STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on June 14, 2012

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.
James L. Larocca

CASE 11-E-0408 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

ORDER ADOPTING TERMS OF JOINT PROPOSAL, WITH MODIFICATION, AND ESTABLISHING ELECTRIC RATE PLAN

(Issued and Effective June 15, 2012)

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BY THE COMMISSION:

I. INTRODUCTION

This order adopts terms set forth in a Joint Proposal (JP) submitted for our review by Orange and Rockland Utilities, Inc. (O&R or the Company), trial staff of the Department of Public Service (Staff), and the Utility Intervention Unit of the New York Department of State's Consumer Protection Division (UIU) (collectively referred to as the signatories).[1] We hereby establish a rate plan and other provisions governing the

[1] The Joint Proposal was filed February 24, 2012, and is attached hereto as Attachment A.

Company's electric service, to remain in effect for three years starting July 1, 2012.[2]

II. BACKGROUND

On July 29, 2011, O&R filed for rates that would increase the Company's electric delivery revenues by $17.7 million, effective July 1, 2012.[3] The Company also proposed a three-year rate plan with rate increases of $20.5 million to take effect July 1, 2012, $12.3 million to take effect on July 1, 2013, and $19.5 million to take effect on July 1, 2014. On October 28, 2011, the Company submitted updates to its filing that increased its proposed revenue requirement from $17.7 million to $25.4 million for the first rate year.

Staff, the Town of Ramapo, and UIU filed initial testimony on December 2, 2012.[4] In its testimony Staff recommended a one-year revenue increase of $6.81 million and also proposed a three-year rate plan with increases in revenues of $8.5 million, $4.63 million, and $15.86 million in years one, two, and three. Staff later adjusted its first year revenue requirement proposal downward by $0.49 million to reflect expected operating and maintenance savings from the Company's implementation of management audit recommendations.

The Company also updated its requested revenue requirement on December 23, 2011, through rebuttal testimony. It increased requested revenue requirement for RY1 by approximately $5.98 million to $31.39 million. The revision,

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[2] Rate Year 1 (RY1) is July 1, 2012 through June 30, 2013, RY2 is July 1, 2013 through June 30, 2014, and RY3 is in July 1, 2014 through June 30, 2015.

[3] Notice of the Company's filing was published in the New York State Register on November 16, 2011 (SAPA No. 11-E-0408SA1).

[4] The Municipal Consortium in Support of Reasonable Electric Rates (MC) was also a party to this proceeding.

according to the Company, was largely attributable to costs associated with an autumn snow storm and an increase in the forecast of pension and other post-employment benefits (OPEB) costs.

The pre-filed testimony became the basis for settlement discussions, which started on January 4, 2012, pursuant to public notice in compliance with our rules in 16 NYCRR 3.9. The negotiations continued for several weeks and culminated in the February 24, 2012 JP. The JP and parties' testimony and exhibits, as well as other information, were introduced into the record at an evidentiary hearing held on April 18, 2012.[5]

The JP proposes a three-year rate plan, which, if approved, would authorize the Company to increase base electric delivery revenues by $19.44 million (7.9%), $8.84 million (3.3%), and $15.23 million (5.6%) for RY1, RY2, and RY3, respectively (or $15.2 million for each of the three rate years on a levelized basis, and average annual increase of 5.8%). Each of the JP's sponsoring parties has submitted a statement supporting it, and no party opposed it.[6]

III. PUBLIC COMMENTS

Throughout this proceeding, public comments were received in letters, e-mails, telephone calls, and oral presentations made at two public hearings held in Goshen, on March 15, 2012, and Ramapo, on March 28, 2012. The public hearings collectively drew approximately 34 commenters. As of May 31, 2012, we had received approximately 40 written comments.

[5] Commissioner Patricia Acampora joined the presiding administrative law judges at the evidentiary hearing.

[6] The Company, Staff and UIU filed statements on March 16, 2012 and the Company filed a reply statement on March 23, 2012.

The vast majority of commenters expressed opposition to O&R's requested rate increase, primarily because of the difficult economic climate and out of concern for the Company's perceived poor responses to Hurricane Irene and an October 2011 snowstorm. One comment in support of the rate increase was filed by the Orange County Chamber of Commerce.

There was significant concern for the impact of rate increases on senior citizens and residents on a fixed income, who have not received cost-of-living increases in several years, as well as the impact of higher rates on struggling business and industry. State and local elected officials urged that we deny the requested revenue requirement increases until the State's economy and their constituents recover from the recession. Others cast O&R's employment costs, including pensions and OPEB costs, as excessive -- particularly given the recent curtailment of such benefits for both private and public sector employees –- and suggested that increasing rates without curbing Company costs was unjust.

Numerous ratepayers stated that they believed O&R's current rates to be excessive. Some questioned why the Company should be permitted to seek another rate increase on top of other recent Commission-approved rate increases. Some expressed confusion as to why the Company's delivery rates were higher that its commodity rates.

Many commenters objected to the rate increase because they felt it put an unfair burden on ratepayers without requiring Company shareholders to assume some financial responsibility for the cost increases. Some were upset by the fact that O&R's parent company, Consolidated Edison Inc., (Con Edison) has continued to pay dividends to its shareholders throughout the recession, while its subsidiaries have asked for multiple rate increases from utility customers. State

Assemblyman Kenneth Zebrowski suggested asking O&R to renegotiate its dividend agreement with Con Edison to help cover some of its increasing costs before allowing the utility to seek additional funds from customers through a rate increase. Ramapo Town Supervisor Christopher St. Lawrence challenged the 9% return on equity afforded O&R in the Joint Proposal, characterizing it as several times higher than the type of return residents and business owners are currently seeing.

A few commenters had specific requests regarding the costs O&R sought to recover through its proposed rate increases. Warwick Town Supervisor Michael Sweeton requested that the Commission require O&R to split the cost of replenishing its underfunded pension system between shareholders and ratepayers, rather than having ratepayers pick up the full cost of that shortfall.

Given their perception of the high cost of O&R's electric service, several ratepayers raised concerns about the utility's treatment of customers who fall behind on their payments or cannot afford their bills, particularly senior citizens and those on a fixed income. Others complained of poor customer service and bad experiences with impolite or unhelpful employees. One residential customer complained of the utility's lack of responsiveness after he reported in January a street light in need of replacement, noting that the street light still had not been replaced in March. Commenters also asked that O&R be required to increase its use of tools like the internet and social media to better disseminate information to ratepayers about outages and repairs.

Customers also expressed serious concern with O&R's customer service and disaster planning related to Hurricane Irene and the October 2011 snowstorm, citing long outages, poor employee treatment of customers, unanswered phones, nonfunctional websites, inaccurate outage maps, and a general lack of responsiveness and timely action by the utility. Municipal and fire department officials were particularly concerned about lengthy response times and a lack of utility communication during the emergencies. Many commenters felt the utility should not be fully reimbursed for having provided poor service during the storms, and suggested that shareholders should be required to absorb some of those costs.

Additional safety concerns were raised by local officials and emergency services personnel, such as the presence of double poles and "splinted" poles that may present a threat to public safety, police and emergency personnel. Fire officials raised concerns such as the lack of a fire suppression system to protect volunteer firefighters responding to the Tomer Valley substation, as well as slow responses to reports of downed lines and requests for disconnection of lines during fires, automobile accidents, and other emergencies.

A few commenters felt that, especially given the high incidence of storm-related outages last year, O&R has been remiss in not pursuing line burial projects, particularly in conjunction with recent highway renovations. While these commenters acknowledged the high expense associated with burying transmission lines, they felt that the high costs of outages and line replacement during storms was evidence that the Company should more seriously consider underground lines in the future. One residential customer pointed out that homeowners and commercial establishments also incur costs during protracted outages –- such as those related to flooded basements, spoiled food, and lost business –- which should be included in O&R's calculation of the true cost of maintaining a "fragile overhead electric system." Another suggested approval of the JP should be predicated on O&R's more aggressively pursuing burial of its electric lines.

Ramapo town officials requested that the Commission decision afford them the opportunity to replace existing street lights with light-emitting diodes (LEDs) and to pursue energy-only street lighting agreements.

IV. STANDARD OF REVIEW

Our obligation in reviewing any Joint Proposal submitted for our consideration is to ensure that its terms, viewed as a whole, produce a result that is in the public interest. Our Settlement Guidelines describe the factors we take into account in making that assessment.[7]

In general, a desirable settlement should balance protection of consumers, fairness to investors and the long-term viability of the utility. It should be consistent with the environmental, social and economic policies of the Commission and the State; and it should produce results that are within the range of reasonable results that would have likely arisen from a Commission decision in a litigated proceeding.

The parties were provided an opportunity to submit testimony and were provided notification of and an opportunity to participate in settlement negotiations. In addition, as Staff points out, three parties support the JP and no formal opposition was filed by the other parties, reflecting the fact that the parties made extensive efforts to address all parties' concerns. Staff also notes that the JP represents a result that

[7] Cases 90-M-0255, et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992).

falls within the range of possible litigation outcomes, as outlined by the parties' pre-filed testimony and exhibits.

We conclude, therefore, that the JP in this case was developed fairly with full opportunity for participation by all interested parties. It is, therefore, properly before us for a determination of its consistency with the public interest.

V. DISCUSSION

This section both summarizes and discusses key elements of the JP that are significant either because of their impact on base rates or because they represent a compromise of heavily contested issues. The complete proposal accompanies this order as Attachment A.

In addition to the issues discussed below, we note that the JP proposes to continue certain important provisions of the 2011 Rate Order. The customer service and reliability performance mechanisms will be continued without modification, while the revenue decoupling mechanism will continue at a reset level.[8]

A. Three-Year Rate Plan

The JP would establish base electric delivery rates for O&R for a three-year period from July 1, 2012, through June 30, 2015. The Company would be precluded from filing for new rates during the term of the plan, unless circumstances occurred which, in the judgment of the Commission, threatened the Company's economic viability or ability to maintain safe, reliable, and adequate service.

The signatories to the JP have agreed that rate increases in the amounts of $19.4 million, $8.8 million and

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[8] Case 10-E-0362, Orange and Rockland Utilities, Inc – Electric Rates, Order Establishing Rates for Electric Service (issued June 17, 2011)(2011 Rate Order).

$15.2 million for RY1, RY2, and RY3, respectively, are reasonably necessary to meet increased costs and to support spending for capital improvements and employee additions. In order to mitigate the first-year impact of the increases, they propose that the new base rates be phased-in in equal increments of $15.2 million per year.

To compensate for the fact that this levelized approach would leave rates higher at the end of RY3 than if rates were increased on a cost of service basis, the JP proposes that $2.1 million of the $15.2 million third year increase be collected as a temporary surcharge through the Company's Energy Cost Adjustment (ECA). If new base delivery rates were put in place immediately following the expiration of the rate plan, the surcharge would expire. If not, the surcharge would be reset effective July 1, 2014, to collect $1.5 million over the lesser of 12 months or the time until new base rates take effect, and would be applied to reduce the Company's accumulated storm deferral balance, which will be discussed more fully below.

In support of the proposal, Staff points out that the $19.4 million increase (which reflects compromises on a number of issues) agreed upon for RY1 is only slightly higher than the position it took in testimony, after taking into account certain updates of expenses that Staff says it would not reasonably have opposed if the case were fully litigated.[9] O&R points out that the first year increase provided for is a reasonable compromise between the Company's final, updated request for $31.4 million and Staff's originally recommended increase of $6.8 million.

The rate increases proposed by the JP are reasonable in light of increasing costs. For example capital additions ($41 million in rate base producing an increase of $4.2 million in revenue requirement, labor expenses ($4.3 million), increase

[9] See Staff Statement in Support, Attachment A, pg. 1.

in ROE from 2011 Rate Order ($2.8 million), and property taxes ($3.3 million) represent approximately 75% of the revenue requirement increase for RY1. In RY2 and RY3 capital additions to rate base of approximately $37 million and $50 million, respectively, contribute to the revenue increases requested in those rate years.

Increasing revenue requirement in order to meet the Company's increasing costs is essential if the Company is to continue meeting its statutory duty to provide safe and adequate electric service and receive a fair rate of return for shareholders. We appreciate the concerns raised by the public in written comments and at the public statement hearing regarding the timing of the increase in rates. Ignoring the capital and financial needs of the Company, however, could possibly jeopardize service or deprive the Company of an opportunity to earn a fair rate of return. The levelization proposal will smooth the impact of the increase in rates over the term of the rate plan and use of a surcharge recovered through the ECA will ensure that rates are not artificially high after the end of RY3.

B. Revenue Allocation and Rate Design

The JP proposes continuation of revenue reallocation among service classifications that was begun in the 2011 Rate Order, as well as several rate design changes. First, the JP proposes to eliminate class revenue deficiencies and surpluses that were identified by an embedded cost of service study filed in the last rate case. In the 2011 Rate Order, we directed the Company to begin bringing the service classifications into parity; each class should provide revenues sufficient to meet the costs incurred to provide service to the class. To begin the process, we reallocated one-third of the class deficiencies and surpluses prior to allocating the proposed revenue requirement increase. The JP proposes to continue this effort, applying the remaining two-thirds of the deficiencies and surpluses in equal amounts (one-third) in RY1 and RY2.

Second, the JP proposes to increase the customer charge for each year of the rate plan, reflecting movement of costs that are fixed in nature out of the volumetric charge and into the customer charge, which better reflects the non-variable component of the cost to serve the customer classes. For example, the JP proposes to increase the customer charge for residential customers in RY1 from $15.60 to $18.00 and to increase the charge in RY2 and RY3 by $1.00 each, bringing the customer charge to $19 and $20, respectively.

As we stated in the 2011 Rate Order it is important that rates generally reflect the cost to serve the customer class and that where disparity exists we will endeavor, keeping in mind bill impacts, to reduce revenue allocation imbalances. The balance we struck in the 2011 Rate Order –- bringing classes closer to parity while minimizing bill impacts –- continues to be valid in this case. With respect to the increases in the customer charge, our reasoning in the 2011 Rate Order remains valid in this case. In that order we approved an increase in the customer charge recognizing, as we did with revenue allocation, that it is best to move toward parity and ensure that rates reflect the costs incurred to serve. Additionally, we noted in the 2011 Rate Order that the embedded cost of service study showed that the customer charge should be $21.38. Even with adoption of the JP, the customer charge will remain below the rate supported by the embedded cost of service study at the end of the rate plan.

C. Cost of Capital

The revenue requirement underlying the rates proposed in the JP is based on an assumed capital structure with 48%

common equity and a return on equity of 9.4% in RY1, 9.5% in RY2, and 9.6% in RY3, which would provide the Company with an after-tax rate of return for RY1 of 7.61%, RY2 of 7.65%, and RY3 of 7.48%. Staff notes that the 48% equity ratio is identical to that which it proposed in its testimony, and is somewhat lower than the Company's requested level. It says that the average 9.5% multi-year return is only slightly higher than its originally recommended 9.2%, is consistent with investor expectations given recent Commission decisions, and is substantially lower than the 11.25% return requested by the Company. The proposal, Staff says, uses a tiered return over the three years of the rate plan to reflect the current reality of historically low interest rates which create the expectation, if the economy continues to improve, that capital costs are more likely than not to increase over the next few years.

O&R also emphasizes the JP's significant reduction in both equity ratio and rate of return from the positions supported by the Company's testimony. It complains that the Commission's framework for establishing the cost of capital puts O&R in the bottom quartile of U.S. public companies in terms of earned returns on equity, but says that the use of a tiered ROE is a "welcome incremental step" reflecting some flexibility in the standard approach. Overall, O&R says it was willing to accept the cost of capital terms in the context of the overall settlement reflected in the JP.

The capital structure proposed by the JP is the same structure we approved in the 2011 Rate order. Since that order, it does not appear that financial circumstances for the Company have materially altered to the extent that the capital structure should be modified. In addition, the proposed capital structure, based upon a 48% equity ratio, is consistent with our decisions for other similarly situated utilities.[10] Therefore we adopt the JP's proposed capital structure and continue the equity ratio for the Company at 48%.

The ROE levels proposed by the JP appropriately reflect the degree of risk faced by the Company over the three-year period of the rate plan and the Company's need to attract capital to support its operations.[11] The average ROE of 9.5% over the three-year term of the JP is consistent with our conventional practice of using a base ROE plus a stay-out premium to reflect the added risk of the multi-year plan. Moreover, the proposed ROE levels fall within the range of ROEs advocated in testimony by Staff (9.2%) and the Company (11.25%) and is significantly closer to Staff's litigation position than the Company. The range of ROEs proposed is also consistent with returns we have approved in recent rate cases.[12]

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[10] See Case 10-E-0050, Niagara Mohawk Power Corporation - Electric Rates, Order Establishing Rates for Electric Service (issued January 24, 2011), p. 71 (setting rates based upon a 48% equity ratio and referring to similar decisions for Consolidated Edison Company of New York and Central Hudson Gas & Electric Corporation.

[11] While we appreciate Supervisor St. Lawrence's perspective, our obligation is to ensure that O&R has the opportunity to earn a return sufficient to attract capital. The return we have provided for is consistent with the expectations of equity investors. Assemblyman Zebrowski's suggestion that O&R use funds that would otherwise be paid as dividends to its parent company to cover its operating costs would effectively preclude the Company from generating a reasonable return for shareholders.

[12] See Case 11-G-0280, Corning Natural Gas Corporation – Gas Rates, Order Adopting Terms of Joint Proposal and Establishing A Multi Year Rate Plan, (issued April 20, 2012) pp. 8-9 (setting rates based upon a 9.5% ROE for the three year term of the rate plan); Case 10-E-0362, supra, Order Establishing Rates for Electric Service (issued June 17, 2011) (setting rates for one year based upon an ROE of 9.2%).

The use of a graduated ROE over the term of a multi-year rate plan is relatively new to our ratemaking practice. We find this approach to be acceptable because, as Staff has pointed out, we are in a historically low interest rate environment. Furthermore, the average level of the graduated ROE compensates for risk while also moderating rates for the first rate year.

D. Earnings Sharing

The JP includes an earnings sharing mechanism (ESM), under which a portion of O&R’s earnings will be credited to ratepayers when the Company’s earned ROE exceeds defined levels. The annual thresholds for sharing are set at 80 basis points above the authorized ROE for the year. If earned ROE, calculated as defined in the JP, exceeds 10.2% in RY1, 10.3% in RY 2 or 10.4% in RY 4, the excess will be deemed shared earnings. The first 100 basis points of shared earnings will be split evenly between customers and the Company; the next 100 basis points will be shared on a 75%/25% customer/Company basis; and any shared earnings above that level will go 90% to customers and 10% to O&R.

Shared earnings will be deferred at the end of each rate year (with interest at the Other Customer Provided Capital Rate) until the end of RY3. At that time the allocation between Company and customers will be calculated, and the customer share will be deferred for the benefit of ratepayers. The JP, also states that the ESM does not prohibit “the netting of under-recoveries and over-recoveries in individual rate years in order to calculate Total Shared Earnings on a cumulative Electric Rate Plan basis.”[13]

[13] Attachment A, JP, n. 6.

If the Company does not file for new rates to be effective immediately following the expiration of the rate plan, the ESM will continue on a year-to-year basis.[14] If new rates take effect on a date other than July 1 of any year after RY3, then the ESM would be prorated for the partial year period as described in Appendix G to the JP.

Staff explains that an ESM provides critical protection to ratepayers in a multi-year rate plan, maintaining an incentive for the Company to control costs and improve its financial performance, while ensuring that customers will receive a reasonable share of the benefit of those efforts if earnings prove significantly better than projected for rate-setting purposes. Staff points out that the ESM's 80 basis point "dead band" between the authorized return and the level of return at which sharing begins is smaller than usual. It says this was done deliberately in order to capture for ratepayers a greater portion of savings not reflected in rates that could result from implementation of recommendations produced by a recent management audit of O&R's affiliate, Consolidated Edison Company of New York, Inc. undertaken by Liberty Consulting Group (Liberty Audit).[15]

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[14] Although the JP does not expressly state that shared earnings are to be calculated annually in the post-rate plan period, the parties to the JP stated at the evidentiary hearing that that was their intent. We accept this clarification to be applied to full rate years following expiration of the rate plan.

[15] Case 08-M-0152, Management Audit of Consolidated Edison Company of New York, Inc., Report of Liberty Consulting Group (August 7, 2009). The audit resulted in 92 recommendations, a substantial number of which have also been adopted and implemented by O&R. Staff and the Company disagreed as to the level of savings that would be produced by the implementation of these recommendations. The JP resolves this issue as discussed below.

O&R echoes Staff's comments. It argues that the ESM provides a reasonable compromise between the competing objectives of transferring a share of cost savings to customers as soon as possible and maintaining a strong incentive for the Company to pursue efficiencies that will enhance short term earnings but will also provide long-term customer benefits.

On June 6, 2012, the signatories, represented by O&R, filed an explanation of how the ESM calculation will operate given the graduated nature of the ROEs and increasing rate base. This letter clarifies for us how this mechanism will work and demonstrates that the signatories understand how to determine, at the end of RY3, the cumulative amount of "Total Shared Earnings."

We agree that the terms of the ESM are reasonable. In particular, the narrow dead band designed to capture additional savings generated by implementation of audit recommendations represents a fair compromise between the extremes of imputing savings which might never be realized, to the detriment of the Company's earnings, or ignoring the potential for cost reductions that are likely to occur, to the detriment of ratepayers.

E. ATIP and Management Audit Savings

In its initial filing, O&R requested that $1.2 million be included in base rates to fund its variable management pay program known as the Annual Team Incentive Plan, or ATIP. Staff opposed the rate allowance in its entirety. Staff's testimony also included a proposal that the Company's revenue requirement be reduced by $485,000 to reflect Staff's estimate of savings that could be expected to result from the Company's implementation of recommendations from the Liberty Audit.

The combined effect of these two competing proposals was to create a $1.7 million gap between the positions of the Company and Staff. The JP does not address the substance of the proposals, which would very likely have been the subject of extensive litigation had no agreement been reached. Instead, it resolves the differences with a compromise that narrows the difference between the Staff Company positions by $700,000. As a result, the JP proposes a reduction in the Company's revenue requirement of $1.0 million from what the Company requested.

Given the complexity of these issues and the considerable litigation uncertainty surrounding them, we find the signatories' compromise to be reasonable as a means of achieving the comprehensive agreement presented in the JP. We will not upset it.

This is the first rate case filed by O&R after our efforts in the 2011 Rate Order and the order on rehearing to clarify the type of evidentiary showing we would require to support an allowance in rates for incentive-based compensation.[16] Although the rate impact of ATIP in this case was resolved by the JP, Staff and the Company continued to disagree as to the appropriate methodology to be used to meet the standard we required. That disagreement is reflected in a footnote to the JP in which the signatories reserved the right to make a recommendation to us "regarding the appropriate methodology to be used to support the Company's request for recovering the costs of its variable management pay program from ratepayers in future rate cases," and to respond to any such recommendation. Staff availed itself of this provision in its Statement in Support of the JP, and the Company responded.

[16] Case 10-E-0362, supra, Order Denying Petitions for Rehearing and/or Clarification (issued November 21, 2011).

Staff recommends that we impose five requirements on any future filing in support of ATIP, two of which may be considered substantive requirements, and three procedural. Substantively, it argues, first, that the Company should be required to use consistent peer groups for all components of the total compensation package being evaluated – base pay, incentive pay, equity grants and benefits. Second, it contends that those peer groups should include all types of companies with which O&R competes for employees, not just energy companies.

Procedurally, Staff complains, essentially, that the Company did not timely provided the type of information needed by Staff to reasonably evaluate the data supporting O&R’s compensation studies. It recommends for future filings that we require that the Company provide a five-year listing of the employers from which new management hires came, and to which departing management employees went. This, we presume, would be to enable Staff to evaluate the make-up of the peer groups used for the comparable compensation studies, consistent with its substantive concern described above.

In addition, Staff asks that we require that all underlying data for each peer company and each benchmarked position be provided at the time of the initial rate case filing, and that arrangements be made to give Staff sufficient access to any benefit evaluation models to permit it to test the sensitivity of the models to variation in input parameters.

O&R responds that there are practical impediments to providing data in the form requested by Staff. It points out that different companies provide their compensation and benefits information to different consultants who compile different peer groups and use different models that they are reluctant to share. This, it says, makes it difficult, if not impossible, to compile consistent peer groups for all categories of compensation.

More fundamentally, however, O&R argues that it makes no sense for the Commission to establish, now, inflexible requirements for a filing that will not be made until the middle of 2014, at the earliest, on an issue –- management incentive compensation –- that is continually evolving. It notes that we will have the opportunity to, and undoubtedly will, address and refine our requirements in this area in numerous rate cases expected to be filed over the next two years.

We simply find that this case does not provide us with an adequate record on which to base any conclusions about the scope and design of studies that may be used in the future to support the total compensation provided to O&R management employees. Staff’s recommendations seem reasonable, but so do the Company’s concerns about them. The positions taken by each party have not been tested in cross-examination, and the issues they raise have not been briefed to the extent they would be in a litigated case.

We also agree that imposing the substantive requirements suggested by Staff is untimely. Not only O&R, but all utilities, are now on notice as to the types of concerns Staff may raise if studies similar to those filed by the Company here are submitted in future cases. As a result, it is highly likely that we will be obliged to address the issues they raise long before the rate plan we are approving in this order has expired.

Although we decline at this time to define any specific parameters for the design of comparable compensation studies to be used by O&R in future filings, we remind the company that it has the burden of demonstrating the reasonableness of whatever methodology it chooses. Staff has raised some serious questions about the current design, and these will certainly have to be addressed in more detail if they persist in future filings. For example, if it is not feasible to demonstrate compensation comparability by using a single peer group, it is nevertheless essential that the choice of peer groups used to assess the comparability of various components of total compensation be fully justified. Peer Group A may provide benefits comparable to those of O&R, and Peer Group B comparable base pay, but that does not necessarily imply that total pay and benefits for A and B combined is comparable to the total for O&R. Similar issues arise when job titles or categories are selectively benchmarked.

We recognize that these are difficult issues that have not been extensively addressed in recent rate cases. Given the methodological complexities and the potential benefit of narrowing the range of disagreement, we direct O&R and our Staff to meet and share their views on these issues prior to the Company’s next rate filing.

On a procedural level, we agree fully with Staff that the parties should have access to all of the data, methodology, and models underlying the studies supporting the reasonableness of total compensation, and that this information should be available at the time of the initial rate filing. Any related information, such as lists of hires and departures, can be obtained by simple information request if Staff continues to deem it necessary.

Rate proceedings are inherently time-constrained by statute. Therefore, if information is not timely forthcoming, we expect Staff, or any other party, to avail itself of our discovery rules by demanding production and, if necessary, pursuing a motion to compel. Not only are the sanctions provided for in the discovery rules –- up to and including issue preclusion –- more than adequate to protect the public interest, but also this procedure ensures that if an information disclosure dispute is significant enough to warrant our attention, we will have the benefit of the decision of the administrative law judges based on a full briefing of the issues by the parties.

F. Storm Expense

The JP recommends continuation of reserve accounting to provide funding for major storm costs. It also addresses the costs associated with two major storms that took place during 2011 –- Hurricane Irene in August and an October 29, 2011 snow storm (October storm). The costs incurred by the Company as a result of these storms were significant.

The JP provides that costs for response to Hurricane Irene would be amortized over five years starting in RY1, creating a $2.08 million annual rate expense.[17] Due to concerns with the RY1 rate impact, the costs for response to the October storm would not begin until RY2, but then would also be recovered over five years. The annual rate expense would be $3.1 million. The JP also provides that, if the Company should not file for new rates to be effective at the end of RY3, it would be allowed to reset the ECA surcharge for up to 12 months in order to collect $1.5 million, which would be applied, in an earnings neutral manner, towards the amortization of the remaining October storm costs. Authorization of the recovery of Hurricane Irene and the October storm costs, according to the JP, would not preclude Staff from reviewing those costs fully. That review had not been completed at the time the JP was signed.

[17] Attachment A, JP, Appendix I.

Staff, in its statement in support, contends that the JP's proposal for treatment of past and future storm costs is consistent with past regulatory practice and enables the Company to recover material costs while remaining mindful of rate impacts. The Company supports this provision of the JP, noting that reconciliation mechanisms are appropriate for cost categories that are not reasonably predictable.

The JP's proposed rate allowance to fund the reserve account for major storm costs is reasonable because it reflects the funding level, adjusted for inflation, that we approved in the 2011 Rate Order. Although Staff's review of the Company's responses to, and costs from, Hurricane Irene and the October storm, however, is not complete, we will, nonetheless, adopt the JP's proposed estimation and treatment of these costs.[18] As discussed above, the JP proposes a five year amortization of the costs associated with these two events, which should provide Staff ample time to conclude its investigations into the Company's responses to the storms, enable it to audit the costs of the events, and permit it to advise us of any actions that should be taken based on its findings and conclusions.

For example, if as a result of Staff's investigations we conclude that some portion of the October storm costs allowed under the terms of the JP should not be recovered by the Company, we will be in a position to take corrective action. Alternatives include an adjustment of base rates, institution of

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[18] We understand that at a public statement hearing in this case numerous members of the community and first response professionals expressed serious concerns about the Company's response to the October storm. The transcript from that hearing has been provided to the staff assigned to investigate the Company's response to this storm.

a credit, or deferral of a portion of the storm-related rate allowance for the benefit of customers.

G. Mandatory Day-Ahead Hourly Pricing

Mandatory Day-Ahead Hourly Pricing (MDAHP) refers to billing for electric consumption based on market-determined prices that vary throughout the day. The JP proposes that the Company expand its MDAHP program to include customers with demand thresholds between 100 kilowatts (kW) and 300 kW. The Company would be required to make a filing in six months providing a timetable for the expansion, costs for the expansion, a proposed mechanism to enable recovery of incremental costs, and implementing tariff leaves.[19]

In its statement in support, the Company notes that its current MDAHP program has a 500 kW threshold, which was previously scheduled to be lowered to 300 kW in May of 2013.[20] It states that reducing this threshold further to 100 kW would add approximately 230 customers to the pool of eligible customers.

Staff explains in its statement in support that the Company, at the time of the execution of the JP, was uncertain as to how much it would cost to lower the MDAHP threshold to 100 kW. Staff notes that the filing requirements for the Company, as outlined above, would allow us to review the appropriateness of the costs before they are passed on to ratepayers.

The parties clarified on the record at the evidentiary hearing that it was not their intent that we approve now,

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[19] The JP also proposes several other changes related to MDAHP customers, but those changes are non-controversial and reasonable and as such do not warrant discussion.

[20] Expansion to the 300 kW threshold was instituted in the 2011 Rate Order.

regardless of cost, the expansion of the MDAHP program.[21] Rather, as Staff articulated on the record, the parties believe that we will be able to determine at a later date, based upon the Company's filing, whether to approve, modify or reject the Company's plan and estimated costs for that expansion.

We continue to support the goal of MDAHP, namely, reducing the electric system's peak period demand by encouraging customers to shift load to less expensive off-peak time periods.[22] Nevertheless, we believe that any review of the costs associated with lowering the MDAHP threshold to 100 kW must be coupled with a review of the benefits of such a step, including those we articulated in our MDAHP Order. Therefore, the Company's filing must also include a description of the benefits, intangible or tangible, of lowering the MDAHP threshold.

In addition, we would find it helpful when evaluating the Company's plan to have information regarding the number of each type of customer (e.g. manufacturing, recreation, schools/colleges) that would be included in the expanded program and those included in the Company's expansion of the program from 500 kW to 300 kW. With this information we will be better able to identify if new types of customers would be introduced to MDAHP. Therefore, the Company must include the foregoing information in its filing.

Also at the evidentiary hearing on the JP, the Company explained that lowering the threshold to 100 kW could result in at least two ratepayers who are billed under a non-residential

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[21] Evidentiary Hearing Tr. 14-16.

[22] Case 03-E-0641, Expedited Implementation of Mandatory Hourly Pricing for Commodity Service, Order Denying Petitions for Rehearing and Clarification in Part and Adopting Mandatory Hourly Pricing Requirements (issued April 24, 2006)(MDAHP Order).

tariff for multi-family buildings becoming subject to MDAHP.[23] The Company must also describe any possible impacts that the lowering of the threshold may have on multi-family building owners' incentive to sub-meter buildings.

H. Street Lighting

Street lighting was an important issue for the Town of Ramapo and the municipalities represented by the Coalition for Reasonable Electric Rates. The JP includes a number of provisions intended to address their desire for greater flexibility in street lighting services, while also taking into account the Company's cost concerns.

First, the JP would significantly expand the opportunity for municipalities that are seeking to upgrade more rapidly to newer, more energy efficient lighting technologies to have replacements performed by O&R at no upfront cost to the local government. Under its current tariff, the Company will replace, at no cost, up to 2% of a municipality's street lights annually. Towns with an ambitious upgrade program must pay the cost of any replacements beyond the 2% limit, even while the no-cost replacement opportunity may go unused in other localities. Under the terms of the JP, for the three years of the rate plan, the 2% limitation would be applied on a system-wide basis; that is, O&R would replace up to 2% of all the luminaires on its system without regard to municipal boundaries. This would make it possible for municipalities with more ambitious lighting modernization programs to use replacement allocations that are not needed by other towns and villages, without incurring additional cost, and with no increase in the Company's overall replacement obligation. At the end of the rate plan, the current tariff terms would be reinstated.

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[23] Evidentiary Hearing Tr. 18, 20-21.

Next, as required by the Commission in the 2011 Rate Order, O&R developed and filed proposed tariff leaves for a new energy-only street lighting service. The JP adopts the Company's proposal, which will allow municipalities to own their own lighting fixtures and to pay only for the electricity needed to power them.

The JP also provides that the cost assessed to municipal customers for the replacement of luminaires in excess of the 2% annual threshold would be based on the actual cost of performing the replacement rather than the net book value of the facilities replaced. This provision addressed a Company concern that luminaire replacement is a non-capital expense and the net book value may be inadequate to compensate for the actual cost of the work.

Subsequent to the filing of the JP, however, O&R proposed an alternative method for determining the cost of excess luminaire replacements.[24] Currently, O&R explains that for accounting purposes, the unit of property for a street light attached to the overhead distribution system consists of both the luminaire and the arm that supports it. Installing the arm and luminaire together is considered a capital cost which is recovered over time through depreciation. Installing the luminaire only is considered a maintenance cost and must be currently expensed.

