Total Positive - Affiliate Taxable Income (1)	1,069,063,853	577,750,974	903,222,011	(55,823,420)	426,189,592	(239,800,567)	646,338,680	196,069,931	498,841,871	886,493,737	(780,852,213)	(102,904,975)	(578,087,254)	128,456,404	3,589,389,237	100.00%
Total Negative - Affiliate Taxable Income (2)	(191,436)	(39,325,835)	(21,688,982)	(12,813,464)	(25,984,803)	(41,467,792)	(147,515,122)	(110,637,705)	(72,878,205)	17,999,746	(25,089,175)	(14,036,619)	(18,229,656)	(32,267,040)	(538,561,779)	
Statutory Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	
Consolidated Tax Savings	(67,003)	(13,764,042)	(7,591,144)	(4,484,712)	(9,094,681)	(14,513,727)	(51,630,293)	(38,723,197)	(25,507,372)	6,299,911	(8,781,211)	(4,912,817)	(6,380,380)	(11,293,464)	(188,496,623)	
Alternative Minimum Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Total Net Savings	(67,003)	(13,764,042)	(7,591,144)	(4,484,712)	(9,094,681)	(14,513,727)	(51,630,293)	(38,723,197)	(25,507,372)	6,299,911	(8,781,211)	(4,912,817)	(6,380,380)	(11,293,464)	(188,496,623)	
RECO's Rounded % of Pos Affl Tax Income															2.39%	
Rate Base Adjustment allocated to RECO T&D															**(4,500,667)**	

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to Rate Counsel Interrogatories – Set RCR-RD1
Date of Response: January 21, 2014
Responding Witness: Rate Panel

Question No. : 10

Reference Exhibit P-7, Schedule 1, Table 6. Do the Rate Base and Operating Expense amounts shown on lines 3 and 5 of the referenced exhibit reflect any portion of the Company's investment and/or expenses related to Accounts 361 through 368? If so, please provide a revised Table 6 that excludes all such investment and/or expenses. Include a copy of all workpapers used to prepare the revised exhibit.

RESPONSE:

See attached the attached pdf file entitled, Attachment to RCR-RD-10.

		TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)	TOTAL PRIMARY (6)
	CUSTOMER COST BY CLASS						
1	NUMBER OF CUSTOMERS	72,621	63,378	8 401	27	773	42
2							
3	RATE BASE	20,111,481	11,102,071	5,893,354	1,129,536	628,272	1,358,247
4							
5	TOTAL CUSTOMER OPERATING EXPS.	16,567,102	11,959,560	3,096,439	642,562	433,771	454,770
6	MONTHLY OP. EXPS. COST/CUST	19.03	15.73	30.71	1,983.22	46.76	902.32
7							
8	RETURN @ 5.78% (CUSTOMER)	1,162,411	641,682	340,626	65,285	36,313	78,504
9	F.I.T. PERCENT ON RETURN	33.31%					
10	INCOME TAX ON RETURN	387,252	213,773	113,478	21,749	12,098	26,153
11	TOTAL RETURN & F.I.T.	1,549,662	855,455	454,104	87,035	48,411	104,656
12	MONTHLY RET. F.I.T. COST/CUST	1.78	1.12	4.50	268.63	5.22	207.65
13							
14	MONTHLY CUSTOMER COSTS	20.81	16.85	35.22	2,251.84	51.98	1,109.98

