ORANGE AND ROCKLAND UTILTIES, INC.

INDEX OF WITNESSES – 14-E-_____

Orange & Rockland
a conEdison, inc. company

Orange and Rockland Utilities, Inc.
One Blue Hill Plaza
Pearl River, NY 10965-9006
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November 14, 2014

VIA EMAIL

Honorable Kathleen H. Burgess
Secretary
State of New York
Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

Re: Orange and Rockland Utilities, Inc.'s Electric and Gas Base rate Filings

Dear Secretary Burgess:

Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") hereby submits for filing revisions to its Schedule for Electric Service, P.S.C. No. 3 – Electricity and its Schedule for Gas Service, P.S.C. No. 4 – Gas. The tariff leaves implementing the Company's proposals for new electric and gas rate plans are set forth in Appendix A and Appendix B, respectively.

The tariff leaves are issued November 14, 2014, with an effective date of January 1, 2015. The Company's expectation is that the Public Service Commission ("Commission") will issue appropriate orders suspending the effective date of the tariff leaves through October 30, 2015, and that the proposed electric and gas rates will become effective on November 1, 2015.

Pursuant to the Commission's procedures, the prepared written testimony and exhibits, which comprise the Company's direct case in support of these rate filings, are being filed electronically with the Commission. Hard copies of this filing are being provided to Staff of the Department of Public Service ("Staff").

Key provisions of the Company's electric and gas filings are summarized below. The Company would note that while the tariff leaves submitted herewith reflect only the Company's proposed rate increase for the Rate Year, *i.e.*, the twelve months ending October 31, 2016, it remains open to negotiating a multi-year rate agreement for both services.

Electric Service

The Company seeks an increase in revenues for electric delivery of $33.4 million, resulting in an overall customer bill increase of approximately 5.2 percent, including projected supply costs.[1] Appendix C shows the estimated effect on the Company's electric revenues by customer class, based on sales and revenues for the Rate Year.

The Company continues to face cost increases that make a rate increase request necessary and unavoidable. As described in the testimony submitted as part of the electric rate filing, the three principal drivers of this rate filing are the costs associated with additional electric infrastructure investment, increased property taxes (resulting from both Orange and Rockland's investment in infrastructure and increasing local tax rates) and the costs associated with Superstorm Sandy.

The Company's electric rate increase request includes programs to harden Orange and Rockland's energy delivery systems through new construction projects designed to reduce potential damage from future storms, and new technology to provide more accurate and timely communications to its customers during major storms. The Company proposes enhanced electric system modernization programs, in conjunction with the Commission's efforts in its Reforming the Energy Vision ("REV") proceeding (Case 14-M-0101), to modernize the electric utility industry, through increased energy efficiency and other investments that have the potential to lower customers' bills. The Company's major electric infrastructure highlights during 2016 include construction of the Blue Lake Substation, implementation of the Central Rockland Smart Grid, and completion of the Sterling Forest Tap project.

The cost of property taxes has risen significantly since 2009. Indeed, property taxes comprise $13.2 million (of which $3.2 million annually represents the recovery over five years of deferred property taxes) of the Company's proposed electric revenue increase.

In addition, in its electric base rate increase request, the Company is seeking to recover $57 million in costs incurred for the emergency rebuilding, repair and system restoration that was required to return electric service to hundreds of thousands of its customers who lost power as a result of the widespread devastation caused by Superstorm Sandy. On October 29, 2012, Superstorm Sandy caused catastrophic damage throughout Orange and Rockland's service territory. Eighty-three percent, or approximately 250,000, of the Company's total customer base of 300,000 customers lost power. Superstorm Sandy damaged 27 transmission lines, 17 substations and almost all of the Company's 280 distribution circuits. Distribution damage occurred at more than 10,000 separate locations.

The electric revenue increase also reflects the Company's plans to install, over a five-year period (commencing in 2016), an Advanced Metering Infrastructure ("AMI") system in the Rockland County portion of Orange and Rockland's service territory. This is the first phase of the Company's installation of AMI throughout all of its service territory. AMI is an enabling technology that will allow customers to better manage their

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[1] Electric supply costs for retail access customers are assumed to be equivalent to the forecasted electric supply costs applicable to customers taking service under the Company's full-service rates. The electric rate increase represents a delivery rate increase of approximately 11.5 percent.

energy costs and facilitate participation in various programs that help reduce their energy consumption. Information from AMI meters will also enhance outage detection, allowing for faster response and quicker service restoration. The implementation of AMI will reduce costs for meter reading and customer field services, as well as the costs associated with the back-office operations required to handle customer billing inquiries. AMI data can greatly enhance the planning and operation of the electric distribution system. Finally, AMI will provide the technology foundation for many of the initiatives emerging from the REV proceeding.

Consistent with the Commission's policies as articulated in the REV proceeding, the Company is proposing to implement a Distributed Energy Resource demonstration project in order to defer construction of the Pomona Substation. The Company also proposes to explore the feasibility of implementing an electric vehicle charging demonstration project and community solar initiative. As discussed in the testimony of the Company's Electric Rate Panel, the Company proposes to recover the costs of these REV-like initiatives through a REV Surcharge.

Gas Service

The Company seeks an increase in revenues for gas delivery of $40.7 million, resulting in an overall customer bill increase of approximately 16.8 percent, including projected supply costs.[2] Appendix D shows the estimated effect on the Company's gas revenues by customer class, based on sales and revenues for the Rate Year. The Company's gas delivery rates have not increased since November 2011. If approved, the increase in the Company's gas delivery rates, effective November 2015, will be the first in four years.

The Company's gas rate increase request is driven primarily by two components, an increase in property taxes (resulting from both Orange and Rockland's investment in infrastructure and increasing local tax rates) and additional gas infrastructure investment. In fact, increased property taxes account for $20.4 million (of which $7.2 million annually represents the recovery over five years of deferred property taxes) of the Company's proposed gas revenue increase. Additional gas infrastructure investment accounts for $12.5 million of the Company's proposed gas revenue increase.

The Company has proposed to expand its current gas infrastructure replacement program so as to remove a total of 100,000 feet of main annually. In order to eliminate all low pressure mains in six years, the Company proposes to replace annually a minimum of 10,000 feet of low pressure mains. Orange and Rockland also proposes to replace an additional 500 bare steel services annually, as part of the Company's ten year program to remove all bare steel services in its service territory.

[2] Gas supply costs for retail access customers are assumed to be equivalent to the forecasted gas supply costs applicable to customers taking service under the Company's full-service rates. The gas rate increase represents a delivery rate increase of approximately 35.1 percent.

In order to support the development of compressed natural gas ("CNG") as an alternate transportation fuel, the Company is proposing to construct and operate a CNG fueling depot with fast fill dispensing at the Company's Spring Valley operating center. The installation of this infrastructure will allow the Company to replace a portion of its vehicle fleet with CNG fueled vehicles, thereby reducing operating costs, and could also be available to support fleet customers interested in CNG.

The Company also will provide greater safety in the operation of the natural gas delivery system by offering stronger protections from damage by excavators through new gas construction protocols, stronger customer education and outreach, and improved signage.

Cost Mitigation Efforts and Other Considerations

To help mitigate cost increases to both the electric and gas sides of its business, the Company has taken a number of steps to manage increases in its labor costs, as well as programs to improve workplace productivity and operational efficiencies.

The Company has redesigned its healthcare plan and increased employee contributions to healthcare costs --- all to reduce costs to customers. O&R also has replaced its traditional pension plan with a plan for all new employees that will cost customers less over time.

As a short term rate mitigation effort to minimize the impact of the electric and gas rate increases, the Company has extended the amortization periods of certain deferrals. For example, the Company proposes to recover Superstorm Sandy costs and deferred property taxes over five years, rather than the usual three years. The Company also has not proposed to increase the annual storm recovery allowance contained in electric base rates even though the Company's experience with major storms over the past several years would justify such an increase.

The Company is currently negotiating long-term agreements to reduce assessments on taxable properties within the Orange and Rockland service territory. The Company expects that negotiations will result in assessment reductions on plant already in service.

Finally, in order to minimize the issues in controversy relating to these filings and to facilitate reaching a multi-year rate plan through settlement, the Company has included a 9.75% return on equity ("ROE") in both its gas and electric rate filings. This ROE figure is at the low end of the unadjusted range of estimates (*i.e.*, 9.75% to 10.5%) identified by the Company's cost of capital witness as being appropriate for the Company. The Company also has included a capital structure with an equity ratio of 48%, in lieu of the Company's actual equity ratio of 48.45%.

The Proposed Increased Revenue Allocation and Rate Design - Electric

The revenue increase was allocated to the Company's various customer classes as follows.

The Company applied one third of the class-specific embedded cost of service ("ECOS") study deficiency and surplus indications in a revenue neutral manner prior to applying the revenue increases. This approach addresses the surplus and deficiency indications while limiting customer bill impacts. The delivery revenue increase was then allocated among customer classes in proportion to the relative contribution made by each class to the realigned total Rate Year delivery revenues.

Based on the proposed increased level of delivery revenue, revised revenue levels were determined for the competitive delivery components, which include: merchant function charge ("MFC") fixed components, *i.e.*, the MFC procurement and credit and collections components; the purchase of receivables ("POR") credit and collections component; and metering charges. Customer charges were increased in each service classification to be more reflective of customer costs, consistent with the ECOS study. The changes in revenues associated with the competitive delivery components, as well as the changes in revenues associated with customer charges, were then subtracted from the delivery revenue increase for each class to determine the non-competitive delivery revenue increase excluding customer charges for each class.

The Company also made several revenue neutral changes to class-specific revenues before applying the non-competitive delivery revenue increases excluding customer charges for each class. Revenue neutral changes were made to reduce the Service Classification No. 1 discounts for optional electric space and water heating. Revenue neutral changes were made to continue the phase out of declining block rates and corresponding demand rate differentials for Service Classification No. 2 Secondary – Demand Billed. Both of these changes continue gradual phase-outs that began in Case 10-E-0362 and Case 11-E-0408. The Company also proposes to shift, on a revenue neutral basis, a portion of usage-related revenue into demand-related revenue for Service Classification No. 2 – Primary, recognizing the fixed nature of transmission and distribution ("T&D") costs and more closely aligning how costs are incurred and collected from customers.

Usage and demand charges, where applicable, were then increased by class-specific percentage increases. In Service Classification Nos. 3, 9 and 22, the entire class specific increases were applied only to demand charges in further recognition of the fixed nature of T&D costs.

The Company prepared its proposed rate design for Service Classification No. 25, Standby Service, 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 October 26, 2001 in Case 99-M-1470.

Other Tariff Changes - Electric

The Company is proposing other electric tariff changes including:

- the addition of Service Classification Nos. 4 and 6 to the list of classes to which the Revenue Decoupling Mechanism ("RDM") is applicable;
- the addition of Reactive Power Demand Charge revenue in the RDM delivery revenue targets;
- an increase in the re-inspection fee from $51.00 to $80.00;
- the establishment of a REV Surcharge component of the Energy Cost Adjustment mechanism to recover future costs from the Company's proposed Pomona demonstration program and other REV related projects;
- the establishment of an AMI Opt Out Fee;
- continuation of the Service Classification No. 4 "2% System Threshold" for municipal street light replacements originally established in Case 11-E-0408;
- changes in the discounts applicable to customers served under Rider C – Excelsior Jobs Program;
- cancellation of Rider G – NYPA EDP Delivery Service and Rider J – NYPA Power for Jobs, since these services are no longer available; and
- changes to the Company's Economic Development Rider – Rider H to reduce the eligibility requirement from 100 kW to 65 kW and to add additional criteria for taking service under Rider H.

The Proposed Increased Revenue Allocation and Rate Design - Gas

The revenue increase was allocated to the Company's Service Classification Nos. 1, 2, and 6 customers as follows.

The Company applied one third of the class-specific ECOS study deficiency and surplus indications in a revenue neutral manner prior to applying the revenue increases. This approach addresses the surplus and deficiency indications while limiting customer bill impacts. The delivery revenue increase was then allocated among customer classes in proportion to the relative contribution made by each class to the realigned total Rate Year delivery revenues.

Based on the proposed increased level of delivery revenue, revised revenue levels were determined for the competitive delivery components, which include MFC fixed components, that is the MFC procurement and credit and collections components; and the POR credit and collections component. The changes in revenues associated with the competitive delivery components were then subtracted from the delivery revenue increase for each class to determine the non-competitive delivery revenue increase for each class.

The first block charges (*i.e.*, the first 3 Ccf) were set to $26.00 for Service Classification Nos. 1 and 6 Rate Schedule IA and $40.00 for Service Classification Nos. 2 and 6 Rate Schedule IB. These increases more closely match the first block charges with their corresponding costs of service while limiting the rate impacts of the changes.

The incremental revenue from the changes in first block charges was subtracted from the class-specific incremental non-competitive delivery revenue increase for each class and the remainder was then allocated to the per Ccf charges.

Rates for the Company's Distributed Generation Riders B and C were increased based on increases to the otherwise applicable service classifications. Currently, there are no customers taking service under Riders B or C.