O&R states that it has investigated the possibility of redefining the units of property for street lighting to make the luminaire, alone, a separate unit for accounting purposes, and has determined that the change is feasible. It says that making the change will be advantageous to municipalities in that it

[24] The proposal is described in a written statement offered by O&R at the evidentiary hearing which was admitted as Exhibit 17.

will lower the initial cost of replacements and will allow the municipalities more time to fully evaluate their options under the current service classification and the new energy-only service. It warns, however, that municipalities must evaluate their individual circumstances, as some scenarios could result in increased replacement costs under the proposal.

At the evidentiary hearing, the ALJs allowed three weeks for parties to respond and comment on the Company's proposal. Only Staff did so. In its filing, Staff concludes that the proposal constitutes a change in accounting method that should be considered under the Commission's rules governing such requests. It says that the procedures provided by those rules would afford the parties an opportunity to analyze the proposal more fully, something they have not been able to do given its filing at such a late stage of the rate case process.

We agree with O&R that this proposal should be considered, and with Staff as to the procedures to be followed. On May 16, 2012, the Company filed its request for the accounting change with the Director of the Office of Accounting and Finance. We will, therefore, take no action on the proposal at this time, pending the Director's review, but will approve the terms of the JP on this issue (the redefinition of cost of removal) while its proposal is pending.

I. Reconciliations

In addition to major storm costs, the JP includes several provisions for the reconciliation and deferral of various cost categories. Annual reconciliations made during the rate plan will be accumulated and deferred until base rates are reset. All reconciliation and deferral provisions of the JP, except for transmission and distribution capital reconciliation and inflation adjustment, would continue until rates are reset. The JP lists the expense items that would be reconciled. In general, this list represents a set of costs for which we have traditionally provided reconciliation because, to a great extent, the costs are those normally outside a company's management's direct control. We find their reconciliation reasonable, and we will not discuss them in great detail, except as otherwise provided below.

The total amount that can be deferred annually by the Company is limited, however. The JP specifies that if O&R's earned ROE exceeds the ESM sharing threshold in any rate year, the Company must apply 50% of its share of the excess earnings to reduce certain regulatory assets, that is, deferred amounts that would otherwise be the responsibility of ratepayers. The provision applies only to deferrals for major storm charges, R&D, and pension/OPEBs. Absent this provision, the Company would be free to build these deferral balances while at the same time retaining excess earnings for shareholders.

The JP appears to provide for an annual determination with respect to the limitation on deferrals. The ESM, however, is a cumulative calculation, with the calculation of "Total Shared Earnings" coming at the end of RY3. There appears to be interplay between the deferral limitation and the ESM. Given this interplay we question how the deferral limitation, determined on an annual basis, will be calculated and implemented if the ESM provides for an end-of-plan calculation. Therefore, we will direct the parties to the JP to file with the Secretary within 30 days of the issuance of this order, agreed-upon examples demonstrating the operation of the limitation on deferrals. If no consensus on such examples can be reached, the remaining disagreements are to be presented to us for resolution.

In addition, the JP does not specifically state that a report of deferrals subject to the limitation should be filed together with the required annual ESM report, the interrelationship of the accounting, however, implies that this will be done, and we will, therefore, make the requirement explicit.

1. Transmission and Distribution Capital Expenditures

The JP would establish annual targets for average net transmission and distribution plant in service. If the actual plant in service in any year of the rate plan is less than the target, the revenue requirement impact of the shortfall would be deferred for the benefit of customers. If actual plant exceeds the target, O&R would be permitted to defer carrying charges for the Company's benefit on the excess amount, up to limits specified in the JP.

This provision operates in the same manner as the one we adopted in the 2011 Rate Order. It is predicated on the assumption, based on past experience, that there is likely to be a degree of "slippage" between forecast and actual expenditures. The reconciliation, as designed, protects ratepayers in advance against that possibility by setting rates based on a lower assumed plant in service, while also providing for the Company to be kept whole if it succeeds in completing additional work, up to its forecast spending levels.

2. Environmental Remediation

The JP would continue the deferral accounting treatment currently in place for the recovery of environmental remediation costs.[25] Deferral balances would be reduced by accruals, insurance and third party recoveries, associated

[25] The JP also requires the Company to file a report regarding SIR expenditures and activities by no later than March 31 for each year of the rate plan. The JP originally had the initial filing date on March 31, 2012. Staff later corrected this error with the Company's consent. The first report would be filed on March 31, 2013).

reserves and deferred taxes, and other offsets, if any, obtained by the Company, and would continue to be allocated between the Company's electric and gas operations on a 70.75%/29.25% basis. In addition, O&R would be required to report annually on site investigation and remediation (SIR) activities that occurred during the previous calendar year. This provision, Staff notes, would allow interested parties to monitor the progress of remediation activities and expenditures.

We find the rate allowance for SIR expenses and the deferral accounting treatment reasonable. They fairly reflect the costs associated with the Company's activities to remediate manufactured gas plan sites.

3. Property Taxes

The JP provides for the reconciliation and deferral of variations between property taxes incurred by the Company during the rate plan and amounts included in revenue requirement. Differences due to changes in property tax rates would be fully reconciled and deferred. For variations due to changes in assessments, 86% would be deferred and 14% would be absorbed by O&R. The difference in treatment, according to Staff, is intended to reflect the fact that the Company has little control over property tax rates, but does have the ability to challenge, and potentially reduce, excessive tax assessments. As an incentive to pursue such opportunities, the JP also would allow O&R to retain 14% of tax refunds recovered as a result of its efforts.

The property tax reconciliation mechanism is consistent with our past rate decisions and reflects our policy of providing an incentive for the Company to pursue tax reductions for the benefit of ratepayers.

J. Double Poles

"Double poles" are created when a new utility pole is temporarily co-located with the pole being replaced until all wires, which may include telecommunications and cable as well as electric, have been transferred to the new pole. Reduction of the number of double poles within their boundaries was a significant issue for the municipal parties.

We are currently investigating this subject on a generic, state-wide basis in Case 08-M-0593, *Proceeding on Motion of the Commission to Evaluate a Standardized Facility and Equipment Transfer Program*. The JP provides that unless, and until we establish different requirements through that proceeding, O&R will produce semi-annual reports on double poles within its service territory, will file them with the Secretary and will provide copies to the signatories to the JP. The reports will be due on February 15 and July 15 each year and will contain, at a minimum, to the extent information is available, an identification of the double poles, the party responsible for the next steps required to remedy the double pole condition, and the date the responsible party was notified of its obligation. As Staff notes, this process will give interested parties the information they need to advocate for the timely transfer of facilities to the new poles and the removal of the old.

The JP is consistent with our directives to O&R and other utilities with respect to double poles. We will require, however, that the Company serve the February 15 and July 15 yearly reports not only on the signatories to the JP but also upon the Town of Ramapo and MC, who have expressed their interest in this issue.

K. Enhanced Call Answering System

The JP provides for $44,000 to be added to the Company's revenue requirement in order to cover fees for maintenance of O&R's enhanced call answering system provided by a third-party vendor. O&R states that the improvements to the system that these funds would permit will enable it to handle the type of high-volume call activity experienced during Hurricane Irene and the October snowstorm and will facilitate its ability to feed pertinent information to its storm outage management system.

Staff says that the parties to the JP recognized that improvements to the call system were needed and concluded that the use of a third-party vendor to provide the enhancements was reasonable and cost-effective. We agree. As evident in the summary of public comments, the Company’s ability to communicate with its customers during an emergency is imperative. This upgrade is an important safety measure and the cost is appropriately included in revenue requirement.

L. Low Income Programs

O&R's current program for low income customers includes a monthly discount, a waiver of fees for reconnection of service and a quarterly reporting requirement. Under the provisions of the JP, monthly discounts for low income heating customers would be increased by $2.40 at the beginning of the rate plan, and monthly discounts for low income non-heating customers would increase by $1 at the beginning of RY2 and RY3. The existing waiver of fees for reconnection of service and reporting requirements would continue for the term of the rate plan.

In addition, O&R agreed that by March 10 of each rate year during the three-year plan it would send a letter to all its low-income customers soliciting their consent to be referred to the New York State Energy Research and Development Authority ("NYSERDA") for participation in NYSERDA's EmPower-NY program. In its final quarterly low income program report for each rate year, O&R would identify the number of referral letters that it sent out to low income customers and the number of customers that requested to be referred to NYSERDA.

As Staff points out, the EmPower-NY program, which provides weatherization and other energy efficiency measures to low income residential customers, relies heavily on referrals from utilities, the majority of which are for customers who are in payment assistance programs. This provision will enhance the ability of low income customers in O&R's service territory to gain access to these valuable services. The low income program provisions of the JP are reasonable and appropriate and are adopted.

VI. CONCLUSION

From the comments we have received and the parties' submissions coupled with the information provided at the evidentiary and public statement hearings, we have a robust record to determine whether the JP is in the public interest and should be adopted. Having reviewed this record, we find that the JP does strike the proper balance described in our Settlement Guidelines and is consistent with Commission policies, as highlighted by our discussion above. By this order we adopt its terms, except paragraphs 26 through 31, which are not proposals for decision by us but rather agreements governing the relationships among the parties.

The proposed increases in revenue requirement over the three-year term of the rate plan are reasonably necessary to meet increased costs and to support spending for capital improvements and employee additions, which are necessary to improve electric operations and enhance overall system integrity. We establish a three-year rate plan governing the rates, charges and terms of service of Orange and Rockland Utilities, Inc. for electric service for the rate year commencing July 1, 2012.

The Commission orders:

1. The terms of the Joint Proposal dated February 24, 2012, which is attached as Attachment A, are adopted as revised in this order, with the exception of paragraphs 26 through 31 of the Joint Proposal.

2. Orange and Rockland Utilities, Inc. is directed to file cancellation supplements, effective on not less than one day’s notice, on or before June 22, 2012, cancelling the tariff amendments and supplements listed in Attachment B to this order.

3. Orange and Rockland Utilities, Inc. is directed to file electronically, to become effective July 1, 2012, on not less than one day’s notice, such further tariff revisions as are necessary to effectuate the provisions adopted by this order. The Company shall serve copies of its filing on all parties to this case. Any comments on the compliance filing must be filed within 14 days of service of the Company’s proposed amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

4. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments directed in Clause 2 above is waived and the Company is directed to file with the Commission, not later than six weeks following the amendments’ effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four

successive weeks in newspapers having general circulation in the areas affected by the amendments.

5. Orange and Rockland Utilities, Inc. is directed, within six months after the issuance of this order, to file its implementation plan for lowering the threshold from 300 kW to 100 kW for its mandatory day-ahead hourly pricing program. The filing should include all information detailed in the body of this order.

6. The signatory parties are directed to file with the Secretary within 30 days of the issuance of this order, agreed-upon examples demonstrating the operation of the limitation on deferrals.

7. The Secretary may extend any compliance deadline established under the terms, provisions, or conditions of this order, including those of the Joint Proposal approved and incorporated in it, for good cause.

8. This proceeding is continued.

By the Commission,

Jaclyn A. Brilling
Digitally Signed by Secretary
New York Public Service Commission

(SIGNED) JACLYN A. BRILLING
Secretary

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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Case 11-E-0408 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service

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JOINT PROPOSAL

Dated: February 24, 2012
Pearl River, New York

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State Of New York
Public Service Commission

Case 11-E-0408 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service

JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal") is made as of the 24th day of February 2012, by and among Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company"), Staff of the New York State Department of Public Service ("Staff"), and the Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection ("UIU") (collectively referred to herein as the "Signatory Parties"), and provides a proposed regulatory framework for the electric business of Orange and Rockland.

I. INTRODUCTION

The Proposal sets forth the terms of an electric rate plan for the period July 1, 2012 through June 30, 2015 ("Electric Rate Plan"). It prescribes agreed-upon rate levels and addresses operational and accounting matters for the term of the Electric Rate Plan, as well as various other rate design and revenue allocation issues. The Electric Rate Plan is designed to support the continued reliability, safety, and security of the Company's electric system at just and reasonable rates.

Among other things, the Electric Rate Plan reflects a revenue requirement based on the adoption of the electric sales and revenue forecast agreed to by the Signatory Parties, the continuation of a revenue decoupling mechanism ("RDM"), reconciliation of capital expenditures, and the continuation of a low-income program. The Electric Rate Plan also provides for expansion of the Company's mandatory day ahead hourly pricing ("MDAHP") program, reflects savings associated with the implementation of those recommendations from the management audit of Consolidated Edison Company of New York, Inc. conducted by Liberty Consulting Group ("Liberty Audit") applicable to the Company, and includes modifications to the program for the replacement of municipal street lights.

II. PROCEDURAL BACKGROUND

On July 29, 2011, the Company filed with the Commission a proposal and amended tariff leaves to increase the charges for electric service and make other changes to its Schedule for Electric Service, P.S.C. No. 2 - Electricity.[1] Under the Company's initial filing, those changes were to become effective August 28, 2011 and were designed to produce a revenue increase of $17.7 million equating to an increase of approximately 2.1 percent a total revenue basis, including projected supply costs and gross receipts taxes, based on the estimated level of sales for the rate year ending June 30, 2013 ("First Rate Year" or "RY1").[2]

The Company also presented a three-year rate proposal as an alternative to a one-year rate plan. Under the Company's three-year proposal, rate increases would be $20.5 million to take effect on July 1, 2012 for the First Rate Year, $12.3 million to take effect on July 1, 2013 for a rate year ending June 30, 2014 ("Second Rate Year" or "RY2"), and $19.5 million to take effect on July 1, 2014 for a rate year ending June 30, 2015 ("Third Rate Year" or RY3"). This

[1] On December 19, 2011, the Company filed a new (electronic version of) Schedule for Electric Service, P.S.C. No. 3 - Electricity ("P.S.C. No. 3") in compliance with the Commission's Order Establishing Rates for Electric Service, issued June 17, 2011, in Case No. 10-E-0362. The Company expects P.S.C. No. 3 to become effective on April 1, 2012. Therefore, any tariff changes described in the Proposal will be made in P.S.C. No. 3.

[2] The impact of the $17.7 million increase on customers' bills would be $12.0 million or 2.1% due to a projected reduction in recoveries associated with the RDM adjustment.

would represent an overall increase in customer bills from current levels of 8.3% over the course of the three rate years.

By orders dated August 8, 2011, and November 22, 2011, the Commission suspended the proposed electric rates first through December 25, 2011, and subsequently through June 25, 2012.

By notice dated August 15, 2011, Procedural and Technical Conferences were held on September 8, 2011, before Administrative Law Judge Kimberly A. Harriman. The purpose of the Procedural Conference was to identify parties and major issues, to establish a schedule for the proceeding and to address issues related to the service of documents, discovery and any other procedural matters identified by the parties at the conference. The Technical Conference consisted of an overview of the rate filing presented by Company representatives. On September 14, 2011, Judge Harriman issued a Ruling on Schedule and Other Procedural Matters.

The Company provided Staff and other parties with a preliminary update to the proposed revenue requirement on October 28, 2011. That update increased the Company’s proposed revenue requirement by approximately $7.8 million, from $17.7 million to $25.5 million. That increase primarily was attributable to unanticipated storm costs incurred as result of Hurricane Irene that occurred on August 28, 2011; recovery of certain environmental costs for site investigation and remediation (“SIR”) presented in the Company’s filing but omitted from the Company's initial revenue requirement calculation; actual health insurance premium costs incurred through September 30, 2011 that were higher than initially projected; actual school taxes paid in September 2011 and later known actual property taxes that were higher than initially forecasted; the actual net plant investment as of September 2011 being higher than initially forecasted; and pollution control debt costs.

On December 2, 2011, Staff filed its direct testimony, plus numerous supporting exhibits, in response to the Company's initial filing as updated on October 28, 2011. The Town of Ramapo ("Ramapo") and UIU also submitted direct testimony. On December 12, 2011, Staff submitted an additional exhibit showing Staff's proposed multi-year revenue requirements for a three-year rate plan covering RY1, RY2 and RY3. On December 23, 2011, the Company filed further testimony and exhibits for purposes of updating information beyond the October 28, 2011 update and rebutting certain of the testimony submitted by Staff, UIU and Ramapo. Staff's Electric Infrastructure Panel also submitted rebuttal testimony. Additionally, Staff submitted supplemental testimony addressing the Company's implementation of those recommendations from the Liberty Audit applicable to the Company. On December 28, 2011, the Company filed responsive testimony to Staff's supplemental testimony.

The Company's December 23, 2011 update and rebuttal filing increased the preliminary revenue requirement filed on October 28, 2011 by approximately $5.9 million, i.e., from $25.5 million to $31.4 million. This increase primarily was attributable to costs for the October 29, 2011 snow storm and for higher pension and other postemployment benefits ("OPEB") costs resulting from the downturn of the equity markets in the second half of 2011.

In accordance with the Commission's rules and regulations (16 NYCRR §3.9), prior to the commencement of settlement discussions, the Company notified all parties to this proceeding of the pendency of settlement negotiations and notice of the impending negotiations was duly filed with the Secretary of the Commission by letter dated January 4, 2012. Negotiations among the parties commenced on January 9, 2012. Additional settlement conferences were held on January 19, January 24, January 27, January 30, and February 1, 2012. Orange and Rockland, Staff, UIU, the Municipal Consortium in Support of Reasonable Electric Rates ("MC"), and Ramapo participated in all of the settlement conferences, in person or via teleconference.

III. ELECTRIC RATE PLAN

1. Rate Plan

The Electric Rate Plan covers three rate years, i.e., from July 1, 2012 through June 30, 2015. As stated above, the First Rate Year covers the 12-month period ending June 30, 2013, the Second Rate Year covers the 12-month period ending June 30, 2014, and the Third Rate Year covers the 12-month period ending June 30, 2015. The Electric Rate Plan provides for the following delivery revenue increases:

First Rate Year	$19.4 million
Second Rate Year	$8.8 million
Third Rate Year	$15.2 million

The Signatory Parties propose that these three base rate increases can be implemented, at the Commission's option, on a levelized basis to mitigate the impact on customers of the RY1 increase. The levelized annual revenue increases would be $15.2 million for RY1, an additional $15.2 million for RY2, and an additional $15.2 million for RY3.[3] The revenue requirement calculations underlying the Proposal are set forth in Appendix A. The increase to each service class associated with the proposed additional revenues is shown in Appendix B.

The proposed increase for each of RY1, RY2 and RY3 will be effective on the first day of each rate year.

[3] The levelized rate increases are inclusive of interest on the deferred rate increase calculated at the 2012 Other Customer-Provided Capital Rate of 3.4 percent. Current regulations require that this rate be updated on January 1 of each year pursuant to a prescribed methodology. Accordingly, any interest variation resulting from such annual updating will be deferred and addressed in the Company's next electric base rate filing.

The Signatory Parties recognize that levelizing the three revenue increases over the three years of the Electric Rate Plan will result in higher base delivery rate revenues for the Company at the end of RY3 than would result if the revenue increases were not levelized. To address this circumstance, should the Commission choose to implement the base rate increases on a levelized basis, $13.1 million of the RY3 levelized rate increase will be included in base rates and $2.1 million of the RY3 increase will be collected via a temporary surcharge through the Energy Cost Adjustment ("ECA").

This ECA surcharge will expire at the end of RY3 if new electric base delivery rates go into effect immediately following the end of RY3. If new electric base delivery rates do not go into effect immediately following the end of RY3, this ECA surcharge will continue at a reset rate for up to 12 months in order to collect $1.5 million. The post-RY3 ECA surcharge revenues will be offset on an earnings neutral basis by the Company expensing deferred major storm costs above the amount reflected in the RY3 revenue requirement under the Electric Rate Plan (i.e., an additional $1.5 million) such that the continued ECA surcharge will not enhance Company earnings.

The ECA surcharge during RY3 and after, if continued, will be shown on statements filed separately from the Company's rate schedules and will be collected on a class-specific per kWh basis. The RDM targets for applicable customer groups (as delineated in Appendix E) for RY3 will include the portion of the $2.1 million to be collected through the ECA surcharge from each of those customer groups.

2. Sales and Revenue Forecasts

The electric sales and delivery revenue forecasts used to determine the revenue requirement for each of RY1, RY2 and RY3 are set forth in Appendix C.

3. Revenue Allocation and Rate Design Tariff Changes

The revenue allocation and rate design changes being made as part of the Proposal are set forth in Appendix B.

4. Other Tariff Changes

In addition to the tariff changes required to implement various provisions of the Proposal, the following tariff change will be made in regards to the determination of the Temporary State Assessment Surcharge ("TSAS"): the voluntary time-of-use service classifications will be consolidated with their otherwise applicable service classifications for purposes of calculating the annual TSAS. On or about June 15, 2012, the Company will be filing its normally scheduled annual reconciliation of the TSAS pursuant to the current methodology. Upon Commission adoption of the Proposal, the Company will file a new statement reflecting the changes to the TSAS groupings and the annual reconciliation filing.

5. Street Lighting

A. Street Light Replacements

The Company will replace up to 2% of its street lights on a system-wide basis ("2% System Threshold") during each of RY1, RY2 and RY3 at no cost to participating municipalities in accordance with the requirements and conditions set forth below. By June 15, 2012 for RY1,[4] May 1, 2013 for RY2 and May 1, 2014 for RY3, the Company will notify the municipalities in its service territory of this opportunity to participate in the replacement program in accordance with the 2% System Threshold approach.

Within 90 days of the Commission's order adopting the Proposal, each municipality wishing to participate in this program during RY1 must notify Orange and Rockland, in writing,

[4] If notice is provided prior to the Commission's issuance of its order adopting the Proposal, the notice will state that the Company's implementation of this street lighting proposal is subject to Commission approval.

of the quantity, location, and types of street lights it would like replaced during RY1 and the types of new street lights it would like installed. Municipalities wishing to participate in RY2 and RY3, must provide the required notice by July 1, 2013 and July 1, 2014, respectively.

In each of RY1, RY2 and RY3, the Company will allocate a portion of the 2% System Threshold to each municipality that requests replacements by the date established for such requests, based on the quantity of existing street lights in each participating municipality. The Company will not be required to honor any additional requests for installations at no direct charge within the 2% System Threshold during the remainder of RY1, RY2 and RY3.

Pursuant to Service Classification No. 4, the Company retains the right to modify any requests based upon operational considerations (e.g., LED lights should not be co-mingled with non-LED lights).

The Company will endeavor to perform replacements requested for RY1 during RY1, replacements requested for RY2 during RY2, and replacements requested for RY3 during RY3. Scheduling replacements will be at the Company's sole discretion. If circumstances beyond the Company’s reasonable control prevent the Company from completing the replacement of any street lights included in the 2% System Threshold in any rate year, the Company will complete the replacement of any such remaining street lights in the following rate year.

B. New Service Classification No. 6, Public Street Lighting - Customer Owned

The new Service Classification ("SC") No. 6, Public Street Lighting - Customer Owned, as proposed by the Company's Municipal Lighting Panel in its direct testimony, shall become effective with the commencement of RY1. The revenue requirements for RY1, RY2, and RY3 reflect the costs for the Company's proposed system enhancements and additional field verification and administration necessary to support the implementation of SC No. 6.

C. SC No. 4 Special Provision A Replacement Charge

The charge under SC No. 4, Special Provision A, for replacement of luminaires other than pursuant to the 2% System Threshold approach in any year of the Electric Rate Plan,[5] or beyond 2% of a municipality's street lights in any year after RY3, will change from the net book value of the facilities to be replaced to the Company's actual costs of performing the replacement. This change will become effective with the commencement of RY1.

[5] The 2% System Threshold approach will terminate at the conclusion of RY3.

6. Mandatory Day Ahead Hourly Pricing ("MDAHP")

The Company will expand MDAHP to full service customers with demand thresholds between 100 kW and 300 kW. The Company will file a plan for such expansion with the Commission, within six months of the date of the order adopting the Proposal, including: (a) a proposed schedule for meter installation and billing for the expansion; (b) costs for the expansion of MDAHP, together with justification and supporting documentation; (c) a proposed mechanism for the recovery of any costs in excess of the amount included in the revenue requirement (i.e., $0 in RY1, $23,000 in RY2, and $113,000 in RY3) ; and (d) draft tariff leaves detailing the expansion.

7. Capacity Cost Recovery from MDAHP Customers

The Company will revise the capacity price applicable to MDAHP customers effective with the commencement of RY1. The capacity price will be based on the New York Independent System Operator monthly auction price for unforced capacity and will be included on the Company's monthly Market Supply Charge ("MSC") statement. Additionally, the Company will revise the tariff to reflect that capacity will be assessed to MDAHP customers based on the individual customer's peak load during the peak hour for the New York Control Area ("NYCA"). The tariff language clarifying the basis of the MDAHP capacity is set forth in Appendix D.

8. Allocation of Capacity Costs for non-MDAHP Customers

As set forth in Appendix D, the Company will revise the manner by which it assesses capacity for non-MDAHP customers from the current hourly load-weighted average price calculation, based on load profiles, to capacity based on capacity obligations, which are based on the peak hour from the prior year during the NYCA peak. The Company will continue to base the capacity price on the six-month strip auction price applicable to non-MDAHP customers.

The resulting per kWh rate then will be added to the weighted average price calculation for energy and ancillary services as currently performed for the MSCs for non-MDAHP customers. Capacity obligations for the classes, including those for both full service and retail access customers, will be summed and grouped into the following seven categories:

Group A: SC Nos. 1 and 19;

Group B: SC No. 2 - Secondary, SC No. 25, Rate 1 customers exempt from MDAHP and SC No. 20;

Group C: SC No. 2 - Primary, SC No. 3, SC No. 21, SC No. 25, Rate 2, and customers from the following classes who are exempt from MDAHP: SC No. 9 - Primary, SC No. 22 - Primary, and SC No. 25, Rates 3 and 4 - Primary;

Group D: Customers from the following classes who are exempt from MDAHP: SC No. 9 - Substation, SC No. 22 - Substation, and SC No. 25, Rates 3 and 4 - Substation;

Group E: Customers from the following classes who are exempt from MDAHP: SC No. 9 - Transmission, SC No. 22 - Transmission, and SC No. 25, Rates 3 and 4 - Transmission;

Group F: SC Nos. 4, 6, and 16; and

Group G: SC No. 5

9. Revenue Decoupling Mechanism (“RDM”)

As set forth in Appendix E, for the term of the Electric Rate Plan, the Company will continue to implement an RDM, as set forth in the Company’s electric tariff. The RDM will continue thereafter until modified by the Commission.

10. Earnings Sharing

The rates of return on common equity capital ("ROE") for RY1, RY2 and RY3 are set forth in Appendix F (i.e., 9.4%, 9.5% and 9.6%, respectively). Following each of RY1, RY2 and RY3, the Company will compute its electric ROE for the preceding rate year. The Company will provide Staff the computations of earnings, by no later than September 30th, after the end of each rate year covered by the Electric Rate Plan.

If the level of the earned ROE exceeds 10.2% for RY1, 10.3% for RY2, and 10.4% for RY3 ("Earnings Sharing Threshold"), calculated as set forth below and as may be adjusted pursuant to Section 11 of the Proposal, then the amount in excess of the Earnings Sharing Threshold shall be deemed "shared earnings" ("Shared Earnings") for the purposes of the Electric Rate Plan.

On an annual basis (i.e., RY1, RY2, RY3) any Shared Earnings will be deferred on the Company's books for treatment at the end of RY3. At the end of RY3, the net Shared Earnings from RY1, RY2, and RY3 ("Total Shared Earnings") will be allocated between customers and shareholders as follows: for the first 100 basis points of Total Shared Earnings above the Earnings Sharing Threshold (e.g., for RY1, in excess of 10.2% and up to and including 11.2%), one-half of the revenue requirement equivalent of the Total Shared Earnings shall be deferred for the benefit of customers, and the remaining one-half of the Total Shared Earnings shall be allocated to the Company. For Total Shared Earnings in excess of 180 basis points above the authorized ROE for the rate year and up to and including 280 basis points above the authorized ROE for the rate year (e.g., for RY1, in excess of 11.2% and up to and including 12.2%), 75% of the revenue requirement equivalent of Total Shared Earnings shall be deferred for the benefit of customers, and the remaining 25% of the Total Shared Earnings shall be allocated to the Company. For Total Shared Earnings in excess of 280 basis points above the authorized ROE for that rate year (e.g., for RY1, in excess of 12.2%), 90% of the revenue requirement equivalent of Total Shared Earnings shall be deferred for the benefit of customers, and the remaining 10% of the Total Shared Earnings shall be allocated to the Company. The Earnings Sharing Threshold (i.e., 80 basis points above the authorized ROE) allows for the capture of potential Liberty Audit related savings, in addition to those savings already reflected in the revenue requirements for RY1, RY2 and RY3 for the benefit of customers. Should the Company not file for rates effective on July 1, 2015, this earnings sharing mechanism will remain in effect as described in Appendix G.

The Company's allocated share of Total Shared Earnings, on a cumulative Electric Rate Plan basis, will be subject to the provisions of Section 11. N, Limitations on Deferrals, set forth below. Orange and Rockland will not be entitled by this provision to recover from customers any amounts by which earnings in RY1, RY2 and RY3 fall below 10.2%, 10.3% and 10.4%, respectively.[6]

The customers' allocated share of Total Shared Earnings will be deferred for the benefit of customers.

For purposes of determining whether the Company has earned in excess of the Earnings Sharing Threshold, the calculation of the actual ROE allocated to New York jurisdictional electric utility operations shall be on a per books basis, adjusted as follows:

a. Any incentive related to property tax refunds, or other incentive mechanisms (e.g., Customer Service and Reliability Performance Measurements) made effective during the term of the Electric Rate Plan pursuant to an Order of the Commission, will be excluded from the calculation.

[6] This provision shall not prevent the netting of under-recoveries and over-recoveries in individual rate years in order to calculate Total Shared Earnings on a cumulative Electric Rate Plan basis (i.e., July 1, 2012 through June 30, 2015.

b. Such earnings computations will reflect the lesser of (i) an equity ratio equal to 50.0% or (ii) the Company's actual average common equity ratio to the extent that it is less than 50.0% of its ratemaking capital structure. The actual common equity ratio will exclude all components related to "other comprehensive income" that may be required by generally accepted accounting principles ("GAAP"); such charges are recognized for financial accounting reporting purposes but are not recognized or realized for ratemaking purposes.

11. Reconciliations

The Company will reconcile the following costs to the levels provided in rates, as set forth in Appendix G. The reconciliations in RY1, RY2, and RY3 will be deferred over the three-year period of the Electric Rate Plan and not be applied until the next proceeding in which the Commission resets the Company's base rates.[7]

A. Transmission and Distribution Capital Expenditures

During the term of the Electric Rate Plan, average electric transmission and distribution net plant balances will be reconciled to capital targets as set forth in Appendix G to the Proposal on a cumulative basis as follows:

- If the actual rate year net plant investment is less than $677,530,000 for RY1, $704,196,000 for RY2 and $752,708,000 for RY3, the Company will defer carrying charges on the amount of the shortfall for future credit to customers;
- If the actual rate year net plant investment is more than $677,530,000 for RY1, $704,196,000 for RY2 and $752,708,000 for RY3, the Company will defer for future

[7] All reconciliation and deferral provisions set forth in the Proposal will continue after the end of RY3 except for the transmission and distribution capital reconciliation and the inflation adjustment.

collection from customers carrying charges on the amount of the excess up to a total of $2,884,000 for RY1, $4,754,000 for RY2 and $7,292,000 for RY3; and

- There will be no deferral of carrying charges on actual rate year net plant investment greater than $698,888,000 for RY1, $739,168,000 for RY2 and $806,936,000 for RY3.

The revenue requirement impact will be calculated by applying an annual carrying charge factor of 13.51 percent, 13.59 percent, and 13.45 percent, (representing a combination of a pre-tax rate of return of 10.57 percent (for RY1), 10.65 percent (for RY2) and 10.51 percent (for RY3) combined with a composite depreciation rate of 2.94 percent) to the actual rate year variance from the capital target (see Appendix G).

The Signatory Parties agree that Orange and Rockland will have the flexibility during the term of the Electric Rate Plan to substitute, change, and modify the capital projects identified in Appendix H.

The Company will provide Staff and other interested parties with quarterly and annual reports that reflect the year-to-date status of on electric transmission and distribution related capital expenditures by rate year. These reports will be in the form set forth in Appendix H.

The Company will continue to defer recovery of carrying costs on stimulus projects until its next electric base rate case.

B. <u>Environmental Remediation</u>

If the level of actual SIR expenditures,[8] including expenditures associated with former manufactured gas plant ("MGP") sites, Superfund sites, Spring Valley, West Nyack and other

[8] These costs are the costs Orange and Rockland incurs to investigate, remediate or pay damages (including natural resource damages) with respect to industrial and hazardous waste or contamination, spills, discharges and emissions for which the Company is deemed responsible. These costs are net of insurance reimbursements (if any); nothing herein will require the Company to initiate or pursue litigation for purposes of obtaining insurance reimbursement, nor preclude or limit the Commission's authority to review the reasonableness of the Company's conduct in such matters.

sites allocated to electric operations varies in any rate year from the levels provided in rates, which are set forth in Appendix I, such variation shall be deferred and recovered from or credited to customers. Deferred SIR cost balances varying from the level reflected in rate base during each rate year will accrue a carrying cost at the pre-tax rate of return, as set forth in Appendix F. The deferred cost balances will be reduced by accruals, insurance and third party recoveries, associated reserves and deferred taxes, and other offsets, if any, obtained by the Company. Orange and Rockland will continue to allocate MGP costs between the Company's electric and gas operations on a 70.75%/29.25% basis.

The Signatory Parties are cognizant of the pendency of Case 11-M-0034, a generic proceeding begun on motion of the Commission to review and evaluate the treatment of the New York State regulated utilities' SIR costs. That case is intended to make policy determinations which would be implemented, thereafter, in orders issued in company specific rate cases.[9] Case 11-M-0034 has not yet concluded, and accordingly, the policy determinations that the Commission may make in Case 11-M-0034 could not have been addressed during the instant proceeding. The Company's revenue requirement incorporated in the Proposal has been developed on the basis that the accounting and ratemaking treatment for SIR costs, as currently applied, would continue during the Electric Rate Plan. As such, the Signatory Parties agree that any policy determinations in Case 11-M-0034 that would modify the treatment of SIR costs, are not anticipated to be implemented during the term of the Electric Rate Plan.

[9] Case 11-M-0034, Evaluation of the Treatment of the State's Regulated Utilities' Site Investigation and Remediation (SIR) Costs, Further Ruling on Scope, Procedure, and Schedule (Issued May 6, 2011).