		RESID SC1 GENERAL (7)	RESID SC1 W/ WTR HTG (8)	RESID SC1 W/ SP HTG (9)	RESID SC1 W/SP & WTR HTG (10)	RESID SC3 T O U (11)	RESID SC5 W/ SP HTG (12)
	CUSTOMER COST BY CLASS						
1	NUMBER OF CUSTOMERS	58,718	2,790	11	114	18	1,727
2							
3	RATE BASE	10,356 151	441,375	4,519	29,770	8,521	261,632
4							
5	TOTAL CUSTOMER OPERATING EXPS.	11,090,535	519,942	2,775	24,759	4,642	316,907
6	MONTHLY OP. EXPS. COST/CUST	15.74	15.53	21.03	18.10	21.49	15.29
7							
8	RETURN @ 5.78% (CUSTOMER)	598,569	25,511	261	1,721	498	15,122
9	F.I.T. PERCENT ON RETURN						
10	INCOME TAX ON RETURN	199,410	8,499	87	573	166	5,038
11	TOTAL RETURN & F.I.T.	797,979	34,010	348	2,294	664	20,160
12	MONTHLY RET. F.I.T. COST/CUST	1.13	1.02	2.64	1.68	3.08	0.97
13							
14	MONTHLY CUSTOMER COSTS	16.87	16.55	23.66	19.78	24.57	16.26
		===========	===========	===========	===========	===========	===========

		C&I SC2 SEC NON MET (13)	C&I SC2 SEC NON DEM MET (14)	C&I SC2 GEN SERV SEC (15)	C&I SC2 SPACE HTG (16)	C&I SC2 PRIMARY (17)	SC4 MUNI STR LTG (18)
	CUSTOMER COST BY CLASS						
1	NUMBER OF CUSTOMERS	772	687	6,668	189	85	27
2							
3	RATE BASE	19,229	76,941	5,040,148	212 769	544,267	1,129,536
4							
5	TOTAL CUSTOMER OPERATING EXPS.	107,741	109,097	2,565,464	97,376	216,761	642,562
6	MONTHLY OP. EXPS. COST/CUST	11.63	13.23	32.06	42.93	212.51	1,983.22
7							
8	RETURN @ 5.78% (CUSTOMER)	1,111	4,447	291,312	12 298	31,456	65,285
9	F.I.T. PERCENT ON RETURN						
10	INCOME TAX ON RETURN	370	1,482	97,049	4,097	10,480	21,749
11	TOTAL RETURN & F.I.T.	1,482	5,929	388,362	16 395	41,936	87,035
12	MONTHLY RET. F.I.T. COST/CUST	0.16	0.72	4.65	7.23	41.12	268.63
13							
14	MONTHLY CUSTOMER COSTS	11.79	13.95	36.92	50.16	253.63	2,251.84
		===========	===========	===========	===========	===========	===========

		SC6 DUSK/ DAWN (19)	SC6 ENERGY LTG (20)	SC7 PRIMARY T.O.U (21)	SC7 SEP MET SP HTG (22)	SC7 HV TOD (23)
	CUSTOMER COST BY CLASS					
1	NUMBER OF CUSTOMERS	667	106	38	3	1
2						
3	RATE BASE	588,512	39,760	1,142,004	205,675	10,568
4						
5	TOTAL CUSTOMER OPERATING EXPS.	408,305	25,466	382,435	51,759	20,575
6	MONTHLY OP. EXPS. COST/CUST	51.01	20.02	838.67	1,437.76	1,714.62
7						
8	RETURN @ 5.78% (CUSTOMER)	34,015	2,298	66,006	11,888	611
9	F.I.T. PERCENT ON RETURN					
10	INCOME TAX ON RETURN	11,332	766	21,990	3,960	203
11	TOTAL RETURN & F.I.T.	45,347	3,064	87,996	15,848	814
12	MONTHLY RET. F.I.T. COST/CUST	5.67	2.41	192.97	440.22	67.86
13						
14	MONTHLY CUSTOMER COSTS	56.68	22.43	1,031.65	1,877.98	1,782.48
		===========	===========	===========	===========	===========

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set S-RCWC1
Date of Response: December 30, 2013
Responding Witness: Richard Kane

Question No. : 2

Cash Working Capital - Provide a lead-lag study, completed no more than six months prior to the rate increase filing using the most recent information available. Provide all data and calculations supporting the revenue collection lag and payment leads/lags reflected in the current study. State all known changes that will affect the leads/lags contained in the current study.