Interruptible Gas Service

The Company is also making specific changes with regard to its interruptible transportation service. Specifically, the Company is proposing to:

- replace the 1,000 Ccf initial block limit in Service Classification No. 8 with an initial block limit of 100 Ccf and establish a minimum monthly charge of $122 for the first 100 Ccf or less;
- remove the temporary caps on the Base Charge that is used to determine the block rates for Service Classification No. 8;
- require customers to pay for all or a portion of the facility costs previously paid for by the Company if a customer moves from firm service to Service Classification No. 8 after less than five years of taking firm service;
- cancel Service Classification No. 3 - Interruptible Sales Service; and
- cancel Service Classification No. 10 – Firm Withdrawable Sales to Electric Generation Facilities.

Other Tariff Changes - Gas

The Company is proposing other gas tariff changes including:

- changes to customer entitlements for gas service;
- the establishment of an AMI Opt Out Fee;
- the addition of tariff language to implement changes to the manner in which the factor of adjustment is determined, and how lost and unaccounted for gas is treated in the annual gas supply charge reconciliation;
- a change to the definition of normal heating degree days used in the Weather Normalization Adjustment;
- a change in the discount applicable to customers served under Rider E – Excelsior Jobs Program;
- updated Revenue Per Customer targets for the RDM;
- the introduction of a CNG option under Service Classification No. 7;
- the transfer of Winter Bundled Sales Service commodity pricing specifics from Service Classification No. 11 to the Company's Gas Sales and Transportation Operating Procedures; and
- changes to the balancing provisions contained in Service Classification No. 14.

Notice

The Company has included a draft Notice of Proposed Rulemaking in the form required by the State Administrative Procedure Act and the Commission's form regarding consent to receive electronic-only service of Commission orders. In accordance with 16 NYCRR 720-8.1, the Company will provide for public notice of the changes proposed in this filing by means of newspaper publication once a week for four consecutive weeks prior to January 1, 2015. Proof of publication will be submitted upon completion. In addition, the Company will issue appropriate bill inserts in accordance with 16 NYCRR 720-9.1.

Conclusion

The Tariff leaves, testimony and exhibits submitted with this filing explain the reasons for and nature of the proposed changes, and establish the reasons for the rate changes requested by the Company. As noted above, the Company will pursue discussions with Staff and other interested parties to the proceedings established by the Commission to consider these filings in an effort to reach agreement on the issues presented and to develop multi-year rate plans for each of the Company's services.

The Company respectfully requests that, in the absence of agreement of the parties, the Commission approve the changes to become effective on and as of November 1, 2015.

Very truly yours,

ORANGE AND ROCKLAND UTILITIES, INC.

By ______________________

Timothy P. Cawley
President and Chief Executive Officer

c: New York State Department of State, Utility Intervention Unit (via email)
Active Parties to Cases 08-G-1398 and 11-E-0408 (via email)

STATE OF NEW YORK
COUNTY OF NEW YORK

Timothy P. Cawley, being duly sworn, says:

I am the President and Chief Executive Officer of ORANGE AND ROCKLAND UTILITIES, INC., the applicant above-named, on behalf of which I have subscribed the foregoing application and know the contents thereof and the same is true to the best of my knowledge, information and belief.

Subscribed and sworn to
Before me this 12 day of November, 2014.

DANIEL J. PERRETTI
Notary Public, State of New York
No. 4988442
Qualified in Rockland County
Commission Expires Nov. 04, 2017

Orange and Rockland Utilities, Inc.
Electric Rate Case
Proposed Tariff Leaves effective January 1, 2015

P.S.C. No. 3 Electricity

2nd	Revised Leaf No. 3	2nd	Revised Leaf No. 277		
3rd	Revised Leaf No. 4	4th	Revised Leaf No. 278		
1st	Revised Leaf No. 9	4th	Revised Leaf No. 283		
1st	Revised Leaf No. 68	4th	Revised Leaf No. 284		
7th	Revised Leaf No. 89	4th	Revised Leaf No. 285		
2nd	Revised Leaf No. 106	2nd	Revised Leaf No. 286		
	Original Leaf No. 108.2	1st	Revised Leaf No. 287		
2nd	Revised Leaf No. 139	4th	Revised Leaf No. 290		
2nd	Revised Leaf No. 147	5th	Revised Leaf No. 295		
2nd	Revised Leaf No. 151	2nd	Revised Leaf No. 296		
3rd	Revised Leaf No. 155	2nd	Revised Leaf No. 303		
1st	Revised Leaf No. 158	4th	Revised Leaf No. 309		
1st	Revised Leaf No. 159	4th	Revised Leaf No. 310		
1st	Revised Leaf No. 160	4th	Revised Leaf No. 312		
1st	Revised Leaf No. 161	4th	Revised Leaf No. 321		
1st	Revised Leaf No. 162	4th	Revised Leaf No. 322		
2nd	Revised Leaf No. 164	4th	Revised Leaf No. 331		
1st	Revised Leaf No. 166	4th	Revised Leaf No. 332		
1st	Revised Leaf No. 167	4th	Revised Leaf No. 333		
1st	Revised Leaf No. 168	4th	Revised Leaf No. 335		
1st	Revised Leaf No. 169	4th	Revised Leaf No. 336		
1st	Revised Leaf No. 173	4th	Revised Leaf No. 341		
1st	Revised Leaf No. 210	2nd	Revised Leaf No. 343		
2nd	Revised Leaf No. 214	4th	Revised Leaf No. 345		
2nd	Revised Leaf No. 218	1st	Revised Leaf No. 346		
2nd	Revised Leaf No. 250	4th	Revised Leaf No. 347		
2nd	Revised Leaf No. 252	2nd	Revised Leaf No. 348		
2nd	Revised Leaf No. 255	4th	Revised Leaf No. 350		
2nd	Revised Leaf No. 257	1st	Revised Leaf No. 351		
1st	Revised Leaf No. 258	4th	Revised Leaf No. 352		
3rd	Revised Leaf No. 259	4th	Revised Leaf No. 356		
4th	Revised Leaf No. 260	1st	Revised Leaf No. 357		
2nd	Revised Leaf No. 261	4th	Revised Leaf No. 358		
2nd	Revised Leaf No. 262	4th	Revised Leaf No. 359		
4th	Revised Leaf No. 264	4th	Revised Leaf No. 372		
4th	Revised Leaf No. 266	4th	Revised Leaf No. 373		
4th	Revised Leaf No. 267	4th	Revised Leaf No. 374		
4th	Revised Leaf No. 268	4th	Revised Leaf No. 375		
4th	Revised Leaf No. 269	1st	Revised Leaf No. 388		
4th	Revised Leaf No. 270	1st	Revised Leaf No. 389		
1st	Revised Leaf No. 271	1st	Revised Leaf No. 390		
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4th	Revised Leaf No. 276				

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GENERAL INFORMATION **LEAF NO.**

GENERAL INFORMATION

1. TERRITORY TO WHICH SCHEDULE APPLIES

County	Township	Communities
Orange	Blooming Grove	Blooming Grove, Salisbury Mills, South Blooming Grove, Washingtonville
	Chester	Chester, Sugarloaf
	Crawford	Bullville, Thompson Ridge
	Deerpark	Cuddebackville, Huguenot, Port Jervis, Sparrowbush
	Goshen	Goshen
	Greenville	Greenville
	Highlands	Fort Montgomery, Highland Falls
	Minisink	Johnson, Unionville, Westtown
	Monroe	Harriman, Monroe, Kiryas Joel
	Mount Hope	Otisville
	Tuxedo	Laurel Ridge, Southfields, Sterling Forest, Tuxedo, Tuxedo Park
	Wallkill	Circleville, Howells, Mechanicstown, Middletown, Silver Lakes, Washington Heights
	Warwick	Florida, Greenwood Lake, Pine Island, Warwick, Wickham Village
	Wawayanda	Amchir, New Hampton, Ridgebury, Slate Hill
	Woodbury	Central Valley, Highland Mills
Rockland	Clarkstown	Bardonia, Central Nyack, Congers, Nanuet, New City, Rockland Lake, Upper Nyack, Valley Cottage, West Nyack
	Haverstraw	Garnerville, Haverstraw, Thiells, West Haverstraw
	Orangetown	Blauvelt, Grand View, Nyack, Orangeburg, Palisades, Pearl River, Piermont, South Nyack, Sparkill, Tappan
	Ramapo	Airmont, Chestnut Ridge, Hillburn, Hillcrest, Kaser, Monsey, Montebello, New Hempstead, New Square, Pomona, Ramapo, Sloatsburg, Spring Valley, Suffern, Tallman, Wesley Hills
	Stony Point	Grassy Point, Stony Point, Tomkins Cove
Sullivan	Forestburg	
	Lumberland	Glen Spey, Pond Eddy
	Mamakating	Bloomingburg, Burlingham, Phillipsport, Summitville, Westbrookville, Wurtsboro

GENERAL INFORMATION

6. WIRING AND EQUIPMENT

6.1 WIRING, APPARATUS AND INSPECTION

All wiring and apparatus, including service switches, fuses, meter loops and a proper location and support for the electric meter and other apparatus shall be furnished and maintained by the customer in accordance with the requirements of the Company, the National Electrical Code of the National Board of Fire Underwriters, any New York State Law and municipal regulations that may be in force, and it shall be a condition precedent to the initial and continuing supply of electricity by the Company that the Company or the customer's Meter Service Provider may seal such service and meter switch and adjust, set and seal such switches, and that such seals shall not be broken and that such adjustments or settings shall not be changed or in any way interfered with by the customer.

The Company reserves the right to make an inspection of premises before connecting service wires or prior to the meter installation in order to see that its rules are complied with. Neither by inspection or non-rejection, nor in any other way, does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, wires, pipes, appliances or devices owned, installed or maintained by the customer, a Meter Service Provider or a Meter Data Service Provider or leased by the customer from third parties. The Company shall conduct an initial inspection of the premises at no cost to the applicant. If the installation is not in compliance with the Company's and/or other applicable rules, service shall not be rendered and the Company shall assess a re-inspection fee of $80.00 for any subsequent re-inspections of the installation. The re-inspection fee for installations in excess of 600 Volts is $120.00.

6.2 INCREASED CAPACITY

The customer shall give the Company reasonable advance notice, preferably in writing, of any proposed increase in service required, stating the amount, character and expected duration of time the increased service will be required. If such increase necessitates added or enlarged facilities (other than metering equipment) for the sole use of the customer, the Company may require the customer to make a reasonable contribution to the cost of adding or enlarging the facilities whenever the customer fails to give assurance, satisfactory to the Company, that the taking of the increased service shall be of sufficient duration to render the supply thereof reasonably compensatory to the Company.

When a customer takes Competitive Metering Services, the customer's Meter Service Provider must install appropriate metering to reflect the change in the customer's requirements.

GENERAL INFORMATION

7. METERING AND BILLING (Continued)

7.5 RENDERING OF BILLS (Continued)

(B) Retail Access Customer Billing Options (Continued)

(2) Utility Single Billing Service

An ESCO requesting that its charges be included on a Utility Single Bill must execute the Company's Consolidated Billing and Assignment Agreement.

Under Utility Single Billing Service, the Company shall purchase the ESCO's receivables. That is, the ESCO assigns to the Company its rights in all amounts due from all of its customers participating in the Company's Retail Access Program and receiving a Utility Single Bill. By the 20th of each month (or the next business day if the 20th falls on a Saturday, Sunday, or public holiday), the Company shall remit to the ESCO all undisputed ESCO charges billed to its customers in the previous calendar month, reduced by the Purchase of Receivables ("POR") Discount Percentage as described below.

The POR Discount Percentage shall consist of an Uncollectibles Percentage, a Risk Factor and a Credit and Collections component. The Uncollectibles Percentage shall be set annually, effective each November 1, based on the Company's actual uncollectibles experience applicable to all gas and electric POR-eligible customers for the twelve month period ended the previous June 30. The Risk Factor shall also be reset each November 1, and shall be equal to 20 percent of the Uncollectibles Percentage. The Credit and Collections Component will be set annually, effective each November 1, and will be determined by dividing the Company's credit and collection expenses attributable to retail access customers whose ESCOs participate in the Company's POR program by the estimated electric supply costs to be billed on behalf of ESCOs through the POR program. The POR Discount Percentage effective November 1, 2014 is 1.151% percent.

The Company will collect and process customers' payments and perform collection activities in accordance with the Home Energy Fair Practices Act.

To be effective for the next cycle bill issued to the customer, at least 15 calendar days prior to a customer's scheduled meter read date, the ESCO will provide the Company a rate per kWh ($/kWh) to be charged each of its customers for electric power supply. Rates must include any applicable gross receipts taxes or

GENERAL INFORMATION

7. METERING AND BILLING (Continued)

7.15 LOW INCOME PROGRAM

Any electric heating customer receiving a grant under the Home Energy Assistance Program ("HEAP") shall receive a monthly bill credit of $17.40, excluding applicable taxes. Any other customer receiving a grant under HEAP shall receive a monthly bill credit of $9.00, excluding applicable taxes. The Company will commence posting the monthly bill credits to a customer's account within 60 days of receiving notification from the New York State Office of Temporary Disability Assistance (or its successor) of a customer's receipt of a HEAP grant.