Reflected in the rates proposed in the Proposal is the recovery, over the course of five year amortization periods beginning in the stated rate years, of the following forecasted SIR expenditures:[10]

Rate Year	Expenditure Amount	Amortization period
RY1	$14,259,663	July 1, 2012 through June 30, 2017
RY2	$8,511,225	July 1, 2013 through June 30, 2018
RY3	$764,100	July 1, 2014 through June 30, 2019

Additionally, there is a credit for over-collection of SIR costs during previous periods in the amount of $2,007,665, which has been reflected in the revenue requirements for RY1 and RY2.

Not later than March 31, 2012, 2013 and 2014, respectively, the Company will file with the Secretary a report regarding SIR expenditures and activities ("SIR Report"). The SIR Report will (a) describe the investigation and remediation activities that occurred at each MGP site during the previous calendar year, (b) summarize the actual SIR costs incurred related to each MGP site during the previous calendar year and a cumulative total to date, and (c) summarize the investigation and/or remediation activities to be conducted at each MGP site during the following calendar year and anticipated costs for that calendar year.[11]

C. Property Taxes

If the level of actual expenses recorded for property taxes, excluding the effect of property tax refunds, varies in any rate year from the levels provided in rates, which are set forth in Appendix G, 100% of any variations due to tax rate changes will be deferred and recovered from or credited to customers, while 86% of any variation due to assessment changes will be

[10] These are the amounts apportioned to the Company's electric operations.

[11] Forecasts of anticipated costs for specific calendar years related to specific MGP sites are subject to change due to among other factors, the reprioritization of remediation schedules, changing requirements of the New York Department of Environmental Conservation, and increased knowledge regarding subsurface conditions.

deferred and recovered from or credited to customers.[12] The Company will accrue interest monthly on such deferred amounts at the Other Customer Capital rate until such amounts are fully reflected in rates.

Property tax refunds (allocated to electric operations) resulting from the Company's efforts, including credits against future tax payments (intended to return or offset past overcharges or payments determined by the taxing authority to have been in excess of the property tax liability appropriate for Orange and Rockland),[13] will be deferred for future disposition except for an amount equal to fourteen percent of the refund,[14] which will be retained by the Company. The fourteen percent retention will apply to all such property tax refunds and/or credits (allocated to electric operations) against future tax payments actually achieved by Orange and Rockland during the term of the Electric Rate Plan.[15]

D. Pension/OPEBs

Pursuant to the Commission's Pension Policy Statement,[16] the Company will reconcile its actual pension/OPEB expenses, including Medicare Part D tax deductions, to the level allowed in rates as set forth in Appendix G.

The Pension Policy Statement provides that companies may seek prospective interest accruals or rate treatment for amounts funded above the cost recoveries included in rates.[17]

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[12] The change in assessments will be first determined by applying the prior year's tax rates to the current bills' assessments. The difference between those results and the prior year's taxes will provide the tax change due to assessment changes. The difference between those resulting change(s) in assessments and the current taxes will provide the tax change due to rate changes.

[13] Outside legal and other incremental costs incurred by the Company in pursuing such property tax refunds will first be deducted from any such refunds and/or credits before any allocation is made to the Company and its customers.

[14] The Company is not relieved of the requirements of 16 NYCRR Part 89 and Public Service Law § 113(2) with respect to any refunds it receives.

[15] This includes 14% of any property tax refunds, finalized during the term of the Electric Rate Plan, but actually received after the end of the term of the Electric Rate Plan (e.g., August 1, 2015).

[16] Case 91-M-0890, In the Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions, *Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions* (issued September 7, 1993) ("Pension Policy Statement").

During the term of the Electric Rate Plan, the Company may be required to fund its pension plan at a level above the rate allowance pursuant to the annual minimum pension funding requirements contained within the Pension Protection Act of 2006. The Company, its actuary and the parties are unable to predict with certainty if the minimum funding threshold will exceed rate recoveries during the term of the Electric Rate Plan. In lieu of a provision in the Proposal addressing the Company's additional financing requirements should it be required to fund its pension plan above the level provided in rates during the term of the Electric Rate Plan, the Proposal does not preclude the Company from petitioning the Commission to defer the financing costs associated with funding the pension plan at levels above the current rate allowance should funding above the rate allowance be required; the Company's right to obtain authority to defer such financing costs on its books of account will not be subject to requirements respecting materiality.

E. R&D Costs

The Company will reconcile its actual R&D expenses to the level allowed in rates as set forth in Appendix G. The reconciliation shall be based on a comparison of actual expenses to the level allowed in rates. The Company shall have the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of the R&D projects to be undertaken.

F. Low-Income Program

The Company will reconcile actual payments (credits) to low-income customers to the level allowed in rates as set forth in Appendix G. All under- and over-recoveries associated with monthly bill credits and the waiver of reconnection fees will be reconciled.

[17] See Pension Policy Statement, Appendix A, page 16, footnote 3.

G. Asbestos Workers' Compensation Reserve

The Company will reconcile the level of actual asbestos claim payments to the Company's former employees, on a cumulative basis over the term of the Electric Rate Plan, to the level provided in rates, which are set forth in Appendix G.

H. Tree Trimming

The Company will defer for the benefit of customers any cumulative shortfall over the term of the Electric Rate Plan between actual expenditures for the Company's transmission and distribution tree trimming program, including the danger tree programs, and the levels provided in rates, which are set forth in Appendix G. Should the Company not file for new rates to be effective on July 1, 2015, the Company will defer for the benefit of customers any shortfall between actual expenditures for the Company's transmission and distribution tree trimming program, including the danger tree programs and the levels proposed in rates on an annual basis, or on a pro rated (by month) basis, for any period less than twelve months. Expenditures after June 30, 2015 shall not be netted against prior shortfalls or overruns.

I. Deferred Income Taxes – 263A, Repair Allowance (481A) and Bonus Depreciation

The Company and the Internal Revenue Service ("IRS") have resolved the methodology that Orange and Rockland may use in calculating the Section 263A tax deduction claimed by Orange and Rockland beginning with tax returns filed for 2005 and later years. To the extent that a portion of plant related tax deductions are disallowed and the Company is required to pay back the disallowed benefit with interest, the Company will be allowed to defer such interest, upon a showing that the customers obtained the benefit of such deductions in rates.

In 2010, the Company changed its methodology for calculating Section 481A repair deductions. Due to the change in tax depreciation to allow for accelerated depreciation ("Bonus Depreciation"), any potential disallowances associated with the change for calculating Section 481A repair deductions will be offset by a corresponding adjustment to Bonus Depreciation for current tax years. It is not known at this point whether Bonus Depreciation will be extended beyond 2012. If it is not extended and a portion of future deductions claimed by the Company for repair allowance are disallowed, the Company will be allowed to defer the incremental revenue requirement impact during the term of the Proposal.

The Company will defer interest at a rate equivalent to the pre-tax rate of return as shown in Appendix F on any difference between the actual deferred Section 263A and tax depreciation (ADR/ACRS/MACRS), including Bonus Depreciation, deferred tax benefits reflected in rate base (see Appendix G) and the actual tax benefits that result from the Section 263A and ADR/ACRS/MACRS deduction allowed by the IRS. The final Section 263A deduction reflected in rate base will recognize any related partial offset (i.e., higher/lower tax deduction), impacting the ADR/ACRS/MACRS rate base balances.[18]

J. Major Storm Costs

The Company's annual revenue requirements during the Electric Rate Plan provide funding for incremental major storm costs as shown in Appendix G.[19] In addition, the Electric Rate Plan provides for recovery of previously deferred major storm costs over a period of five years as shown in Appendix I. In order to mitigate the overall annual increases, the recovery of

[18] The ADR/ACRS/MACRS rate base balances reflected in rates may change if a higher or lower level of costs is capitalized for tax purposes, as a result of a change in the level of costs deducted under Section 263A.

[19] A "major storm" is defined as a period of adverse weather during which service interruptions affect at least 10% of the Company's customers within an operating area and/or results in customers being without electric service for durations of at least 24 hours and exceeds $200,000 in incremental cost.

costs for the October 29, 2011 snow storm will commence in RY2. The amortization of these costs does not preclude the review of all major storm costs by Staff and the Commission.

K. Inflation Adjustment

If the general inflation rate exceeds 6.0% ("Inflation Threshold") in any of the rate years during the Electric Rate Plan and the Company's electric earnings[20] are less than the authorized ROE applicable to that rate year (i.e., 9.4%, 9.5% and 9.6% for RY1, RY2 and RY3), respectively, the Company will be allowed to request authorization from the Commission to defer actual inflationary increases above the Inflation Threshold applicable to the expenses set forth in Appendix G ("Inflation Pool"). Any such request will not be subject to the Company meeting the Commission's deferral materiality threshold for the impact of these cost increases.

The deferral will be based on the lower of the following:

(a) Inflationary increases above the Inflation Threshold, determined using Price Index numbers for Gross Domestic Product ("GDP") published by the U.S. Department of Commerce, Bureau of Economic Analysis ("BEA"),[21] applicable to the Inflation Pool; or

(b) Actual costs incurred by the Company for the expenses, contained in the Inflation Pool, above the Inflation Threshold.

For example, if during RY1, the inflation rate according to the Blue Chip Economic Indicators is 6.1%, as compared to the 2% increase in the expenses contained in the Inflation Pool used for purposes of establishing the revenue requirements for the Electric Rate Plan, the deferral would be equal to 4.1% (i.e., 6.1% less the 2% threshold) of the Inflation Pool,

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[20] Actual return on common equity capital allocated to the Company's New York jurisdictional electric operations, calculated as set forth in Section 10 of the Proposal.

[21] The estimate of inflation that occurred during the three rate years (ending June 30, 2015) will be calculated using price index numbers available from BEA as of August 1, 2015. Likewise, all individual rate year inflation calculations will be based on available data as of August 1st in the appropriate year.

provided that the Company's earned ROE, as calculated pursuant to Section 10 of the Proposal was less than 9.4%.

L. Variable Rate Debt

The Company will reconcile the costs of its variable rate long-term (e.g., pollution control tax-exempt) debt to the amounts reflected in rates for such costs as set forth in Appendix G and defer as a regulatory asset or regulatory liability, as the case may be, any difference between actual and rate level costs for refund to customers (if actual is less than the rate level) or recovery from customers (if actual is greater than the rate level). Variable rate long-term debt costs include interest charges, letter of credit fees, bond insurance premiums, the costs of any related interest rate hedging activities, refinancing, swap and other costs and expenses in connection with the issuance and maintenance of the debt. Without limiting the generality of any of the foregoing, the Company's actual long-term debt costs for its retired and sole outstanding issue of tax-exempt pollution control debt will be so reconciled, including, without duplication, interest paid while such tax-exempt debt is outstanding, interest paid on borrowing used to fund purchase of the tax-exempt debt during the period from any tender of such debt by investors until such debt is remarketed or refunded, interest paid on any new tax-exempt or taxable debt the proceeds of which are used to refund the tax-exempt debt, and any other costs and expenses in connection with the issuance and maintenance of the existing tax-exempt debt and any refunding debt. It will also include settlement or termination payments, in connection with the swap agreement entered into in 1992 with respect to the already retired series of the tax-exempt debt.

M. Additional Reconciliation/Deferral Provisions

In addition to the foregoing reconciliation provisions, all other applicable existing reconciliations and/or deferral accounting will continue in effect through the term of the Electric

Rate Plan and thereafter unless modified or discontinued by the Commission, including but not limited to, Accounting Standards Codification ("ASC") 740 Income Taxes, MTA taxes, New York Public Service Law §18-a regulatory assessment, Renewable Portfolio Standard charges, vacation pay accrual pursuant to ASC 980 Regulated Operations, carrying charges for the MSC, ECA, and System Benefits Charge ("SBC") mechanisms. The Company will defer any differences between the Company's actual revenues and authorized revenues, as determined by the Company's RDM. In addition, the Company will defer any carrying costs for projects approved or required by the Commission that are incremental to the Company's capital additions, such as Advanced Metering Infrastructure projects, and participation in regulated backstop solutions or generation as the provider of last resort.

Appendix I sets forth the annual amortization of deferred regulatory assets and liabilities included in the annual revenue requirements.

N. Limitations on Deferrals

When calculating the level of earned ROE for electric operations that may be subject to sharing pursuant to Section 10 of the Proposal, the Company will make the following adjustments if its earnings exceed the Earnings Sharing Threshold:

a. For earnings on common equity above 10.2% for RY1, 10.3% for RY2 and 10.4% for RY4, the Company will apply up to 50% of its share of any such earnings to reduce net expenses (debits) deferred for later recovery pursuant to subsection c below,[22] provided that such reduction in deferrals will not cause the resulting earnings to decrease below the returns on common equity stated above.

[22] For example, if the Company earns $100 over the 10.2% RY1 threshold, $50 will be allocated to customers, $25 will be applied against the Company's deferrals, and $25 will be allocated to the Company's shareholders.

b. For purposes of (a), above, the analysis will be performed on a single rate year basis. For example, costs deferred in RY1 will not be considered in the analysis for RY2.

c. This deferral limitation will apply to net debit deferrals for major storm charges, R&D, and pension/OPEBs.

12. ATIP/Management Audit Savings

The Company requested a $1.2 million base delivery rate revenue increase in RY1 to fund its variable management pay program (i.e., Annual Team Incentive Plan ("ATIP")) that Staff did not include in its proposed RY1 revenue requirement. Staff proposed a $485,000 imputation representing Staff's estimated savings resulting from the Company's implementation of Liberty Management Audit recommendations, in addition to those savings identified by the Company in its proposed RY1 revenue requirement. The difference between the filed positions of the Company and Staff regarding the revenue impact of these two items amounts to approximately $1.7 million. In order to reach a settlement regarding the revenue impact of these two items, the base delivery rate revenue increase in RY1 reflects a net impact of $700,000.[23]

13. Direct Labor/Wages

The cost of direct labor reflects a 1% productivity adjustment and a slippage adjustment of 3.3 months for new positions included in the revenue requirement. The base delivery rate revenue requirements by rate year under the Proposal reflect the funding of new positions as set forth in Appendix J.

[23] The Signatory Parties understand that any Signatory Party may make a recommendation to the Commission in this case regarding the appropriate methodology to be used to support the Company's request for recovering the costs of its variable management pay program from ratepayers in future rate cases. The Signatory Parties also understand that any Signatory Party may respond to any such recommendations, including stating why such recommendations may be inappropriate to impose on the Company.

14. Spill Prevention Control and Countermeasure (“SPCC”) Program

The Company’s revenue requirement includes $50,000 per rate year in order to reflect the funding requirements associated with the SPCC Inspection Program. The Program requires that the Company inspect each of its 72 substations over a five-year cycle. The cost of such inspections is currently $3,500 per station, or $252,000 in total.

15. Enhanced Customer Call Answering System

The Company’s revenue requirement includes $44,000 per rate year in order to reflect the funding requirements associated with the maintenance fees relating to the Company’s enhanced customer call answering system.

16. Common Plant Allocation

During the term of the Electric Rate Plan, common plant costs will be allocated according to the percentages approved by the Commission in Case 99-G-1695 (i.e., 29.25% gas operations, 70.75% electric operations).

17. Customer Service and Reliability Performance Measurements

The Electric Customer Service and Reliability Performance Mechanism set forth in Appendix K of the Proposal will be in effect until modified or discontinued by the Commission. The Electric Customer Service and Reliability Performance Mechanism will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during the calendar years 2012, 2013, and 2014, respectively, will be applied to Rate Years 1, 2, and 3, respectively.[24]

The Company will file an annual report by March 1, providing the results of the performance measurements for the preceding calendar year (e.g., the annual report for 2012 shall

[24] Any negative revenue adjustments incurred by the Company during the Electric Rate Plan relating to the Electric Customer Service and Reliability Performance Mechanism will be deferred for the benefit of customers and will be addressed in the Company’s next electric base rate case.

be due by March 1, 2013) and the Company's calculation of any applicable credits due to customers in accordance with Appendix K.

18. Low-Income Program

A. Monthly Bill Credit

The Company will modify its current electric low-income program, so that any Orange and Rockland electric space heating customer, who receives a Home Energy Assistance Program ("HEAP") grant, will receive from the Company a monthly bill credit of $17.40 during each of RY1, RY2 and RY3. Any Orange and Rockland electric non-space heating customer, who receives a HEAP grant, will receive from the Company a monthly bill credit of $7.00, $8.00, and $9.00 for RY1, RY2 and RY3, respectively. The Company will commence posting such bill credits to the customer's account within 60 days of being notified by the New York State Office of Temporary Disability Assistance (or its successor) of the customer's receipt of a HEAP grant. This modified electric low-income program will commence on July 1, 2012. The bill credits will remain at the level in effect after the conclusion of RY3 until modified by the Commission. The Electric Rate Plan provides a rate allowance for the low-income program as set forth in Appendix G.

B. Reconnection Fee Waiver

During the term of the Electric Rate Plan the Company will continue its policy of waiving its reconnection fee for any Orange and Rockland electric customer who receives a HEAP grant, according to the terms set forth in the Company's electric tariff.

C. EmPower Support

Once during each rate year (i.e., by March 10, 2013, 2014, 2015), Orange and Rockland will send a letter to all its low-income customers soliciting the consent of such customers so that they can be referred to the New York State Energy Research and Development Authority

("NYSERDA") for participation in NYSERDA's EmPower-NY services program. For low-income customers that consent, the Company will forward through a confidential electronic means such customers' contact and usage information to NYSERDA. Staff will make a good faith effort during the term of the Electric Rate Plan to encourage NYSERDA to promote the EmPower-NY services program in the Company's service territory. Staff also will encourage NYSERDA to provide the Company, Staff, and UIU with a report describing whether, and if so how, the customers referred to NYSERDA by the Company participated in NYSERDA's EmPower-NY services program.

In the final quarterly low income report for each rate year, to the extent applicable, the Company will identify the number of referral letters that it sent out to low income customers during the rate year and the number of customers that requested that the Company refer them to NYSERDA.

19. Double Poles

During the term of the Electric Rate Plan, the Company will provide semi-annual reports to the Secretary and all Signatory Parties relating to the double poles in its service territory. Reports will be due 45 days after the end of the January to June, and July to December periods (i.e., February 15th and August 15th). The initial report will be due on or about February 15, 2013. The semi-annual reports will contain at a minimum, and to the extent the information is available, an identification of the double poles, the party responsible for the next steps required to remediate the double pole condition, and the date the responsible party was notified of its obligation. This obligation will be modified prospectively so as to be consistent with all applicable future Commission orders and directives, particularly in Case 08-M-0593, Proceeding on Motion of the Commission to Evaluate a Standardized Facility and Equipment Transfer

Program; however, unless the reporting requirement agreed to herein is specifically addressed, the Company will provide this report to all Signatory Parties on at least a semi-annual basis.

20. Depreciation

The average service lives, net salvage factors and life tables used in calculating the depreciation reserve and in establishing the revenue requirement are set forth in Appendix L. They are the same as those adopted by the Commission in the Company's last electric base rate case (i.e., Case 10-E-0362).

The base delivery rate revenue requirements under the Proposal reflect the continued amortization of an excess common plant depreciation reserve of approximately $11.4 million, of which approximately $8.1 is allocable to electric operations, which, in Case No. 07-E-0949, the Commission directed be credited to customers over a five-year period. The electric portion of that common plant excess depreciation reserve will be fully credited to customers as of the end of RY1.

21. Interest

The Company will record on its books and records of accounts various credits and debits that ultimately will be reflected in the rates to be charged or credited to customers. Unless otherwise specified in the Proposal or by Commission Order, the Company will accrue interest on all such book amounts, net of federal and state income taxes, at the Other Customer Provided Capital Rate published by the Commission annually and applicable on a calendar year basis. ASC 740 Income Taxes and MTA tax deferrals are either offset by other balance sheet items or reflected in the Company's rate base and will not be subject to interest.

22. Other Allowed Rate Changes

Notwithstanding the other provisions of the Proposal, the Signatory Parties agree that the following rate changes will be permitted[25] during the Electric Rate Plan, provided that Commission approval is granted prior to the implementation of such changes:

A. A minor change in any individual base rate or rates whose revenue effect is de minimis or essentially offset by associated changes in other base rates, terms or conditions of service -- for example, an increase in a specific base rate charge in one service classification that is offset by a decrease in another base rate charge in the same or in other service classifications. It is understood that, over time, such minor changes are routinely made and that they may continue to be made during the term of the Electric Rate Plan provided they will not result in a change (other than a de minimis change) in the revenues that Orange and Rockland's base electric rates are designed to produce overall before such changes.

B. If a circumstance occurs which, in the judgment of the Commission, so threatens the Company's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to this undertaking, Orange and Rockland will be permitted to file for an increase in base electric rates at any time under such circumstances.

C. The Signatory Parties recognize that the Commission reserves the authority to act on the level of Orange and Rockland's base electric rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by the Electric Rate Plan as to render Orange and

[25] The Signatory Parties agree that any Signatory Party will be allowed to take any position it may wish regarding any such proposed rate change.

Rockland's base electric rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

D. Nothing herein will preclude Orange and Rockland from petitioning the Commission for approval of new services or of rate design or revenue allocation changes on an overall revenue-neutral basis, including, but not limited to, the implementation of new service classifications and/or cancellation of existing service classifications.

23. Legislative, Regulatory and Related Actions

A. If at any time the federal government, State of New York and/or other local governments make changes in their tax laws (other than local property taxes, which will be reconciled in accordance with Section 11.C of the Proposal) that result in a change in the Company's electric costs in an annual amount of ten basis points or more of return on New York electric equity,[26] and if the Commission does not address the treatment (*e.g.*, through a surcharge or credit) of any such tax law changes, including any new, additional, repealed or reduced federal, State of New York or local government taxes, fees or levies, the Company will defer on its books of account the full change in expense and reflect such deferral as credits or debits to customers in the next base rate change subject to any final Commission determination in a generic proceeding prescribing utility implementation of a specific tax enactment, including a Commission determination of any Company-specific compliance filing made in connection therewith.[27]

B. If at any time any other law, rule, regulation, order, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other

[26] Ten basis points on New York electric equity equates to approximately $0.55 million as of July 1, 2012.

[27] All Signatory Parties reserve all of their administrative and judicial rights in connection with such generic proceeding(s).

requirement) of the federal, State of New York, or local government or courts, results in a change in the Company's annual electric costs or expenses not anticipated in the expense forecasts and assumptions on which the rates in the Proposal are based in an annual amount of ten basis points or more of return on New York electric equity, the Company will defer on its books of account the full change in expense, with any such deferrals to be reflected in the next base rate case or in a manner to be determined by the Commission.[28]

C. Orange and Rockland will retain the right to petition the Commission for authorization to defer on its books of account extraordinary costs not otherwise addressed in the Proposal.

D. Nothing herein precludes Orange and Rockland from filing a new general electric base rate case prior to July 1, 2015, for rates to be effective on or after July 1, 2015. Except as provided pursuant to Section 20 of the Proposal, Orange and Rockland will not file for a base rate change to become effective before July 1, 2015.

24. Trade Secret Protections

Nothing in this document prevents the Company from seeking trade secret protection under 16 NYCRR Part 6 for all or any part(s) of any document or report filed (or submitted to Staff) in accordance with the Electric Rate Plan (e.g., SIR Report), or prohibits or restricts any other Signatory Party from challenging any such request.

[28] For purposes of this Proposal, the ten basis point threshold will be applied on a case-by-case basis and not to the aggregate impact of changes of two or more laws, rules, etc.; provided, however, that this threshold will be applied on a rate year basis to the incremental aggregate impact of all contemporaneous changes (*e.g.*, changes made as a package even if they occur or are implemented over a period of months) affecting a particular subject area and not to the individual provisions of the new law, rule, etc.

IV. GENERAL PROVISIONS

25. Continuation of Provisions

The provisions of the Proposal adopted herein, that are not designated to expire by their own terms, will remain in effect after RY3 unless and until changed by the Commission. For the period following RY3, any provision subject to targets and goals set forth in the Proposal will continue at their RY3 levels unless modified by the Commission in any future action affecting this proceeding or in a subsequent proceeding. The amortization and deferral of all credits/debits addressed by the Proposal will continue until the Company's base rates are reset by the Commission.

26. Provisions Not Separable

The Signatory Parties intend the Proposal to be the complete resolution of all the issues in Case 11-E-0408. It is understood that each provision of the Electric Rate Plan set forth in the Proposal is in consideration and support of all the other provisions, and expressly conditioned upon their acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. If the Commission's Order establishing rates and terms of a three-year rate plan fails to adopt the Electric Rate Plan set forth in the Proposal according to its terms, then the Signatory Parties will be free to pursue their respective positions in this proceeding without prejudice.

27. Provisions Not Precedent

The terms and provisions of the Proposal apply solely to, and are binding only in the context of, the purposes and results of the Proposal. None of the terms and provisions of the Proposal and none of the positions taken herein by any Signatory Party may be cited or relied upon by any other Signatory Party in any fashion as precedent or otherwise in any other proceeding before the Commission, or before any other regulatory agency or any court of law for any purpose other than the furtherance of the purposes, results, and disposition of matters governed by the Proposal.

28. Dispute Resolution

In the event of any disagreement over the interpretation of provisions in the Proposal or the implementation of any of the provisions of the Electric Rate Plan, which cannot be resolved informally by the Signatory Parties, such disagreement will be resolved in the following manner: the Signatory Parties will promptly convene a conference and in good faith will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatory Parties within 30 days, any Signatory Party may petition the Commission for relief on a disputed matter.

29. Submission of Proposal

The Signatory Parties agree to submit the Proposal to the Commission and to individually support and request adoption by the Commission of the Electric Rate Plan set forth in the Proposal in its entirety as set forth herein. The Signatory parties believe that the Proposal will satisfy the requirements of Public Service Law §65(1) that Orange and Rockland provide safe and adequate service at just and reasonable rates.

30. Further Assurances

The Signatory Parties recognize that certain provisions of the Proposal require that actions be taken in the future to fully effectuate the Electric Rate Plan. Accordingly, the Signatory Parties agree to cooperate with each other in good faith in taking such actions.

31. Execution

The Proposal is being executed in counterpart originals, and will be binding on each Signatory Party when the counterparts have been executed.

IN WITNESS WHEREOF, the Signatory Parties hereto have affixed their signatures below as evidence of their agreement to be bound by the provisions of the Proposal on the day and year first written above.

Dated: February 24, 2012

John L. Carley
Orange and Rockland Utilities, Inc.

(Signatures continued on following page)

Case 11-E-0408

Dated: February 24, 2012

Staff of the Department of Public Service
By: Brandon F. Goodrich, Assistant Counsel

Case 11-E-0408

Cesar Perales
Secretary of State

By: Lisa R. Harris

Lisa R. Harris, Esq.
Director, Division of Consumer Protection
Utility Intervention Unit of the New York State
Department of State's Division of Consumer
Protection

February 24, 2012

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Electric Revenue Requirement
For Twelve Months Ending June 30, 2013
(000's)

	Rate Year Forecast	Rate Change	Rate Year With Rate Change
Operating Revenues			
Sales to Public	$392,885	$19,436	$ 412,321
Sales for Resale	22,528	-	22,528
Delivery Revenues	415,412	19,436	434,848
Other Revenues	21,077	113	21,190
Net Operating Revenues	436,490	19,549	456,039
Operating Expenses			
Purchased Power	147,362	-	147,362
Deferred Purchased Power	(873)	-	(873)
Other	164,819	107	164,926
Operations & Maintenance Expenses	311,308	107	311,415
Depreciation & Amortization	33,477	-	33,477
Taxes Other Than Income Taxes & GRT	39,100	225	39,325
Total Deductions	383,884	332	384,216
Operating Income Before Income Taxes	52,605	19,217	71,822
Income Taxes			
New York State Income Taxes	2,185	1,364	3,549
Federal Income Tax	2,570	6,248	8,819
Deferred Federal Income Taxes	9,623	-	9,623
Amortization of Deferred 263A and ITC	(1,213)	-	(1,213)
Total Income Taxes	13,166	7,613	20,778
Utility Operating Income	$ 39,439	$11,604	$ 51,044
Electric Rate Base	$671,049	$ -	$ 671,049
Rate of Return	5.88%		7.61%

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Electric Revenue Requirement
For Twelve Months Ending June 30, 2014
(000's)

	Rate Year 1 With Rate Change	Rate Year 2 Changes	Rate Change	Rate Year 2 With Rate Change
Operating Revenues				
Sales to Public	$ 412,321	$ 499	$ 8,835	$ 421,655
Sales for Resale	22,528	470		22,998
Delivery Revenues	434,848	969	8,835	444,652
Other Revenues	21,190	211	51	21,454
Net Operating Revenues	456,039	1,180	8,886	466,107
Operating Expenses				
Purchased Power	147,362	23	-	147,385
Deferred Purchased Power	(873)	(1,317)	-	(2,190)
Other	164,926	4,996	49	169,970
Operations & Maintenance Expenses	311,415	3,702	49	315,165
Depreciation & Amortization	33,477	300		33,777
Taxes Other Than Income Taxes & GRT	39,325	1,523	102	40,950
Total Deductions	384,216	5,525	151	389,891
Operating Income Before Income Taxes	71,822	(4,345)	8,735	76,215
Income Taxes				
New York State Income Taxes	3,549	(390)	620	3,779
Federal Income Tax	8,819	1,219	2,840	12,878
Deferred Federal Income Taxes	9,623	(3,076)	-	6,547
Amortization of Deferred 263A and ITC	(1,213) .	-	-	(1,213)
Total Income Taxes	20,778	(2,248)	3,460	21,991
Utility Operating Income	$ 51,044	$ (2,097)	$ 5,275	$ 54,224
Electric Rate Base	$ 671,049	$ 37,324	$ -	$ 708,373
Rate of Return	7.61%			7.65%
Return on Equity	9.40%			9.50%

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Electric Revenue Requirement
For Twelve Months Ending June 30, 2015
(000's)

	Rate Year 2 With Rate Change	Rate Year 3 Changes	Rate Change	Rate Year 3 With Rate Change
Operating Revenues				
Sales to Public	$ 421,655	10,687	15,228	447,570
Sales for Resale	22,998	1,858		24,856
Delivery Revenues	444,652	12,545	15,228	472,425
Other Revenues	21,454	(9,713)	89	11,830
Net Operating Revenues	466,107	2,832	15,317	484,256
Operating Expenses				
Purchased Power	147,385	9,450	-	156,835
Deferred Purchased Power	(2,190)	1,232	-	(958)
Other	169,970	(1,009)	84	169,044
Operations & Maintenance Expenses	315,165	9,673	84	324,921
Depreciation & Amortization	33,777	3,642	-	37,419
Taxes Other Than Income Taxes & GRT	40,950	(1,190)	177	39,937
Total Deductions	389,891	12,125	261	402,277
Operating Income Before Income Taxes	76,215	(9,293)	15,056	81,979
Income Taxes				
New York State Income Taxes	3,779	(648)	1,069	4,200
Federal Income Tax	12,878	(1,659)	4,895	16,114
Deferred Federal Income Taxes	6,547	(441)	-	6,106
Amortization of Deferred 263A and ITC	(1,213)	-	-	(1,213)
Total Income Taxes	21,991	(2,749)	5,964	25,206
Utility Operating Income	$ 54,224	(6,544)	9,092	56,773
Electric Rate Base	$ 708,373	$ 50,605	$ -	$ 758,979
Rate of Return	7.65%			7.48%
Return on Equity	9.50%			9.60%

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Average Electric Rate Base
July 1, 2012 - June 30, 2015
(000's)

	Rate Year 1	Changes	Rate Year 2	Changes	Rate Year 3
Utility Plant:					
Electric Plant In Service	$ 997,958	$ 50,772	$ 1,048,730	$ 75,370	$ 1,124,100
Electric Plant Held For Future Use	10,093	-	10,093	-	10,093
Common Utility Plant (Electric Allocation)	128,858	5,499	134,357	6,571	140,928
CWIP Not Taking Interest	14,402	-	14,402	-	14,402
Total Utility Plant	1,151,311	56,271	1,207,582	81,941	1,289,523
Utility Plant Reserves:					
Accum. Prov. For Deprec. of Electric Plant In Service (Including Future Use Plant)	(320,429)	(24,104)	(344,533)	(26,859)	(371,392)
Accum. Prov. For Deprec. & Amortization of Common Plant	(59,075)	(3,884)	(62,959)	(3,472)	(66,431)
Total Utility Plant Reserves	(379,504)	(27,988)	(407,492)	(30,331)	(437,823)
Net Plant	771,807	28,283	800,090	51,610	851,700
Working Capital Requirements:					
O&M Expenditures	22,770	214	22,984	302	23,286
Materials & Supplies	6,313	129	6,442	135	6,578
Prepayments	9,849	702	10,551	737	11,288
Regulatory Assets & Other Rate Base Additions					
Deferred Unbilled Revenue	17,574	-	17,574	-	17,574
Deferred Purchased Power	2,333	856	3,189	(801)	2,388
Deferred M.T.A. Surtax	1,978	-	1,978	-	1,978
Deferred M.T.A. Mobility Tax	187	(125)	62	(62)	-
Deferred MFC Credit & Collection	619	(619)	-	-	-
Deferred Storm Reserve Expenditures	3,471	(992)	2,479	(992)	1,487
Deferred Storm Reserve Expenditures - Hurricane Irene (Net of Tax)	5,652	(1,256)	4,396	(1,256)	3,140
Deferred Storm Reserve Expenditures - Oct. 2011 Snow Storm (Net of Tax	9,486	(948)	8,538	(1,897)	6,641
Deferred MGP Expenditures	2,974	5,943	8,917	440	9,357
Deferred Environmental Expenditures- West Nyack/Spring Valley UST	228	(44)	184	(59)	125
Deferred Environmental Expenditures- Cottman/Newark Bay/ Borne	91	(26)	65	(26)	39
Deferred R&D Expenditures	473	(315)	158	(158)	-
Deferred Pollution Control Debt	1,588	(635)	953	(635)	318
Deferred Workers Compensation - Asbestos Expense	51	(51)	-	-	-
Deferred Low Income Program	148	(99)	49	(49)	-
Deferred Property Tax Undercollection	2,370	(1,580)	790	(790)	-
Deferred Property Tax Refund - Haverstraw	91	(61)	30	(30)	-
Deferred Rate Case Cost - Case 10-E-0362	45	(30)	15	(15)	-
Deferred PSC Smart Grid Maintenance Cost	16	-	16	-	16
Deferred Rate Case Cost - Case 11-E-0408	101	(40)	61	(40)	21
Regulatory (Liabilities) & Other Rate Base Deductions					
Deferred Carrying Charges Net Plant Reconciliation	(8,227)	5,485	(2,742)	2,742	-
Deferred Performance Reliability Revenue Adjustment	(424)	283	(141)	141	-
Deferred Current NYS Tax Rate Change	(91)	60	(31)	31	-
Deferred Conservation Cost	(27)	25	(2)	2	-
Deferred Oil Supplier Refunds	(50)	33	(17)	17	-
Customer Advances For Construction	(54)	-	(54)	-	(54)
Deferred CATV Billing	(107)	71	(36)	36	-
Deferred Interest Repair Allowance	(20)	19	(1)	1	-
Deferred Environmental Cost Electric Carrying Charges	(1,013)	405	(608)	405	(203)
Deferred Hillburn Property Tax Settlement	(5)	2	(3)	2	(1)
Deferred Electric EEPS Adjustments	(377)	(76)	(453)	-	(453)
Deferred Tree Trimming	(603)	241	(362)	241	(121)
Accum. Deferred Income Taxes					
Accum. Deferred FIT - ACRS / ADR / MCRS	(119,364)	791	(118,573)	(153)	(118,726)
Accum. Deferred FIT - 263(A) Capitalized Overheads	(38,894)	1,213	(37,681)	1,213	(36,468)
Accum. Deferred FIT - Repair Allowance	(4,093)	(257)	(4,350)	(433)	(4,783)
Accum. Deferred SIT	(7,898)	(277)	(8,174)	(54)	(8,228)
Accum. Deferred Investment Tax Credits	(772)	-	(772)	-	(772)
Electric Rate Base	$ 678,197	$ 37,324	$ 715,521	$ 50,606	$ 766,127
EBCAP Adjustment to Electric Rate Base	(7,148)	-	(7,148)	-	(7,148)
Total Electric Rate Base	$ 671,049	$ 37,324	$ 708,373	$ 50,606	$ 758,979

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Implementation of Rate Increases
(000's)

Option A

	Twelve Months Ending June 30,			
Annual Increases	2013	2014	2015	Total
RY 1	$ 19,436	$ 19,436	$ 19,436	$58,308
RY 2	-	8,835	8,835	17,670
RY 3	-	-	15,228	15,228
Total Increases	$ 19,436	$ 28,271	$ 43,499	$91,206

Option B - Levelized Rate Increases

Annual Rate Increases w/o interest				
RY 1	$ 15,201	$ 15,201	$ 15,201	$ 45,603
RY 2	-	15,201	15,201	30,402
RY 3	-	-	15,201	15,201
	$15,201	$30,402	$45,603	$91,206
Levelized vs. Annual	$4,235	-$2,131	-$2,104	$0
Interest @ 3.4%	$43	$65	$22	$130
Annual Rate Increases w/interest				
RY 1	$ 15,223	$ 15,223	$ 15,223	$ 45,668
RY 2	-	15,223	15,223	30,445
RY 3	-	-	15,223	15,223
Total	$ 15,223	$ 30,445	$ 45,668	$ 91,336

REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

The incremental revenue requirement for each rate year was adjusted by subtracting amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. For each rate year, before the adjusted incremental revenue requirement was applied to each customer class, the Rate Year delivery revenues for each class were realigned to reduce interclass deficiencies and surpluses. In the Company's last electric base rate proceeding (i.e., Case 10-E-0362), the Company applied one third of the class-specific deficiency and surplus indications from the embedded cost of service ("ECOS") study in a revenue neutral manner prior to applying the revenue increases. In RY1, deficiency and surplus indications have been further eliminated by applying another one third of the class-specific deficiency and surplus indications. The RY1 delivery revenue increase was then allocated among the service classifications ("SC") in proportion to the relative contribution made by each SC’s realigned RY1 delivery revenue to the total realigned RY1 delivery revenue. The remaining one-third of the surplus and deficiency indications was applied in RY2. The RY2 delivery revenue increase was then allocated among the SCs in proportion to the relative contribution made by each SC’s realigned RY2 delivery revenue to the total realigned RY2 delivery revenue. The RY3 delivery revenue increase was allocated among the SCs in proportion to the relative contribution made by each SC to total RY3 delivery revenue.