RESPONSE:

See attached (S-RCWC1-2). Please also see the direct testimony of Richard Kane at pages 19-23.

ROCKLAND ELECTRIC COMPANY
ITEMS WITH A ZERO LAG ASSIGNED
FOR 12 MONTHS ENDING DECEMBER 31, 2012

Deferred Purchased Power, Materials and Supplies, Amortization Expense, and Depreciation & Amortization of Plant –

A zero lag was assigned to the amounts included in the cost of service for these items because the related assets are either non-cash or are included in rate base as separate components.

Return On Invested Capital –

This amount is equal to operating income booked during the test year. A zero lag is used for the net amount representing operating income available for investors to recognize the fact that the return is earned when service is provided but the related revenues are not received for an additional 38.8 days.

Deferred Federal Income Taxes –

Deferred federal income tax has a zero lag in recognition of the fact that an immediate reduction in rate base occurs when the expense is booked.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set S-RCWC1
Date of Response: May 5. 2014
Responding Witness: Richard Kane

Question No. : 3

Cash Working Capital – Referencing Exhibit P-3 (Rate Base), Schedule 6, Page 2 of 4, 12 + 0 Update, Other Post-Employment Benefits ("OPEBs") are shown on this schedule with a distribution amount of $640,000, (lead)/lag days of 79.5, and distribution dollar days amount of zero. Why is the distribution dollar days amount for OPEBs zero instead of the total of [640,000 x 79.5]?

RESPONSE:

The distribution dollar days amount for OPEBs should be the total of 640,000 x 79.5, or $50,880,000. The error was caused by the inadvertent absence of the formula in the cell in the EXCEL file.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set S-RREV1
Date of Response: January 6, 2014
Responding Witness: Kenneth Kosior

Question No. : 30

Submit a listing (description, dollar amounts, account numbers) of all expenses in the test year results related to institutional advertising and public relations (i.e., corporate branding or promoting the Company's goodwill.) Submit samples of advertisements in each classification. Update this response with each set of updated workpapers you provide.

RESPONSE:

A. The table below represents the Company's expenses in the test year related to institutional advertising and public relations. This data is based on actual activity through September 2013 and forecasted data through March 2014. Updated information will be provided in subsequent updates.

Activity		($'000's)
Professional Advertising Services		106.5
Print Materials		22.9
	Total	129.4

Advertising Services represents the professional services of The Gate Worldwide, the Company's advertising agency which creates advertisements and places the media buys for publications, online and radio. Examples of their work product are included in the samples of advertisements (S-RREV1-30 Advertising Samples, pages 3 -7).
Print Materials represent material inserted in customer bills.

B. Please see the attached Adobe file S-RREV1-30 Advertising Samples, which provides samples of the Company's advertisements.

Company Name: Rockland Electric Company
Case Description: Rockland Electric Co. Rate Filing
Case: ER13111135

Response to BPU Interrogatories – Set S-RREV1
Date of Response: January 6, 2014
Responding Witness: Kenneth Kosior

Question No. : 31

Provide the level of community affairs" and/or "public relations" expenses that are included in the test year results, if any.

RESPONSE:

Please see the attached file S-RREV1-31 – Community Affairs, which sets forth the Company's expenses in the test year results related to community affairs and/or public relations.

Rockland Electric Company
BPU Docket No. ER13111135
S-RREV, No. 31
($000's)

Community Affairs/Public Relations

Element of Expense	Test Yr Total
Management Payroll- Regular	**166.4**
Management Payroll- Overtime	**0.1**
Materials & Supplies - Non-Stock	**0.4**
Permits, Licenses and Fees	**1.3**
Employee Expenses	**4.6**
Empl Train, Test & Develop	**0.1**
Contract Services NonField	**1.0**
Other Community Affairs Activities	**6.4**
Facilities	**17.4**
Telecommunications	**11.0**
	208.7