GENERAL INFORMATION

7. METERING AND BILLING (Continued)

7.18 AMI AND AMR METER OPT OUT FEES

Any customer who requests that the transmitter of an AMI meter be disabled or requests an AMR meter be removed, will be classified as having opted out of AMI or AMR metering and will be required to submit an application and agreement with the Company.

Customers who opt out of AMI or AMR metering will be subject to the following.

(A) Access to Premises

Customers who opt out of AMI or AMR metering must provide reasonable access for meter reading and meter maintenance. If the customer fails to provide access for two months in a twelve-month period, then the customer will be required to: (a) relocate their metering equipment to an external location, at the customer's expense; or (b) permit the Company to reinstall an AMR meter or enable the AMI meter transmitter feature.

(B) Manual Meter Reading Fee

A monthly fee of $15 will apply to any customer who: refuses to allow the Company to install an AMI or AMR meter; requests that the transmitter of an AMI meter be disabled; or requests that an AMR meter be removed.

(C) Meter Change Out Fee

(1) A one-time meter change fee will apply for a customer who requests the change-out of an AMR meter. Such fee will be $225 for a customer who receives both electric and gas service from the Company, or $135 for a customer who receives only electric service from the Company.

(2) The meter change out fee is not applicable to an AMI electric meter that can have its transmitter disabled remotely.

(3) A customer who elects to switch back to AMI or AMR metering after requesting the removal of such meter will be reassessed the meter change out fee.

GENERAL INFORMATION

11. REFUSAL OR DISCONTINUANCE OF SERVICE (Continued)

11.14 RESTORATION OF SERVICE (Continued)

(C) A reconnection charge of $27.00 shall apply when the above conditions are satisfied and the customer specifies service is to be re-established during normal business hours regardless of the time that service is actually re-established. For purposes of this section, normal business hours are 8:00 a.m. to 4:00 p.m., local time, Monday through Friday, excluding holidays. A reconnection charge of $41.00 shall apply when the customer specifies that service is to be re-established during other than normal business hours.

(D) Commencing with the twelve month period November 1, 2015 through October 31, 2016, and in each subsequent twelve month period, the Company will waive the reconnection charge one time for any customer who is enrolled in the Company's low income program, subject to the following conditions:

(1) No waiver shall be granted once the Company has waived $40,000 in reconnection charges during such a twelve month period; and

(2) The Company may grant a waiver to an individual customer more than once, on a case-by-case basis, if the Company does not forecast that it will waive more than $40,000 in reconnection charges during such a twelve month period.

(3) If reconnection of service results from a payment from a social service agency, the Company must ascertain whether the payment covers the reconnection of service prior to granting the reconnection fee waiver.

(E) If service was disconnected at the street, a reconnection charge of $169.00 shall apply when the above conditions are satisfied and the customer specifies service is to be re-established during normal business hours, as defined above, regardless of the time that service is actually re-established. A reconnection charge of $253.00 shall apply when the customer specifies that service is to be re-established during other than normal business hours. These reconnection charges, applicable when service was disconnected at the street, shall not be assessed on customers taking service under residential service classifications.

(F) At the time the customer requests reconnection, the Company shall advise the customer of the reconnection charges fully explaining under what conditions the higher charge will be made. Should service be restored for both electric and gas service at the same time, the reconnection charge shall be made for only one service.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER B

NYPA – RECHARGE NEW YORK (RNY) PROGRAM RIDER

Pursuant to the RNY Power Program Act (L. 2011, c. 60, Part CC), the New York Power Authority (NYPA) will offer qualifying customers an allocation of RNY power ("RNY Allocation") comprised of 50 percent hydropower and 50 percent market power.

Any demand-billed customer who is qualified to take service under Service Classification Nos. 2, 3, 9, 20, 21, 22, or eligible customers taking service under Service Classification No. 25 of this Schedule, and enters into a contract with NYPA to receive an RNY Allocation represented in kW, under the NYPA RNY Program as provided in Section 1005, subdivision 13-a, of the Public Authorities Law, shall be eligible to take and pay for RNY Service under this Rider.

The Company shall have no responsibility for ensuring that a customer’s bill for service hereunder will be less than or equal to the amount the Company would charge if full service were provided by the Company.

NYPA shall provide at least 30 days’ prior written notice to the Company for the initial delivery of an RNY Allocation to an individual customer, changes in the RNY Allocation, and termination of any RNY Allocation, unless otherwise agreed upon by NYPA and the Company. Service will be initiated, modified, or terminated as of the customer's first scheduled meter reading date on or before the end of such notice period.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER C

Applicable to any demand-billed customer who is qualified to take service under Service Classification Nos. 2, 3, 9, 20, 21, 22, and eligible customers taking service under Service Classification No. 25. Customers who qualify for tax credits pursuant to the Excelsior Jobs Program ("EJP") Act (L. 2011, c. 61) may receive EJP discounts as described hereunder.

DEFINITIONS

Baseline Billing Determinants shall be established for an Existing Customer and shall be determined based on the twelve monthly billing periods immediately preceding the Company's receipt of the customer's Initial Certification. Baseline Billing Determinants are based on: (a) the billable demand and usage for customers served under Service Classification Nos. 2 and 3; (b) the billable demand and usage for customers served under Service Classification Nos. 9, 20, 21, and 22, for each specified time period, as applicable; and (c) the contract demand for customers served under Service Classification No. 25. The Company may estimate or adjust the Baseline Billing Determinants if sufficient billing information does not exist, or if the Company determines the billing history is not representative of usage and demand characteristics of the customer. The Baseline Billing Determinants that are established per month will remain fixed for the entire EJP term.

Incremental Billing Determinants shall mean: (a) an Existing Customer's monthly billable demand and usage in excess of the applicable Baseline Billing Determinants; (b) a New Customer's monthly billable demand and usage; (c) an existing Service Classification No. 25 customer's incremental contract demand and incremental as-used daily demand; or (d) a new Service Classification No. 25 customer's contract demand and as-used daily demand. For an existing Service Classification No. 25 customer, the incremental contract demand will be determined based upon the difference between the new contract demand and the baseline contract demand. The incremental as-used daily demand will be determined by applying the ratio of the incremental contract demand to the total contract demand (after increased EJP load) and applying the ratio to the as-used daily demand. The Incremental Billing Determinants will be the basis for the delivery demand and usage subject to the EJP discounts under this Rider.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER C (Continued)

RATES

Upon Annual Certification, discounts under this Rider shall be applied only to the Incremental Billing Determinants for the Customer Charge and Delivery Charges of the customers applicable service classification. Any discounts provided in this Rider shall not apply to the Baseline Billing Determinants.

For purposes of this Rider, percentage reductions will be applied to the Customer Charge and the Delivery Charge under Service Classification Nos. 2, 3, 9, 20, 21, and 22, and to the Customer Charge, Contract Demand Delivery Charge, and As-Used Daily Demand Delivery Charges under Service Classification No. 25, as applicable, before application of the Increase in Rates and Charges, as described in General Information Section No. 18.

Incremental Billing Determinants for EJP customers and all billing determinants for Service Classification No. 25 customers are not subject to the Revenue Decoupling Mechanism Adjustment.

Load served under this Rider is not eligible for service under Riders H and N

For customers who commenced service under Rider C prior to November 1, 2015, the EJP discounts are 0 percent.

For customers commencing service under Rider C on or after November 1, 2015, the EJP discounts are as follows:

Service Classification No. 2 – Secondary	63%
Service Classification No. 2 – Primary	66%
Service Classification No. 3	61%
Service Classification No. 9	62%
Service Classification No. 20	64%
Service Classification No. 21	61%
Service Classification No. 22	61%
Service Classification No. 25	*See Note Below

* The EJP discount for a customer served under Service Classification No. 25 shall be equal to the EJP discount of the customer's otherwise applicable service classification.

To the extent that marginal delivery costs change over time, the Company may file amended discount percentages with the Commission for its review and approval.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER G

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER G (Continued)

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER G (Continued)

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER H

ECONOMIC DEVELOPMENT RIDER

ELIGIBILITY

Any customer who qualifies to take service under Service Classification No. 2*, 3, 9, 20*, 21, 22, or eligible customers taking service under Service Classification No. 25 and:

(A) who obtains a letter of intent dated before November 1, 2015 and adds at least 100 kW of separately metered load to the Company's system, or obtains a letter of intent dated on or after November 1, 2015 and adds at least 65 kW of separately metered load to the Company's system by (a) constructing a new building; or (b) purchasing or leasing an existing building that has been vacant for at least three months; or (c) expanding an existing building; and

(B) whose operations are classified by the North American Industry Classification System (1997 edition or supplements thereto) as Manufacturing (Sector 31-33), Wholesale Trade (Sector 42), Transportation and Warehousing (Sector 48-49), Information (Sector 51), Finance and Insurance (Sector 52), Real Estate, Rental and Leasing (Sector 53), Professional, Scientific and Technical Services (Sector 54), Management of Companies and Enterprises (Sector 55), Administrative Support, Waste Management and Remediation Services (Sector 56); and

(C) who applies for service hereunder prior to beginning construction of a new or expanded building, or prior to closing the purchase of or signing a lease for an existing building; and

(D) who qualifies for, receives, and provides the Company with suitable documentation substantiating the receipt of a comprehensive package of economic incentives conferred by the local municipality or state authorities and including substantial financial assistance or a substantial tax incentive program designed to maintain or increase employment levels in the service area; and

(E) who obtains an energy efficiency audit, performed by either NYSERDA or by an independent qualified energy efficiency firm under the Company's Small Business Direct Install or the Commercial & Industrial programs (this requirement applies only to customers who are purchasing or leasing an existing building);

shall be eligible to take service hereunder and to pay for such service at a discounted rate and in accordance with the provisions of Service Classification No. 2*, 3, 9, 20*, 21, 22, or 25. Service supplied hereunder shall not be used to supply any of the customer's existing operations.

* The "Revenue Test for Facility Extensions" provision of this Rider does not apply to Service Classification No. 20 customers and Service Classification No. 2 customers taking service at secondary voltage.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER H (Continued)

ECONOMIC DEVELOPMENT RIDER

ELIGIBILITY (Continued)

Once a customer with a letter of intent dated on or after July 1, 2011 and before November 1, 2015 commences service under this Rider, the customer must maintain a metered demand of 100 kW or more in six months of any twelve-month period, otherwise the customer shall be permanently removed from this Rider. Once a customer with a letter of intent dated on or after November 1, 2015 commences service under this Rider, the customer must maintain a metered demand of 65 kW or more in six months of any twelve-month period, otherwise the customer shall be permanently removed from this Rider.

LETTER OF INTENT

The Company is authorized to issue letters of intent to eligible applicants through December 31, 2020. Service hereunder must commence within two years of the date of such letter of intent. The customer shall select the date on which service under this Rider will commence. Service for customers with a letter of intent dated before November 1, 2015 can commence service only once the customer’s metered demand meets or exceeds 100 kW in two consecutive months following issuance of such letter of intent. Service for customers with a letter of intent dated on or after November 1, 2015, can commence service only once the customer’s metered demand meets or exceeds 65 kW in two consecutive months following issuance of such letter of intent.

ECONOMIC DEVELOPMENT DISCOUNT

Any customer with a letter of intent dated before July 1, 2011 shall receive a discount of 10 percent of the Customer Charge, and Delivery Charge contained in the applicable service classification for a period of five years from the date service commences.

Any customer with a letter of intent dated on or after July 1, 2011 shall receive a discount of 20 percent of the Customer Charge, and Delivery Charge contained in the applicable service classification for a period of five years from the date service commences.

REVENUE TEST FOR FACILITY EXTENSIONS

The Company shall implement a revenue test to determine a customer’s contribution for a Company facility extension for a customer whose free footage allowance under General Information Section No. 3.7 is exceeded by the cost of the Company’s facilities thereby making it uneconomical for the customer to construct a new building or expand its operations within the Company’s service territory.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER I

RETAIL ACCESS PROGRAM

The Retail Access Program is designed to allow customers qualified to take service under Service Classification No. 1, 2, 3, 4, 5, 6, 9, 16, 19, 20, 21, 22, and 25 to purchase their electric power supply from ESCOs meeting the requirements of Service Classification No. 24. A customer may designate only one ESCO to serve an individual electric account. The operational requirements of the program are fully described in the Company's Retail Access Implementation Plan and Operating Procedure.

CUSTOMER ELIGIBILITY

All retail customers shall be eligible to contract with an ESCO for electric power supply effective May 1, 1999. A customer with monthly demand of 1 MW or greater may directly procure electric power supply, solely for its own use, without an ESCO. A customer may designate only one ESCO to serve each electric account. Customers who have designated a portion of their electric power supply requirements to be provided by the New York Power Authority ("NYPA") under its Recharge New York program, shall be permitted to select an ESCO, or the Company, to provide the remainder of their electric power supply.

Service is provided in accordance with the provisions of this Rider and the provisions of the UBP. In the event of any conflict between the provisions of this Rider and the provisions of the UBP, the UBP shall control.