2. <u>Rate Design</u>

The rate design process for each rate year consists of the following six steps:

- Determine revised customer charges and associated delivery revenue changes;
- Determine revised competitive service charges and associated delivery revenue changes;
- Adjust class-specific delivery revenue increases to determine non-competitive delivery revenue increases excluding customer charges;
- Calculate class-specific non-competitive delivery revenue increases excluding customer charges for a historical period;
- Implement intraclass rate structure changes for certain SCs; and
- Apply non-competitive delivery revenue increase excluding customer charges within each SC.

a. <u>Revised Customer Charges and Associated Delivery Revenue Changes</u>

Customer charges were increased to better reflect customer costs, consistent with the ECOS study. Schedule 1 summarizes the customer charges for RY1, RY2, and RY3. Customer charges for SC No. 15 were increased by the overall delivery revenue increase percentage applicable to all SCs. Customer charges for SC No. 25 are described in the Standby Rate Design section of this appendix. SC-specific changes in customer charge revenue for each rate year were determined based on the changes in customer charges described above and the forecast of customer bills for each rate year.

b. <u>Revised Competitive Service Charges and Associated Delivery Revenue Changes</u>

The competitive delivery components include the billing and payment processing ("BPP") charge; the Merchant Function Charge ("MFC") fixed components, that is the

MFC procurement and credit and collections components; the purchase of receivables ("POR") credit and collections component; and Metering Charges. For each rate year, revised revenue levels for the MFC fixed components, POR credit and collections component and Metering Charges were based on percentages of delivery revenue as determined in the ECOS study. The revised revenue levels for each rate year were compared with competitive service charge revenues determined based on competitive service charges for the previous rate year to determine the change in competitive service revenues.

c. Determination of Class-Specific Non-Competitive Delivery Revenue Increases Excluding Customer Charges.

For each rate year, the revenue changes associated with the revised Customer Charges, MFC Fixed Components, POR credit and collections component and Metering Charges were used to adjust the class-specific delivery revenue increases to determine class-specific non-competitive delivery revenue increases excluding customer charges. There were no revenue changes associated with the BPP Charge since it will remain at its current level during the period of the Electric Rate Plan.

d. Determination of Class-Specific Non-Competitive Delivery Revenue Increases Excluding Customer Charges for a Historical Period.

Class-specific revenue ratios were developed for each rate year by dividing (a) non-competitive delivery revenues excluding customer charges for each class based on billing data for the historical period (i.e., the twelve months ended March 31, 2011) and rates for the previous rate year by (b) non-competitive delivery revenues excluding customer charges for each class based on rate year billing data and rates for the previous rate year. These revenue ratios for each class were applied to each rate year's "non-competitive delivery revenue increase excluding customer charges" for each class to determine each class's "non-competitive delivery revenue increase excluding customer charges" for the historical period.

e. Intraclass Rate Structure Changes

The following rate structure changes were made in a revenue neutral manner before applying the non-competitive delivery revenue increase excluding customer charges within each of the affected SCs.

SC No. 1

The optional electric space and water heating discounts were reduced by 20 percent in RY1 and an additional 10 percent in each of RY2 and RY3.

SC No. 2

Declining block usage rates and, where applicable, demand rate differentials in SC No. 2 Non-Demand Metered Service and SC No. 2 Primary were fully eliminated in RY1. For SC No. 2 Secondary Demand Metered Service, 10 percent of the current usage rate differentials and a corresponding portion of demand rate differentials were eliminated in each of RY1, RY2, and RY3.

SC No. 3

Declining block usage rates and demand rate differentials were fully eliminated in RY1. If the Company does not file for new base delivery rates to take effect upon the expiration of RY3, the above-referenced rate structure changes for SC No. 1 and SC No. 2 Secondary Demand Metered Service will continue to be made on a revenue neutral basis effective July 1, 2015, and each July 1 thereafter until the Company's base rates are next reset by the Commission or until the subject discounts/differentials are eliminated, whichever is earlier.

f. Application of Non-Competitive Delivery Revenue Increase Excluding Customer Charges Within Each SC.

Each class-specific non-competitive delivery revenue increase excluding customer charges, determined as set forth above, was divided by the total of the usage charge, and where applicable, demand charge revenues, at current rate levels, to establish average class-specific percentages by which non-competitive delivery rates were increased.

3. Unbundled Charges

a. Merchant Function Charge

For the term of the Electric Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's electric tariff**.** The MFC fixed component monthly targets (commodity procurement and credit and collections) for rates effective July 1, 2012, July 1, 2013 and July 1, 2014 are set forth in Schedule 5 of this Appendix for the levelized option and in Schedule 9 of this Appendix for the non-levelized option.

b. Transition Adjustment for Competitive Services

For the term of the Electric Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's electric tariff.

c. POR Discount

For the term of the Electric Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's electric tariff**.**

d. Billing and Payment Processing Charge

The Company's billing and payment processing charge will remain at its current level, $1.02 per bill.

e. Metering Charges

To determine Metering Charges for classes not subject to mandatory day-ahead hourly pricing ("MDAHP") for each rate year, the Metering Charges were increased based on the class-specific metering cost percentages of delivery revenue as determined in the ECOS study. For SC Nos. 9 and 22, the Metering Charges were increased based on their combined metering cost percentage of delivery revenue to develop common charges. For the customers subject to MDAHP in SC Nos. 2, 3, 20 or 21, the Metering Charges were based on their combined delivery revenue percentage increases.

4. Standby Rate Design

The standby rate design is consistent with the guidelines set forth in the Commission's Opinion 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued and effective October 26, 2001 in Case 99-M-1470. The billing determinants used to design standby rates were based on those used in the formulation of the proposed rates for the otherwise applicable non-standby SCs. The cost allocation matrix contained in Appendix B of the March 11, 2003 Joint Proposal adopted by the Commission in its Order Establishing Electric Standby Rates, issued July 29, 2003, in Case Nos. 02-E-0780 and 02-E-0781 also was used. This matrix shows the percentage allocation of costs between the as-used demand charge and the contract demand charge, at various service levels.

The class revenue requirements to be recovered through the contract demand charges were developed by applying the percentages applicable to the contract demand from the cost allocation matrix to the portions of the revenue requirement applicable to transmission, substation, primary, and secondary costs. The contract demand revenue requirements were divided by the applicable estimated standby contract demand billing determinants, which were developed based on a ratio reflecting the relationship between contract demand and monthly billing demands. This resulted in the contract demand charges.

The class revenue requirements to be recovered through the as-used daily demand charges were developed by applying the percentages applicable to as-used demand charges from the cost allocation matrix to the portions of the revenue requirement applicable to transmission, substation, primary, and secondary costs. The as-used daily demand charge revenue requirements were divided by the applicable estimated as-used daily demand billing determinants to develop the as-used daily demand charges.

The customer charges for standby service were based on the customer's otherwise applicable SC.

ORANGE & ROCKLAND UTILITIES, INC.

Case 11-E-0408

Appendix B - Revenue Allocation and Rate Design

Index of Schedules

Appendix B
Schedule 1

ORANGE & ROCKLAND UTILITIES, INC.

Case 11-E-0408

Summary of Customer Charges
For Rates Effective July 1, 2012, July 1, 2013 and July 1, 2014

	Rates Effective 7/1/2012	Rates Effective 7/1/2013	Rates Effective 7/1/2014
SC No. 1	$18.00	$19.00	$20.00
SC No. 2 - Pri	35.00	35.00	35.00
SC No. 2 - Sec Demand Metered	18.00	18.00	18.00
SC No. 2 - Non-Demand Metered	18.00	18.00	18.00
SC No. 2 - Unmetered	13.00	15.00	17.00
SC No. 3	100.00	100.00	100.00
SC No. 6 - Option C	15.00	18.00	21.00
SC No. 9 (P/S/T)	500.00	500.00	500.00
SC No. 16 - Option C Metered	15.00	18.00	21.00
SC No. 16 - Option C Unmetered	13.00	15.00	17.00
SC No. 19	32.00	32.00	32.00
SC No. 20	35.00	35.00	35.00
SC No. 21	163.00	163.00	163.00
SC No. 22 (P/S/T)	500.00	500.00	500.00

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending June 30, 2013 (1) (2)
(Based on Billed Sales and Revenues)

LEVELIZED OPTION

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,564,754	190,265	261,544	268,322	6,778	2.6%
SC19	84,887	3,810	12,977	13,238	261	2.0%
Total Res	1,649,641	194,074	274,521	281,560	7,040	2.6%
SC2 Sec	851,302	27,371	125,074	126,182	1,108	0.9%
SC20	56,448	349	6,979	6,980	1	0.0%
Total Secondary	907,750	27,720	132,053	133,163	1,109	0.8%
SC2 Pri	36,183	138	4,678	4,657	(20)	-0.4%
SC3	379,818	269	43,171	43,424	254	0.6%
SC21	59,802	32	6,501	6,546	46	0.7%
Total Primary	475,803	440	54,349	54,628	279	0.5%
Total Sec & Pri	1,383,553	28,159	186,402	187,790	1,388	0.7%
SC9 (Commercial)	456,599	47	47,114	47,132	18	0.0%
SC22 (Industrial)	349,170	33	34,732	34,705	(27)	-0.1%
Total SC9 & SC22	805,769	80	81,846	81,836	(9)	0.0%
SC4	19,569	75	5,647	6,182	535	9.5%
SC5	3,349	526	617	593	(24)	-3.9%
SC 16 -dusk-to-dawn	10,071	2,486	3,127	3,730	603	19.3%
SC 16 - energy only	4,184	432	672	691	19	2.9%
SC16 - Total	14,255	2,918	3,799	4,422	622	16.4%
Total Lighting	37,173	3,518	10,063	11,197	1,133	11.3%
Public Authority	101,577	1	10,020	10,020	0	0.0%
Total	3,977,713	225,833	562,852	572,404	9,552	1.7%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.
2. Revenue at proposed rates reflects a reduction in RDM recoveries.

Appendix B
Schedule 2
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ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 1 Rates Effective July 1, 2012

Calculation of Incremental Revenue Requirement for Rate Year (1)

LEVELIZED OPTION

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$15,223,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	177,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$15,046,000
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$240,063,038
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	6.26752%

Note:

1. Twelve months ending June 30, 2013
2. GRT/MTA Gross Up Included in Rev Req = 1.16%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 1 Rates Effective July 1, 2012

Allocation of Rate Year Incremental Revenue Requirement Among Customer Classes

LEVELIZED OPTION

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 6.26752% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Rate Yr. Bundled %
SC1	133,522,000	593,699	134,115,699	8,405,728	142,521,427	8,999,427	6.74003%
SC19	6,105,000	0	6,105,000	382,632	6,487,632	382,632	6.26752%
Total Res	139,627,000	593,699	140,220,699	8,788,360	149,009,059	9,382,059	6.71937%
SC2 Sec	56,405,000	(1,115,162)	55,289,838	3,465,302	58,755,140	2,350,140	4.16655%
SC20	2,492,000	(68,421)	2,423,579	151,898	2,575,477	83,477	3.34979%
Total Sec	58,897,000	(1,183,583)	57,713,417	3,617,200	61,330,617	2,433,617	4.13199%
SC2 Pri	1,785,000	(74,286)	1,710,714	107,219	1,817,933	32,933	1.84499%
SC3	12,933,000	0	12,933,000	810,578	13,743,578	810,578	6.26752%
SC21	1,709,000	24,000	1,733,000	108,616	1,841,616	132,616	7.75986%
Total Pri	16,427,000	(50,286)	16,376,714	1,026,413	17,403,127	976,127	5.94221%
Total Sec & Pri	75,324,000	(1,233,869)	74,090,131	4,643,613	78,733,744	3,409,744	4.52677%
Total SC9 (Com)	11,002,000	0	11,002,000	689,553	11,691,553	689,553	6.26752%
Total SC22 (Mfg)	7,117,000	0	7,117,000	446,059	7,563,059	446,059	6.26750%
Total SC 9 & SC 22	18,119,000	0	18,119,000	1,135,612	19,254,612	1,135,612	6.26752%
SC4	4,028,000	260,000	4,288,000	268,751	4,556,751	528,751	13.12689%
SC5	349,000	(43,496)	305,504	19,147	324,651	(24,349)	-6.97690%
SC 16 -dusk-to-dawn	2,311,000	423,667	2,734,667	171,396	2,906,063	595,063	25.74914%
SC 16 - energy only	305,038	0	305,038	19,118	324,156	19,118	6.26741%
SC16 - Total	2,616,038	423,667	3,039,705	190,514	3,230,219	614,181	23.47751%
Total Lights	6,993,038	640,170	7,633,208	478,412	8,111,620	1,118,582	15.99565%
Total	240,063,038	0	240,063,038	15,045,997	255,109,035	15,045,997	

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 1 Rates Effective July 1, 2012

Determination of Non-competitive RY Delivery Revenue Increase

LEVELIZED OPTION

		Rate Year Incremental Competitive Services Revenues							
Class	Adj. Rate Yr. Incr. Incl. (Surplus)/Deficiency ($)	MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	8,999,427	239,640	43,580	67,889	32,483	0	5,479,168	5,862,759	3,136,668
SC19	382,632	9,587	1,743	2,717	2,592	0	107,848	124,487	258,145
Total Res	9,382,059	249,227	45,323	70,606	35,075		5,587,016	5,987,246	3,394,813
SC2 Sec	2,350,140	68,457	16,478	18,286	4,679	194,308	1,439,452	1,741,660	608,480
SC20	83,477	1,729	416	462	345	1,474	12,580	17,005	66,471
Total Sec	2,433,617	70,185	16,894	18,748	5,024	195,782	1,452,032	1,758,665	674,951
SC2 Pri	32,933	1,479	487	322	247	(3,960)	18,135	16,710	16,223
SC3	810,578	13,256	4,369	2,890	1,701	(13,784)	(100)	8,332	802,246
SC21	132,616	730	240	159	93	1,189	(408)	2,003	130,613
Total Pri	976,127	15,465	5,096	3,371	2,041	(16,555)	17,627	27,045	949,082
Total Sec & Pri	3,409,744	85,650	21,990	22,119	7,065	179,227	1,469,659	1,785,710	1,624,034
Total SC9 (Com)	689,553	19,824	6,533	4,323	625	767	0	32,072	657,481
Total SC22 (Mfg)	446,059	21,738	7,164	4,740	(119)	539	0	34,062	411,997
Total SC 9 & SC 22	1,135,612	41,562	13,697	9,063	506	1,306	0	66,134	1,069,478
SC4	528,751	1,233	297	330	225	0	0	2,085	526,666
SC5	(24,349)	175	42	46	42	0	0	306	(24,655)
SC 16 -dusk-to-dawn	595,063	1,431	344	383	23	0	0	2,182	592,881
SC 16 - energy only	19,118	594	143	158	8	0	15,934	16,837	2,281
SC16 - Total	614,181	2,026	487	541	31	0	15,934	19,019	595,162
Total Lights	1,118,582	3,434	826	917	298	0	15,934	21,409	1,097,173
Total	15,045,997	379,873	81,836	102,705	42,944	180,533	7,072,609	7,860,500	7,185,497

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending June 30, 2014 (1)
(Based on Billed Sales and Revenues)

LEVELIZED OPTION

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,575,600	191,082	270,010	279,162	9,151	3.4%
SC19	85,419	3,784	13,279	13,666	386	2.9%
Total Res	1,661,019	194,866	283,290	292,827	9,538	3.4%
SC2 Sec	852,479	27,632	126,479	128,783	2,304	1.8%
SC20	56,786	373	6,940	7,017	77	1.1%
Total Secondary	909,265	28,005	133,419	135,799	2,381	1.8%
SC2 Pri	36,412	140	4,688	4,717	29	0.6%
SC3	381,768	271	43,643	44,464	821	1.9%
SC21	60,008	32	6,565	6,700	135	2.1%
Total Primary	478,188	443	54,896	55,881	984	1.8%
Total Sec & Pri	1,387,453	28,448	188,315	191,680	3,365	1.8%
SC9 (Commercial)	458,987	47	47,300	47,995	695	1.5%
SC22 (Industrial)	350,372	33	34,796	35,246	450	1.3%
Total SC9 & SC22	809,359	80	82,096	83,242	1,145	1.4%
SC4	19,521	76	6,141	6,689	547	8.9%
SC5	3,341	529	593	566	(27)	-4.6%
SC 16 -dusk-to-dawn	10,052	2,489	3,726	4,355	628	16.9%
SC 16 - energy only	4,173	434	690	710	20	2.9%
SC16 - Total	14,225	2,923	4,416	5,065	649	14.7%
Total Lighting	37,087	3,527	11,151	12,319	1,169	10.5%
Public Authority	103,390	1	10,203	10,203	0	0.0%
Total	3,998,308	226,922	575,055	590,272	15,217	2.7%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 2 Rates Effective July 1, 2013

Calculation of Incremental Revenue Requirement for Rate Year (1)

LEVELIZED OPTION

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$15,223,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	177,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$15,046,000
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$256,106,000
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	5.87491%

Note:

1. Twelve months ending June 30, 2014
2. GRT/MTA Gross Up Included in Rev Req = 1.16%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 2 Rates Effective July 1, 2013

Allocation of Rate Year Incremental Revenue Requirement Among Customer Classes

LEVELIZED OPTION

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 5.87491% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Rate Yr. Bundled %
SC1	143,293,000	593,699	143,886,699	8,453,214	152,339,913	9,046,913	6.31358%
SC19	6,495,000	0	6,495,000	381,575	6,876,575	381,575	5.87490%
Total Res	149,788,000	593,699	150,381,699	8,834,789	159,216,488	9,428,488	6.29456%
SC2 Sec	58,983,000	(1,115,162)	57,867,838	3,399,683	61,267,521	2,284,521	3.87319%
SC20	2,517,000	(68,421)	2,448,579	143,852	2,592,431	75,431	2.99685%
Total Sec	61,500,000	(1,183,583)	60,316,417	3,543,535	63,859,952	2,359,952	3.83732%
SC2 Pri	1,830,000	(74,286)	1,755,714	103,147	1,858,861	28,861	1.57711%
SC3	13,821,000	0	13,821,000	811,971	14,632,971	811,971	5.87491%
SC21	1,841,000	24,000	1,865,000	109,567	1,974,567	133,567	7.25513%
Total Pri	17,492,000	(50,286)	17,441,714	1,024,685	18,466,399	974,399	5.57054%
Total Sec & Pri	78,992,000	(1,233,869)	77,758,131	4,568,220	82,326,351	3,334,351	4.22112%
Total SC9 (Com)	11,698,000	0	11,698,000	687,247	12,385,247	687,247	5.87491%
Total SC22 (Mfg)	7,553,000	0	7,553,000	443,732	7,996,732	443,732	5.87490%
Total SC 9 & SC 22	19,251,000	0	19,251,000	1,130,979	20,381,979	1,130,979	5.87491%
SC4	4,521,000	260,000	4,781,000	280,879	5,061,879	540,879	11.96370%
SC5	324,000	(43,496)	280,504	16,479	296,983	(27,017)	-8.33870%
SC 16 -dusk-to-dawn	2,908,000	423,667	3,331,667	195,732	3,527,399	619,399	21.29982%
SC 16 - energy only	322,000	0	322,000	18,917	340,917	18,917	5.87484%
SC16 - Total	3,230,000	423,667	3,653,667	214,649	3,868,316	638,316	19.76209%
Total Lights	8,075,000	640,170	8,715,170	512,007	9,227,177	1,152,177	14.26845%
Total	256,106,000	0	256,106,000	15,045,995	271,151,995	15,045,995	

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 2 Rates Effective July 1, 2013

Determination of Non-competitive RY Delivery Revenue Increase

LEVELIZED OPTION

Class	Adj. Rate Yr. Incr. Incl. (Surplus)/Deficiency ($)	Rate Year Incremental Competitive Services Revenues: MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	9,046,913	291,507	2,155	73,737	41,475	0	2,293,000	2,701,874	6,345,039
SC19	381,575	11,304	84	2,859	2,786	0	0	17,032	364,543
Total Res	9,428,488	302,811	2,239	76,596	44,261		2,293,000	2,718,906	6,709,582
SC2 Sec	2,284,521	94,698	778	26,623	7,107	233,185	50,000	412,391	1,872,130
SC20	75,431	2,184	19	614	287	(390)	0	2,714	72,717
Total Sec	2,359,952	96,883	797	27,237	7,394	232,795	50,000	415,105	1,944,846
SC2 Pri	28,861	1,925	23	383	267	1,637	0	4,236	24,625
SC3	811,971	16,256	200	3,238	2,086	7,090	0	28,870	783,101
SC21	133,567	921	12	183	114	1,328	0	2,558	131,009
Total Pri	974,399	19,103	235	3,804	2,467	10,055	0	35,664	938,735
Total Sec & Pri	3,334,351	115,985	1,032	31,041	9,861	242,850	50,000	450,769	2,883,582
Total SC9 (Com)	687,247	24,214	299	4,822	2,136	3,356	0	34,827	652,420
Total SC22 (Mfg)	443,732	28,212	348	5,619	2,012	2,354	0	38,545	405,187
Total SC 9 & SC 22	1,130,979	52,426	647	10,441	4,148	5,710	0	73,372	1,057,607
SC4	540,879	1,735	14	488	199	0	0	2,436	538,443
SC5	(27,017)	237	2	66	33	0	0	338	(27,355)
SC 16 -dusk-to-dawn	619,399	2,067	17	581	112	0	0	2,777	616,622
SC 16 - energy only	18,917	859	7	240	46	0	15,000	16,152	2,765
SC16 - Total	638,316	2,925	24	821	158	0	15,000	18,929	619,387
Total Lights	1,152,177	4,897	40	1,375	390	0	15,000	21,703	1,130,475
Total	15,045,995	476,119	3,958	119,453	58,660	248,560	2,358,000	3,264,750	11,781,245

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending June 30, 2015 (1)
(Based on Billed Sales and Revenues)

LEVELIZED OPTION

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,600,982	192,022	282,972	291,528	8,555	3.0%
SC19	86,701	3,758	13,832	14,218	386	2.8%
Total Res	1,687,683	195,779	296,804	305,745	8,941	3.0%
SC2 Sec	860,060	27,981	129,953	133,383	3,430	2.6%
SC20	57,589	397	7,187	7,338	151	2.1%
Total Secondary	917,649	28,378	137,139	140,720	3,581	2.6%
SC2 Pri	36,914	145	4,742	4,845	103	2.2%
SC3	385,233	273	44,851	45,673	821	1.8%
SC21	60,442	32	6,654	6,760	106	1.6%
Total Primary	482,589	449	56,248	57,278	1,030	1.8%
Total Sec & Pri	1,400,238	28,827	193,387	197,998	4,611	2.4%
SC9 (Commercial)	464,316	47	48,491	49,187	696	1.4%
SC22 (Industrial)	352,810	33	35,502	35,951	449	1.3%
Total SC9 & SC22	817,126	80	83,993	85,138	1,145	1.4%
SC4	19,501	76	6,681	6,960	280	4.2%
SC5	3,337	532	564	581	17	2.9%
SC 16 -dusk-to-dawn	10,041	2,493	4,348	4,547	199	4.6%
SC 16 - energy only	4,168	436	710	729	19	2.7%
SC16 - Total	14,209	2,929	5,059	5,277	218	4.3%
Total Lighting	37,047	3,537	12,304	12,818	514	4.2%
Public Authority	106,478	1	10,511	10,511	0	0.0%
Total	4,048,572	228,225	596,999	612,210	15,211	2.6%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Calculation of Incremental Revenue Requirement for Rate Year (1)

LEVELIZED OPTION

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$13,054,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	151,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$12,903,000
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$273,848,000
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	4.71174%

Note:

1. Twelve months ending June 30, 2015
2. GRT/MTA Gross Up Included in Rev Req = 1.16%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Allocation of Rate Year Incremental Revenue Requirement Among Customer Classes

LEVELIZED OPTION

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 4.71174% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Rate Yr. Bundled %
SC1	154,038,000	0	154,038,000	7,257,870	161,295,870	7,257,870	4.71174%
SC19	6,948,000	0	6,948,000	327,372	7,275,372	327,372	4.71174%
Total Res	160,986,000	0	160,986,000	7,585,242	168,571,242	7,585,242	4.71174%
SC2 Sec	61,859,000	0	61,859,000	2,914,635	64,773,635	2,914,635	4.71174%
SC20	2,704,000	0	2,704,000	127,405	2,831,405	127,405	4.71172%
Total Sec	64,563,000	0	64,563,000	3,042,040	67,605,040	3,042,040	4.71174%
SC2 Pri	1,846,000	0	1,846,000	86,979	1,932,979	86,979	4.71176%
SC3	14,761,000	0	14,761,000	695,500	15,456,500	695,500	4.71174%
SC21	1,900,000	0	1,900,000	89,523	1,989,523	89,523	4.71174%
Total Pri	18,507,000	0	18,507,000	872,002	19,379,002	872,002	4.71174%
Total Sec & Pri	83,070,000	0	83,070,000	3,914,042	86,984,042	3,914,042	4.71174%
Total SC9 (Com)	12,505,000	0	12,505,000	589,203	13,094,203	589,203	4.71174%
Total SC22 (Mfg)	8,067,000	0	8,067,000	380,096	8,447,096	380,096	4.71170%
Total SC 9 & SC 22	20,572,000	0	20,572,000	969,299	21,541,299	969,299	4.71174%
SC4	5,056,000	0	5,056,000	238,226	5,294,226	238,226	4.71175%
SC5	299,000	0	299,000	14,088	313,088	14,088	4.71171%
SC 16 -dusk-to-dawn	3,525,000	0	3,525,000	166,089	3,691,089	166,089	4.71174%
SC 16 - energy only	340,000	0	340,000	16,020	356,020	16,020	4.71176%
SC16 - Total	3,865,000	0	3,865,000	182,109	4,047,109	182,109	4.71175%
Total Lights	9,220,000	0	9,220,000	434,423	9,654,423	434,423	4.71175%
Total	273,848,000	0	273,848,000	12,903,006	286,751,006	12,903,006	

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Determination of Non-competitive RY Delivery Revenue Increase

LEVELIZED OPTION

		Rate Year Incremental Competitive Services Revenues							
Class	Adj. Rate Yr. Incr. ($)	MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	7,257,870	249,877	32,444	69,321	31,980	0	2,302,000	2,685,622	4,572,248
SC19	327,372	9,360	1,216	2,597	1,717	0	0	14,890	312,482
Total Res	7,585,242	259,237	33,660	71,918	33,697		2,302,000	2,700,512	4,884,730
SC2 Sec	2,914,635	105,883	11,126	27,137	6,727	205,446	51,000	407,319	2,507,316
SC20	127,405	2,180	229	559	139	(219)	0	2,888	124,517
Total Sec	3,042,040	108,063	11,355	27,696	6,866	205,227	51,000	410,207	2,631,833
SC2 Pri	86,979	2,388	351	538	213	1,173	0	4,663	82,316
SC3	695,500	18,806	2,767	4,239	1,674	7,726	0	35,212	660,288
SC21	89,523	983	145	221	88	1,475	0	2,911	86,612
Total Pri	872,002	22,177	3,263	4,998	1,975	10,374	0	42,787	829,215
Total Sec & Pri	3,914,042	130,240	14,618	32,694	8,841	215,601	51,000	452,994	3,461,048
Total SC9 (Com)	589,203	27,955	4,114	6,301	2,488	3,267	0	44,125	545,078
Total SC22 (Mfg)	380,096	34,671	5,103	7,816	3,086	2,295	0	52,971	327,125
Total SC 9 & SC 22	969,299	62,626	9,217	14,117	5,574	5,562	0	97,096	872,203
SC4	238,226	1,967	207	503	125	0	0	2,801	235,425
SC5	14,088	259	27	66	16	0	0	368	13,720
SC 16 -dusk-to-dawn	166,089	2,402	253	615	153	0	0	3,423	162,666
SC 16 - energy only	16,020	998	105	256	63	0	15,000	16,422	(402)
SC16 - Total	182,109	3,400	358	871	216	0	15,000	19,845	162,264
Total Lights	434,423	5,625	592	1,440	357	0	15,000	23,014	411,409
Total	12,903,006	457,729	58,087	120,169	48,469	221,163	2,368,000	3,273,617	9,629,389

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Calculation of Rate Year 3 Increase Collected through a Temporary Surcharge to the Energy Cost Adjustment

LEVELIZED OPTION

Class	Bundled Rate Yr. 3 Delivery Rev. ($)	Rate Yr. 3 Incr. 0.78292% ($)	Rate Yr. 3 Sales (MWh)	Temporary ECA Surcharge ($)/kWh
SC1	154,038,000	1,205,994	1,600,982	0.00075
SC19	6,948,000	54,397	86,701	0.00063
Total Res	160,986,000	1,260,391	1,687,683	
SC2 Sec	61,859,000	484,306	860,060	0.00056
SC20	2,704,000	21,170	57,589	0.00037
Total Sec	64,563,000	505,476	917,649	
SC2 Pri	1,846,000	14,453	36,914	0.00039
SC3	14,761,000	115,567	385,233	0.00030
SC21	1,900,000	14,875	60,442	0.00025
Total Pri	18,507,000	144,895	482,589	
Total Sec & Pri	83,070,000	650,371	1,400,238	
Total SC9 (Com)	12,505,000	97,904	464,316	0.00021
Total SC22 (Mfg)	8,067,000	63,158	352,810	0.00018
* Includes SC25 Rate IV				
Total SC 9 & SC 22	20,572,000	161,062	817,126	
SC4	5,056,000	39,584	19,501	0.00203
SC5	299,000	2,341	3,337	0.00070
SC 16 -dusk-to-dawn	3,525,000	27,598	10,041	0.00275
SC 16 - energy only	340,000	2,662	4,168	0.00064
SC16 - Total	3,865,000	30,260	14,209	
Total Lights	9,220,000	72,185	37,047	
Total	273,848,000	2,144,009	3,942,094	

RY 3 ECA Increase	$2,169,000
Revenue Taxes	25,000
Increase Less Revenue Taxes	2,144,000
RY 3 Delivery Revenues	273,848,000
% Increase	0.78292%

ORANGE & ROCKLAND UTILITIES, INC.

Case 11-E-0408

Summary of MFC Monthly Targets
For Rates Effective July 1, 2012, July 1, 2013 and July 1, 2014

LEVELIZED OPTION

For Rates Effective July 1, 2012	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Supply Related Component*	$800,481	$869,252	$815,256	$633,971	$575,678	$648,983	$730,862	$665,667	$601,708	$556,031	$545,690	$654,261	$8,097,842
Credit and Collections Related Component	191,879	208,503	195,054	151,015	136,838	155,338	174,893	159,356	143,658	132,511	129,519	155,673	1,934,238
POR Discount Related Component	84,758	92,200	86,498	66,916	61,015	70,369	79,066	72,793	65,238	60,200	58,635	70,756	868,443
Total	$1,077,118	$1,169,956	$1,096,808	$851,902	$773,531	$874,690	$984,821	$897,816	$810,604	$748,742	$733,845	$880,690	$10,900,523

For Rates Effective July 1, 2013	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Supply Related Component*	$857,067	$937,035	$860,701	$670,795	$606,173	$703,000	$771,901	$678,008	$650,225	$589,009	$557,299	$696,172	$8,577,385
Credit and Collections Related Component	205,989	225,718	206,565	160,268	144,701	168,511	185,639	162,941	155,626	140,974	132,845	166,097	2,055,875
POR Discount Related Component	91,355	100,421	91,741	70,954	64,579	75,869	84,027	74,401	70,325	64,001	60,121	75,259	923,055
Total	$1,154,411	$1,263,174	$1,159,007	$902,017	$815,453	$947,381	$1,041,568	$915,351	$876,176	$793,984	$750,265	$937,529	$11,556,315

For Rates Effective July 1, 2014	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Supply Related Component*	$900,348	$1,005,638	$899,767	$699,387	$654,554	$735,910	$829,024	$719,062	$678,813	$627,206	$583,849	$755,798	$9,089,358
Credit and Collections Related Component	216,022	241,056	215,857	166,612	156,021	176,253	198,792	172,538	162,250	149,757	138,936	180,052	2,174,147
POR Discount Related Component	95,882	106,606	96,231	73,540	69,719	79,554	89,782	78,871	73,387	67,920	62,918	81,748	976,157
Total	$1,212,252	$1,353,300	$1,211,855	$939,540	$880,295	$991,717	$1,117,598	$970,471	$914,451	$844,883	$785,702	$1,017,598	$12,239,662

* MFC Supply Related Component Includes purchased power working capital.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending June 30, 2013 (1) (2)
(Based on Billed Sales and Revenues)

NON-LEVELIZED OPTION

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,564,754	190,265	261,544	270,675	9,132	3.5%
SC19	84,887	3,810	12,977	13,346	368	2.8%
Total Res	1,649,641	194,074	274,521	284,021	9,500	3.5%
SC2 Sec	851,302	27,371	125,074	127,156	2,083	1.7%
SC20	56,448	349	6,979	7,023	44	0.6%
Total Secondary	907,750	27,720	132,053	134,179	2,126	1.6%
SC2 Pri	36,183	138	4,678	4,687	10	0.2%
SC3	379,818	269	43,171	43,652	481	1.1%
SC21	59,802	32	6,501	6,577	76	1.2%
Total Primary	475,803	440	54,349	54,916	567	1.0%
Total Sec & Pri	1,383,553	28,159	186,402	189,095	2,693	1.4%
SC9 (Commercial)	456,599	47	47,114	47,325	211	0.5%
SC22 (Industrial)	349,170	33	34,732	34,830	98	0.3%
Total SC9 & SC22	805,769	80	81,846	82,155	309	0.4%
SC4	19,569	75	5,647	6,257	610	10.8%
SC5	3,349	526	617	599	(18)	-3.0%
SC 16 -dusk-to-dawn	10,071	2,486	3,127	3,778	651	20.8%
SC 16 - energy only	4,184	432	672	696	24	3.6%
SC16 - Total	14,255	2,918	3,799	4,474	675	17.8%
Total Lighting	37,173	3,518	10,063	11,330	1,267	12.6%
Public Authority	101,577	1	10,020	10,020	0	0.0%
Total	3,977,713	225,833	562,852	576,622	13,770	2.5%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.
2. Revenue at proposed rates reflects a reduction in RDM recoveries.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 1 Rates Effective July 1, 2012

Calculation of Incremental Revenue Requirement for Rate Year (1)

NON-LEVELIZED OPTION

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$19,436,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	225,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$19,211,000
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$240,063,038
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	8.00248%

Note:

1. Twelve months ending June 30, 2013
2. GRT/MTA Gross Up Included in Rev Req = 1.16%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 1 Rates Effective July 1, 2012

Allocation of Rate Year Incremental Revenue Requirement Among Customer Classes

NON-LEVELIZED OPTION

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 8.00248% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Rate Yr. Bundled %
SC1	133,522,000	593,699	134,115,699	10,732,582	144,848,281	11,326,281	8.48271%
SC19	6,105,000	0	6,105,000	488,551	6,593,551	488,551	8.00247%
Total Res	139,627,000	593,699	140,220,699	11,221,133	151,441,832	11,814,832	8.46171%
SC2 Sec	56,405,000	(1,115,162)	55,289,838	4,424,558	59,714,396	3,309,396	5.86720%
SC20	2,492,000	(68,421)	2,423,579	193,946	2,617,525	125,525	5.03711%
Total Sec	58,897,000	(1,183,583)	57,713,417	4,618,504	62,331,921	3,434,921	5.83208%
SC2 Pri	1,785,000	(74,286)	1,710,714	136,900	1,847,614	62,614	3.50779%
SC3	12,933,000	0	12,933,000	1,034,961	13,967,961	1,034,961	8.00248%
SC21	1,709,000	24,000	1,733,000	138,683	1,871,683	162,683	9.51919%
Total Pri	16,427,000	(50,286)	16,376,714	1,310,544	17,687,258	1,260,258	7.67187%
Total Sec & Pri	75,324,000	(1,233,869)	74,090,131	5,929,048	80,019,179	4,695,179	6.23331%
Total SC9 (Com)	11,002,000	0	11,002,000	880,433	11,882,433	880,433	8.00248%
Total SC22 (Mfg)	7,117,000	0	7,117,000	569,537	7,686,537	569,537	8.00250%
Total SC 9 & SC 22	18,119,000	0	18,119,000	1,449,970	19,568,970	1,449,970	8.00248%
SC4	4,028,000	260,000	4,288,000	343,146	4,631,146	603,146	14.97383%
SC5	349,000	(43,496)	305,504	24,448	329,952	(19,048)	-5.45799%
SC 16 -dusk-to-dawn	2,311,000	423,667	2,734,667	218,841	2,953,508	642,508	27.80215%
SC 16 - energy only	305,038	0	305,038	24,411	329,449	24,411	8.00260%
SC16 - Total	2,616,038	423,667	3,039,705	243,252	3,282,957	666,919	25.49346%
Total Lights	6,993,038	640,170	7,633,208	610,846	8,244,054	1,251,016	17.88945%
Total	240,063,038	0	240,063,038	19,210,997	259,274,035	19,210,997	

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 1 Rates Effective July 1, 2012

Determination of Non-competitive RY Delivery Revenue Increase

NON-LEVELIZED OPTION

Class	Adj. Rate Yr. Incr. Incl. (Surplus)/Deficiency ($)	Rate Year Incremental Competitive Services Revenues: MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	11,326,281	327,519	43,580	87,417	44,225	0	5,479,168	5,981,908	5,344,373
SC19	488,551	13,103	1,743	3,498	3,493	0	107,848	129,685	358,866
Total Res	11,814,832	340,622	45,323	90,915	47,718		5,587,016	6,111,593	5,703,239
SC2 Sec	3,309,396	86,916	16,478	25,670	4,679	267,175	1,439,452	1,840,370	1,469,026
SC20	125,525	2,195	416	648	345	2,607	12,580	18,790	106,734
Total Sec	3,434,921	89,110	16,894	26,318	5,024	269,782	1,452,032	1,859,160	1,575,760
SC2 Pri	62,614	1,916	487	431	247	(3,415)	18,135	17,801	44,813
SC3	1,034,961	17,171	4,369	3,869	1,701	(11,553)	(100)	15,457	1,019,504
SC21	162,683	945	240	213	93	1,608	(408)	2,691	159,992
Total Pri	1,260,258	20,032	5,096	4,513	2,041	(13,360)	17,627	35,949	1,224,309
Total Sec & Pri	4,695,179	109,142	21,990	30,831	7,065	256,422	1,469,659	1,895,109	2,800,070
Total SC9 (Com)	880,433	25,680	6,533	5,787	625	1,642	0	40,267	840,166
Total SC22 (Mfg)	569,537	28,159	7,164	6,346	(119)	1,152	0	42,702	526,835
Total SC 9 & SC 22	1,449,970	53,839	13,697	12,133	506	2,794	0	82,969	1,367,001
SC4	603,146	1,566	297	463	225	0	0	2,551	600,595
SC5	(19,048)	222	42	65	42	0	0	372	(19,420)
SC 16 -dusk-to-dawn	642,508	1,817	344	537	23	0	0	2,722	639,786
SC 16 - energy only	24,411	755	143	222	8	0	15,934	17,062	7,349
SC16 - Total	666,919	2,573	487	759	31	0	15,934	19,784	647,135
Total Lights	1,251,016	4,361	826	1,287	298	0	15,934	22,706	1,228,310
Total	19,210,997	507,964	81,836	135,166	55,587	259,216	7,072,609	8,112,378	11,098,619

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending June 30, 2014 (1)
(Based on Billed Sales and Revenues)

NON-LEVELIZED OPTION

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,575,600	191,082	272,362	277,918	5,556	2.0%
SC19	85,419	3,784	13,385	13,609	224	1.7%
Total Res	1,661,019	194,866	285,747	291,527	5,780	2.0%
SC2 Sec	852,479	27,632	127,446	128,319	873	0.7%
SC20	56,786	373	6,980	6,995	15	0.2%
Total Secondary	909,265	28,005	134,427	135,315	888	0.7%
SC2 Pri	36,412	140	4,716	4,702	(14)	-0.3%
SC3	381,768	271	43,870	44,345	476	1.1%
SC21	60,008	32	6,600	6,688	88	1.3%
Total Primary	478,188	443	55,186	55,735	549	1.0%
Total Sec & Pri	1,387,453	28,448	189,612	191,050	1,438	0.8%
SC9 (Commercial)	458,987	47	47,486	47,890	404	0.9%
SC22 (Industrial)	350,372	33	34,918	35,177	259	0.7%
Total SC9 & SC22	809,359	80	82,404	83,067	663	0.8%
SC4	19,521	76	6,240	6,669	429	6.9%
SC5	3,341	529	598	564	(34)	-5.8%
SC 16 -dusk-to-dawn	10,052	2,489	3,772	4,317	545	14.5%
SC 16 - energy only	4,173	434	696	706	10	1.5%
SC16 - Total	14,225	2,923	4,468	5,024	555	12.4%
Total Lighting	37,087	3,527	11,306	12,256	950	8.4%
Public Authority	103,390	1	10,203	10,203	0	0.0%
Total	3,998,308	226,922	579,272	588,103	8,830	1.5%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 2 Rates Effective July 1, 2013

Calculation of Incremental Revenue Requirement for Rate Year (1)

NON-LEVELIZED OPTION

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$8,835,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	102,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$8,733,000
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$260,264,000
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	3.35544%

Note:

1. Twelve months ending June 30, 2014
2. GRT/MTA Gross Up Included in Rev Req = 1.16%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 2 Rates Effective July 1, 2013

Allocation of Rate Year Incremental Revenue Requirement Among Customer Classes

NON-LEVELIZED OPTION

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 3.35544% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Rate Yr. Bundled %
SC1	145,607,000	593,699	146,200,699	4,905,677	151,106,376	5,499,376	3.77686%
SC19	6,600,000	0	6,600,000	221,459	6,821,459	221,459	3.35544%
Total Res	152,207,000	593,699	152,800,699	5,127,136	157,927,835	5,720,835	3.75859%
SC2 Sec	59,936,000	(1,115,162)	58,820,838	1,973,698	60,794,536	858,536	1.43242%
SC20	2,557,000	(68,421)	2,488,579	83,503	2,572,082	15,082	0.58982%
Total Sec	62,493,000	(1,183,583)	61,309,417	2,057,201	63,366,618	873,618	1.39794%
SC2 Pri	1,859,000	(74,286)	1,784,714	59,885	1,844,599	(14,401)	-0.77466%
SC3	14,042,000	0	14,042,000	471,171	14,513,171	471,171	3.35544%
SC21	1,875,000	24,000	1,899,000	63,720	1,962,720	87,720	4.67840%
Total Pri	17,776,000	(50,286)	17,725,714	594,776	18,320,490	544,490	3.06306%
Total Sec & Pri	80,269,000	(1,233,869)	79,035,131	2,651,977	81,687,108	1,418,108	1.76669%
Total SC9 (Com)	11,884,000	0	11,884,000	398,760	12,282,760	398,760	3.35544%
Total SC22 (Mfg)	7,674,000	0	7,674,000	257,496	7,931,496	257,496	3.35540%
Total SC 9 & SC 22	19,558,000	0	19,558,000	656,256	20,214,256	656,256	3.35544%
SC4	4,619,000	260,000	4,879,000	163,712	5,042,712	423,712	9.17324%
SC5	330,000	(43,496)	286,504	9,613	296,117	(33,883)	-10.26770%
SC 16 -dusk-to-dawn	2,954,000	423,667	3,377,667	113,336	3,491,003	537,003	18.17883%
SC 16 - energy only	327,000	0	327,000	10,972	337,972	10,972	3.35535%
SC16 - Total	3,281,000	423,667	3,704,667	124,308	3,828,975	547,975	16.70145%
Total Lights	8,230,000	640,170	8,870,170	297,633	9,167,803	937,803	11.39494%
Total	260,264,000	0	260,264,000	8,733,002	268,997,002	8,733,002	

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 2 Rates Effective July 1, 2013

Determination of Non-competitive RY Delivery Revenue Increase

NON-LEVELIZED OPTION

		Rate Year Incremental Competitive Services Revenues							
Class	Adj. Rate Yr. Incr. Incl. (Surplus)/Deficiency ($)	MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	5,499,376	156,768	2,155	44,627	22,795	0	2,293,000	2,519,345	2,980,031
SC19	221,459	6,079	84	1,730	1,354	0	0	9,247	212,212
Total Res	5,720,835	162,847	2,239	46,357	24,149		2,293,000	2,528,592	3,192,243
SC2 Sec	858,536	70,670	778	16,113	3,896	119,633	50,000	261,090	597,446
SC20	15,082	1,630	19	372	90	(2,158)	0	(47)	15,129
Total Sec	873,618	72,300	797	16,485	3,986	117,475	50,000	261,042	612,575
SC2 Pri	(14,401)	1,298	23	277	260	793	0	2,652	(17,053)
SC3	471,171	10,966	200	2,341	2,024	3,449	0	18,980	452,191
SC21	87,720	621	12	133	111	634	0	1,511	86,209
Total Pri	544,490	12,886	235	2,751	2,395	4,876	0	23,143	521,347
Total Sec & Pri	1,418,108	85,185	1,032	19,236	6,381	122,351	50,000	284,185	1,133,923
Total SC9 (Com)	398,760	16,337	299	3,488	2,042	2,035	0	24,201	374,559
Total SC22 (Mfg)	257,496	19,033	348	4,063	1,904	1,430	0	26,778	230,718
Total SC 9 & SC 22	656,256	35,370	647	7,551	3,946	3,465	0	50,979	605,277
SC4	423,712	1,295	14	296	71	0	0	1,676	422,036
SC5	(33,883)	177	2	41	10	0	0	230	(34,114)
SC 16 -dusk-to-dawn	537,003	1,543	17	351	85	0	0	1,996	535,007
SC 16 - energy only	10,972	640	7	146	35	0	15,000	15,828	(4,856)
SC16 - Total	547,975	2,183	24	497	120	0	15,000	17,824	530,151
Total Lights	937,803	3,655	40	834	201	0	15,000	19,730	918,073
Total	8,733,002	287,057	3,958	73,978	34,677	125,816	2,358,000	2,883,486	5,849,516

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending June 30, 2015 (1)
(Based on Billed Sales and Revenues)

NON-LEVELIZED OPTION

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,600,982	192,022	281,712	290,273	8,561	3.0%
SC19	86,701	3,758	13,777	14,164	386	2.8%
Total Res	1,687,683	195,779	295,489	304,437	8,948	3.0%
SC2 Sec	860,060	27,981	129,488	132,923	3,435	2.7%
SC20	57,589	397	7,165	7,314	150	2.1%
Total Secondary	917,649	28,378	136,653	140,237	3,585	2.6%
SC2 Pri	36,914	145	4,733	4,835	102	2.2%
SC3	385,233	273	44,731	45,551	820	1.8%
SC21	60,442	32	6,637	6,743	106	1.6%
Total Primary	482,589	449	56,101	57,129	1,028	1.8%
Total Sec & Pri	1,400,238	28,827	192,754	197,366	4,613	2.4%
SC9 (Commercial)	464,316	47	48,391	49,087	696	1.4%
SC22 (Industrial)	352,810	33	35,437	35,886	449	1.3%
Total SC9 & SC22	817,126	80	83,828	84,973	1,145	1.4%
SC4	19,501	76	6,660	6,943	282	4.2%
SC5	3,337	532	563	580	16	2.9%
SC 16 -dusk-to-dawn	10,041	2,493	4,314	4,512	198	4.6%
SC 16 - energy only	4,168	436	707	726	18	2.6%
SC16 - Total	14,209	2,929	5,021	5,238	217	4.3%
Total Lighting	37,047	3,537	12,245	12,760	515	4.2%
Public Authority	106,478	1	10,511	10,511	0	0.0%
Total	4,048,572	228,225	594,827	610,047	15,221	2.6%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Calculation of Incremental Revenue Requirement for Rate Year (1)

NON-LEVELIZED OPTION

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes	$15,228,000
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	177,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$15,051,000
d.	Rate Year Bundled Delivery Revenues Excl. West Point	$271,707,000
e.	Rate Year Overall Percentage Increase in Delivery Revenues (c / d)	5.53942%

Note:
1. Twelve months ending June 30, 2015
2. GRT/MTA Gross Up Included in Rev Req = 1.16%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Allocation of Rate Year Incremental Revenue Requirement Among Customer Classes

NON-LEVELIZED OPTION

Class	Bundled Rate Yr. Delivery Rev. ($)	(Surplus)/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 5.53942% ($)	Rate Yr. Bundled Delivery Rev. at Proposed Rate Level ($)	Proposed Rate Yr. Increase Incl. (Surplus)/Deficiency ($)	Rate Yr. Bundled %
SC1	152,800,000	0	152,800,000	8,464,234	161,264,234	8,464,234	3.77686%
SC19	6,893,000	0	6,893,000	381,832	7,274,832	381,832	3.35544%
Total Res	159,693,000	0	159,693,000	8,846,066	168,539,066	8,846,066	3.75859%
SC2 Sec	61,401,000	0	61,401,000	3,401,259	64,802,259	3,401,259	1.43242%
SC20	2,682,000	0	2,682,000	148,567	2,830,567	148,567	0.58982%
Total Sec	64,083,000	0	64,083,000	3,549,826	67,632,826	3,549,826	1.39794%
SC2 Pri	1,836,000	0	1,836,000	101,704	1,937,704	101,704	-0.77466%
SC3	14,643,000	0	14,643,000	811,137	15,454,137	811,137	3.35544%
SC21	1,884,000	0	1,884,000	104,363	1,988,363	104,363	4.67840%
Total Pri	18,363,000	0	18,363,000	1,017,204	19,380,204	1,017,204	3.06306%
Total Sec & Pri	82,446,000	0	82,446,000	4,567,030	87,013,030	4,567,030	1.76669%
Total SC9 (Com)	12,404,000	0	12,404,000	687,110	13,091,110	687,110	3.35544%
Total SC22 (Mfg)	8,001,000	0	8,001,000	443,209	8,444,209	443,209	3.35540%
Total SC 9 & SC 22	20,405,000	0	20,405,000	1,130,319	21,535,319	1,130,319	3.35544%
SC4	5,037,000	0	5,037,000	279,021	5,316,021	279,021	9.17324%
SC5	298,000	0	298,000	16,507	314,507	16,507	-10.26770%
SC 16 -dusk-to-dawn	3,491,000	0	3,491,000	193,381	3,684,381	193,381	18.17883%
SC 16 - energy only	337,000	0	337,000	18,668	355,668	18,668	3.35535%
SC16 - Total	3,828,000	0	3,828,000	212,049	4,040,049	212,049	16.70145%
Total Lights	9,163,000	0	9,163,000	507,577	9,670,577	507,577	11.39494%
Total	271,707,000	0	271,707,000	15,050,992	286,757,992	15,050,992	

ORANGE AND ROCKLAND UTILITIES, INC.

Case 11-E-0408

Rate Design Workpapers

Rate Year 3 Rates Effective July 1, 2014

Determination of Non-competitive RY Delivery Revenue Increase

NON-LEVELIZED OPTION

		Rate Year Incremental Competitive Services Revenues							
Class	Adj. Rate Yr. Incr. ($)	MFC Supply Related Rev. ($)	MFC PP WC Related Rev. ($)	MFC Credit & Collections Related Rev. ($)	POR Credit & Collections Related Rev. ($)	Competitive Metering Related Rev. ($)	Customer Charge Rev. ($)	Total Rate Yr. Incrmtl Comp. Services Rev. ($)	Non-Competitive Rate Yr. Delivery Revenue Incr. ($)
SC1	8,464,234	297,784	32,444	80,557	36,588	0	2,302,000	2,749,373	5,714,861
SC19	381,832	11,156	1,216	3,018	2,148	0	0	17,537	364,295
Total Res	8,846,066	308,939	33,660	83,575	38,736		2,302,000	2,766,910	6,079,156
SC2 Sec	3,401,259	112,214	11,126	30,990	9,290	245,895	51,000	460,515	2,940,744
SC20	148,567	2,311	229	638	326	384	0	3,888	144,679
Total Sec	3,549,826	114,525	11,355	31,628	9,616	246,279	51,000	464,403	3,085,423
SC2 Pri	101,704	2,588	351	554	195	1,475	0	5,163	96,541
SC3	811,137	20,381	2,767	4,360	1,539	8,974	0	38,021	773,116
SC21	104,363	1,066	145	227	81	1,712	0	3,230	101,133
Total Pri	1,017,204	24,034	3,263	5,141	1,815	12,161	0	46,414	970,790
Total Sec & Pri	4,567,030	138,559	14,618	36,769	11,431	258,440	51,000	510,817	4,056,213
Total SC9 (Com)	687,110	30,295	4,114	6,481	2,288	3,713	0	46,892	640,218
Total SC22 (Mfg)	443,209	37,575	5,103	8,039	2,838	2,606	0	56,161	387,048
Total SC 9 & SC 22	1,130,319	67,870	9,217	14,520	5,126	6,319	0	103,052	1,027,267
SC4	279,021	2,084	207	575	240	0	0	3,106	275,915
SC5	16,507	275	27	75	38	0	0	415	16,092
SC 16 -dusk-to-dawn	193,381	2,546	253	702	163	0	0	3,664	189,717
SC 16 - energy only	18,668	1,058	105	292	67	0	15,000	16,522	2,146
SC16 - Total	212,049	3,604	358	994	230	0	15,000	20,186	191,863
Total Lights	507,577	5,963	592	1,644	508	0	15,000	23,707	483,870
Total	15,050,992	521,332	58,087	136,508	55,801	264,759	2,368,000	3,404,487	11,646,505

Appendix B
Schedule 9

ORANGE & ROCKLAND UTILITIES, INC.

Case 11-E-0408

Summary of MFC Monthly Targets
For Rates Effective July 1, 2012, July 1, 2013 and July 1, 2014

NON-LEVELIZED OPTION

For Rates Effective July 1, 2012	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Supply Related Component*	$812,649	$882,470	$827,641	$643,585	$584,401	$658,842	$741,964	$675,779	$610,840	$564,464	$553,954	$664,180	$8,220,769
Credit and Collections Related Component	195,011	211,907	198,238	153,480	139,072	157,874	177,748	161,958	146,003	134,674	131,634	158,215	1,965,815
POR Discount Related Component	86,141	93,705	87,910	68,009	62,011	71,517	80,357	73,981	66,303	61,183	59,592	71,911	882,621
Total	$1,093,802	$1,188,083	$1,113,790	$865,073	$785,484	$888,234	$1,000,069	$911,717	$823,146	$760,321	$745,180	$894,306	$11,069,205

For Rates Effective July 1, 2013	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Supply Related Component*	$850,705	$930,074	$854,315	$665,826	$601,685	$697,787	$766,171	$672,977	$645,406	$584,644	$553,175	$691,018	$8,513,782
Credit and Collections Related Component	204,352	223,924	204,923	158,995	143,551	167,172	184,164	161,646	154,390	139,854	131,789	164,777	2,039,535
POR Discount Related Component	90,629	99,623	91,012	70,390	64,066	75,267	83,360	73,810	69,766	63,493	59,644	74,661	915,720
Total	$1,145,686	$1,253,622	$1,150,250	$895,211	$809,302	$940,226	$1,033,695	$908,433	$869,561	$787,990	$744,607	$930,456	$11,469,037

For Rates Effective July 1, 2014	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Supply Related Component*	$900,369	$1,005,661	$899,788	$699,403	$654,569	$735,927	$829,043	$719,078	$678,829	$627,221	$583,862	$755,815	$9,089,565
Credit and Collections Related Component	216,027	241,062	215,863	166,617	156,025	176,257	198,797	172,542	162,254	149,760	138,939	180,057	2,174,200
POR Discount Related Component	95,884	106,608	96,233	73,542	69,721	79,555	89,784	78,873	73,389	67,921	62,919	81,750	976,181
Total	$1,212,280	$1,353,332	$1,211,883	$939,562	$880,315	$991,740	$1,117,624	$970,493	$914,472	$844,902	$785,721	$1,017,622	$12,239,946

* MFC Supply Related Component Includes purchased power working capital.

Orange and Rockland Electric Utilies, Inc.
Case 11-E-0408
Sales Forecast for RY1: 12 months ending June 30, 2013
(MWhs)

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 16	PA	Total O&R
Jul-12	157,644	9,441	76,980	5,512	3,205	32,694	38,637	5,159	28,632	3,788	1,357	280	1,034	9,105	373,468
Aug-12	173,415	9,712	80,631	5,545	3,343	33,357	43,366	5,284	29,927	4,101	1,491	285	1,001	10,176	401,634
Sep-12	159,598	9,130	79,310	5,293	3,230	35,876	42,159	6,094	30,032	4,615	1,654	287	1,085	9,876	388,239
Oct-12	119,178	7,082	69,000	4,212	2,716	28,003	34,146	4,491	26,367	4,026	1,787	274	1,196	8,180	310,658
Nov-12	107,346	5,739	62,853	4,277	2,605	32,854	37,570	5,424	25,339	1,729	1,897	273	1,312	7,707	296,925
Dec-12	126,874	6,474	69,046	4,188	2,923	31,232	35,793	4,817	24,202	113	2,045	272	1,428	7,587	316,994
Jan-13	143,578	7,003	76,157	4,718	3,290	33,215	41,632	5,231	26,268	1,462	2,096	287	1,473	8,588	354,998
Feb-13	129,939	6,451	74,510	4,545	3,329	32,684	37,977	4,882	23,263	206	1,733	284	1,332	8,152	329,287
Mar-13	115,769	5,860	67,210	4,202	3,063	28,317	32,596	4,359	25,543	485	1,707	282	1,262	6,998	297,653
Apr-13	105,997	5,357	62,695	3,562	2,922	29,137	33,435	4,240	25,129	301	1,413	280	1,059	7,528	283,055
May-13	101,161	5,472	62,564	5,124	2,625	29,298	36,134	4,966	25,526	3,269	1,301	265	1,040	8,354	287,099
Jun-13	124,255	7,166	70,346	5,270	2,932	33,151	43,154	4,855	30,845	4,002	1,088	280	1,033	9,326	337,703
Total Billed	1,564,754	84,887	851,302	56,448	36,183	379,818	456,599	59,802	321,073	28,097	19,569	3,349	14,255	101,577	3,977,713
Net Unbilled	(2,115)	(120)	(637)	(51)	(26)	457	354	78	205	-	-	-	-	-	(1,855)
RY 1 Total	1,562,639	84,767	850,665	56,397	36,157	380,275	456,953	59,880	321,278	28,097	19,569	3,349	14,255	101,577	3,975,858

Orange and Rockland Electric Utilies, Inc.
Case 11-E-0408
Sales Forecast for RY2: 12 months ending June 30, 2014
(MWhs)

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 16	PA	Total O&R
Jul-13	160,192	9,585	78,116	5,629	3,271	34,048	40,262	5,362	29,775	3,745	1,340	277	1,021	9,487	382,110
Aug-13	178,703	9,997	83,191	5,750	3,464	32,355	42,144	5,118	28,989	4,051	1,472	281	990	9,908	406,413
Sep-13	159,993	9,144	79,460	5,327	3,254	36,082	42,440	6,123	30,167	4,568	1,632	283	1,072	9,949	389,494
Oct-13	119,602	7,102	68,780	4,212	2,725	28,461	34,726	4,560	26,778	4,004	1,790	274	1,199	8,516	312,729
Nov-13	107,796	5,758	62,643	4,289	2,612	32,274	36,942	5,330	24,835	1,707	1,900	274	1,314	7,756	295,430
Dec-13	129,269	6,592	69,879	4,253	2,973	34,892	40,003	5,378	27,018	91	2,049	273	1,430	8,654	332,754
Jan-14	145,186	7,076	76,559	4,758	3,317	31,091	38,994	4,890	24,560	1,440	2,090	286	1,468	8,198	349,913
Feb-14	126,006	6,251	71,721	4,396	3,223	31,318	36,432	4,676	22,214	184	1,727	283	1,328	7,961	317,720
Mar-14	118,257	5,982	68,162	4,275	3,119	30,121	34,684	4,628	27,174	464	1,702	281	1,258	7,569	307,676
Apr-14	107,043	5,404	63,043	3,589	2,953	28,518	32,703	4,138	24,602	248	1,419	281	1,064	7,472	282,477
May-14	98,489	5,321	60,458	4,997	2,551	27,799	34,308	4,712	24,154	3,221	1,307	267	1,044	8,033	276,661
Jun-14	125,064	7,207	70,467	5,311	2,950	34,809	45,349	5,093	32,430	3,953	1,093	281	1,037	9,887	344,931
Total Billed	1,575,600	85,419	852,479	56,786	36,412	381,768	458,987	60,008	322,696	27,676	19,521	3,341	14,225	103,390	3,998,308
Net Unbilled	(627)	(36)	1,369	110	57	2,952	2,285	503	1,320	-	-	-	-	-	7,933
RY 2 Total	1,574,973	85,383	853,848	56,896	36,469	384,720	461,272	60,511	324,016	27,676	19,521	3,341	14,225	103,390	4,006,241

Orange and Rockland Electric Utilies, Inc.

Case 11-E-0408

Sales Forecast for RY3: 12 months ending June 30, 2015

(MWhs)

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 16	PA	Total O&R
Jul-14	161,554	9,656	78,625	5,700	3,311	33,187	39,274	5,213	28,969	3,693	1,332	275	1,015	9,387	381,191
Aug-14	181,247	10,129	84,207	5,854	3,522	37,338	48,669	5,903	33,435	4,002	1,463	280	983	11,539	428,571
Sep-14	161,628	9,228	80,210	5,402	3,301	32,876	38,720	5,571	27,438	4,513	1,624	282	1,065	9,229	381,087
Oct-14	119,022	7,063	67,708	4,160	2,701	28,986	35,384	4,639	27,253	3,976	1,792	275	1,199	8,881	313,039
Nov-14	111,930	5,974	64,520	4,443	2,705	32,850	37,634	5,427	25,227	1,676	1,902	274	1,315	8,088	303,965
Dec-14	130,560	6,653	69,930	4,271	2,990	33,377	38,286	5,141	25,817	61	2,051	273	1,431	8,494	329,335
Jan-15	148,888	7,252	77,793	4,848	3,380	33,214	41,673	5,219	26,215	1,418	2,086	285	1,467	8,882	362,620
Feb-15	128,499	6,369	72,382	4,457	3,270	31,417	36,586	4,689	22,217	164	1,725	283	1,325	8,118	321,501
Mar-15	118,834	6,005	67,751	4,264	3,113	29,110	33,538	4,460	26,271	443	1,700	280	1,257	7,451	304,477
Apr-15	109,138	5,504	63,603	3,629	2,995	29,460	33,769	4,266	25,419	204	1,422	281	1,066	7,873	288,629
May-15	99,098	5,348	60,287	5,025	2,555	27,636	34,131	4,685	23,948	3,170	1,309	267	1,047	8,173	276,679
Jun-15	130,584	7,520	73,044	5,536	3,071	35,782	46,652	5,229	33,376	3,905	1,095	282	1,039	10,363	357,478
Total Billed	1,600,982	86,701	860,060	57,589	36,914	385,233	464,316	60,442	325,585	27,225	19,501	3,337	14,209	106,478	4,048,572
Net Unbilled	4,715	267	4,372	350	180	5,427	4,199	924	2,426	-	-	-	-	-	22,860
RY 3 Total	1,605,697	86,968	864,432	57,939	37,094	390,660	468,515	61,366	328,011	27,225	19,501	3,337	14,209	106,478	4,071,432

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Sales Revenues
($000's)

	RY 1	Change	**RY 2**	Change	**RY 3**
Delivery*	$ 226,935	$ 1,316	$ 228,251	$ 3,278	$ 231,529
Competitive Services*	16,054	60	16,114	81	16,195
Subtotal*	$ 242,989	$ 1,376	$ 244,365	$ 3,359	$ 247,724
MSC	133,248	(1,112)	132,136	7,865	140,001
SBC	12,111	228	12,339	(601)	11,738
Tax Recovery Revenue	4,537	7	4,544	64	4,608
Total Sales Revenues	$ 392,885	$ 499	$ 393,384	$ 10,687	$ 404,071
Rate Relief (Unlevelized)	19,436	8,835	28,271	15,228	43,499
Total Sales Revenues with Rate Relief	$ 412,321	$ 9,334	$ 421,655	$ 25,915	$ 447,570

*At July 2011 rates

CAPACITY COST ALLOCATION

A. MANDATORY DAY-AHEAD HOURLY PRICING ("MDAHP") CUSTOMERS

The language in the Company's tariff regarding capacity cost recovery from MDAHP customers will be amended as follows:

Current Language (Company's tariff, P.S.C. No. 2 – Electricity, Leaf No. 22Z):

Customers shall be subject each month to a Capacity Charge per kilowatt of Capacity Obligation, as determined below. The Capacity Charge shall be based on the pre-capability period strip auction price paid by the Company for the capacity it purchases from the NYISO for Zone G prior to the start of each summer and winter capability period. Such capacity charge shall be shown on the "Statement of Market Supply Charge" filed each month with the Public Service Commission.