CUSTOMER ENROLLMENT

A customer may choose an ESCO by directly contacting an ESCO whom the Commission and the Company have determined to be eligible to serve retail customers in the Company's service territory. Customers may enroll with such ESCO either by telephone or in writing. The customer may enroll with an ESCO by providing its account number and the name of the customer of record who is financially responsible for the account. If this information is insufficient to verify the customer's account, the Company will inform the ESCO of any additional verification information required.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER J

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER J (Continued)

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER J (Continued)

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER J (Continued)

RESERVED FOR FUTURE USE

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER K (Continued)

DAY AHEAD DEMAND REDUCTION PROGRAM

RESTRICTIONS AS TO AVAILABILITY OF THIS RIDER

Service under this Rider shall not be available to customers receiving service under Rider I. Payments under this Rider shall not be provided by the Company for load reductions for which the customer received payment under another program implemented by the Company or another entity. Customers taking service under Rider B are allowed to participate for curtailment bids up to the total amount of load supplied by the Company subject to the 100 kW minimum load reduction required under this Rider.

METERING

Each customer's entire service must be measured by one or more interval meters, and customers must maintain any associated control wiring in good working order. If the customer's service is not measured by one or more interval meters, provided in connection with other Company service requirements, the customer shall arrange for the furnishing and installation of interval metering with telecommunications capability, and arrange for telecommunications service, at the customer's expense, net of any available discount or rebate for metering equipment. A customer with on-site generation will be required to provide interval metering data establishing, to the Company's reasonable satisfaction, that the generator was not used to achieve its Bid.

GENERAL INFORMATION

14. FORM OF APPLICATION FOR SERVICE (Continued)

14.6

RESERVED FOR FUTURE USE

GENERAL INFORMATION

15. MARKET SUPPLY CHARGE ("MSC")

The Company will provide electric power supply to all customers who: (1) choose to have their entire electric power supply requirement provided by the Company, or (2) are not offered Retail Access Service by an ESCO, or (3) return to the Company's service after having been previously supplied by an ESCO, or (4) contract for their electric power supply with an ESCO that fails to deliver. The Market Supply Charge ("MSC") shall be used to recover all costs associated with purchasing energy, capacity and ancillary services incurred by the Company in providing electric power supply to the above-referenced customers. Such costs shall also include costs associated with Non-Utility Generator ("NUG") contracts and costs/benefits associated with hedging instruments. Costs/benefits associated with hedging instruments (e.g., transaction costs, such as option premiums, costs of providing credit support and margin requirements, professional fees, and gains and losses associated with such transactions made in the commodities exchanges and with other counterparties) shall be recovered as described in the Forecast MSC Component section below. The MSC shall also be used to recover the lost delivery service revenue associated with Rider K and Rider M. The MSC shall be reduced by any penalty amounts received from customers under Rider K, in excess of penalty amounts paid by the Company to the NYISO under the NYISO's Day Ahead Demand Reduction Program.

The MSC is applicable to customers receiving electric power supply from the Company under Service Classifications Nos. 1, 2, 3, 4, 5, 6, 16, 19, 20, 21 and 25 (Rates 1 and 2) and under Rider B. The MSC does not apply to Mandatory Day-Ahead Hourly Pricing customers or to customers electing voluntary DAHP under Rider M.

The MSC shall consist of two components, the Forecast MSC Component and the MSC Adjustment as described below.

15.1 FORECAST MSC COMPONENT

The Forecast MSC Component shall be separately determined on a monthly basis for each of the following customer classes:

- Residential – Service Classification No. 1;
- Residential Voluntary Time of Use – Service Classification No. 19;
- Non-Residential Secondary Service – Service Classification No. 2 (Secondary) and Service Classification No. 25, Rate 1 who are exempt from Mandatory Day-Ahead Hourly Pricing;
- Non-Residential Secondary Voluntary Time of Use Service – Service Classification No. 20;
- Primary Service – Service Classification No. 2 (Primary), Service Classification No. 3, and Service Classification No. 25, Rate 2, and primary service customers under Service Classification No. 9, Service Classification No. 22, and Service Classification No. 25, Rates 3 and 4 who are exempt from Mandatory Day-Ahead Hourly Pricing;
- Primary Voluntary Time of Use Service – Service Classification No. 21;

GENERAL INFORMATION

15. MARKET SUPPLY CHARGE ("MSC") (Continued)

15.3 MANDATORY DAY-AHEAD HOURLY PRICING ("DAHP") (Continued)

(A) Applicability (Continued)

Mandatory DAHP is also applicable, commencing with bills having a “from” date on or after each May 1, to customers receiving power supply from the Company under Service Classification Nos. 2, 3, 20, 21 or 25 (Rates 1 and 2), who maintain a demand in excess of 300 kW in any two months of the previous 12-month period ending September 30. Once on Mandatory DAHP, a customer whose demand does not exceed 200 kW for 12 consecutive months during the period ending September 30, shall be transferred out of Mandatory DAHP effective with its bill having a “from” date on or after the following May 1 unless the customer elects to remain on DAHP service on a voluntary basis.

Mandatory DAHP is not applicable to customers taking service under Riders B or I of this Rate Schedule. A Customer may elect at any time to have its electric power supply provided by an ESCO in accordance with Rider I of this Rate Schedule.

GENERAL INFORMATION

25. ENERGY COST ADJUSTMENT ("ECA")

The ECA will be applied to the bills of all customers served under this Schedule. The ECA consists of a Base ECA, a Variable ECA and a REV Surcharge.

(A) Base ECA

The Base ECA will be determined annually and is designed to recover: (a) lost revenue resulting from the implementation of individually negotiated contracts under Service Classification No. 23, (b) implementation costs, including costs for enabling technologies, associated with Rider M and Mandatory DAHP as set forth in General Information Section No. 15 (Market Supply Charge), and (c) any prior period over/undercollection of Base ECA and Variable ECA costs.

Each year, the Company shall submit to the Commission, on not less than thirty days notice, its annual filing to establish the Base ECA to become effective on March 1. The Base ECA for all customers except those billed under Service Classification No. 25 shall be assessed on a cents per kWh basis, and shall be equal to such customers' proportionate share of the Company's projection of the cost components defined above, divided by the Company's estimate of total customer kWh usage applicable to such customers for the coming recovery period, rounded to the nearest $0.00001 per kWh. The Base ECA for Service Classification No. 25 customers shall be assessed on a per kW of contract demand basis and shall be equal to the Service Classification No. 25 customers' proportionate share of the Company's projection of the cost components defined above, divided by the Company's estimate of total Service Classification No. 25 contract demand kW for the coming recovery period, rounded to the nearest $0.0001 per kW. The Base ECA will remain in effect until changed as authorized by the Commission.

GENERAL INFORMATION

25. ENERGY COST ADJUSTMENT ("ECA") (Continued)

(D) Reforming the Energy Vision ("REV") Surcharge

The REV Surcharge is designed to recover the incremental revenue requirement associated with the Company's REV-related projects.

Costs recovered through the REV Surcharge include program costs for customer-side and utility-side demand management programs that specifically address identified distribution system needs, other potential demonstration projects, as well as expenditures necessary to begin deployment of REV-related foundational investments. The REV Surcharge includes: (a) carrying charges on capital expenditures, customer incentives and program costs, and costs of third-party engagement (based on recovery periods of five years and ten years for customer-side and utility-side expenditures, respectively); and (b) recovery of O&M costs, incentives earned by the Company for achieving defined outcomes, and the costs to set up new programs or tools for customers, including customer outreach and education enhancements. Carrying charges are based on the Company's overall rate of return authorized by the Commission.

The initial REV Surcharge will be calculated to recover any expenditure made prior to the filing of the surcharge and the forecasted revenue requirement for the succeeding period. Subsequent filings will be made every six months and will include a true-up, including interest, of any prior period over- or under-collections of the actual revenue requirement for the prior period and the forecasted revenue requirement for the subsequent six-month period.

The REV Surcharge shall be assessed on a cents per kWh basis, and shall be equal to the REV Surcharge cost components defined above, divided by the Company's estimate of total customer kWh usage for the coming recovery period, rounded to the nearest $0.00001 per kWh. The REV Surcharge shall not exceed $0.00200 per kWh in any period unless a higher REV Surcharge is authorized by the Commission.

(E) Statement of Energy Cost Adjustment

A Statement of Energy Cost Adjustment showing the Base ECA, Variable ECA, REV Surcharge, if applicable, and effective date shall be filed with the Commission, apart from this Schedule. Such Statement shall be filed each year, on not less than thirty days notice, to establish the Base ECA to become effective on March 1. Such Statement shall also be filed not less than three business days prior to a proposed change in the Variable ECA or REV Surcharge. The Statement of Energy Cost Adjustment shall be made available to the public at Company offices where applications for service may be made.

GENERAL INFORMATION

28. MERCHANT FUNCTION CHARGE ("MFC")

(A) Applicability

A Merchant Function Charge ("MFC") will be applied, on a per kWh basis, to the bills of all Full Service Customers, except with respect to electric power supply provided by NYPA under Rider B. Retail Access Customers are not subject to an MFC. The MFC shall include the following components:

(1) a commodity procurement charge including purchased power working capital and a commodity revenue-based allocation of information resources and education and outreach costs;

(2) a credit and collections charge; and

(3) an uncollectibles charge.

(B) MFC Fixed Components

Service Classification	Commodity Procurement, IR, and Education and Outreach	Credit and Collections	Total
Commencing November 1, 2015			
SC Nos. 1 and 19	$0.00446	$0.00078	$0.00524
SC Nos. 2 Secondary, 20, 4, 5, 6 and 16	$0.00309	$0.00046	$0.00355
SC Nos. 2 Primary, 3, 9, 21, 22 and 25	$0.00165	$0.00015	$0.00180

GENERAL INFORMATION

29. TRANSITION ADJUSTMENT FOR COMPETITIVE SERVICES ("TACS")

(A) Applicability

A Transition Adjustment for Competitive Services ("TACS") will be applied, on a per kWh basis, to the bills of all customers taking service under this Rate Schedule. The TACS shall be reset annually effective November 1 of each year.

(B) Definitions for Purposes of the TACS

"Merchant Function Charge Fixed Component Lost Revenue" shall be equal to a revenue target attributable to the Merchant Function Charge ("MFC") Fixed Components consisting of a) commodity procurement costs, including purchased power working capital and a commodity revenue-based allocation of information resources and education and outreach costs; and b) credit and collections costs portions of the MFC, minus the revenues received through the MFC relating to such MFC Fixed Components. The MFC Fixed Component revenue targets are $4,344,689 for the 4 month period commencing July 1, 2015 and $6,080,953 for the 12 month period commencing November 1, 2015.

"Billing and Payment Processing Lost Revenue" shall be equal to the total of billing and payment processing charges avoided by retail access customers less billing service charges assessed on ESCOs participating in the Company's Electric Retail Access program and electing the Utility Single Bill Option, less the Company's avoided costs associated with ESCOs participating in the Company's Electric Retail Access Program and electing the ESCO Single Bill Option.

"Metering Lost Revenue" shall be equal to the total of metering services charges (i.e., the total of meter ownership charges, meter service provider charges, and meter data service provider charges), avoided by customers taking competitive metering services, less the Company's avoided costs associated with customers taking competitive metering services.

“Credit and Collections Lost Revenue Associated with Retail Access” shall be equal to the target level of credit and collections costs reflected in the POR discount minus revenues received through the credits and collections component of the POR discount. The revenue targets are $372,258 for the 4 month period commencing July 1, 2015 and $811,834 for the 12 month period commencing November 1, 2015.

GENERAL INFORMATION

29. TRANSITION ADJUSTMENT FOR COMPETITIVE SERVICES ("TACS") (Continued)

(B) Definitions for Purposes of the TACS (Continued)

"Prior Period Reconciliation" represents the difference between the amount to be recovered through the TACS and the actual amount recovered through the TACS. Any under-recovery or over-recovery resulting from such reconciliation, plus interest (calculated at the Other Customer Capital Rate), shall be included in the calculation of the subsequent year's TACS.

(C) Calculation of the TACS

The amount to be recovered from or credited to customers through the TACS shall be equal to the sum of the MFC Fixed Component Lost Revenue, Billing and Payment Processing Lost Revenue, Metering Lost Revenue, Credit and Collections Lost Revenue Associated with Retail Access and the Prior Period Reconciliation. Half of the amount to be recovered from or credited to customers through the TACS will be assigned to Full Service Customers; the balance will be assigned to both Full Service Customers and Retail Access Customers. The amounts to be collected from or credited to customers will be divided by the estimated total annual kWh deliveries, to which the TACS will be applied, to determine the per kWh TACS, expressed to the nearest 0.001 cent per kWh. If the above calculation results in a TACS of less than 0.001 cent per kWh, the total amount to be recovered from or refunded to customers will be deferred, with interest, for later recovery or refund through application to customers' bills in a subsequently determined TACS.

Each TACS will be in effect for a twelve-month period; provided, however, that the Company may adjust the TACS for the remaining months of a twelve-month period on not less than fifteen days' notice if the total deferred debit or credit amount exceeds $1 million. The TACS effective November 1, 2015 will reconcile the period July 1, 2015 – October 31, 2015.