The customer's Capacity Obligation, in kilowatts, is determined by the Company no less frequently than once per year. The Capacity Obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer's share of the overall summer peak load assigned to the Company by the NYISO as adjusted by NYISO assigned capacity related factors. The Capacity Obligation for customers taking service in a new facility, as determined by the Company, is based upon the load requirements, as estimated by the Company, of the customer's building or premise.

Revised Language:

Customers shall be subject each month to a Capacity Charge per kilowatt of Capacity Obligation, as determined below. The Capacity Charge shall be based on the monthly auction price paid by the Company for the capacity it purchases from the NYISO for Zone G. Such capacity charge shall be shown on the "Statement of Market Supply Charge" filed each month with the Public Service Commission.

The customer's Capacity Obligation, in kilowatts, is determined by the Company no less frequently than once per year. The customer's Capacity Obligation is based on the individual share of the peak load assigned to the Company and is determined based on the individual customer's peak load during the peak hour for the New York Control Area ("NYCA"). The customer's peak load is adjusted to include demand losses by multiplying it by the applicable demand loss factor contained in the Company's tariff at Leaf No. 23Z-4. The customer's peak load is also adjusted for capacity related factors of the NYISO by applying the Unforced Capacity Effective percentage for the applicable capability period as posted by the NYISO.

B. NON-MDAHP CUSTOMERS

The language in the Company's tariff regarding the determination of capacity costs for non-MDAHP customers will be amended as follows:

Current Language (Company's tariff, P.S.C. No. 2 – Electricity, Leaf No. 22W):

The Forecast MSC Component shall be comprised of: (a) a load shape weighted average of forecast peak and off-peak energy charges; ancillary services and NYPA Transmission Adjustment Charges ("NTAC"); and capacity charges; and (b) an estimate of hedging gains/losses. The energy, capacity and ancillary services/NTAC charges will be adjusted for losses using the loss factors set forth in General Information Section No. 24. Estimated hedging gains/losses will be applied through a Hedging Adjustment on a per kWh basis. The resulting class-specific Forecast MSC Component will be applied to all kWh usage during the billing month. For Service Classification Nos. 19, 20 and 21, separate peak and off-peak Forecast MSC Components will be determined based on the time periods defined in each service classification.

c) Capacity

The capacity component shall be based on the pre-capability period strip auction price paid by the Company for the capacity it purchases from the NYISO for Zone G prior to the start of each summer and winter capability period. Capacity costs shall be reflected in the Forecast MSC Component only during peak hours defined as the eight-hour period between 12:00 noon and 8:00 PM on weekdays, excluding holidays. For each peak hour, the capacity price will be adjusted for the Unforced Capacity Requirement of the NYISO and shall be adjusted by the applicable class-specific load factor.

Revised Language:

The Forecast MSC Component shall be comprised of: (a) a load shape weighted average of forecast peak and off-peak energy charges; and ancillary services and NYPA Transmission Adjustment Charges ("NTAC"); (b) capacity charges; and (c) an estimate of hedging gains/losses. The energy, capacity and ancillary services/NTAC charges will be adjusted for losses using the loss factors set forth in General Information Section No. 24. Estimated hedging gains/losses will be applied through a Hedging Adjustment on a per kWh basis. The resulting class-specific Forecast MSC Component will be applied to all kWh usage during the billing month. For Service Classification Nos. 19, 20 and 21, separate peak and off-peak Forecast MSC Components will be determined based on the time periods defined in each service classification.

c) Capacity

For each capacity group (as defined below)the capacity component, in cents per kWh, shall be determined for each NYISO capability period by dividing the product of (a) the total full service customer and retail access customer capacity obligations and (b) the pre-capability period strip auction price paid by the Company for the capacity it purchases from the NYISO for Zone G prior to the start of each summer and winter *capability period by (c) the total projected full service customer and retail access customer kWh deliveries for the capability period. Capacity obligations are based on the peak loads from the prior year at the time of the New York Control Area peak. Each customer's peak load is adjusted to include the Unforced Capacity Requirement of the NYISO and the applicable class-specific demand loss factor. The capacity component is set for each of the following seven categories:*

Group A: *SC Nos. 1 and 19;*
Group B: *SC No. 2 - Secondary, SC No. 20, SC No. 25, Rate 1 customers exempt from MDAHP;*
Group C: *SC No. 2 - Primary, SC No. 3, SC No. 21, SC No. 25, Rate 2, and customers from the following classes who are exempt from MDAHP: SC No. 9 - Primary, SC No. 22 - Primary, and SC No. 25, Rates 3 and 4 - Primary;*
Group D: *Customers from the following classes who are exempt from MDAHP: SC No. 9 - Substation, SC No. 22 - Substation, and SC No. 25, Rates 3 and 4 - Substation;*
Group E: *Customers from the following classes who are exempt from MDAHP: SC No. 9 - Transmission, SC No. 22 - Transmission, and SC No. 25, Rates 3 and 4 - Transmission;*
Group F: *SC Nos. 4, 6, and 16; and*
Group G: *SC No. 5*

REVENUE DECOUPLING MECHANISM

The Revenue Decoupling Mechanism ("RDM") will be based on a total delivery revenue[1] methodology for customer groups that are included in the RDM.

Those service classifications that are included in the RDM customer groups and those classes that are excluded from the RDM are as follows.

Service Classifications Included in the RDM

Group A
1 General Residential
19 Residential Optional Time of Use Service
Group B
2 General Service - Secondary
20 General Secondary Optional Time of Use Service
Group C
2 General Service - Primary
3 General Primary Service (100 – 1,000 kW)
21 General Primary Optional Time of Use Service
Group D
9 Commercial Service Over 1,000 kW (Mandatory Time of Use)
Group E
22 Industrial Service Over 1,000 kW (Mandatory Time of Use)

Service Classifications Excluded From the RDM

4 Public Street Lighting - Company Owned
5 Traffic Signal Lighting
6 Public Street Lighting - Customer Owned
15 Buyback Service
16 Private Area Lighting
23 Individually Negotiated Contracts
25 Standby Service

[1] Total delivery revenue includes both billed and unbilled revenue.
[2] Customer load served under the Company's economic development riders, i.e., Riders G, H, and J, is included in Service Classification Nos. 2, 3, 9, 20, 21 and 22 and must be removed from those classes for purposes of setting delivery revenue targets and determining the actual delivery revenues for customer groups that include those classes. Customer load served under these riders will be excluded from the RDM until the Company's base delivery rates and delivery revenue targets are next reset, even if service under these riders expires.

- Contract Customers
- Riders G, H, J[2]
- Usage delivered under Rider B, NYPA Recharge New York ("RNY") Program up to the RNY allocation[3]

Under the RDM, actual delivery revenue is compared, on a monthly basis, with a delivery revenue target for each customer group.

Actual Delivery Revenue

Actual delivery revenue, determined for each customer group on a monthly basis, will be calculated as the sum of total revenue derived from customer charges and delivery charges, as defined in the service classifications included in each customer group. Actual delivery revenue shall not include revenues derived from the RDM Adjustment. Commencing July 1, 2014, actual delivery revenue will also include revenues associated with the temporary surcharge in the Energy Cost Adjustment ("ECA").

Delivery Revenue Targets

Delivery revenue targets will be adjusted to reflect delivery rate changes that occur during a rate plan. Monthly and rate year delivery revenue targets effective July 1, 2012, July 1, 2013, and July 1, 2014 for each customer group included in the RDM are set forth in Schedules 1and 2 of this Appendix for both the levelized and non-levelized options.

In addition, the delivery revenue targets will be adjusted, as necessary, if new legislation or regulation results in a change in delivery revenues for some or all customer groups included in the RDM.

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[3] Since load served under Rider B is exempt from the RDM, delivery revenue targets will be revised for allocations made under the RNY Program. Delivery revenue targets will be decreased/increased as RNY load moves from/into RDM customer groups.

RDM Adjustment

For each customer group subject to the RDM, the Company will, on a monthly basis, compare actual delivery revenue to the delivery revenue target. If the monthly actual delivery revenue exceeds the delivery revenue target, the delivery revenue excess will be accrued for refund to customers at the end of the Annual RDM Period.[4] Likewise, if the monthly actual delivery revenue is less than the delivery revenue target, this delivery revenue shortfall will be accrued for recovery from customers at the end of the Annual RDM Period.

On a monthly basis, interest at the Commission's rate for other customer provided capital will be calculated on the average of the current and prior month's cumulative delivery revenue excess/shortfall (net of state and federal income tax benefits).

At the end of an Annual RDM Period, total delivery revenue excess/shortfalls for each customer group will be refunded/surcharged to customers through customer group-specific RDM Adjustments applicable during the subsequent twelve-month period commencing August 1. The Company will file a Statement of RDM Adjustments during the month following the end of each Annual RDM Period and no less than ten calendar days before the date on which the statement is proposed to be effective.

The customer group specific RDM Adjustments will be determined on a cents per kWh basis by dividing the total delivery revenue excess/shortfalls for the Annual RDM Period for each customer group by forecast kWh deliveries of the associated customer group for the corresponding RDM Adjustment Recovery Period. If at any time during an Annual RDM Period the total cumulative delivery revenue excess/shortfall for all of the Company's service

[4] "Annual RDM Periods" are twelve-month periods commencing July 1 of each year.

classifications subject to the RDM exceeds 1.5% of the total of the Delivery Revenue Targets for such Annual RDM Period, the Company may implement interim RDM Adjustments by customer group on no less than ten days notice. Such interim RDM Adjustments shall normally be determined by customer group by dividing the portion of the cumulative delivery revenue excess/shortfall for each customer group by the projected kWh deliveries associated with each customer group for the subsequent twelve-month period. The Company may implement an interim RDM adjustment for a time period other than the normal time period after consultation with Commission Staff. These interim RDM Adjustments would be subject to reconciliation at the end of the Annual RDM Period as part of the annual RDM Adjustment process described above.

If for any reason, a customer group included in the RDM no longer has any customers, the revenue target for that discontinued customer group, plus any delivery revenue excess or shortfall, would be reallocated to other remaining customer groups to provide for equitable treatment of any revenue excess or shortfall from the discontinued customer group. The Company will consult with Commission Staff regarding such reallocation.

If the Company does not file for new base delivery rates to take effect upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective commencing July 1, 2015 shall be equal to the delivery revenue targets effective July 1, 2014, adjusted to reflect the reduction in the temporary surcharge in the ECA from $2.1 million to $1.5 million per year. If the Company does not file for new base delivery rates to take effect prior to July 1, 2016, the RDM will remain in effect and the delivery revenue targets effective commencing July 1, 2016 shall be equal to the delivery revenue targets effective July 1, 2014, adjusted to eliminate the temporary surcharge in the ECA. If new base delivery rates take effect on a date other than July 1, the sum of the monthly delivery revenue excess/shortfalls for each month of the partial year, for each customer group, will be refunded/surcharged to customers through customer group-specific RDM Adjustments applicable during the subsequent twelve-month period commencing one month after new base delivery rates take effect.

Appendix E
Schedule 1
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Orange and Rockland Utilies, Inc.

Case 11-E-0408
Revenue Decoupling Mechanism Targets for RY1: 12 months ending June 30, 2013
($000's)

LEVELIZED

	Group A (SC 1/19)	Group B (SC 2/20)	Group C (SC 2p/3/21)	Group D (SC 9)	Group E (SC 22)	TOTAL Billed	Unbilled	O&R
Jul-12	$14,556	$5,831	$1,851	$1,177	$720	$24,135	$4,664	$28,799
Aug-12	15,659	6,064	1,902	1,359	697	25,681	1,078	26,759
Sep-12	14,665	6,056	2,106	1,374	734	24,935	(4,660)	20,275
Oct-12	11,584	4,971	1,115	675	397	18,742	(1,655)	17,087
Nov-12	9,891	3,713	1,203	783	437	16,027	(9)	16,018
Dec-12	10,827	3,952	1,122	704	400	17,005	639	17,644
Jan-13	11,576	4,222	1,168	765	398	18,129	(1,186)	16,943
Feb-13	10,971	4,196	1,197	757	392	17,513	(1,938)	15,575
Mar-13	10,304	3,849	1,057	658	398	16,266	819	17,085
Apr-13	9,822	3,777	1,142	715	405	15,861	102	15,963
May-13	9,593	3,880	1,151	745	411	15,780	616	16,396
Jun-13	11,098	4,703	1,875	1,364	719	19,759	1,941	21,700
RY ending June 2013	$140,546	$55,214	$16,889	$11,076	$6,108	$229,833	$411	$230,244

Appendix E
Schedule 1
Page 2 of 3

Orange and Rockland Utilies, Inc.
Case 11-E-0408
Revenue Decoupling Mechanism Targets for RY2: 12 months ending June 30, 2014
($000's)

LEVELIZED

	Group A (SC 1/19)	Group B (SC 2/20)	Group C (SC 2p/3/21)	Group D (SC 9)	Group E (SC 22)	TOTAL Billed	Unbilled	O&R
Jul-13	$15,692	$6,102	$2,035	$1,290	$781	$25,900	$3,932	$29,832
Aug-13	17,083	6,463	1,966	1,390	707	27,609	102	27,711
Sep-13	15,639	6,289	2,241	1,455	779	26,403	(4,810)	21,593
Oct-13	12,283	5,133	1,186	723	423	19,748	(1,647)	18,101
Nov-13	10,563	3,846	1,246	814	450	16,919	225	17,144
Dec-13	11,666	4,132	1,302	826	467	18,393	85	18,478
Jan-14	12,414	4,390	1,164	763	386	19,117	(868)	18,249
Feb-14	11,496	4,213	1,224	767	381	18,081	(969)	17,112
Mar-14	11,108	4,042	1,164	733	438	17,485	629	18,114
Apr-14	10,521	3,943	1,172	734	428	16,798	198	16,996
May-14	10,072	3,920	1,141	742	416	16,291	1,230	17,521
Jun-14	11,775	4,876	2,069	1,501	807	21,028	2,682	23,710
RY ending June 2014	$150,312	$57,349	$17,910	$11,738	$6,463	$243,772	$789	$244,561

Orange and Rockland Utilies, Inc.

Case 11-E-0408

Revenue Decoupling Mechanism Targets for RY3: 12 months ending June 30, 2015

($000's)

LEVELIZED

	Group A (SC 1/19)	Group B (SC 2/20)	Group C (SC 2p/3/21)	Group D (SC 9)	Group E (SC 22)	TOTAL Billed	Unbilled	O&R
Jul-14	$16,665	$6,512	$2,076	$1,315	$805	$27,373	$4,444	$31,817
Aug-14	18,228	6,912	2,322	1,694	861	30,017	(384)	29,633
Sep-14	16,631	6,709	2,156	1,379	751	27,626	(4,678)	22,948
Oct-14	13,049	5,374	1,267	776	451	20,917	(1,513)	19,404
Nov-14	11,410	4,172	1,338	873	483	18,276	(375)	17,901
Dec-14	12,408	4,383	1,311	828	467	19,397	451	19,848
Jan-15	13,328	4,722	1,296	855	438	20,639	(255)	20,384
Feb-15	12,302	4,498	1,279	811	411	19,301	(974)	18,327
Mar-15	11,790	4,253	1,185	748	449	18,425	871	19,296
Apr-15	11,251	4,202	1,265	803	466	17,987	586	18,573
May-15	10,693	4,135	1,203	781	429	17,241	998	18,239
Jun-15	12,754	5,332	2,228	1,638	873	22,825	2,515	25,340
RY ending June 2015	$160,509	$61,204	$18,926	$12,501	$6,884	$260,024	$1,686	$261,710

Appendix E
Schedule 2

Orange and Rockland Utilies, Inc.

Case 11-E-0408
Revenue Decoupling Mechanism Targets for RY1: 12 months ending June 30, 2013
($000's)

NONLEVELIZED

	Group A (SC 1/19)	Group B (SC 2/20)	Group C (SC 2p/3/21)	Group D (SC 9)	Group E (SC 22)	TOTAL Billed	Unbilled	O&R
Jul-12	$14,816	$5,928	$1,882	$1,196	$732	$24,554	$4,908	$29,462
Aug-12	15,943	6,164	1,933	1,385	708	26,133	1,091	27,224
Sep-12	14,925	6,157	2,141	1,397	746	25,366	(4,743)	20,623
Oct-12	11,773	5,055	1,131	686	403	19,048	(1,694)	17,354
Nov-12	10,042	3,773	1,222	794	445	16,276	(19)	16,257
Dec-12	11,000	4,011	1,143	715	406	17,275	666	17,941
Jan-13	11,766	4,291	1,188	777	405	18,427	(1,206)	17,221
Feb-13	11,145	4,264	1,217	769	398	17,793	(1,975)	15,818
Mar-13	10,464	3,912	1,072	669	405	16,522	836	17,358
Apr-13	9,971	3,838	1,161	726	413	16,109	94	16,203
May-13	9,735	3,942	1,168	756	418	16,019	620	16,639
Jun-13	11,275	4,780	1,906	1,387	731	20,079	1,987	22,066
RY ending June 2013	$142,855	$56,115	$17,164	$11,257	$6,210	$233,601	$565	$234,166

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Schedule 2
Page 2 of 3

Orange and Rockland Utilies, Inc.
Case 11-E-0408
Revenue Decoupling Mechanism Targets for RY2: 12 months ending June 30, 2014
($000's)

NONLEVELIZED

	Group A (SC 1/19)	Group B (SC 2/20)	Group C (SC 2p/3/21)	Group D (SC 9)	Group E (SC 22)	TOTAL Billed	Unbilled	O&R
Jul-13	$15,552	$6,052	$2,019	$1,278	$775	$25,676	$3,662	$29,338
Aug-13	16,926	6,410	1,951	1,380	700	27,367	103	27,470
Sep-13	15,499	6,237	2,225	1,446	773	26,180	(4,768)	21,412
Oct-13	12,187	5,098	1,175	717	418	19,595	(1,628)	17,967
Nov-13	10,487	3,817	1,237	807	446	16,794	230	17,024
Dec-13	11,574	4,101	1,293	813	467	18,248	74	18,322
Jan-14	12,316	4,358	1,154	757	382	18,967	(857)	18,110
Feb-14	11,408	4,183	1,215	762	377	17,945	(962)	16,983
Mar-14	11,025	4,012	1,154	727	434	17,352	625	17,977
Apr-14	10,445	3,916	1,161	727	424	16,673	198	16,871
May-14	10,001	3,892	1,132	735	413	16,173	1,223	17,396
Jun-14	11,681	4,836	2,053	1,489	800	20,859	2,650	23,509
RY ending June 2014	$149,101	$56,912	$17,769	$11,638	$6,409	$241,829	$550	$242,379

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Schedule 2
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Orange and Rockland Utilies, Inc.

Case 11-E-0408
Revenue Decoupling Mechanism Targets for RY3: 12 months ending June 30, 2015
($000's)

NONLEVELIZED

	Group A (SC 1/19)	Group B (SC 2/20)	Group C (SC 2p/3/21)	Group D (SC 9)	Group E (SC 22)	TOTAL Billed	Unbilled	O&R
Jul-14	$16,533	$6,469	$2,066	$1,308	$801	$27,177	$4,534	$31,711
Aug-14	18,080	6,867	2,311	1,684	855	29,797	(390)	29,407
Sep-14	16,498	6,665	2,146	1,371	746	27,426	(4,678)	22,748
Oct-14	12,951	5,336	1,255	769	446	20,757	(1,512)	19,245
Nov-14	11,319	4,135	1,323	865	479	18,121	(378)	17,743
Dec-14	12,315	4,344	1,299	819	464	19,241	458	19,699
Jan-15	13,206	4,678	1,282	845	433	20,444	(257)	20,187
Feb-15	12,197	4,456	1,266	803	408	19,130	(977)	18,153
Mar-15	11,691	4,214	1,172	741	443	18,261	869	19,130
Apr-15	11,162	4,168	1,252	795	461	17,838	591	18,429
May-15	10,612	4,101	1,193	774	425	17,105	999	18,104
Jun-15	12,647	5,292	2,216	1,628	867	22,650	2,515	25,165
RY ending June 2015	$159,211	$60,725	$18,781	$12,402	$6,828	$257,947	$1,774	$259,721

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Capital Structure & Cost of Money
July 1, 2012 - June 30, 2015

Rate Year 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost
Long Term Debt	50.60%	6.07%	3.07%	3.07%
Customer Deposits	1.40%	1.65%	0.02%	0.02%
Debt & Customer Deposits	52.00%		3.09%	3.09%
Common Equity	48.00%	9.40%	4.51%	7.47%
Total	100.00%		7.61%	10.57%

Rate Year 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost
Long Term Debt	50.60%	6.07%	3.07%	3.07%
Customer Deposits	1.40%	1.65%	0.02%	0.02%
Debt & Customer Deposits	52.00%		3.09%	3.09%
Common Equity	48.00%	9.50%	4.56%	7.55%
Total	100.00%		7.65%	10.65%

Rate Year 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre-Tax Cost
Long Term Debt	50.60%	5.64%	2.85%	2.85%
Customer Deposits	1.40%	1.65%	0.02%	0.02%
Debt & Customer Deposits	52.00%		2.88%	2.88%
Common Equity	48.00%	9.60%	4.61%	7.63%
Total	100.00%		7.48%	10.51%

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
LONG TERM DEBT
Forecast - Thirteen Months Ended June 30, 2013

Orange and Rockland Utilities, Inc.	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Debentures:									
Series F, 6.50%	12/18/97	12/1/27	80,000,000	80,000,000	0	901,750	79,098,250	6.59%	5,272,000
Series A, 2005, 5.30%	3/31/05	4/1/15	40,000,000	40,000,000	(80,000)	495,000	39,425,000	5.49%	2,196,000
Series A, 2006, 5.45%	10/4/06	10/1/16	75,000,000	75,000,000	(136,500)	562,500	74,301,000	5.57%	4,177,500
Series A, 2008, 6.15%	9/1/08	9/1/18	50,000,000	50,000,000	(89,500)	625,000	49,285,500	6.34%	3,170,000
Series A, 2009, 4.96%	12/1/09	12/1/19	60,000,000	60,000,000	0	2,216,052	57,783,948	5.44%	3,264,000
Series B, 2009, 6.00%	12/1/09	12/1/39	60,000,000	60,000,000	0	2,351,052	57,648,948	6.29%	3,774,000
Series A, 2010, 2.50%	8/12/10	8/15/15	55,000,000	55,000,000	(67,100)	461,118	54,471,782	2.67%	1,468,500
Series B, 2010, 5.50%	8/12/10	8/15/40	115,000,000	115,000,000	(218,500)	1,156,872	113,624,628	5.58%	6,417,000
			535,000,000					5.56%	29,739,000
Pollution Control Debt*									
1994, 6.09%**	10/1/94	8/19/10	0	55,000,000	0	0	0	N/A	3,300,000
1995, Variable Rate	8/1/95	8/1/15	44,000,000	44,000,000	0	3,571,683	40,428,317	3.49%	1,535,600
			44,000,000					10.99%	4,835,600
Sub Total ORU Debt			579,000,000					5.97%	34,574,600
Unamortized Loss on Reacquired Debt Expense			(3,386,501)					0.09%	494,073
Unamortized Debt Discount			(330,490)						
Total ORU			575,283,008						
Pike County Light & Power Company									
First Mortgage Bonds:									
Series A, 7.07%	11/10/98	10/1/18	3,200,000	3,200,000	0	284,129	2,915,871	7.97%	255,040
Total Pike			3,200,000					7.97%	255,040
Consolidated Total									
Long Term Debt			582,200,000					6.07%	35,323,713
Unamortized Loss on Reacquired Debt Expense			(3,386,501)						
Unamortized Debt Discount			(330,490)						
Total Consolidated			578,483,008						
Rounded			578,483,000						

* The Company will reconcile the costs of its Pollution Control debt (including costs of replacement debt and swap and swap termination costs) to the amounts reflected in rates for such costs as detailed in Section III.11.L. of the Joint Proposal.

** Normal maturity date was October 2014, however, this bond was called in August 2010.
The Effective Annual Cost represents payments to the counterparty on an interest rate swap related to the retired bond pursuant to which O&R pays a fixed-rate of 6.09 percent and receives a LIBOR-based variable rate.

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
LONG TERM DEBT
Forecast - Thirteen Months Ended June 30, 2014

Orange and Rockland Utilities, Inc.	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Debentures:									
Series F, 6.50%	12/18/97	12/1/27	80,000,000	80,000,000	0	901,750	79,098,250	6.59%	5,272,000
Series A, 2005, 5.30%	3/31/05	4/1/15	40,000,000	40,000,000	(80,000)	495,000	39,425,000	5.49%	2,196,000
Series A, 2006, 5.45%	10/4/06	10/1/16	75,000,000	75,000,000	(136,500)	562,500	74,301,000	5.57%	4,177,500
Series A, 2008, 6.15%	9/1/08	9/1/18	50,000,000	50,000,000	(89,500)	625,000	49,285,500	6.34%	3,170,000
Series A, 2009, 4.96%	12/1/09	12/1/19	60,000,000	60,000,000	0	2,216,052	57,783,948	5.44%	3,264,000
Series B, 2009, 6.00%	12/1/09	12/1/39	60,000,000	60,000,000	0	2,351,052	57,648,948	6.29%	3,774,000
Series A, 2010, 2.50%	8/12/10	8/15/15	55,000,000	55,000,000	(67,100)	461,118	54,471,782	2.67%	1,468,500
Series B, 2010, 5.50%	8/12/10	8/15/40	115,000,000	115,000,000	(218,500)	1,156,872	113,624,628	5.58%	6,417,000
			535,000,000					5.56%	29,739,000
Pollution Control Debt*									
1994, 6.09%**	10/1/94	8/19/10	0	55,000,000	0	0	0	N/A	3,300,000
1995, Variable Rate	8/1/95	8/1/15	44,000,000	44,000,000	0	3,571,683	40,428,317	3.49%	1,535,600
			44,000,000					10.99%	4,835,600
Sub Total ORU Debt			579,000,000					5.97%	34,574,600
Unamortized Loss on Reacquired Debt Expense			(2,791,023)					0.09%	494,073
Unamortized Debt Discount			(279,199)						
Total ORU			575,929,778						
Pike County Light & Power Company									
First Mortgage Bonds:									
Series A, 7.07%	11/10/98	10/1/18	3,200,000	3,200,000	0	284,129	2,915,871	7.97%	255,040
Total Pike			3,200,000					7.97%	255,040
Consolidated Total									
Long Term Debt			582,200,000					6.07%	35,323,713
Unamortized Loss on Reacquired Debt Expense			(2,791,023)						
Unamortized Debt Discount			(279,199)						
Total Consolidated			579,129,778						
Rounded			579,129,800						

* The Company will reconcile the costs of its Pollution Control debt (including costs of replacement debt and swap and swap termination costs) to the amounts reflected in rates for such costs as detailed in Section III.11.L. of the Joint Proposal.

** Normal maturity date was October 2014, however, this bond was called in August 2010.
The Effective Annual Cost represents payments to the counterparty on an interest rate swap related to the retired bond pursuant to which O&R pays a fixed-rate of 6.09 percent and receives a LIBOR-based variable rate.

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
LONG TERM DEBT
Forecast - Thirteen Months Ended June 30, 2015

Orange and Rockland Utilities, Inc.	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Debentures:									
Series F, 6.50%	12/18/97	12/1/27	80,000,000	80,000,000	0	901,750	79,098,250	6.59%	5,272,000
Series A, 2005, 5.30%	3/31/05	4/1/15	30,000,000	40,000,000	(80,000)	495,000	39,425,000	5.49%	1,647,000
Series A, 2006, 5.45%	10/4/06	10/1/16	75,000,000	75,000,000	(136,500)	562,500	74,301,000	5.57%	4,177,500
Series A, 2008, 6.15%	9/1/08	9/1/18	50,000,000	50,000,000	(89,500)	625,000	49,285,500	6.34%	3,170,000
Series A, 2009, 4.96%	12/1/09	12/1/19	60,000,000	60,000,000	0	2,216,052	57,783,948	5.44%	3,264,000
Series B, 2009, 6.00%	12/1/09	12/1/39	60,000,000	60,000,000	0	2,351,052	57,648,948	6.29%	3,774,000
Series A, 2010, 2.50%	8/12/10	8/15/15	55,000,000	55,000,000	(67,100)	461,118	54,471,782	2.67%	1,468,500
Series B, 2010, 5.50%	8/12/10	8/15/40	115,000,000	115,000,000	(218,500)	1,156,872	113,624,628	5.58%	6,417,000
Series, 2014, 6.85%	9/1/14	9/1/24	37,500,000	50,000,000	0	600,000	49,400,000	5.64%	2,115,000
			562,500,000					5.57%	31,305,000
Pollution Control Debt*									
1994, 6.09%**	10/1/94	8/19/10	0	55,000,000	0	0	0	N/A	825,000
1995, Variable Rate	8/1/95	8/1/15	44,000,000	44,000,000	0	3,571,683	40,428,317	3.49%	1,535,600
			44,000,000					5.37%	2,360,600
Sub Total ORU Debt			606,500,000					5.55%	33,665,600
Unamortized Loss on Reacquired Debt Expense			(2,417,911)					0.08%	494,073
Unamortized Debt Discount			(229,908)						
Total ORU			603,852,181						
Pike County Light & Power Company									
First Mortgage Bonds:									
Series A, 7.07%	11/10/98	10/1/18	3,200,000	3,200,000	0	284,129	2,915,871	7.97%	255,040
Total Pike			3,200,000					7.97%	255,040
Consolidated Total									
Long Term Debt			609,700,000					5.64%	34,414,713
Unamortized Loss on Reacquired Debt Expense			(2,417,911)						
Unamortized Debt Discount			(229,908)						
Total Consolidated			607,052,181						
Rounded			607,052,200						

* The Company will reconcile the costs of its Pollution Control debt (including costs of replacement debt and swap and swap termination costs) to the amounts reflected in rates for such costs as detailed in Section III.11.L. of the Joint Proposal.

** Normal maturity date was October 2014, however, this bond was called in August 2010.
The Effective Annual Cost represents payments to the counterparty on an interest rate swap related to the retired bond pursuant to which O&R pays a fixed-rate of 6.09 percent and receives a LIBOR-based variable rate.