The TACS will be calculated on an annual or more frequent basis, as provided herein. Not less than fifteen days prior to a proposed change in the TACS, a Statement showing the determination of the TACS and the effective date will be filed with the Commission apart from this Schedule. Such Statement shall be made available to the public at Company offices at which applications for service may be made.

GENERAL INFORMATION

30. REVENUE DECOUPLING MECHANISM (“RDM”) ADJUSTMENT

Actual delivery revenues for certain customer classes are subject to reconciliation through an RDM Adjustment.

(A) Applicability

The RDM Adjustment is applicable to Service Classification (“SC”) Nos. 1, 2, 3, 4, 6, 9, 19, 20, 21,and 22. For RDM purposes, these Service Classifications shall be assigned to customer groups as follows:

Group A – SC Nos. 1 and 19 customers
Group B – SC No. 2 Secondary and SC No. 20 customers
Group C – SC No. 2 Primary and SC Nos. 3 and 21 customers
Group D – SC No. 9 customers
Group E – SC No. 22 customers
Group F – SC Nos. 4 and 6 customers

The RDM is not applicable to (a) Service Classification Nos. 5, 15, 16, 23, and 25; (b) customers taking service under Rider H; (c) kWh usage delivered under Rider B, NYPA RNY Program, up to the RNY Allocation; and (d) usage delivered under Rider C, Excelsior Jobs Program, above the Baseline Billing Determinants. Customers taking service under Rider H, and usages delivered under Rider C, Excelsior Jobs Program, above the Baseline Billing Determinants will be excluded from the RDM from November 1, 2015 until the Company’s base electric rates are next reset, even if service under these riders expires during this period.

(B) Determination of RDM Adjustment

For each customer group subject to the RDM Adjustment, the Company will compare, on a monthly basis, the difference between Actual Delivery Revenue and corresponding Delivery Revenue Targets. Actual Delivery Revenue is defined as the sum of total revenue derived from customer charges, delivery charges, and, if applicable, the reactive power demand charge as defined in the service classifications included in each customer group. Actual Delivery Revenue shall not include revenues derived from the RDM Adjustment.

For each customer group subject to the RDM Adjustment, the Company will, on a monthly basis, compare Actual Delivery Revenue to a 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 as defined below. 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.

GENERAL INFORMATION

30. REVENUE DECOUPLING MECHANISM (“RDM”) ADJUSTMENT (Continued)

(B) Determination of RDM Adjustment (Continued)

For Service Classification No. 4 customer purchases of street lights from the Company resulting in the customer taking service under Service Classification No. 6 for such street lights, the applicable monthly differences between Actual Delivery Revenue and the Delivery Revenue Target shall be adjusted to account for estimates of the lower carrying cost on the net value of the assets, property taxes and depreciation realized by the Company as a result of the sale. Such adjustment shall be made only for street light purchases that were not reflected in the Delivery Revenue Targets.

Since loads served under Rider B, NYPA – Recharge New York (“RNY”), and usage above the Baseline Billing Determinants under Rider C, Excelsior Jobs Program (“EJP”), are exempt from the RDM, Delivery Revenue Targets will be revised for allocations made under RNY and deliveries under EJP. Delivery Revenue Targets will be decreased/increased as RNY and EJP customers move from/into RDM customer groups.

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, as defined below, total delivery revenue excess/shortfalls for each customer group will be refunded/surcharged to customers through customer group specific RDM Adjustments applicable during a corresponding RDM Adjustment Period as defined below. The RDM Adjustment for each applicable customer group shall be determined by dividing the amount to be refunded/surcharged to customers in that customer group by estimated kWh deliveries to customers in that customer group over the RDM Adjustment Period. RDM Adjustments shall be rounded to the nearest $0.00001 per kWh.

Following each RDM Adjustment Period, any difference between amounts required to be charged or credited to customers in each customer group and amounts actually charged or credited will be charged or credited to customers in that customer group, with interest, over a subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect. RDM targets will be adjusted, as applicable, to exclude credits applied to customer accounts pursuant to General Information Section No. 7.17(A).

Annual RDM Periods are the 12-month periods ending October 31, of each year. 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 December 1 on which the statement becomes effective for one year.

GENERAL INFORMATION

30. REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT (Continued)

(B) Determination of RDM Adjustment (Continued)

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 RDM delivery revenue excess or shortfall, will be reallocated to other remaining customer groups to provide for equitable treatment of any revenue excess or shortfall from the discontinued customer group. In the event RDM revenue is reallocated, the Company will consult with Commission Staff regarding such reallocation.

(C) Delivery Revenue Targets ($000s)

Customer Group	Effective: 11/1/2015
A	To Be Determined
B	To Be Determined
C	To Be Determined
D	To Be Determined
E	To Be Determined
F	To Be Determined
Unbilled Revenue	To Be Determined
Total	To Be Determined

For the period July 1, 2015 through October 31, 2015, the RDM will be implemented in accordance with the methodology set forth in Appendix E to the Joint Proposal adopted by the Commission in its Order Adopting Terms of a Joint Proposal, With Modification, and Establishing Electric Rate Plan, issued June 15, 2012 in Case No. 11-E-0408.

(D) Interim RDM Adjustments

If at any time during an Annual RDM Period, the total of cumulative delivery revenue excess/shortfall for all of the Company's service classifications subject to the RDM Adjustment exceeds 1.5 percent of the total of the Delivery Revenue Target, 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.

GENERAL INFORMATION

30. REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT (Continued)

(D) Interim RDM Adjustments (Continued)

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 are subject to reconciliation at the end of the Annual RDM Period as part of the annual RDM Adjustment process described above.

(E) Statement of RDM Adjustments

A Statement of RDM Adjustments, showing the RDM Adjustments by service classification and their effective date shall be filed with the Commission, apart from this Schedule. Such statement shall be filed not less than ten calendar days prior to a proposed change in RDM Adjustments. The Statement of RDM Adjustments shall be made available to the public at Company offices where applications for service may be made.

SERVICE CLASSIFICATION NO. 1

APPLICABLE TO USE OF SERVICE FOR:

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an Energy Service Company under the Company's Retail Access Program to residential customers and other customers eligible for residential service as defined in General Information Section No. 8.

CHARACTER OF SERVICE:

Residential Customers:

Continuous, 60 cycles, A.C., from any one of the following systems as designated by the Company:

(a) Single phase at approximately 120, 120/208 or 120/240 Volts.

(b) Three phase four wire at approximately 120/208 Volts in limited areas.

Other Customers Eligible for Residential Service as Defined in General Information Section No. 8:

Continuous, 60 cycles, A.C., single or three phase secondary, or three phase primary as defined in General Information Section No. 4.

RATES – MONTHLY:

(For additional rates and charges see Special Provisions A, B, C, and F.)

		Summer Months*	Other Months
(1)	Customer Charge	$25.00	$25.00
(2)	Delivery Charge		
	First 250 kWh .... @	7.090 ¢ per kWh	7.090 ¢ per kWh
	Over 250 kWh .... @	8.466 ¢ per kWh	7.090 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 1 (Continued)

RATES – MONTHLY: (Continued)

(8) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(9) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION:

The sum of $25.00 monthly, but not less than $150.00 per contract, plus any applicable billing and payment processing charges.

TERMS OF PAYMENT:

Bills are due when rendered, subject to a late payment charge in accordance with provisions of General Information Section No. 7.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section Nos. 11.1 and 11.2.

TERM:

Terminable at any time unless a specified period is required under a line extension agreement.

EXTENSION OF FACILITIES:

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

SERVICE CLASSIFICATION NO. 1 (Continued)

SPECIAL PROVISIONS:

(A) Water Heating (Optional)

Where an approved electric storage heater is used for the Customer's entire water heating requirements, use in excess of 500 up to 1,000 kWh for bills rendered monthly will be billed at a Delivery Charge of 7.489¢ per kWh during the summer billing months and 5.491¢ per kWh during the other billing months. Use in excess of 1,000 kWh monthly will be billed at a Delivery Charge of 8.466¢ per kWh during the summer billing months and 7.090¢ per kWh during the other billing months. Except for usage as stated above, the provisions of RATES – MONTHLY shall apply.

This special provision is closed to new customers effective July 1, 2011.

An approved electric water heater is one that has a minimum storage capacity of 50 gallons and two heating elements. The size of the elements shall not exceed those listed in the tabulation below:

Gallons	50	66	82	100
Upper element, Maximum Watts	1,500	2,500	3,000	4,000
Lower element, Maximum Watts	1,000	1,500	1,500	2,500

(B) Space Heating (Optional)

All use in excess of 500 kWh monthly will be billed at a Delivery Charge of 8.466¢ per kWh during the summer billing months (customers with water heating see Special Provision A) and 5.491¢ per kWh during the other billing months provided permanently installed electric space heating equipment is the sole source of space heating, excluding fire places, on the premises. Except for usage as stated above, the provisions of RATES –MONTHLY shall apply.

This special provision is closed to new customers effective July 1, 2011.

SERVICE CLASSIFICATION NO. 1 (Continued)

SPECIAL PROVISIONS: (Continued)

(C) Short Term Service

Customers desiring service under this Service Classification for less than six months, where service is already installed, shall pay in advance the contract minimum as specified under "Minimum Charge Each Contract Each Location" or under an applicable line extension agreement, or, if the estimated bill for two months or such shorter period as service may be desired exceeds the contract minimum, the Company reserves the right to request a deposit equal to this estimated bill. A part of a month shall be considered a full month for computing all charges hereunder.

(D) Budget Billing (Optional)

Any customer taking service hereunder may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section No. 7 of this Schedule.

(E) Redistribution

Submetering may be available under certain conditions as contained in General Information Section No. 8 of this Schedule.

(F) Heat Pump Space Conditioning (Optional)

Any customer taking service under this Service Classification who uses a heat pump as the major source of space conditioning shall pay a Delivery Charge of 5.491¢ per kWh for all monthly usage in excess of 500 kWh during the billing months of October through May. Customers taking service under this Special Provision who use an electric water heater as the primary source of domestic water heating, must install an insulation wrap on the water heater and shall pay a Delivery Charge of 7.489¢ per kWh for all monthly usage in excess of 500 kWh up to 1,000 kWh during the billing months of June through September. This Special Provision may not be used in conjunction with Special Provisions A, B, or C of this Service Classification. Except for usage as stated above, the provisions of RATES – MONTHLY shall apply.

This special provision is closed to new customers effective July 1, 2011.

SERVICE CLASSIFICATION NO. 2

APPLICABLE TO USE OF SERVICE FOR:

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an Energy Service Company under the Company's Retail Access Program to general secondary or primary service customers. All service at one location shall be taken through one meter except that service supplied under Special Provision B, Space Heating or Rider H shall be separately metered.

CHARACTER OF SERVICE:

Continuous, 60 cycles, A.C., single or three phase secondary or three phase primary as defined in General Information Section No. 4.

RATES - MONTHLY:

	Summer Months*	Other Months
(1) Customer Charges		
(a) Non-Demand Billed Customers		
Metered Service	$21.00	$21.00
Unmetered Service	$19.00	$19.00
(b) Secondary Demand Service	$21.00	$21.00
(c) Primary Service	$35.00	$35.00

(2) Delivery Charges

(a) Non-Demand Billed Customers (Includes Unmetered)

Usage Charge

	Summer Months*	Other Months
All kWh ………...........@	8.972 ¢ per kWh	6.631 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 2 (Continued)

RATES - MONTHLY: (Continued)

(2) Delivery Charges (Continued)

(b) Secondary Demand Billed Service

		Summer Months*	Other Months
Demand Charge			
First 5 kW or less	..….…....@	$2.37 per kW	$1.36 per kW
All Over 5 kW	..….…....@	$14.26 per kW	$8.27 per kW
Usage Charge			
First 1250 kWh	..….…....@	7.047 ¢ per kWh	5.497 ¢ per kWh
Use up to 30,000 kWh or 300 hours use of billing demand, whichever is greater	..….…....@	3.459 ¢ per kWh	3.310 ¢ per kWh
Use in excess of 30,000 kWh or 300 hours use of billing demand, whichever is greater	..@	1.948 ¢ per kWh	1.798 ¢ per kWh

(c) Primary Service

		Summer Months*	Other Months
Demand Charge			
All kW	..….…....@	$14.55 per kW	$8.08 per kW
Usage Charge			
All kWh	..….…....@	2.092 ¢ per kWh	2.085 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 2 (Continued)

RATES - MONTHLY: (Continued)

(3) Reactive Power Demand Charge

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7.

(4) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services, and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(5) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification.

Customers taking service under Rider H shall not be subject to this provision.

(6) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(7) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

(8) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

SERVICE CLASSIFICATION NO. 2 (Continued)

RATES - MONTHLY: (Continued)

(9) Metering Charges

The following Metering Charges shall be assessed on all customers, except unmetered service customers, taking service under this Service Classification, unless such metering service(s) is obtained competitively pursuant to General Information Section No. 7:

		Customers Eligible For Mandatory DAHP	All Other Customers
Secondary Service			
a)	Meter Ownership Charge	$20.44	$3.02
b)	Meter Service Provider Charge	$18.48	$11.01
c)	Meter Data Service Provider Charge	$31.76	$3.28
Primary Service			
a)	Meter Ownership Charge	$20.44	$5.67
b)	Meter Service Provider Charge	$18.48	$20.65
c)	Meter Data Service Provider Charge	$31.76	$3.17

(10) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(11) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

SERVICE CLASSIFICATION NO. 2 (Continued)

EXTENSION OF FACILITIES:

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

SPECIAL PROVISIONS:

(A) Short Term Service

When short term service is requested, the Company reserves the right to require a deposit of the estimated bill for the period service is desired. The minimum charge for such short term service shall be an amount equal to six times the minimum monthly charge, payable in advance. When construction is necessary, the cost of installation and removal of all equipment, less salvage value, must be borne by the customer, and a sufficient amount to cover these charges shall be paid in advance. A part of a month shall be considered a full month for computing all charges hereunder.

(B) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use will be billed at a Delivery Charge of 2.447¢ per kWh during the billing months of October through May and at a Delivery Charge of 9.793¢ per kWh during the other billing months. When this option is requested it shall apply for at least twelve months and shall be subject to a minimum charge of $19.96 per year per kW of space heating capacity. This rule applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit. All usage under this Special Provision shall also be subject to Parts (3) through (11) of RATES – MONTHLY.

This special provision is closed to new customers effective July 1, 2011.

SERVICE CLASSIFICATION NO. 3

APPLICABLE TO USE OF SERVICE FOR:

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an Energy Service Company under the Company's Retail Access Program to general primary service customers. Customers must meet the following demand criteria and provide all equipment required to take service at a primary voltage as designated by the Company. All service at one location shall be taken through one meter except that service supplied under Rider H shall be separately metered.

Customer must maintain a minimum of 100 kW for at least two consecutive months during the previous 12 months to be eligible for service hereunder. Customers who do not maintain said minimum shall be transferred to Service Classification No. 2 and shall not be eligible for service hereunder for one year and until 100 kW demand has been maintained for two consecutive months.

A customer whose demand exceeds 1,000 kW during any two of the previous twelve months shall not be eligible for this rate and shall be transferred to Service Classification No. 9 or 22. A Customer so transferred shall only be eligible for transfer back to Service Classification No. 3 on the annual anniversary of the transfer to Service Classification No. 9 or 22 and only if said customer has not exceeded 1,000 kW during any two of the previous twelve months.

CHARACTER OF SERVICE:

Continuous, 60 cycles, A.C., three phase primary as defined in General Information Section No. 4.

RATES - MONTHLY:

	Summer Months*	Other Months
(1) Customer Charge	$120.00	$120.00
(2) Delivery Charges		
Demand Charge		
All kW …..………@	$17.51 per kW	$9.91 per kW
Usage Charge		
All kWh …..………@	1.087 ¢ per kWh	1.087 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 3 (Continued)

RATES - MONTHLY: (Continued)

(3) Reactive Power Demand Charge

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7.

(4) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(5) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification.

Customers taking service under Rider H shall not be subject to this provision.

* June through September

SERVICE CLASSIFICATION NO. 3 (Continued)

RATES - MONTHLY: (Continued)

(6) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(7) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

(8) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

(9) Metering Charges

The following Metering Charges shall be assessed on all customers taking service under this Service Classification, unless such metering service(s) is obtained competitively pursuant to General Information Section No. 7:

		Customers Eligible for Mandatory DAHP	All Other Customers
a)	Meter Ownership Charge	$20.44	$4.80
b)	Meter Service Provider Charge	$18.48	$17.51
c)	Meter Data Service Provider Charge	$31.76	$1.55

SERVICE CLASSIFICATION NO. 4 (Continued)

RATES – MONTHLY:

(1) Luminaire Charge:

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Delivery Charge
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	$14.89
9,500	Sodium Vapor	100	142	16.25
16,000	Sodium Vapor	150	199	19.30
27,500	Sodium Vapor	250	311	25.78
46,000	Sodium Vapor	400	488	36.12
3,400	Induction	40	45	16.21
5,950	Induction	70	75	16.52
8,500	Induction	100	110	18.48
12,750	Induction	150	160	22.14
21,250	Induction	250	263	30.71
5,890	LED	70	74	19.82
9,365	LED	100	101	21.93
Off-Roadway Luminaires				
27,500	Sodium Vapor	250	311	$33.44
46,000	Sodium Vapor	400	488	41.32

SERVICE CLASSIFICATION NO. 4 (Continued)

RATES – MONTHLY: (Continued)

(1) Luminaire Charge: (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Delivery Charge
600	Open Bottom Incandescent	52	52	$7.36
800	Open Bottom Incandescent	62	62	7.41
1,000	Open Bottom Incandescent	92	92	10.02
2,500	Open Bottom Incandescent	189	189	13.62
2,500	Closed Bottom Incandescent	189	189	13.91
4,000	Closed Bottom Incandescent	295	295	17.63
6,000	Closed Bottom Incandescent	405	405	21.22
-	Ornamental Incandescent	200	200	15.05
4,000	Mercury Vapor Power Bracket	100	127	11.80
4,000	Mercury Vapor Street Light	100	127	13.36
7,900	Mercury Vapor Power Bracket	175	215	14.51
7,900	Mercury Vapor Street Light	175	211	16.19
12,000	Mercury Vapor	250	296	21.22
40,000	Mercury Vapor	700	786	41.63
22,500	Mercury Vapor	400	459	27.13
59,000	Mercury Vapor	1,000	1,105	53.24
130,000	Sodium Vapor	1,000	1,120	76.03
	Post Top M.V.	100	130	18.19
	Post Top M.V.	175	215	21.69
	Post Top – Offset M.V.	175	215	25.78

SERVICE CLASSIFICATION NO. 4 (Continued)

RATES – MONTHLY: (Continued)

(2) Additional Charge:

A. An additional $5.15 per luminaire per month will be charged for existing Underground Service where the customer has installed, owns and maintains the duct system completely, but not the aluminum standard or luminaire.

B. An additional 52 ¢ per month will be charged for a fifteen foot bracket when installed.

(3) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services, and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(4) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification.

(5) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(6) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

(7) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

SERVICE CLASSIFICATION NO. 4 (Continued)

RATES – MONTHLY: (Continued)

(8) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(9) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

The charges in RATES - MONTHLY Parts (3), (4), (5), (6) and (8) shall apply to the kWh estimated in the following manner:

kWh = (Total Wattage ÷ 1,000) Times Monthly Burn Hours*

* See Monthly Burn Hours Table.

MINIMUM CHARGE PER INSTALLATION:

The minimum charge per installation shall be the monthly charge as specified in RATES - MONTHLY, Parts (1) and (2) times sixty months (five years) plus any billing and payment processing charges. Should the monthly charge change during the initial term, the minimum charge per installation shall be prorated accordingly.

SPECIAL PROVISIONS:

(A) The Company shall not be required to replace more than two percent of the luminaires in any lighting district in any one year with one of a different type or design unless the customer shall pay to the Company a replacement charge for the excess equal to the Company's actual costs (material and labor) of performing the replacement. Replacement is defined as renewed service at the same location by the same customer within one year of termination.

SERVICE CLASSIFICATION NO. 4 (Continued)

SPECIAL PROVISIONS: (Continued)

(A) (Continued)

For the period November 1, 2015 to October 31, 2016, the Company will replace up to two percent of its street lights on a system wide basis (“2% System Threshold”). Municipalities wishing to participate must provide the Company with required notice by January 1, 2016. The Company will allocate a portion of the 2% System Threshold to each municipality that requests replacement 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 the 12-month period commencing November 1, 2015.

(B) Charges to customers under revised or superseding Service Classification shall commence with the first day of the billing period following the effective date of such revised or superseding Service Classification.

(C) Service to customer owned lighting facilities shall not be made under this Service Classification except for existing underground services where the customer has installed, owns and maintains the duct system complete, but not aluminum standards or luminaires.

(D) A customer may apply for service hereunder for a proposed residential subdivision in which all electric facilities will be underground. Such application shall be signed by the customer and builder or developer and when accepted by the Company, shall constitute an agreement between the Company, customer and builder or developer subject to the terms and provisions hereunder.

The builder or developer shall pay to the Company prior to the commencement of any construction all costs associated with the installation of the facilities to be served hereunder and a prepayment of six times the total monthly charge for all luminaires installed. Said monthly charges shall be determined using the rates in effect at the time said costs and charges are determined. The Company shall not bill the customer for the first six months of service of the facilities installed under this provision.

(E) The customer shall furnish the Company with all easements or rights-of-way necessary to provide service to the desired location before any installation or construction will be started.

(F) The Company shall not be obligated to repair or replace in kind any obsolete luminaire for which it cannot reasonably obtain the necessary parts. The Company will, remove the obsolete luminaire or, at the customer's request, replace it with any luminaire offered for service at that time for which the customer will be charged the appropriate rates.

SERVICE CLASSIFICATION NO. 5 (Continued)

TERMS OF PAYMENT:

If a bill is not paid, service may be discontinued in accordance with provisions of General Information Section Nos. 11.1 and 11.2. Bills are subject to a late payment charge in accordance with provisions of General Information Section No. 7.6.

A. Un-metered Service Bills will be rendered on approximately the twenty-ninth of each month and are due on the first of the following month.

B. Metered Service Bills are due when rendered.

RATES - MONTHLY:

(1) Delivery Charge

All kWh at 9.295 ¢ per kWh

(2) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(3) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(4) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

SERVICE CLASSIFICATION NO. 6 (Continued)

TERMS OF PAYMENT:

Bills will be rendered on approximately the twenty-ninth of each month and are due on the first of the following month, subject to a late payment charge in accordance with provisions of General Information Section No. 7.6. If the bill is not paid, service may be discontinued in accordance with General Information Section Nos. 11.1 and 11.2.

MONTHLY BURN HOURS TABLE:

January	430	July	267
February	361 (*)	August	298
March	358	September	328
April	302	October	383
May	277	November	407
June	249	December	440

(*) 373 Burning Hours for Leap Year.

RATES – MONTHLY:

(1a) Delivery Charge for Service Types A and B

All kWh at 7.265 ¢ per kWh

(1b) Delivery Charge for Service Type C

Customer Charge at $24.00 per month plus
Delivery Charge at 6.146 ¢ per kWh

(2) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services, and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(3) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification.

SERVICE CLASSIFICATION NO. 6 (Continued)

RATES – MONTHLY: (Continued)

(4) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(5) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

(6) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

(7) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(8) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

For Service Types A and B, the charges in RATES - MONTHLY Parts (1), (2), (3), (4), (5) and (7) shall apply to the kWh estimated in the following manner:

kWh = (Total Wattage ÷ 1,000) Times Monthly Burn Hours*

Total Wattage shall be determined by the Company from manufacturers' rated wattages and the quantities of lamps and auxiliary equipment in operation.

* See Monthly Burn Hours Table.

MINIMUM CHARGE PER INSTALLATION:

The minimum charge per installation shall be the monthly charge as specified in RATES - MONTHLY, Part (1) times 120 months plus any billing and payment processing charges. Should the monthly charge change during the initial term, the minimum charge per installation shall be prorated accordingly.

SERVICE CLASSIFICATION NO. 6 (Continued)

SPECIAL PROVISIONS: (Continued)

(H) Outages (Continued)

(3) When a luminaire served under Service Type A or B is found illuminated during daylight hours, the Company shall notify the customer and the customer shall have 48 hours to repair such luminaire. If the luminaire is not repaired within 48 hours, the customer will be assessed a daily charge retroactive to the first day of the month of such finding and until the lamp has been repaired and the Company has been so notified. Such daily charge shall be determined as follows:

$$\text{Daily Charge} = \frac{4{,}660 \text{ hrs/yr} \times \text{Lamp Wattage}/1{,}000 \text{ Watts/kW} \times \text{Rate (\$/kWh)}}{365 \text{ days/yr}}$$

Rate ($/kWh) = Sum of RATES – MONTHLY, Parts (1), (2), (3), (4), (5), (7) and (8) for the billing month

(I) Tree Trimming

The customer authorizes the Company, insofar as it lawfully may, to trim, cut, remove and to keep trimmed, cut and removed any trees and all other obstructions which, in the opinion of the Company, interfere with or may tend to interfere with the construction, operation and maintenance of the Company's service under this Service Classification. Tree trimming required for light distribution on the highway, street and/or sidewalk surfaces is the responsibility of the customer, and shall be done by the customer or at the customer's expense.

(J) Customer Purchases of Company Facilities

The customer may, at its option, elect to purchase all or a portion of the Company's street lighting system being used to serve the customer. Such purchase may consist of a purchase of both luminaires and associated support arms, or a purchase of only support arms. The following guidelines will apply to any sale of the Company's street lighting facilities:

(1) A customer desiring to purchase the street lighting system being used to serve it shall inform the Company in writing of such desire, and indicate which portion of that system it desires to purchase. The lights and support arms to be purchased, or the support arms to be purchased, must be all such facilities contained in a single contiguous geographic area, defined as being an area bounded on all sides by a public right of way and containing all area within those bounds.