Orange and Rockland Utilities, Inc.
T&D Net Plant In Service Target Balances - Included in Rate Base
Effective July 1, 2012-June 30, 2015
$ 000's

MONTH ENDED	Rate Year 1 T&D Elec. Plant In Service Target	Rate Year 1 T&D Reserve For Depreciation Target	Rate Year 1 T&D Net Plant Target
June 30, 2012 @ 50%	$ 488,683	$ (154,445)	$ 334,239
July	980,466	(310,783)	669,682
August	982,381	(312,687)	669,695
September	985,196	(314,594)	670,602
October	988,509	(316,508)	672,000
November	990,778	(318,430)	672,348
December	1,000,826	(320,357)	680,469
January	1,004,158	(322,313)	681,846
February	1,005,259	(324,276)	680,983
March	1,008,950	(326,243)	682,708
April	1,010,694	(328,219)	682,475
May	1,012,233	(330,200)	682,033
June 30, 2013 @ 50%	517,367	(166,093)	351,275
13 Point Average	$ 11,975,500.9	$ (3,845,146.6)	$ 8,130,354.2
Monthly Average	$ 997,958	$ (320,429)	$ 677,530

MONTH ENDED	Rate Year 2 T&D Elec. Plant In Service Target	Rate Year 2 T&D Reserve For Depreciation Target	Rate Year 2 T&D Net Plant Target
June 30, 2013 @ 50%	$ 517,367	$ (166,093)	$ 351,275
July	1,036,360	(334,227)	702,133
August	1,037,766	(336,273)	701,494
September	1,039,063	(338,308)	700,755
October	1,040,816	(340,337)	700,479
November	1,042,864	(342,373)	700,491
December	1,047,189	(344,464)	702,725
January	1,051,441	(346,554)	704,887
February	1,052,551	(348,652)	703,899
March	1,054,030	(350,752)	703,278
April	1,055,546	(352,857)	702,689
May	1,057,107	(354,967)	702,140
June 30, 2014 @ 50%	552,657	(178,543)	374,114
13 Point Average	$ 12,584,757	$ (4,134,399)	$ 8,450,358
Monthly Average	$ 1,048,730	$ (344,533)	$ 704,196

MONTH ENDED	Rate Year 3 T&D Elec. Plant In Service Target	Rate Year 3 T&D Reserve For Depreciation Target	Rate Year 3 T&D Net Plant Target
June 30, 2014 @ 50%	$ 552,657	$ (178,543)	$ 374,114
July	1,107,362	(359,456)	747,906
August	1,109,189	(361,833)	747,356
September	1,110,571	(364,215)	746,356
October	1,112,342	(366,601)	745,742
November	1,113,343	(368,975)	744,368
December	1,119,846	(371,341)	748,505
January	1,133,850	(373,724)	760,126
February	1,135,179	(376,139)	759,040
March	1,136,508	(378,559)	757,949
April	1,137,837	(380,983)	756,854
May	1,139,166	(383,411)	755,755
June 30, 2015 @ 50%	581,345	(192,922)	388,423
13 Point Average	$ 13,489,195	$ (4,456,701)	$ 9,032,494
Monthly Average	$ 1,124,100	$ (371,392)	$ 752,708

Case 11-E-0408

Orange and Rockland Utilities, Inc.
T&D Net Plant In Service Target Balances -- CAP
Effective July 1, 2012 - June 30, 2015
$ 000's

Rate Year 1

MONTH ENDED		T&D Elect. Plant In Service Target	T&D Reserve For Depreciaton Target	T&D Net Plant Target
JUNE 30, 2012	@1/2	$496,531	($154,488)	$342,043
JULY 31, 2012		997,082	(310,907)	686,175
AUGUST 31, 2012		999,623	(312,851)	686,772
SEPTEMBER 30, 2012		1,003,288	(314,801)	688,488
OCTOBER 31, 2012		1,007,575	(316,759)	690,816
NOVEMBER 30, 2012		1,010,558	(318,727)	691,831
DECEMBER 31, 2012		1,023,265	(320,702)	702,562
JANUARY 31, 2013		1,027,576	(322,713)	704,864
FEBRUARY 28, 2013		1,029,098	(324,733)	704,365
MARCH 31, 2013		1,033,859	(326,757)	707,102
APRIL 30, 2013		1,036,185	(328,793)	707,391
MAY 31, 2013		1,038,255	(330,836)	707,418
JUNE 30, 2013	@1/2	533,264	(166,443)	366,821
13 POINT AVERAGE		$12,236,159	($3,849,510)	$8,386,650
MONTHLY AVERAGE		$1,019,680	($320,792)	$698,888

Rate Year 2

MONTH ENDED		T&D Elect. Plant In Service Target	T&D Reserve For Depreciaton Target	T&D Net Plant Target
JUNE 30, 2013	@1/2	$533,264	($166,443)	$366,821
JULY 31, 2013		1,068,706	(335,004)	733,702
AUGUST 31, 2013		1,070,610	(337,129)	733,481
SEPTEMBER 30, 2013		1,072,378	(339,245)	733,133
OCTOBER 31, 2013		1,074,715	(341,356)	733,359
NOVEMBER 30, 2013		1,077,421	(343,474)	733,947
DECEMBER 31, 2013		1,082,974	(345,651)	737,322
JANUARY 31, 2014		1,088,436	(347,829)	740,607
FEBRUARY 28, 2014		1,089,968	(350,016)	739,952
MARCH 31, 2014		1,091,964	(352,208)	739,756
APRIL 30, 2014		1,094,006	(354,406)	739,600
MAY 31, 2014		1,096,102	(356,610)	739,493
JUNE 30, 2014	@1/2	578,253	(179,412)	398,841
13 POINT AVERAGE		$13,018,796	($4,148,782)	$8,870,015
MONTHLY AVERAGE		$1,084,900	($345,732)	$739,168

Rate Year 3

MONTH ENDED		T&D Elect. Plant In Service Target	T&D Reserve For Depreciaton Target	T&D Net Plant Target
JUNE 30, 2014	@1/2	$578,253	($179,412)	$398,841
JULY 31, 2014		1,159,215	(361,322)	797,893
AUGUST 31, 2014		1,161,644	(363,826)	797,818
SEPTEMBER 30, 2014		1,163,518	(366,338)	797,180
OCTOBER 31, 2014		1,165,879	(368,855)	797,024
NOVEMBER 30, 2014		1,167,276	(371,362)	795,914
DECEMBER 31, 2014		1,175,551	(373,862)	801,689
JANUARY 31, 2015		1,193,203	(376,383)	816,820
FEBRUARY 28, 2015		1,195,010	(378,944)	816,066
MARCH 31, 2015		1,196,817	(381,512)	815,306
APRIL 30, 2015		1,198,625	(384,085)	814,540
MAY 31, 2015		1,200,432	(386,664)	813,768
JUNE 30, 2015	@1/2	614,991	(194,624)	420,367
13 POINT AVERAGE		$14,170,415	($4,487,188)	$9,683,226
MONTHLY AVERAGE		$1,180,868	($373,932)	$806,936

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Capital True-up Rate - T&D
July 1, 2012 - June 30, 2015

Rate Year 1

Electric Carrying Charge - Transmission & Distribution Plant	
- Before Tax ROR *	10.57%
- Composite Depr. Rate	2.94%
Total	13.51%

Rate Year 2

Electric Carrying Charge - Transmission & Distribution Plant	
- Before Tax ROR *	10.65%
- Composite Depr. Rate	2.94%
Total	13.59%

Rate Year 3

Electric Carrying Charge - Transmission & Distribution Plant	
- Before Tax ROR *	10.51%
- Composite Depr. Rate	2.94%
Total	13.45%

* See Appendix F

Orange and Rockland Utilities, Inc.
Case 11-E-0408
True-Up Targets
$ 000's

Expense Items	Twelve Months Ending June 30, 2013	2014	2015	3-Year Rate Period
Research and Development	$ 696	$ 710	$ 725	$ 2,131
Contractor Tree Trimming (shortfall true-up only) *	7,993	8,157	8,328	24,478
Worker's Compensation Claims (Asbestos)	299	299	-	598
Storm Reserve	3,563	3,636	3,712	10,911
Low Income Program	1,009	1,417	1,825	4,251
Pension Costs - Qualified Plan	21,262	19,184	16,372	56,818
- Non Qualified Plan	1,757	1,738	1,704	5,199
OPEB Costs	5,808	5,567	5,087	16,462
Subtotal	28,827	26,489	23,163	78,479
Rate relief phase-in adjustment	(4,235)	2,131	2,104	-
Net Target	24,592	28,620	25,267	78,479
Property Taxes - State, County & Town	8,319	8,736	9,174	26,229
Property Taxes - Village	1,471	1,545	1,623	4,639
Property Taxes - School	18,270	19,183	20,142	57,595
Total Property Taxes	28,060	29,464	30,939	88,463

* Annual tree trimming over / under expenditures may be netted, true up is cumulative.

Rate Base - Environmental and Deferred FIT	2013	2014	2015
Environmental Remediation			
MGP	2,974	8,917	9,357
West Nyack	131	106	77
Spring Valley UST	97	78	48
Cottman / Newark Bay / Borne	91	65	39
Deferrred Environmental Balances	3,294	9,167	9,521
Accumulated Deferred FIT			
ACRS / MACRS / ADR	(119,364)	(118,573)	(118,726)
263(A) Capitalized Overheads	(38,894)	(37,681)	(36,468)
Repair Allowance	(4,093)	(4,350)	(4,783)
Deferrred Accumulated Deferred FIT Balances	(162,351)	(160,604)	(159,977)

Orange and Rockland Utilities, Inc.
Case 11-E-0408
O&M expenses subject to inflation (excl. Payroll, Amortizations & Trued Up Expenses)
$ 000's

	Twelve Months Ending June 30,		
	2013	2014	2015
Shared Services	$ 9,534	$ 9,730	$ 9,934
Employee and Other Insurance Costs	8,894	9,077	9,269
T&D O&M (Excluding Tree Trimming & Storms)	12,338	12,593	12,855
Regulatory Commission Expenses	1,491	1,522	1,554
Other O&M Costs			
Advertising	25	26	26
Building Service	132	135	138
Information Technology Solutions	3,515	3,587	3,663
Legal & Other Professional Services	875	892	911
Rents	1,187	1,211	1,236
Reproduction	124	126	129
Materials and Supplies	1,214	1,239	1,265
Corporate Fiscal	1,526	1,557	1,590
Telephones	950	1,007	1,100
Transportation	2,720	2,776	2,834
Other O&M	2,780	2,837	2,897
Total	$ 47,305	$ 48,315	$ 49,401

Orange & Rockland Utilities, Inc.
Case 11-E-0408
Pro forma Calculation of Earnings
During Stub Period Starting July 1, 2015
(000's)

Assumption: O&R Delays Filing for New Rates for Six Months

Month / Year	Electric Earnings	
July 31, 2015	$ 6,500	
August 31, 2015	6,500	
September 30, 2015	5,000	
October 31, 2015	3,500	
November 30, 2015	3,500	
December 31, 2015	5,500	
Total		$ 30,500

	Electric Rate Base	
Rate Base as of June 30, 2015	$ 760,000	
Rate Base as of December 31, 2015	785,000	
Total	1,545,000	
Divided by Two	50%	
Average Rate Base During Stub Period	$ 772,500	
x ratio of billed sales during stub period to annual sales forecast (Appendix C page 3)	52.8%	
Rate Base Subject to Earnings Test		$ 407,793
Overall Rate of Return ($ 30,500 / $ 407,793)		7.48%
Return on Equity (Page 7)	9.59%	
Earnings Sharing Threshold	10.40%	
Earnings Above / (Under) Threshold	-0.81%	
Equity Earnings Base ($ 407,793 x 48.00%)	$ 195,740	
Equity Earnings Above / (Under) Target ($ 195,740 x -0.81%)	$ (1,590)	

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Capital Structure & Cost of Money
During Stub Period Starting July 1, 2015

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.60%	5.64%	2.85%
Customer Deposits	1.40%	1.65%	0.02%
Total Debt	52.00%		2.88%
Common Equity	48.00%	9.59%	4.60%
Total	100.00%		7.48%

Appendix H

Electric Capital Program Reporting Requirements

The Company will file a quarterly report within 45 days after the end of the first three calendar quarters of each rate year (e.g., the report for the quarter January – March 2013 would be due by May 15, 2013). The annual report, which also will include the report for the fourth quarter, would be due 60 days after the end of each rate year (i.e., by August 31, 2013 for Rate Year 1). The quarterly and annual reports will include the following information as outlined below. Reports for illustrative purposes are attached.

Quarterly Reports - reports will reflect cumulative expenditures during the rate year

- Summary of Capital Expenditures categorized by Blankets (i.e., costs of certain recurring labor and equipment), Regular Projects under $1.0 million and Regular Projects Over $1.0 million
- Summary of Capital Additions categorized by Blankets, Regular Projects under $1.0 million and Regular Projects Over $1.0 million
- Capital Projects Over $1.0 million that includes:
    - Rate Case – In-service date
    - Current projected in-service date
    - Breakdown of expenditures (e.g., payroll, accounts payable, and materials & supplies categories)
    - Comparison of rate year budgeted vs. rate year actual to date
    - Comparison of calendar year budgeted vs. calendar year actual to date
    - Narrative on cost deltas exceeding 15% to date
    - Narrative on project design, permitting and/or construction status (including a detailed construction schedule for each project).
    - Inclusion of any new projects exceeding $1 million
    - Capital project details for any projects exceeding $1 million that were appropriated during the previous quarter

Annual Reports

- Summary of Capital Expenditures categorized by Blankets, Regular Projects under $1.0 million, and Regular Projects Over $1.0 million
- Summary of Capital Additions categorized by Blankets, Regular Projects under $1.0 million and Regular Projects Over $1.0 million
- Blankets (detail listing) - comparison of actual expenditures vs. rate case expenditures
- Regular Projects less than $1.0 million (detail listing) - comparison of actual expenditures vs. rate case expenditures
- Regular Projects greater than $1.0 million (detailed listing) - comparison of actual expenditures vs. rate case expenditures

- Capital Projects Over $1.0 million that includes
    - Rate Case – In-service date
    - Current projected in-service date
    - Breakdown of expenditures (e.g., payroll, accounts payable, and materials & supplies categories)
    - Comparison of rate year budgeted vs. rate year actual to date
    - Comparison of calendar year budgeted vs. calendar year actual to date
    - Narrative on cost delta's exceeding 15% to date
    - Narrative on project design, permitting and/or construction status (including a detailed construction schedule for each project).
    - Inclusion of any new projects exceeding $1 million
    - Capital project details for any projects exceeding $1 million that were appropriated during the previous quarter

Orange and Rockland Utilities, Inc.
Electric Rate Case - Quarter Update Example
Electric Plant Additions
Nine Months Ending Rate Year 1

Project Description	Rate Case (Nine Months Ending Rate Year 1)	Actual (Nine Months Ending Rate Year 1)	Variance
Blankets	**$ 29,191.8**	**$ 29,191.8**	-
Regular Projects Under $1 Million	**5,260.5**	**5,260.5**	-
Regular Projects Over $1 Million			
Rt 218/9W double circuit from Mine Torne to Morgan Road	1,119.5	1,119.5	-
Mobile #1 Replacement	1,665.6	1,665.6	-
Line 562/563 CAT-1 OPGW	1,565.7	1,565.7	-
Sugarloaf 69kV Yard Breaker Replacement	1,128.6	1,128.6	-
Line 311 Shoreline Erosion	4,604.4	4,604.4	-
Control Center Renovation	8,953.0	8,953.0	-
New Hempstead Road Substation, 32MVAR Cap and UG Exits	13,786.5	13,786.5	-
Municipal Streetlight Ownership Software Program	-	-	-
Port Jervis Substation and UG Exits	-	-	-
New Hartley Road Substation, UG Exits, and Transmission Tap	-	-	-
Little Tor Substation and UG Exits	-	-	-
Sterling Forest New 69KV Source (L26 tap)	-	-	-
Line 49 Upgrade	-	-	-
Line 702 Upgrade	-	-	-
Future Breaker Position for Northern 345kV Tap	-	-	-
Westtown 2nd 35MVA Bank and New Circuits	-	-	-
West Warwick Substation, Transmission and UG Exits	-	-	-
Blooming Grove Substation Upgrade and UG Exits	-	-	-
Tappan Substation Property	-	-	-
Tappan Substation, UG Exits, and Transmission Tap	-	-	-
	32,823.3	**32,823.3**	-
Total	**67,275.5**	**67,275.5**	-

Orange and Rockland Utilities, Inc.
Electric Rate Case - Quarter Update Example
Electric Capital Expenditures
Nine Months Ending Rate Year 1

		Nine Months Ending Rate Year 1	
Project Description	**Rate Case**	**Actual**	**Variance**
Blankets	**30,647.5**	**30,647.5**	-
Regular Projects Under $1 Million	**5,087.9**	**5,087.9**	-
Regular Projects Over $1 Million			
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	466.5	466.5	-
Mobile #1 Replacement	1,579.6	1,579.6	-
Line 562/563 CAT-1 OPGW	187.5	187.5	-
Sugarloaf 69kV Yard Breaker Replacement	955.0	955.0	-
Line 311 Shoreline Erosion	1,606.2	1,606.2	-
Control Center Renovation	8,000.0	8,000.0	-
New Hempstead Road Substation, 32MVAR Cap and UG Exits	8,417.0	8,417.0	-
Municipal Streetlight Ownership Software Program	1,356.0	1,356.0	-
Port Jervis Substation and UG Exits	7,400.0	7,400.0	-
New Hartley Road Substation, UG Exits, and Transmission Tap	4,488.0	4,488.0	-
Little Tor Substation and UG Exits	4,095.0	4,095.0	-
Sterling Forest New 69KV Source (L26 tap)	3,053.3	3,053.3	-
Line 49 Upgrade	1,600.0	1,600.0	-
Line 702 Upgrade	1,600.0	1,600.0	-
Future Breaker Position for Northern 345kV Tap	84.0	84.0	-
Westtown 2nd 35MVA Bank and New Circuits	-	-	-
West Warwick Substation, Transmission and UG Exits	5,055.2	5,055.2	-
Blooming Grove Substation Upgrade and UG Exits	59.2	59.2	-
Tappan Substation, UG Exits, and Transmission Tap	673.0	673.0	-
	50,675.5	**50,675.5**	-
Total	**86,410.9**	**86,410.9**	-

Orange and Rockland Utilities, Inc.
Electric Rate Case - Quarter Update Example
Total Estimate and Spending Summary - Projects Over $1 Million
Detail Narrative - Original vs. Current

Electric Capital Expenditures:

Project Description	Original Estimate	Previous Quarterly Estimate	Current Estimate	Delta	Delta From Prev. Quarter	Reason for difference	Total Project Spending Thru 03-31-12
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	$ 466.5	$ 466.5	$ 466.5	$ -	$ -	No change	$ 8,207.4
Mobile #1 Replacement	$ 1,579.6	$ 1,579.6	$ 1,579.6	$ -	$ -	No change	$ 4,563.9
Line 562/563 CAT-1 OPGW	$ 187.5	$ 187.5	$ 187.5	$ -	$ -	No change	$ 3,965.8
Sugarloaf 69kV Yard Breaker Replacement	$ 955.0	$ 955.0	$ 955.0	$ -	$ -	No change	$ 10,077.4
Line 311 Shoreline Erosion	$ 1,606.2	$ 1,606.2	$ 1,606.2	$ -	$ -	No change	$ 5,828.3
Control Center Renovation	$ 8,000.0	$ 8,000.0	$ 8,000.0	$ -	$ -	No change	$ 7,398.2
New Hempstead Road Substation, 32MVAR Cap and UG Exits	$ 8,417.0	$ 8,417.0	$ 8,417.0	$ -	$ -	No change	$ 3,043.5
Municipal Streetlight Ownership Software Program	$ 1,356.0	$ 1,356.0	$ 1,356.0	$ -	$ -	No change	$ 255.9
Port Jervis Substation and UG Exits	$ 7,400.0	$ 7,400.0	$ 7,400.0	$ -	$ -	No change	$ 2,092.2
New Hartley Road Substation, UG Exits, and Transmission Tap	$ 4,488.0	$ 4,488.0	$ 4,488.0	$ -	$ -	No change	$ 5,632.5
Little Tor Substation and UG Exits	$ 4,095.0	$ 4,095.0	$ 4,095.0	$ -	$ -	No change	$ 165.2
Sterling Forest New 69KV Source (L26 tap)	$ 3,053.3	$ 3,053.3	$ 3,053.3	$ -	$ -	No change	$ 1,296.7
Line 49 Upgrade	$ 1,600.0	$ 1,600.0	$ 1,600.0	$ -	$ -	No change	$ 25,457.7
Line 702 Upgrade	$ 1,600.0	$ 1,600.0	$ 1,600.0	$ -	$ -	No change	$ 1,564.7
Future Breaker Position for Northern 345kV Tap	$ 84.0	$ 84.0	$ 84.0	$ -	$ -	No change	$-
Westtown 2nd 35MVA Bank and New Circuits	$ -	$ -	$ -	$ -	$ -	No change	$ 2,073.6
West Warwick Substation, Transmission and UG Exits	$ 5,055.2	$ 5,055.2	$ 5,055.2	$ -	$ -	No change	$ 428.4
Blooming Grove Substation Upgrade and UG Exits	$ 59.2	$ 59.2	$ 59.2	$ -	$ -	No change	$ 1,235.4
Tappan Substation, UG Exits, and Transmission Tap	$ 673.0	$ 673.0	$ 673.0	$ -	$ -	No change	$ 0.6

Orange and Rockland Utilities, Inc.
Electric Rate Case - Quarter Update Example
Detail Breakdown - Projects Over $1 Million

Nine Mo. Ending Rate Year 1

Project Description	Rate Case In Service Date	Projected Actual In Service Date	Payroll	Accounts Payable	Materials & Supplies	Overheads	Total $	Remarks
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	Aug-12	Aug-12	116.6	116.6	116.6	116.6	466.5	On Time
Mobile #1 Replacement	Dec-12	Dec-12	394.9	394.9	394.9	394.9	1,579.6	On Time
Line 562/563 CAT-1 OPGW	Dec-12	Dec-12	46.9	46.9	46.9	46.9	187.5	On Time
Sugarloaf 69kV Yard Breaker Replacement	Dec-12	Dec-12	238.8	238.8	238.8	238.8	955.0	On Time
Line 311 Shoreline Erosion	Dec-12	Dec-12	401.6	401.6	401.6	401.6	1,606.2	On Time
Control Center Renovation	Jun-13	Jun-13	2,000.0	2,000.0	2,000.0	2,000.0	8,000.0	On Time
New Hempstead Road Substation, 32MVAR Cap and UG Exits	Jun-13	Jun-13	2,104.3	2,104.3	2,104.3	2,104.3	8,417.0	On Time
Municipal Streetlight Ownership Software Program	Dec-13	Dec-13	339.0	339.0	339.0	339.0	1,356.0	On Time
Port Jervis Substation and UG Exits	Jun-14	Jun-14	1,850.0	1,850.0	1,850.0	1,850.0	7,400.0	On Time
New Hartley Road Substation, UG Exits, and Transmission Tap	Jun-14	Jun-14	1,122.0	1,122.0	1,122.0	1,122.0	4,488.0	On Time
Little Tor Substation and UG Exits	Jun-14	Jun-14	1,023.8	1,023.8	1,023.8	1,023.8	4,095.0	On Time
Sterling Forest New 69KV Source (L26 tap)	Jun-14	Jun-14	763.3	763.3	763.3	763.3	3,053.3	On Time
Line 49 Upgrade	Jun-14	Jun-14	400.0	400.0	400.0	400.0	1,600.0	On Time
Line 702 Upgrade	Jun-14	Jun-14	400.0	400.0	400.0	400.0	1,600.0	On Time
Future Breaker Position for Northern 345kV Tap	Dec-14	Dec-14	21.0	21.0	21.0	21.0	84.0	On Time
Westtown 2nd 35MVA Bank and New Circuits	Dec-14	Dec-14	-	-	-	-	-	On Time
West Warwick Substation, Transmission and UG Exits	Jun-15	Jun-15	1,263.8	1,263.8	1,263.8	1,263.8	5,055.2	On Time
Blooming Grove Substation Upgrade and UG Exits	Jun-15	Jun-15	14.8	14.8	14.8	14.8	59.2	On Time
Tappan Substation, UG Exits, and Transmission Tap	Jun-15	Jun-15	168.3	168.3	168.3	168.3	673.0	On Time
Total							**$ 50,675.5**	

Orange and Rockland Utilities, Inc.

Electric Rate Case - Quarter Update Example

Electric Capital Expenditures - Projects Over $1 Million

Detail Narrative - Forecasted vs. Actuals

Electric Capital Expenditures:

Project Description	Actual Plant Expenditures	Expenditures in Rate Case	Delta	Reason for difference
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	466.5	466.5	0.0	On budget
Mobile #1 Replacement	1,579.6	1,579.6	0.0	On budget
Line 562/563 CAT-1 OPGW	187.5	187.5	0.0	On budget
Sugarloaf 69kV Yard Breaker Replacement	955.0	955.0	0.0	On budget
Line 311 Shoreline Erosion	1,606.2	1,606.2	0.0	On budget
Control Center Renovation	8,000.0	8,000.0	0.0	On budget
New Hempstead Road Substation, 32MVAR Cap and UG Exits	8,417.0	8,417.0	0.0	On budget
Municipal Streetlight Ownership Software Program	1,356.0	1,356.0	0.0	On budget
Port Jervis Substation and UG Exits	7,400.0	7,400.0	0.0	On budget
New Hartley Road Substation, UG Exits, and Transmission T	4,488.0	4,488.0	0.0	On budget
Little Tor Substation and UG Exits	4,095.0	4,095.0	0.0	On budget
Sterling Forest New 69KV Source (L26 tap)	3,053.3	3,053.3	0.0	On budget
Line 49 Upgrade	1,600.0	1,600.0	0.0	On budget
Line 702 Upgrade	1,600.0	1,600.0	0.0	On budget
Future Breaker Position for Northern 345kV Tap	84.0	84.0	0.0	On budget
Westtown 2nd 35MVA Bank and New Circuits	-	-	0.0	On budget
West Warwick Substation, Transmission and UG Exits	5,055.2	5,055.2	0.0	On budget
Blooming Grove Substation Upgrade and UG Exits	59.2	59.2	0.0	On budget
Tappan Substation, UG Exits, and Transmission Tap	673.0	673.0	0.0	On budget

Orange and Rockland Utilities, Inc.
Electric Rate Case - Annual Update Example
Electric Plant Additions
Rate Year 1

	Rate Year 1		
Project Description	**Rate Case**	**Actual**	**Variance**
Blankets	**$ 29,191.8**	**$ 29,191.8**	-
Regular Projects Under $1 Million	**5,260.5**	**5,260.5**	-
Regular Projects Over $1 Million			
Rt 218/9W double circuit from Mine Torne to Morgan Road	1,119.5	1,119.5	-
Mobile #1 Replacement	1,665.6	1,665.6	-
Line 562/563 CAT-1 OPGW	1,565.7	1,565.7	-
Sugarloaf 69kV Yard Breaker Replacement	1,128.6	1,128.6	-
Line 311 Shoreline Erosion	4,604.4	4,604.4	-
Control Center Renovation	8,953.0	8,953.0	-
New Hempstead Road Substation, 32MVAR Cap and UG Exits	13,786.5	13,786.5	-
Municipal Streetlight Ownership Software Program	-	-	-
Port Jervis Substation and UG Exits	-	-	-
New Hartley Road Substation, UG Exits, and Transmission Tap	-	-	-
Little Tor Substation and UG Exits	-	-	-
Sterling Forest New 69KV Source (L26 tap)	-	-	-
Line 49 Upgrade	-	-	-
Line 702 Upgrade	-	-	-
Future Breaker Position for Northern 345kV Tap	-	-	-
Westtown 2nd 35MVA Bank and New Circuits	-	-	-
West Warwick Substation, Transmission and UG Exits	-	-	-
Blooming Grove Substation Upgrade and UG Exits	-	-	-
Tappan Substation Property	-	-	-
Tappan Substation, UG Exits, and Transmission Tap	-	-	-
	32,823.3	**32,823.3**	-
Total	**67,275.5**	**67,275.5**	-

Orange and Rockland Utilities, Inc.
Electric Rate Case - Annual Update Example
Electric Capital Expenditures
Rate Year 1

		Nine Months Ending Rate Year 1	
Project Description	**Rate Case**	**Actual**	**Variance**
Blankets	**30,647.5**	**30,647.5**	-
Regular Projects Under $1 Million	**5,087.9**	**5,087.9**	-
Regular Projects Over $1 Million			
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	466.5	466.5	-
Mobile #1 Replacement	1,579.6	1,579.6	-
Line 562/563 CAT-1 OPGW	187.5	187.5	-
Sugarloaf 69kV Yard Breaker Replacement	955.0	955.0	-
Line 311 Shoreline Erosion	1,606.2	1,606.2	-
Control Center Renovation	8,000.0	8,000.0	-
New Hempstead Road Substation, 32MVAR Cap and UG Exits	8,417.0	8,417.0	-
Municipal Streetlight Ownership Software Program	1,356.0	1,356.0	-
Port Jervis Substation and UG Exits	7,400.0	7,400.0	-
New Hartley Road Substation, UG Exits, and Transmission Tap	4,488.0	4,488.0	-
Little Tor Substation and UG Exits	4,095.0	4,095.0	-
Sterling Forest New 69KV Source (L26 tap)	3,053.3	3,053.3	-
Line 49 Upgrade	1,600.0	1,600.0	-
Line 702 Upgrade	1,600.0	1,600.0	-
Future Breaker Position for Northern 345kV Tap	84.0	84.0	-
Westtown 2nd 35MVA Bank and New Circuits	-	-	-
West Warwick Substation, Transmission and UG Exits	5,055.2	5,055.2	-
Blooming Grove Substation Upgrade and UG Exits	59.2	59.2	-
Tappan Substation, UG Exits, and Transmission Tap	673.0	673.0	-
	50,675.5	**50,675.5**	-
Total	**86,410.9**	**86,410.9**	-

Orange and Rockland Utilities, Inc.
Electric Rate Case - Annual Update
Electric Blanket Expenditures
Rate Year 1

Project Description	**Rate Year 1**	**Actual**	**Variance**
Electric Distribution Blankets - OH NY	956.7	956.7	-
Electric Distribution Blankets - OH NY	11,113.9	11,113.9	-
Electric Distribution Blankets - UG NY	179.1	179.1	-
Electric Distribution Blankets - UG NY	3,042.9	3,042.9	-
Transformers - NY OH (Incl Contributions	1,935.5	1,935.5	-
Transformers - NY UG (Incl Contributions	3,656.6	3,656.6	-
O/H Capital Tools Blanket (NY)	91.5	91.5	-
Electric Meter Purchases - NY	1,047.2	1,047.2	-
T&S Engneering Software/Hardware Bkt	45.4	45.4	-
Distrib Substation Automation Bkt - NY	203.9	203.9	-
U/G Rebuild Blanket (NY)	1,507.2	1,507.2	-
U/G Gasification (Rehab) Blanket (NY)	221.1	221.1	-
Electric Meter 1st Install Bkt - NY	1,356.8	1,356.8	-
Mobile OMS Blanket - NY	114.2	114.2	-
SG Metering Upgrade Bkt - NY	232.8	232.8	-
Smart Grid Devices Bkt - NY	112.3	112.3	-
Distribution Cap Program Blanket - NY	51.2	51.2	-
Load Study Meters - NY	31.2	31.2	-
Distribution Automation Blanket - NY	1,427.1	1,427.1	-
OMS Hardware Blanket - NY	57.2	57.2	-
Distrib Engineering Equipmt/Hardware Bkt	50.0	50.0	-
Sale Of Scrap Blanket	46.4	46.4	-
PCB Oil Testing And Disposal Blanket	104.5	104.5	-
Low Voltage Area Conversion Blanket	800.4	800.4	-
2011 OMS Development	225.2	225.2	-
DOE NY - Distribution Capacitors	159.0	159.0	-
CMO Miscellaneous Equipment Bkt - NY	171.0	171.0	-
2011 NRG Development	225.3	225.3	-
U/G Capital Tools Blanket (NY)	57.8	57.8	-
Substation Department Blanket - NY	62.3	62.3	-
Install Battery Banks Blanket - NY	10.0	10.0	-
Install Battery Banks Blanket - NY	17.0	17.0	-
Relay Department Blanket	41.8	41.8	-
Purchase Relay Test Set Bkt	67.3	67.3	-
Substation Comm. Protection Bkt - NY	58.9	58.9	-
Transmission Relay Upgrade Bkt - NY	275.9	275.9	-
EMS Equipment Upgrade Blanket	460.4	460.4	-
JUMP Program - EMS Expansion Bkt	382.5	382.5	-
Substation Small Equipment Blanket - NY	48.0	48.0	-
	30,647.5	**30,647.5**	**-**

Orange and Rockland Utilities, Inc.
Electric Rate Case - Annual Update Example
Electric Projects Under $1 Million Expenditures
Rate Year 1

Project Description	Rate Year 1	Actual	Variance
Rye Hill Rd-Subdivision Feed 61-2-13	-	-	-
Tappan - Hickory Hill Rd. Conversion (summer prep)	-	-	-
New Hempstead - New Hempstead Road Widening - 2nd Sectio	-	-	-
Suffern - Church Rd Conversion (summer prep)	-	-	-
West Nyack - Rt 59 Double Circuit (NYSDOT Project)	-	-	-
New Hempstead - New Hempstead Road Widening - 3rd Sectior	-	-	-
Snake Hill Rd. - RR Right-of Way Removal and Conversion	-	-	-
Sloatsburg - Seven Lakes Dr Conversion - Part 1	-	-	-
Wheeler Rd. - Florida	33.1	33.1	-
Snake Hill Rd. - West Nyack Road/Strawtown Removal 4kV Ckt.	75.0	75.0	-
Westtown Circuit 103-2-13-Route 284 to Lower Road	107.0	107.0	-
Remove - Rt 218/9W double circuit from Mine Torne to Morgan	50.7	50.7	-
Route 42 - End of Ckt. to Old Plank Rd-reconductor	430.0	430.0	-
Orchard Lake	148.7	148.7	-
Port Jervis-Clark St to Hammond St	145.2	145.2	-
Pearl River - Washington Ave Conversion Part 1	250.0	250.0	-
Route 42 - Peenpack Rd. to End of Ckt-reconductor	480.0	480.0	-
West Nyack - Viaduct Rd Reconductor (NYSDOT Project)	75.0	75.0	-
2010 LTS System Improvement - Arden House (removal)	114.0	114.0	-
Tower Drive-Route 211 to Industrial Double Circuit	215.5	215.5	-
Port Jervis-Main Street-Convert 5-10-34 from station to Canal	59.4	59.4	-
Pearl River - Washington Ave Conversion Part 2	200.0	200.0	-
Port Jervis-Main St-Canal St to Kingston St-double ckt	56.4	56.4	-
Ingrassia Rd-Route 17M to Howells Rd-reconductor	760.1	760.1	-
Pearl River - Blauvelt Rd Reconductor & Extend	155.0	155.0	-
Mud Mills-Silver Lake to Cottage Street-Reconductor	385.0	385.0	-
Orchard Hill Rd. - Monroe	622.8	622.8	-
Tappan - ROW Single Circuit to Lawrence St	175.0	175.0	-
Hartley Road - Echo Lake Road - Sub to Golf Links Road	325.0	325.0	-
Tappan - Oak Tree Rd West Double Circuit	-	-	-
Sloatsburg - Seven Lakes Dr Conversion - Part 2	100.0	100.0	-
Tappan - Oak Tree Rd East Double Circuit	-	-	-
Hartley Station - Owens Road-Station to Philipsburg Rd-Double C	-	-	-
Tappan - Lawrence Reconductor	-	-	-
Orangeburg - Route 303 Reconductor (50-4-13/54-3-13 Tie)	-	-	-
New Vernon/Spruce-Co Rd 62 to Rt 212	125.0	125.0	-
West Warwick Dist Part 1 (Sanfordville -1A to PI Tnpk-double)	-	-	-
Pennsylvania Ave-34kV Step to Sullivan Ave	-	-	-
Sloatsburg - Seven Lakes Dr Conversion - Part 3	-	-	-
West Warwick part 2 - Ryerson Rd (RT 94 to Blooms Corner)	-	-	-
Orangeburg - Kings Highway Extension/Tie	-	-	-
Little Tor Transmission tap	-	-	-
Mt. Orange/Hunter-Jogee to Waywayanda	-	-	-
Sullivan Ave - Penn to Yankee Lake feed-Part 1	-	-	-
West Warwick part 3 - RT 94 (Ryerson to Warwick Tpke)	-	-	-
Pomona - Spook Rock Rd Reconductor Part 1	-	-	-
West Warwick part 4 - Miller/Dekay (Sandfordville to Waterbury	-	-	-
Pearl River - Washington Ave Conversion Part 3	-	-	-
Tappan - Route 303 Reconductor	-	-	-
Sullivan Ave - Penn to Yankee Lake feed-Part 2	-	-	-
West Warwick part 5 - Waterbury (Edenville to Blooms Corners)	-	-	-
West Warwick part 6 (Sandfordville-West to Covered Bridge-dou	-	-	-
Fair Oaks-VanBurenville Rd-Cortright Rd to Pine Grove	-	-	-
Pomona - Wilder Rd double ckt	-	-	-
West Warwick part 7 (West St - Sandfordville to Pelton Rd - doul	-	-	-
Ledge Road-New Vernon Road to Van Burenville Road	-	-	-
	5,087.9	**5,087.9**	-

Orange and Rockland Utilities, Inc.
Electric Rate Case - Annual Update Example
Total Estimate and Spending Summary - Projects Over $1 Million
Detail Narrative - Original vs. Current

Electric Capital Expenditures:

Project Description	Original Estimate	Previous Quarterly Estimate	Current Estimate	Delta	Delta From Prev. Quarter	Reason for difference	Total Project Spending Thru 03-31-12
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	$ 466.5	$ 466.5	$ 466.5	$ -	$ -	No change	$ 8,207.4
Mobile #1 Replacement	$ 1,579.6	$ 1,579.6	$ 1,579.6	$ -	$ -	No change	$ 4,563.9
Line 562/563 CAT-1 OPGW	$ 187.5	$ 187.5	$ 187.5	$ -	$ -	No change	$ 3,965.8
Sugarloaf 69kV Yard Breaker Replacement	$ 955.0	$ 955.0	$ 955.0	$ -	$ -	No change	$ 10,077.4
Line 311 Shoreline Erosion	$ 1,606.2	$ 1,606.2	$ 1,606.2	$ -	$ -	No change	$ 5,828.3
Control Center Renovation	$ 8,000.0	$ 8,000.0	$ 8,000.0	$ -	$ -	No change	$ 7,398.2
New Hempstead Road Substation, 32MVAR Cap and UG Exits	$ 8,417.0	$ 8,417.0	$ 8,417.0	$ -	$ -	No change	$ 3,043.5
Municipal Streetlight Ownership Software Program	$ 1,356.0	$ 1,356.0	$ 1,356.0	$ -	$ -	No change	$ 255.9
Port Jervis Substation and UG Exits	$ 7,400.0	$ 7,400.0	$ 7,400.0	$ -	$ -	No change	$ 2,092.2
New Hartley Road Substation, UG Exits, and Transmission Tap	$ 4,488.0	$ 4,488.0	$ 4,488.0	$ -	$ -	No change	$ 5,632.5
Little Tor Substation and UG Exits	$ 4,095.0	$ 4,095.0	$ 4,095.0	$ -	$ -	No change	$ 165.2
Sterling Forest New 69KV Source (L26 tap)	$ 3,053.3	$ 3,053.3	$ 3,053.3	$ -	$ -	No change	$ 1,296.7
Line 49 Upgrade	$ 1,600.0	$ 1,600.0	$ 1,600.0	$ -	$ -	No change	$ 25,457.7
Line 702 Upgrade	$ 1,600.0	$ 1,600.0	$ 1,600.0	$ -	$ -	No change	$ 1,564.7
Future Breaker Position for Northern 345kV Tap	$ 84.0	$ 84.0	$ 84.0	$ -	$ -	No change	$-
Westtown 2nd 35MVA Bank and New Circuits	$ -	$ -	$ -	$ -	$ -	No change	$ 2,073.6
West Warwick Substation, Transmission and UG Exits	$ 5,055.2	$ 5,055.2	$ 5,055.2	$ -	$ -	No change	$ 428.4
Blooming Grove Substation Upgrade and UG Exits	$ 59.2	$ 59.2	$ 59.2	$ -	$ -	No change	$ 1,235.4
Tappan Substation, UG Exits, and Transmission Tap	$ 673.0	$ 673.0	$ 673.0	$ -	$ -	No change	$ 0.6

Orange and Rockland Utilities, Inc.
Electric Rate Case - Annual Update Example
Detail Breakdown - Projects Over $1 Million

Rate Year 1

Project Description	Rate Case In Service Date	Projected Actual In Service Date	Payroll	Accounts Payable	Materials & Supplies	Overheads	Total $	Remarks
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	Aug-12	Aug-12	116.6	116.6	116.6	116.6	466.5	On Time
Mobile #1 Replacement	Dec-12	Dec-12	394.9	394.9	394.9	394.9	1,579.6	On Time
Line 562/563 CAT-1 OPGW	Dec-12	Dec-12	46.9	46.9	46.9	46.9	187.5	On Time
Sugarloaf 69kV Yard Breaker Replacement	Dec-12	Dec-12	238.8	238.8	238.8	238.8	955.0	On Time
Line 311 Shoreline Erosion	Dec-12	Dec-12	401.6	401.6	401.6	401.6	1,606.2	On Time
Control Center Renovation	Jun-13	Jun-13	2,000.0	2,000.0	2,000.0	2,000.0	8,000.0	On Time
New Hempstead Road Substation, 32MVAR Cap and UG Exits	Jun-13	Jun-13	2,104.3	2,104.3	2,104.3	2,104.3	8,417.0	On Time
Municipal Streetlight Ownership Software Program	Dec-13	Dec-13	339.0	339.0	339.0	339.0	1,356.0	On Time
Port Jervis Substation and UG Exits	Jun-14	Jun-14	1,850.0	1,850.0	1,850.0	1,850.0	7,400.0	On Time
New Hartley Road Substation, UG Exits, and Transmission Tap	Jun-14	Jun-14	1,122.0	1,122.0	1,122.0	1,122.0	4,488.0	On Time
Little Tor Substation and UG Exits	Jun-14	Jun-14	1,023.8	1,023.8	1,023.8	1,023.8	4,095.0	On Time
Sterling Forest New 69KV Source (L26 tap)	Jun-14	Jun-14	763.3	763.3	763.3	763.3	3,053.3	On Time
Line 49 Upgrade	Jun-14	Jun-14	400.0	400.0	400.0	400.0	1,600.0	On Time
Line 702 Upgrade	Jun-14	Jun-14	400.0	400.0	400.0	400.0	1,600.0	On Time
Future Breaker Position for Northern 345kV Tap	Dec-14	Dec-14	21.0	21.0	21.0	21.0	84.0	On Time
Westtown 2nd 35MVA Bank and New Circuits	Dec-14	Dec-14	-	-	-	-	-	On Time
West Warwick Substation, Transmission and UG Exits	Jun-15	Jun-15	1,263.8	1,263.8	1,263.8	1,263.8	5,055.2	On Time
Blooming Grove Substation Upgrade and UG Exits	Jun-15	Jun-15	14.8	14.8	14.8	14.8	59.2	On Time
Tappan Substation, UG Exits, and Transmission Tap	Jun-15	Jun-15	168.3	168.3	168.3	168.3	673.0	On Time
Total							**$ 50,675.5**	

Orange and Rockland Utilities, Inc.

Electric Rate Case - Quarter Update Example

Electric Capital Expenditures - Projects Over $1 Million

Detail Narrative - Forecasted vs. Actuals

Electric Capital Expenditures:

Project Description	Actual Plant Expenditures	Expenditures in Rate Case	Delta	Reason for difference
Rt 218/9W Double Circuit - Mine Torne to Morgan Road	466.5	466.5	0.0	On budget
Mobile #1 Replacement	1,579.6	1,579.6	0.0	On budget
Line 562/563 CAT-1 OPGW	187.5	187.5	0.0	On budget
Sugarloaf 69kV Yard Breaker Replacement	955.0	955.0	0.0	On budget
Line 311 Shoreline Erosion	1,606.2	1,606.2	0.0	On budget
Control Center Renovation	8,000.0	8,000.0	0.0	On budget
New Hempstead Road Substation, 32MVAR Cap and UG Exits	8,417.0	8,417.0	0.0	On budget
Municipal Streetlight Ownership Software Program	1,356.0	1,356.0	0.0	On budget
Port Jervis Substation and UG Exits	7,400.0	7,400.0	0.0	On budget
New Hartley Road Substation, UG Exits, and Transmission T	4,488.0	4,488.0	0.0	On budget
Little Tor Substation and UG Exits	4,095.0	4,095.0	0.0	On budget
Sterling Forest New 69KV Source (L26 tap)	3,053.3	3,053.3	0.0	On budget
Line 49 Upgrade	1,600.0	1,600.0	0.0	On budget
Line 702 Upgrade	1,600.0	1,600.0	0.0	On budget
Future Breaker Position for Northern 345kV Tap	84.0	84.0	0.0	On budget
Westtown 2nd 35MVA Bank and New Circuits	-	-	0.0	On budget
West Warwick Substation, Transmission and UG Exits	5,055.2	5,055.2	0.0	On budget
Blooming Grove Substation Upgrade and UG Exits	59.2	59.2	0.0	On budget
Tappan Substation, UG Exits, and Transmission Tap	673.0	673.0	0.0	On budget

Orange and Rockland Utilities, Inc.
Case 11-E-0408
Amortization of Regulatory Deferrals (Credits & Debits)

Electric Operations	Twelve Months Ending June 30, 2013	2014	2015	Total	Twelve Months Ending June 30, 2016	2017	2018
Regulatory Assets (Debits)							
Regulatory assets approved in Case 10-E-0362	$(10,498,061)	$(10,498,061)	$ (6,680,286)	$(27,676,409)	$ (6,680,286)	$ -	$ -
Pension	(506,386)	(506,386)	(506,386)	(1,519,158)	(506,386)	(506,386)	-
Medicare Part D	(252,505)	(252,505)	(252,505)	(757,515)	-	-	-
Storm Reserve-Hurricane Irene	(2,080,000)	(2,080,000)	(2,080,000)	(6,240,000)	(2,080,000)	(2,080,000)	-
Storm Reserve-October Snow Storm	-	(3,142,000)	(3,142,000)	(6,284,000)	(3,142,000)	(4,785,000)	(1,500,000)
Interest on Pollution Control Debt	(1,052,092)	(1,052,092)	(1,052,092)	(3,156,276)	-	-	-
MGP-RY1 spending	(2,441,583)	(2,441,583)	(2,441,583)	(7,324,748)	(2,441,583)	(2,441,583)	-
MGP-RY2 spending	-	(1,702,245)	(1,702,245)	(3,404,490)	(1,702,245)	(1,702,245)	(1,702,245)
MGP-RY3 spending	-	-	(152,820)	(152,820)	(152,820)	(152,820)	(152,820)
West Nyack	(59,672)	(59,672)	(59,672)	(179,015)	(59,672)	-	-
West Nyack RY1 spending	(5,000)	(5,000)	(5,000)	(15,000)	(5,000)	(5,000)	-
West Nyack RY2 spending	-	(5,000)	(5,000)	(10,000)	(5,000)	(5,000)	(5,000)
West Nyack RY2 3pending	-	-	(5,000)	(5,000)	(5,000)	(5,000)	(5,000)
Spring Valley UST	(42,509)	(42,509)	(42,509)	(127,526)	(42,509)	-	-
Spring Valley UST RY1 spending	(6,582)	(6,582)	(6,582)	(19,746)	(6,582)	(6,582)	-
Rate Case Cost (11-E-0408)	(66,667)	(66,667)	(66,667)	(200,001)	-	-	-
OPEBs - Transitional Obligation	(909,000)	-	-	(909,000)	-	-	-
Asbestos Claims	(170,000)	-	-	(170,000)	-	-	-
Total Regulatory Assets (a)	$(18,090,056)	$(21,860,301)	$(18,200,346)	$(58,150,703)	$(16,829,082)	$(11,689,616)	$(3,365,065)
Regulatory Liabilities (Credits)							
Regulatory liabilities approved in Case 10-E-0362	$ 9,849,514	$ 9,849,514	$ -	$ 19,699,027	$ -	$ -	$ -
OPEBs (exc. Transitional Obligation)	89,120	89,120	89,120	267,360	89,120	89,120	-
MGP-removed land	1,003,832	1,003,832	-	2,007,665	-	-	-
Reactive Power	114,551	114,551	114,551	343,653	-	-	-
Conservation Cost	17,682	17,682	17,682	53,046	-	-	-
Tree Trimming	399,727	399,727	399,727	1,199,181	-	-	-
Hillburn Property Tax Settlement	3,290	3,290	3,290	9,870	-	-	-
Town of Monroe Property Tax Settlement	109,385	109,385	109,385	328,155	-	-	-
Town of Middletown Property Tax	17,834	17,834	17,834	53,502	-	-	-
Environmental Carrying Charge	671,196	671,196	671,196	2,013,588	-	-	-
Total Regulatory Liabilities (b)	$ 12,276,131	$ 12,276,131	$ 1,422,785	$ 25,975,047	$ 89,120	$ 89,120	$ -
Net Debits (a - b)	$ (5,813,925)	$ (9,584,170)	$(16,777,561)	$(32,175,656)	$(16,739,962)	$(11,600,496)	$(3,365,065)

ORANGE AND ROCKLAND UTILITIES, INC.
AMORTIZATION OF REGULATORY DEFERRALS APPROVED IN CASE 10-E-0362

Regulatory Assets approved in Case 10-E-0362	Account	Exh. / Sched.	Allowance 10-E-0362	Staff's Adjustment	10-E-0362 Amortization 7/1/11 - 6/30/12	Updated Balance 6/30/2012	Amortization Period	Updated Annual Amortization approved in Case 10-E-0362 June 30, 2013	2014	2015	2016
1 Pension	182321	E-5, SCH 6	25,750,000	(8,942,880)	(5,150,000)	11,657,120	5	(2,914,280)	(2,914,280)	(2,914,280)	(2,914,280)
2 OPEBs (exc. Transitional Obligation)	182323	E-5, SCH 6	13,725,000	(2,657,975)	(2,745,000)	8,322,025	5	(2,080,506)	(2,080,506)	(2,080,506)	(2,080,506)
3 Medicare Part D	254540	E-5, SCH 6	480,000	-	(160,000)	320,000	3	(160,000)	(160,000)		-
4 Total Pension/OPEB Recoveries			39,955,000	(11,600,855)	(8,055,000)	20,299,145		(5,154,786)	(5,154,786)	(4,994,786)	(4,994,786)
5 Cottman, Newark Bay, and Bourne	182394/182497/182498/242393	E-5, SCH 8	568,000	(282,000)	(113,600)	172,400	5	(43,000)	(43,000)	(43,000)	(43,000)
6 Storm Reserve	182373/228450	E-5, SCH 9	10,005,000	(1,434,000)	(2,001,000)	6,570,000	5	(1,642,500)	(1,642,500)	(1,642,500)	(1,642,500)
7 R&D	188100/188104	E-5, SCH 5	1,415,073	101,512	(471,691)	1,044,894	3	(522,000)	(522,000)	-	-
8 Low Income	254430	E-5, SCH 5	465,000	16,000	(155,000)	326,000	3	(163,000)	(163,000)	-	-
9 Rate Case Cost (10-E-0362)	182568	E-5, SCH 10	150,000	-	(50,000)	100,000	3	(50,000)	(50,000)	-	-
10 MTA Mobility Tax	182448	E-4, SCH 7	618,000	-	(206,000)	412,000	3	(206,000)	(206,000)	-	-
11 Property Tax Undercollection	182406	E-4, SCH 7	7,158,000	460,000	(2,386,000)	5,232,000	3	(2,616,000)	(2,616,000)	-	-
12 Property Tax Refunds - Haverstraw (86%)	254084	E-4, SCH 5	302,325	-	(100,775)	201,550	3	(100,775)	(100,775)	-	-
13 Total Recoveries			60,636,398	(12,739,343)	(13,539,066)	34,357,989		(10,498,061)	(10,498,061)	(6,680,286)	(6,680,286)
Regulatory Liabilities approved in Case 10-E-0362											
14 CATV Order Deferred Billing	254344	E-4, SCH 5	(345,000)	(6,000)	115,000	(236,000)	3	118,000	118,000	-	-
15 Net Plant Reconciliation	254331	E-4, SCH 5	(27,735,000)	324,000	9,245,000	(18,166,000)	3	9,083,000	9,083,000	-	-
16 Performance Penalties - CAIDI	229620	E-4, SCH 5	(1,404,000)	-	468,000	(936,000)	3	468,000	468,000	-	-
17 Oil Supplier Refunds	253064	E-4, SCH 5	(165,000)	-	55,000	(110,000)	3	55,000	55,000	-	-
18 Current SIT - NYS Rate Change 7.5% - 7.1%	254313	E-4, SCH 5	(303,102)	-	101,034	(202,068)	3	101,034	101,034	-	-
19 Interest Repair Allowance/Bonus Depr	254345	E-4, SCH 5	(95,088)	14,433	31,696	(48,959)	3	24,480	24,480	-	-
20 Total Refunds			(30,047,190)	332,433	10,015,730	(19,699,027)		9,849,514	9,849,514	-	-
Recoveries less Refunds			30,589,208	(12,406,910)	(3,523,336)	14,658,962		(648,548)	(648,548)	(6,680,286)	(6,680,286)

ORANGE AND ROCKLAND UTILITIES, INC.
Electric Base Rate Case 11-E-0408
New Positions Reflected in Settlement - Labor (a)

	RY 1		RY 2		RY 3		Total	
	# of positions	Payroll Allocated to Electric	# of positions	Payroll Allocated to Electric	# of positions	Payroll Allocated to Electric	# of positions	Payroll Allocated to Electric
Monthly Employees:								
Market Research and Forecasting	1	$ 16,088		$ 19,672		$ 20,066	1	$ 55,826
Cost Management Analyst	1	30,549		31,316		31,942	1	93,806
Cost Management Analyst	1	61,097		62,631		63,884	1	187,612
Cost Management Analyst	1	47,538		48,731		49,705	1	145,974
Senior Specialist CIP Compliance	1	48,442		68,627		69,999	1	187,069
Environmental Natural Resource - Permitting	1	19,837		28,103		28,665	1	76,606
Systems Analyst -ITP	1	35,707		50,586		51,597	1	137,890
Project Management Cost Administrator	1	43,343		61,403		62,631	1	167,377
SCADA Engineer	1	46,989		66,568		67,899	1	181,457
Engineer - Power System Application	1	46,989		66,568		67,899	1	181,457
CIMS - Associate Specialist	1	31,740		44,965		45,864	1	122,569
Electric Meter Technicians 3rd Class (CMO)	1	28,249		40,019		40,819	1	109,087
Electric Meter Technicians 3rd Class (CMO)			1	39,234		40,019	1	79,253
Project Manager	1	19,716		27,930		28,489	1	76,135
Project Manager	1	11,542		27,930		28,489	1	67,961
Project Manager			1	27,383		27,930	1	55,313
Project Manager	1	27,306		27,852		28,409	1	83,568
Construction Manager	1	24,706		25,200		25,704	1	75,609
Project Manager	1	29,907		30,505		31,115	1	91,527
Systems Analyst - Operations Support (WMS)	1	30,595		43,343		44,210	1	118,149
	18	$ 600,341	2	$ 838,566	-	$ 855,337	20	$ 2,294,244

(a) Dollar amounts represent electric operation and maintenance portion only including wage increase.

Appendix K

Electric Customer Service and Reliability Performance Mechanism

1. Customer Service

Customer Surveys

During the Electric Rate Plan, the Customer Contact Satisfaction Survey ("CCSS") target and associated revenue adjustments will be as set forth below.

Customer Contact Satisfaction Survey ("CCSS")	Threshold Level	Negative Revenue Adjustment
	>89.0%	$0
	<= 89.0%	$150,000
	<= 88.0%	$300,000
	<87.0%	$450,000

The Company contracts with a third-party vendor to conduct a monthly Customer Contact Satisfaction Survey. The vendor surveys customers utilizing a 10-point scale to rank customer satisfaction with Company performance based upon a series of questions and one overall customer satisfaction index question:

> "*Using a scale from 1 to 10 where 1 means you were very dissatisfied and 10 means you were very satisfied, how satisfied were you the way the Orange and Rockland's Customer Service Representative handled your recent issue/request?*"

The Company reports the percentage of customers surveyed that responded with a score of 7 – 10 to the overall customer satisfaction index question.

Adjusted Bills

Adjusted Bills	Threshold Level	Negative Revenue Adjustment
	<=2.42%	$0
	>2.42%	$50,000
	>2.54%	$100,000
	>2.66%	$150,000

The Company reports the number of bills adjusted each month. A cancelled estimated cycle bill based on an actual meter reading is not considered an adjusted bill. A bill containing gas and electric charges is counted as one bill/account.

Customer Complaint Rate Target

The annual Complaint Rate will be calculated in the manner approved by the Commission in its Order Approving Complaint Rate Targets issued August 26, 2005.[1] In calculating the annual Complaint Rate, (i) duplicative rate consultant complaints, and (ii) high commodity prices complaints, as described in the Complaint Rate Targets Order, will be excluded. During the Electric Rate Plan, the complaint rate not to exceed targets and associated revenue adjustment levels are set forth below.

PSC Complaint Rate per 100K 12 months rolling	Threshold Level	Negative Revenue Adjustment
	1.8	$150,000
	1.9	$300,000
	>=2.0	$500,000

For measurement purposes, results from months having abnormal operating conditions will not be considered. Abnormal operating conditions are deemed to occur during any period of

[1] Case 02-G-1553, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, and Case 03-E-0797, *In the Matter of Orange and Rockland Utilities, Inc.'s Proposal for an Extension of an Existing Rate Plan, filed in Case 96-E-0900,* Order Approving Complaint Rate Target (issued August 26, 2005) ("Complaint Rate Targets Order").

emergency, catastrophe, strike, natural disaster, “Major Storm” (as that term is defined by 16 NYCRR Part 97), or other unusual event not in the Company’s control affecting more than ten percent of the customers during any month. When abnormal operating conditions occur, application of the Customer Complaint Rate Target will be based on PSC complaint rates for the remaining months of the affected year.

2. Reliability Performance Mechanism

<u>Operation of Mechanism:</u>

The Reliability Performance Mechanism (“RPM”) includes targets for the frequency and duration of electric service interruption, defined as:

1. Customer Average Interruption Duration Index (“CAIDI”) – the average interruption duration time (hours) for those customers that experience an interruption during the year.
2. System Average Interruption Frequency Index (“SAIFI”) – the average number of times that a customer is interrupted during a year.

The SAIFI and CAIDI performance targets for Orange and Rockland are 1.20 and 1.85, respectively, with negative revenue adjustments of 20 basis points for failure to meet each target on a calendar year basis. These targets are currently in effect and will continue until reset by the Commission.

<u>Exclusions:</u>

The following exclusions are applicable to operating performance under this reliability mechanism.

1. Any outages resulting from a major storm, as defined in 16 NYCRR Part 97.

2. Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to a plane crash, water main break, or natural disasters (e.g., hurricanes, floods, earthquakes).
3. Any incident where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

<u>Reporting:</u>

The Company will prepare an annual report(s) on its performance under this reliability mechanism. The annual report(s) will be filed by March 31st of each year with the Secretary to the Commission. The report(s) will state the following:

1. Company's annual system-wide performance under the RPM and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;
2. Whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

ORANGE & ROCKLAND UTILITIES
DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
ELECTRIC PLANT					
TRANSMISSION PLANT					
350000 01	LAND-EASEMENTS	h3.0	60	-	1.67
350100 01	LAND AND LAND RIGHTS	-	-	-	-
352000 01	STRUCTURES AND IMPROVEMENTS	h2.0	60	(10)	1.83
353000 01	STATION EQUIPMENT	h1.0	40	(15)	2.88
354000 01	TOWERS AND FIXTURES	h3.0	65	(20)	1.85
355000 01	POLES AND FIXTURES-WOOD	h2.5	50	(50)	3.00
355100 01	POLES AND FIXTURES-STEEL	h2.5	50	(50)	3.00
356000 01	OVERHEAD CONDUCTORS & DEVICES	h2.0	65	(15)	1.77
356100 01	OVERHEAD COND & DEVICES-CLEARING	h2.0	65	(15)	1.77
357000 01	UNDERGROUND CONDUIT	h2.5	30	-	3.33
358000 01	UNDERGROUND COND AND DEVICES	h3.5	30	-	3.33
359000 01	ROADS AND TRAILS	h3.0	60	-	1.67
DISTRIBUTION PLANT					
360000 01	LAND-EASEMENTS	h3.0	50	-	2.00
360100 01	LAND AND LAND RIGHTS-FEE	-	-	-	-
361000 01	STRUCTURES AND IMPROVEMENTS	h2.5	55	(15)	2.09
362000 01	STATION EQUIPMENT	h1.5	40	(10)	2.75
364000 01	POLES,TOWERS, AND FIXTURES	h1.5	50	(100)	4.00
365000 01	OVERHEAD CONDUCTOR AND DEVICES	h1.5	65	(90)	2.92
365100 01	O/H COND AND DEVICES-CAPACITORS	h2.5	30	(40)	4.67
366000 01	UNDERGROUND CONDUIT	h2.0	75	(50)	2.00
367000 01	UNDERGROUND CONDUCTOR & DEVICES	h2.5	70	(50)	2.14
367100 01	U.G. COND. & DEVICES - CABLE CURE		AMORTIZABLE		
368100 01	LINE TRANSFORMERS-OVERHEAD	h1.0	45	(10)	2.44
368200 01	LINE TRANSFORMERS-O/H INSTALLS	h1.0	45	(10)	2.44
368300 01	LINE TRANSFORMERS-UNDERGROUND	h1.0	45	(10)	2.44
368400 01	LINE TRANSFORMERS-U/G INSTALLS	h1.0	45	(10)	2.44
369100 01	SERVICES-OVERHEAD	h2.5	60	(100)	3.33
369200 01	SERVICES-UNDERGROUND	h3.5	55	(100)	3.64
370100 01	METERS - ELECTRO-MECHANICAL	h1.0	30	-	3.33
370110 01	METERS - SOLID-STATE	h1.0	20	-	5.00
370200 01	METER INSTALLATIONS - ELECTRO-MECHANICAL	h1.0	30	-	3.33
370210 01	METER INSTALLATIONS - SOLID-STATE	h1.0	20	-	5.00
371000 01	INSTALLATION ON CUSTOMER PREMISES	h2.0	40	-	2.50
371100 01	PALISADES MALL METERING		FULLY AMORTIZED		
373100 01	STREET LIGHTS-OVERHEAD	h1.0	40	(60)	4.00
373200 01	STREET LIGHTS-UNDERGROUND	h1.0	40	(60)	4.00
INTANGIBLE PLANT					
303100 01	WMS SOFTWARE		FULLY AMORTIZED		
303110 01	DISTRIBUTION MANAGEMENT SYSTEM		FULLY AMORTIZED		
303120 01	DISTRIBUTION ENGINEERING SYSTEM (DEW)		AMORTIZABLE		
303130 01	STRAY VOLTAGE SYSTEM		AMORTIZABLE		
303140 01	OUTAGE MANAGEMENT SYSTEM (OMS)		AMORTIZABLE		
303150 01	WEB WMS PHASE 1		AMORTIZABLE		
303170 01	2009 ELECTRIC SOFTWARE ADDITIONS		AMORTIZABLE		

ORANGE & ROCKLAND UTILITIES
DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
ELECTRIC PLANT					
GENERAL PLANT					
389100 01	LAND AND RIGHTS - FEE	-	-	-	-
390000 01	STRUCTURES AND IMPROVEMENTS	h1.5	45	(20)	2.67
391100 01	OFFICE FURN/EQUIP-FURNITURE	h1.5	20	-	5.00
391200 01	OFFICE FURN/EQUIP-OFFICE MACHINES	h1.0	15	-	6.67
391700 01	OFFICE FURN/EQUIP-P/C EQUIPMENT	h2.0	8	-	12.50
391710 01	OFFICE FURN/EQUIP-NON P/C EQUIPMENT	-	-	-	-
391800 01	OFFICE FURN/EQUIP-E.C.C.	h2.5	13	-	7.69
392100 01	TRANSP EQUIP-PASSENGER CARS	h2.5	8	10	11.25
392200 01	TRANSP EQUIP-LIGHT TRUCKS	h2.5	8	10	11.25
392300 01	TRANSP EQUIP-HEAVY TRUCKS	h2.5	12	5	7.92
392400 01	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	h2.5	12	5	7.92
393000 01	STORES EQUIPMENT	h2.0	25	-	4.00
394000 01	TOOLS, SHOP AND WORK EQUIPMENT	h1.5	25	-	4.00
395000 01	LABORATORY EQUIPMENT	h2.0	25	-	4.00
396000 01	POWER OPERATED EQUIPMENT	h3.5	17	15	5.00
396100 01	POWER OPERATED EQ - NON FLEET	h3.5	17	15	5.00
397000 01	COMMUNICATION EQUIPMENT	h1.5	15	-	6.67
397100 01	COMMUNICATION EQUIPT-TELE SYSTEM COMPUTER	h2.0	8	-	12.50
397200 01	COMMUNICATION EQUIPT-TELE SYSTEM EQUIPMENT	-	-	-	-
398000 01	MISCELLANEOUS EQUIPMENT	h1.5	20	-	5.00
PLANT HELD FOR FUTURE USE - TRANSMISSION					
350009 01	LAND AND LAND RIGHTS-EASEMENTS	h3.0	60	-	1.67
355179 01	POLES AND FIXTURES - STEEL - FUTURE USE - DEFERRED	-	-	-	-
356079 01	OH CONDUCTORS AND DEVICES - FUTURE USE - DEFERRED	-	-	-	-
PLANT HELD FOR FUTURE USE - DISTRIBUTION					
360009 01	LAND AND LAND RIGHTS-EASEMENTS	h3.0	50	-	2.00
360109 01	LAND AND LAND RIGHTS-EASEMENTS	-	-	-	-

ORANGE & ROCKLAND UTILITIES

DEPRECIATION RATES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	A S L	NET SALVAGE %	ANNUAL RATE %
COMMON PLANT					
INTANGIBLE PLANT					
301000 03	ORGANIZING	-	-	-	-
303200 03	MAPPING SOFTWARE		FULLY AMORTIZED		
303310 03	EZ VMS SYSTEM		AMORTIZABLE		
303320 03	PEOPLESOFT HR/PR SYSTEM		AMORTIZABLE		
303400 03	CIMS SYSTEM SOFTWARE		AMORTIZABLE		
303410 03	CUSTOMER BILLING SYSTEM		AMORTIZABLE		
303500 03	PLUS SYSTEM SOFTWARE		FULLY AMORTIZED		
303510 03	POWERPLAN SOFTWARE		AMORTIZABLE		
303600 03	WALKER SYSTEM SOFTWARE		FULLY AMORTIZED		
303700 03	BUDGET SYSTEM SOFTWARE		FULLY AMORTIZED		
303800 03	RETAIL ACCESS SOFTWARE		FULLY AMORTIZED		
303810 03	RETAIL ACCESS SOFTWARE PHASE 4		FULLY AMORTIZED		
303840 03	FIELD ORDER ROUTE DESIGN SYSTEM		FULLY AMORTIZED		
303870 03	DATAPIPE SOFTWARE		FULLY AMORTIZED		
303910 03	NEW CONSTRUCTION SERVICES (NUCON)		AMORTIZABLE		
GENERAL PLANT EQUIPMENT					
389000 03	LAND-EASEMENTS	h3.0	50	-	2.00
389100 03	LAND AND LAND RIGHTS -FEES	-	-	-	-
389500 03	LAND AND LAND RIGHTS - MOMBASHA		AMORTIZABLE		
390000 03	STRUCTURES AND IMPROVEMENTS	h1.5	45	(20)	2.67
390100 03	LEASEHOLD IMPROVEMENTS-BLUE HILL		AMORTIZABLE		
391100 03	OFFICE FURN/EQUIP-FURNITURE	h1.5	20	-	5.00
391200 03	OFFICE FURN/EQUIP-OFFICE MACHINES	h1.0	15	-	6.67
391300 03	OFFICE FURN/EQUIP-CASH EQUIPMENT	h2.0	8	-	12.50
391700 03	OFFICE FURN/EQUIP-P/C EQUIPMENT	h2.0	8	-	12.50
391710 03	OFFICE FURN/EQUIP-NON P/C EQUIPMENT	h2.0	8	-	12.50
392100 03	TRANSP EQUIP-PASSENGER CARS	h2.5	8	10	11.25
392200 03	TRANSP EQUIP-LIGHT TRUCKS	h2.5	8	10	11.25
392300 03	TRANSP EQUIP-HEAVY TRUCKS	h2.5	12	5	7.92
392400 03	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	h2.5	12	5	7.92
393000 03	STORES EQUIPMENT	h2.0	25	-	4.00
394000 03	TOOLS, SHOP AND WORK EQUIPMENT	h1.5	25	-	4.00
394200 03	GARAGE EQUIPMENT	h1.5	25	-	4.00
395000 03	LABORATORY EQUIPMENT	h2.0	25	-	4.00
396000 03	POWER OPERATED EQUIPMENT	h3.5	17	15	5.00
396100 03	POWER OPERATED EQ. - NON FLEET	h3.5	17	15	5.00
397000 03	COMMUNICATION EQUIPMENT	h1.5	15	-	6.67
397100 03	COMMUNICATION EQ.-TELE SYS COMPUTER	h2.0	8	-	12.50
397200 03	COMMUNICATION EQ.-TELE SYS EQPT	h1.5	15	-	6.67
398000 03	MISCELLANEOUS EQUIPMENT	h1.5	20	-	5.00

UNALLOCATED RESERVE AMORTIZATIONS

In addition to the depreciation produced by application of the above rates, the following additional amounts of depreciation are in effect:

		TOTAL	ANNUAL	AMORT. END DATE
699110 01	UNALLOCATED RESERVE - ELEC PORTION - CASE 07-E-0949	(8,068,140)	(1,613,628)	JUNE 2013

SUBJECT: Filing by ORANGE AND ROCKLAND UTILITIES, INC.

Amendments to Schedule P.S.C. No. 2 – Electricity

Original Leaves Nos. 40B, 40C, 40D, 40E, 40F, 40G, 40H, 40I, 40J, 40K
Second Revised Leaf No. 26A
Third Revised Leaves Nos. 23X, 23Z-4, 23Z-5-1, 23Z-5-2, 23Z-5-3
Fourth Revised Leaves Nos. 23Z-3-1, 23Z-3-2, 23Z-3-3, 77A-1
Fifth Revised Leaves Nos. 23Z-5, 40A
Seventh Revised Leaves Nos. 22L-5, 89A
Eighth Revised Leaf No. 127
Ninth Revised Leaves Nos. 27C, 32B, 33A, 78, 99A, 126
Eleventh Revised Leaves Nos. 16F-4, 93, 95A, 128
Twelfth Revised Leaves Nos. 22W, 92A
Thirteenth Revised Leaf No. 98
Fourteenth Revised Leaf No. 100
Fifteenth Revised Leaf No. 40
Sixteenth Revised Leaf No. 22V
Seventeenth Revised Leaves Nos. 25B, 39
Nineteenth Revised Leaf No. 71
Twentieth Revised Leaf No. 72
Twenty-First Revised Leaves Nos. 32A, 77, 94
Twenty-Second Revised Leaf No 49
Twenty-Third Revised Leaf No. 29A
Twenty-Fourth Revised Leaf No. 75
Twenty-Fifth Revised Leaves Nos. 76, 91
Twenty-Seventh Revised Leaf No 48A
Twenty-Ninth Revised Leaf No. 3
Thirty-First Revised Leaves Nos. 25C, 48
Thirty-Fifth Revised Leaf No. 88
Thirty-Sixth Revised Leaf No. 29
Thirty-Seventh Revised Leaf No. 32
Thirty-Ninth Revised Leaf No. 25A
Forty-First Revised Leaf No. 37
Forty-Eighth Revised Leaves Nos. 27A, 28
Sixty-Ninth Revised Leaf No. 26
Seventy-Seventh Revised Leaf No. 24