SERVICE CLASSIFICATION NO. 9 (Continued)

RATES - MONTHLY: (Continued)

(2) Delivery Charges

	Primary	Substation	Transmission
Demand Charge			
Period A All kW @	$17.31 /kW	$ 11.75 /kW	$ 7.79 /kW
Period B All kW @	$ 8.12 /kW	$ 5.31 /kW	$ 5.30 /kW
Period C All kW @	No Charge	No Charge	No Charge
Usage Charge			
Period A All kWh @	1.632 ¢/kWh	0.903 ¢/kWh	0.218 ¢/kWh
Period B All kWh @	1.632 ¢/kWh	0.903 ¢/kWh	0.218 ¢/kWh
Period C All kWh @	0.609 ¢/kWh	0.556 ¢/kWh	0.205 ¢/kWh

(3) Reactive Power Demand Charge

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7.

(4) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(5) Revenue Decoupling Mechanism Adjustment

The provisions of the Company’s Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification. Customers taking service under Rider H shall not be subject to this provision.

SERVICE CLASSIFICATION NO. 9 (Continued)

RATES - MONTHLY: (Continued)

(6) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(7) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access customers shall not be subject to this charge.

(8) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

(9) Metering Charges

The following Metering Charges shall be assessed on all customers taking service under this Service Classification, unless such metering service(s) is obtained competitively pursuant to General Information Section No. 7:

		Primary	Substation	Transmission
a)	Meter Ownership Charge	$21.20	$21.20	$21.20
b)	Meter Service Provider Charge	$77.28	$77.28	$77.28
c)	Meter Data Service Provider Charge	$31.76	$31.76	$31.76

SERVICE CLASSIFICATION NO. 9 (Continued)

MINIMUM MONTHLY DEMAND CHARGE:

The minimum monthly demand charge shall be $57.36 plus the contract demand charge and the reactive power demand charge, if applicable. The contract demand charge shall be $4.17 per kW of contract demand per month for service metered at the primary voltage, or $6.84 per kW of contract demand per month for service metered at the secondary voltage.

CONTRACT DEMAND:

The customer's contract demand shall be the customer's maximum metered demand in any of the immediately preceding eleven months.

DETERMINATION OF DEMAND:

The billing demand, for each of the rating periods above, shall be defined as the highest 15-minute integrated kW demand determined during each rating period by the use of a suitable demand indicator. If applicable, the billing demand shall equal the metered demand adjusted for appropriate losses as determined by the Company and referenced in the METERING section of this Tariff.

TERMS OF PAYMENT:

Bills are due when rendered, subject to late payment charge in accordance with General Information Section No. 7.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section Nos. 11.1 and 11.2.

TERM:

The initial term shall be one year unless the Company requires a longer initial term where special construction is required to furnish service. Thereafter, service is terminable upon ninety days written notice.

Termination of service hereunder by the customer followed by renewed service at the same location under another service classification will only be permitted on the anniversary of the date service commenced hereunder.

SERVICE CLASSIFICATION NO. 15 (Continued)

DEFINITION OF RATING PERIODS:

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday except holidays, all months.

Period B - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and Holidays, all months.

Holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

RATE TO BE PAID BY CUSTOMER - MONTHLY:

(1) Customer Charge

A customer who takes service hereunder and, in addition, takes service under another Service Classification at the same location shall pay a customer charge as follows:

Service Voltage	Contract Demand	Customer Charge
Primary	1000 kW and over	$147.08 per month
Primary	Under 1000 kW	$111.94 per month
Secondary	Any kW	$13.82 per month

All other customers shall pay a customer charge as follows:

Service Voltage	Contract Demand	Customer Charge
Primary	1000 kW and over	$152.98 per month
Primary	Under 1000 kW	$117.87 per month
Secondary	Any kW	$27.46 per month

(2) Contract Demand Charge

The contract demand charge for each billing period shall be as follows:

SERVICE CLASSIFICATION NO. 15 (Continued)

RATE TO BE PAID BY CUSTOMER - MONTHLY: (Continued)

(2) Contract Demand Charge (Continued)

	Primary	Secondary
All kW of Contract Demand @	$4.03 per kW	$6.63 per kW

(3) Reactive Power Demand Charge:

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7. If the meter registers no kW demand for a billing period, the Reactive Power Demand Charge shall be applied to the highest kVAr recorded during the billing period.

A customer who takes service hereunder and, in addition, takes service under another Service Classification at the same location shall not be assessed the Reactive Power Demand Charge if all of the customer's reactive power usage is assessed the Reactive Power Demand Charge applicable under the other Service Classification.

(4) Increase in Rates and Charges:

The customer charge and contract demand charge for service hereunder will be increased pursuant to General Information Section No. 19.

MINIMUM CHARGE PAID BY CUSTOMER:

(A) Monthly - The applicable customer charge, plus the applicable contract demand charge.

(B) Contract - Twelve times the applicable monthly customer charge, plus the applicable contract demand charges for the initial term.

SERVICE CLASSIFICATION NO. 16 (Continued)

RATES – MONTHLY:

(1a) Luminaire Charges for Service Types A and B:

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Delivery Charge
Power Bracket Luminaires				
5,800	Sodium Vapor	70	108	$24.59
9,500	Sodium Vapor	100	142	26.27
16,000	Sodium Vapor	150	199	30.90
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	$26.91
9,500	Sodium Vapor	100	142	28.68
16,000	Sodium Vapor	150	199	33.19
27,500	Sodium Vapor	250	311	42.32
46,000	Sodium Vapor	400	488	58.11
3,400	Induction	40	45	29.30
5,950	Induction	70	75	29.89
8,500	Induction	100	110	32.62
12,750	Induction	150	160	38.06
21,250	Induction	250	263	50.43
5,890	LED	70	74	35.82
9,365	LED	100	101	38.72
Flood Lighting Luminaires				
27,500	Sodium Vapor	250	311	$42.32
46,000	Sodium Vapor	400	488	58.11

SERVICE CLASSIFICATION NO. 16 (Continued)

RATES – MONTHLY: (Continued)

(1a) Luminaire Charges for Service Types A and B: (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Delivery Charge
Power Bracket Luminaires				
4,000	Mercury Vapor	100	127	$22.44
7,900	Mercury Vapor	175	215	26.14
22,500	Mercury Vapor	400	462	37.53
Street Lighting Luminaires				
4,000	Mercury Vapor	100	127	$24.73
7,900	Mercury Vapor	175	211	28.64
12,000	Mercury Vapor	250	296	36.06
22,500	Mercury Vapor	400	459	44.43
40,000	Mercury Vapor	700	786	65.72
59,000	Mercury Vapor	1,000	1,105	82.02
130,000	Sodium Vapor	1,000	1,120	112.29
1,000	Incandescent	92	92	19.64
2,500	Incandescent	189	189	25.14
Flood Lighting Luminaires				
12,000	Mercury Vapor	250	296	$36.06
22,500	Mercury Vapor	400	459	44.43
40,000	Mercury Vapor	700	786	65.72
59,000	Mercury Vapor	1,000	1,105	82.02

SERVICE CLASSIFICATION NO. 16 (Continued)

RATES – MONTHLY: (Continued)

(1b) Delivery Charges for Service Type C

Metered Service -	Customer Charge at $24.00 per month plus Delivery Charge at 6.146 cents per kWh; or
Un-metered Service -	Customer Charge at $19.00 per month plus Delivery Charge at 6.146 cents per kWh.

(2) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section No. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(3) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(4) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

SERVICE CLASSIFICATION NO. 16 (Continued)

MINIMUM CHARGE:

The minimum charge per luminaire for Service Type A or B shall be the monthly delivery charge as specified in RATES - MONTHLY, Part (1) times twelve plus any applicable billing and payment processing charges. Should the monthly charge be revised during the initial term, the minimum charge per installation shall be prorated accordingly.

The minimum charge for Service Type C – Metered shall be $24.00 per month plus any applicable billing and payment processing charges and not less than $288.00 for the initial term.

The minimum charge for Service Type C – Unmetered shall be $19.00 per month plus any applicable billing and payment processing charges and not less than $228.00 for the initial term.

MONTHLY BURN HOURS TABLE:

January	430	July	267
February	361 *	August	298
March	358	September	328
April	302	October	383
May	277	November	407
June	249	December	440

* 373 Burning Hours for Leap Year.

SERVICE CLASSIFICATION NO. 16 (Continued)

TERM:

The Initial Term shall be one year. Service shall continue in effect thereafter until by either party upon thirty days written notice. The Company shall require an Initial Term of one year for each luminaire for Service Types A or B.

TERMS OF PAYMENT:

Bills are due when rendered subject to a late payment charge in accordance with provisions of Section No. 7.6. If the bill is not paid, service may be discontinued in accordance with provisions of General Information Section Nos. 11.1 and 11.2.

SPECIAL PROVISIONS:

Special Provisions A, B, D, E, F, and J apply only to Service Types A and B. Special Provision K applies only to Service Type C. Special Provisions C, G, H, and I apply to Service Types A, B, and C.

(A) Street lighting luminaires will normally be mounted on eight foot aluminum brackets. Fifteen foot brackets are available at an additional charge of $0.78 per bracket per month.

(B) Luminaires will be installed free of charge where all facilities necessary to serve a luminaire are present. Customer shall pay the cost of any additional facilities required, prior to the commencement of the construction of such facilities.

(C) The customer shall furnish the Company will all easements or rights-of-way necessary to provide service to the desired location before any installation or construction will be started.

(D) A customer may apply for service hereunder for a proposed residential subdivision in which all electric facilities will be underground. Such application shall be signed by the customer and builder or developer and when accepted by the Company, shall constitute an agreement between the Company, customer and builder or developer subject to the terms and provisions hereunder.

The builder or developer shall pay to the Company prior to the commencement of any construction all costs associated with the installation of the facilities to be served hereunder and shall prepay six times the total monthly charge for all luminaires installed. Said monthly charges shall be determined using the rates in effect at the time said costs and charges are determined. The Company shall not bill the customer for the first six months of service of the facilities installed under this special provision.

SERVICE CLASSIFICATION NO. 19

APPLICABLE TO USE OF SERVICE FOR:

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an Energy Service Company under the Company's Retail Access Program for residential service at customer's option, and other customers eligible for residential service as defined in General Information Section No. 8. Residential service is also available under Service Classification No. 1 of this Rate Schedule.

CHARACTER OF SERVICE:

Residential Customers:

Continuous, 60 cycles, A.C., from any one of the following systems as designated by the Company:

(a) Single phase at approximately 120, 120/208 or 120/240 Volts.

(b) Three phase four wire at approximately 120/208 Volts in limited areas.

Other Customers Eligible for Residential Service as Defined in General Information Section No. 8:

Continuous, 60 cycles, A.C., single or three phase secondary, or three phase primary as defined in General Information Section No. 4.

RATES - MONTHLY:

(1) Customer Charge $37.00

(2) Delivery Charge

Period I	All kWh @	30.242	¢ per kWh
Period II	All kWh @	10.821	¢ per kWh
Period III	All kWh @	10.821	¢ per kWh
Period IV	All kWh @	1.947	¢ per kWh

SERVICE CLASSIFICATION NO. 19 (Continued)

RATES - MONTHLY: (Continued)

(8) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(9) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

DEFINITION OF RATING PERIODS:

Period I - 12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period II - 10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period III- 10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period IV - 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday and Sunday and holidays, all months.

For purposes of this section holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION:

The customer charge, not less than $444.00 per contract, plus any applicable billing and payment processing charges.

SERVICE CLASSIFICATION NO. 20

APPLICABLE TO USE OF SERVICE FOR:

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an Energy Service Company under the Company's Retail Access Program for general secondary service, at customer's option, to any customer who maintains a minimum demand level of 5 kW for at least two consecutive months during the previous twelve months.

CHARACTER OF SERVICE:

Continuous, 60 cycles, A.C., single or three phase secondary as defined in General Information Section No. 4.

RATES - MONTHLY:

(1) Customer Charge $ 40.00

(2) Delivery Charges

Demand Charge

Period I	All kW @	$ 22.92	per kW
Period II	All kW @	$ 9.89	per kW
Period III	All kW @	No Charge	

Usage Charge

Period I	All kWh @	8.938	¢ per kWh
Period II	All kWh @	2.149	¢ per kWh
Period III	All kWh @	0.286	¢ per kWh

SERVICE CLASSIFICATION NO. 20 (Continued)

RATES - MONTHLY: (Continued)

(3) Reactive Power Demand Charge

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7.

(4) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section No. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(5) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification.

Customers taking service under Rider H shall not be subject to this provision.

(6) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(7) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access customers shall not be subject to this charge.

(8) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

SERVICE CLASSIFICATION NO. 20 (Continued)

RATES - MONTHLY: (Continued)

(9) Metering Charges

The following Metering Charges shall be assessed on all customers taking service under this Service Classification, unless such metering service(s) is obtained competitively pursuant to General Information Section No. 7:

	Customers Eligible for Mandatory DAHP	All Other Customers
a) Meter Ownership Charge	$20.44	$4.57
b) Meter Service Provider Charge	$18.48	$16.66
c) Meter Data Service Provider Charge	$31.76	$2.13

(10) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(11) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

SERVICE CLASSIFICATION NO. 20 (Continued)

DEFINITION OF RATING PERIODS:

Period I 1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period II 10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period III 7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

For the purposes of this section, holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

MINIMUM MONTHLY CHARGE:

The sum of the Customer Charge and $120.00 plus any applicable metering and/or billing and payment processing charges.

DETERMINATION OF DEMAND:

The minimum billing demand shall be 5 kW.

The billing demand, for each of the rating periods above, shall be defined as the highest 15-minute integrated kW demand determined during each rating period by the use of a suitable demand indicator.

SERVICE CLASSIFICATION NO. 21

APPLICABLE TO USE OF SERVICE FOR:

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an Energy Service Company under the Company's Retail Access Program for general Primary Service, at the customer's option, to customers who provide all equipment required to take service at a primary voltage as designated by the Company. All service at one location shall be taken through one meter.

A customer whose demand exceeds 1,000 kW during any two of the previous twelve months shall not be eligible for this rate and shall be transferred to Service Classification No. 9 or 22. A customer so transferred shall only be eligible for transfer back to Service Classification No. 21 on the annual anniversary of the transfer to Service Classification No. 9 or 22 and only if said customer has not exceeded 1,000 kW during any two of the previous twelve months.

CHARACTER OF SERVICE:

Continuous, 60 cycles, A.C., three phase primary as defined in General Information Section No. 4.

RATES - MONTHLY:

(1) Customer Charge $ 163.00

(2) Delivery Charges

Demand Charge

Period I	All kW @	$ 27.46	per kW
Period II	All kW @	$ 9.68	per kW
Period III	All kW @	No Charge	

Usage Charge

Period I	All kWh @	1.400	¢ per kWh
Period II	All kWh @	1.400	¢ per kWh
Period III	All kWh @	0.123	¢ per kWh

SERVICE CLASSIFICATION NO. 21 (Continued)

RATES - MONTHLY: (Continued)

(3) Reactive Power Demand Charge

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7.

(4) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section No. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(5) Revenue Decoupling Mechanism Adjustment

The provisions of the Company’s Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification.

Customers taking service under Rider H shall not be subject to this provision.

(6) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(7) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access customers shall not be subject to this charge.

(8) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

SERVICE CLASSIFICATION NO. 21 (Continued)

RATES - MONTHLY: (Continued)

(9) Metering Charges

The following Metering Charges shall be assessed on all customers taking service under this Service Classification, unless such metering service(s) is obtained competitively pursuant to General Information Section No. 7:

	Customers Eligible for Mandatory DAHP	All Other Customers
(a) Meter Ownership Charge	$20.44	$6.45
(b) Meter Service Provider Charge	$18.48	$23.51
(c) Meter Data Service Provider Charge	$31.76	$1.38

(10) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(11) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

SERVICE CLASSIFICATION NO. 22 (Continued)

APPLICABLE TO USE OF SERVICE FOR: (Continued)

- no longer maintains energy use for mining or manufacturing purposes of at least 60% of their total usage

may, at the customer's option, transfer to another Service Classification, provided that such transfer shall only be made on the annual anniversary date that such customer began service hereunder.

All service at one location shall be taken through one meter.

CHARACTER OF SERVICE:

Continuous, 60 cycles, A.C., three phase primary, substation or transmission service as defined in General Information Section No. 4 and depending upon the magnitude and characteristics of the load and the circuit from which service is supplied.

RATES - MONTHLY:

	Primary	Substation	Transmission
(1) Customer Charge	$500.00	$500.00	$500.00
(2) Delivery Charges			
Demand Charge			
Period A All kW @	$14.48 /kW	$ 9.85 /kW	$ 5.97 /kW
Period B All kW @	$ 8.28 /kW	$ 5.42 /kW	$ 5.22 /kW
Period C All kW @	No Charge	No Charge	No Charge
Usage Charge			
Period A All kWh @	1.109 ¢/kWh	0.466 ¢/kWh	0.130 ¢/kWh
Period B All kWh @	1.109 ¢/kWh	0.466 ¢/kWh	0.130 ¢/kWh
Period C All kWh @	0.188 ¢/kWh	0.141 ¢/kWh	0.066 ¢/kWh

SERVICE CLASSIFICATION NO. 22 (Continued)

RATES - MONTHLY: (Continued)

(3) Reactive Power Demand Charge

A Reactive Power Demand Charge shall be assessed in accordance with General Information Section No. 7.

(4) Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Renewable Portfolio Standard Charge and Transition Adjustment for Competitive Services as described in General Information Section No. 25, 26, 27 and 29, respectively, and Charges for Municipal Undergrounding as described in General Information Section No. 20, if applicable, shall apply to electricity delivered under this Service Classification.

(5) Revenue Decoupling Mechanism Adjustment

The provisions of the Company’s Revenue Decoupling Mechanism Adjustment as described in General Information Section No. 30 shall apply to electricity delivered under this Service Classification. Customers taking service under Rider H shall not be subject to this provision.

(6) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section No. 24 shall apply to electricity delivered under this Service Classification.

(7) Merchant Function Charge

The Merchant Function Charge as described in General Information Section No. 28 shall apply to Full Service Customers. Retail Access Customers shall not be subject to this charge.

(8) Billing and Payment Processing Charge

A Billing and Payment Processing Charge shall be assessed in accordance with General Information Section No. 7.5.

SERVICE CLASSIFICATION NO. 22 (Continued)

RATES - MONTHLY: (Continued)

(9) Metering Charges

The following Metering Charges shall be assessed on all customers taking service under this Service Classification, unless such metering service(s) is obtained competitively pursuant to General Information Section No. 7:

	Primary	Substation	Transmission
(a) Meter Ownership Charge	$21.20	$21.20	$21.20
(b) Meter Service Provider Charge	$77.28	$77.28	$77.28
(c) Meter Data Service Provider Charge	$31.76	$31.76	$31.76

(10) Market Supply Charge

The provisions of General Information Section No. 15 shall apply to electricity provided and sold by the Company under this Service Classification. Retail Access Customers shall not be subject to this charge.

(11) Increase in Rates and Charges

All rates and charges for service under this Service Classification will be increased pursuant to General Information Section No. 19.

DEFINITION OF RATING PERIODS

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

For purposes of this section, holidays are: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

SERVICE CLASSIFICATION NO. 22 (Continued)

MINIMUM MONTHLY CHARGE:

The sum of the Customer Charge and the Minimum Monthly Demand Charge plus any applicable metering and/or billing and payment processing charges.

MINIMUM MONTHLY DEMAND CHARGE:

The minimum monthly demand charge shall be $57.36 plus the contract demand charge and the reactive power demand charge, if applicable. The contract demand charge shall be $4.17 per kW of contract demand per month for service metered at the primary voltage, or $6.84 per kW of contract demand per month for service metered at the secondary voltage.

CONTRACT DEMAND:

The customer's contract demand shall be the customer's maximum metered demand in any of the immediately preceding eleven months.

DETERMINATION OF DEMAND:

The billing demand, for each of the rating periods above, shall be defined as the highest 15-minute integrated kW demand determined during each rating period by the use of a suitable demand indicator. If applicable, the billing demand shall equal the metered demand adjusted for appropriate losses as determined by the Company and referenced in the METERING section of this schedule.

TERMS OF PAYMENT:

Bills are due when rendered, subject to late payment charges in accordance with General Information Section No. 7.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section Nos. 11.1 and 11.2.

TERM:

The initial term shall be one year unless the Company requires a longer initial term where special construction is required to furnish service. Thereafter, service is terminable upon ninety days written notice.

SERVICE CLASSIFICATION NO. 25 (Continued)

RATES – MONTHLY:

Customers are billed for standby service at the applicable rate under Part 1, plus Parts 2, 3, 4 and 5 of this Service Classification.

(1) Customer Charges and Delivery Charges

The service classification under which the customer would otherwise receive service if it did not take service hereunder determines the standby Customer Charges and Delivery Charges applicable to the customer. The customer's contract demand shall be used to determine the otherwise applicable service classification.

(a) Rate 1: Applicable to demand-metered customers that would otherwise be eligible for service under Service Classification No. 2 or Service Classification No. 20 of this Rate Schedule.

Customer Charge

Secondary	$46.00
Primary	$66.00

Delivery Charges

Contract Demand Charge (per kW of contract demand, as described in the "Determination of Demand" Section of this Service Classification)

Secondary	All kW @	$4.33 per kW
Primary	All kW @	$5.69 per kW

As-Used Daily Demand Charge (per kW of as-used daily demand, as described in the "Determination of Demand" Section of this Service Classification)

		Summer Months*	Other Months
Secondary	All kW @	$0.6903 per kW	$0.5209 per kW
Primary	All kW @	$0.6507 per kW	$0.4961 per kW

* June – September

SERVICE CLASSIFICATION NO. 25 (Continued)

RATES – MONTHLY: (Continued)

(1) Customer Charges and Delivery Charges (Continued)

(b) Rate 2: Applicable to demand-metered customers that would otherwise be eligible for service under Service Classification No. 3 or Service Classification No. 21 of this Rate Schedule.

Customer Charge $163.00

Delivery Charges

Contract Demand Charge (per kW of contract demand, as described in the "Determination of Demand" Section of this Service Classification)

All kW @ $8.45 per kW

As-Used Daily Demand Charge (per kW of as-used daily demand, as described in the "Determination of Demand" Section of this Service Classification)

	Summer Months*	Other Months
All kW @	$0.6121 per kW	$0.4321 per kW

* June – September

SERVICE CLASSIFICATION NO. 25 (Continued)

RATES – MONTHLY: (Continued)

(1) Customer Charges and Delivery Charges (Continued)

(c) Rate 3: Applicable to demand-metered customers that would otherwise be eligible for service under Service Classification No. 9 of this Rate Schedule.

Customer Charge $530.00

Delivery Charges

Contract Demand Charge (per kW of contract demand, as described in the "Determination of Demand" Section of this Service Classification)

Primary	All kW @	$6.76 per kW
Substation	All kW @	$4.30 per kW
Transmission	All kW @	$1.45 per kW

As-Used Daily Demand Charge (per kW of as-used daily demand, as described in the "Determination of Demand" Section of this Service Classification)

		Summer Months*	Other Months
Primary	All kW @	$0.6081 per kW	$0.3912 per kW
Substation	All kW @	$0.4722 per kW	$0.3136 per kW
Transmission	All kW @	$0.3661 per kW	$0.2781 per kW

* June – September

SERVICE CLASSIFICATION NO. 25 (Continued)

RATES – MONTHLY: (Continued)

(1) Customer Charges and Delivery Charges (Continued)

(d) Rate 4: Applicable to demand-metered customers that would otherwise be eligible for service under Service Classification No. 22 of this Rate Schedule.

Customer Charge $530.00

Delivery Charges

Contract Demand Charge (per kW of contract demand, as described in the "Determination of Demand" Section of this Service Classification)

Primary	All kW @	$5.36 per kW
Substation	All kW @	$2.86 per kW
Transmission	All kW @	$1.15 per kW

As-Used Daily Demand Charge (per kW of as-used daily demand, as described in the "Determination of Demand" Section of this Service Classification)

		Summer Months*	Other Months
Primary	All kW @	$0.5448 per kW	$0.3989 per kW
Substation	All kW @	$0.3743 per kW	$0.2581 per kW
Transmission	All kW @	$0.3078 per kW	$0.2810 per kW

* June – September

SERVICE CLASSIFICATION NO. 25 (Continued)

SPECIAL PROVISIONS: (Continued)

(B) A customer billed under this Service Classification may segregate any portion of the total requirements of its load so that such portion is served exclusively with the Company's service under another appropriate Service Classification of this Rate Schedule. The portion of the load that is segregated and supplied under another service classification shall not be considered in the determination of the customer's contract demand.

(C) Wholesale generators that take station service through the same bus bar as they supply the wholesale grid are eligible for standby service. For purposes of this section, same bus bar shall be defined as a common point of interconnection between the Company's systems and the customer's systems at the voltage level at which the customer takes service. Standby service shall not apply in cases where the wholesale generator is operating and it supplies all of its electric needs "behind the meter" i.e., the energy does not pass through the point of interconnection between the Company's systems and the customer's systems.

(D) Billing under this Service Classification for Customers with Designated Technologies, as defined below, is as follows.

For the purposes of this provision, Customers With Designated Technologies shall mean a customer who meets both of the following criteria:

(1) has a Contract Demand of 50 kW or greater and has on-site generation equipment having a total nameplate rating equal to more than 15 percent of the maximum potential demand served by all sources; and

(2) has an on-site generation facility that (i) exclusively uses one or more of the following technologies and/or fuels: fuel cells, wind, solar thermal, photovoltaics, sustainably-managed biomass, tidal, geothermal, or methane waste, or (ii) uses small, efficient types of combined heat and power generation that do not exceed 1 MW of capacity in aggregate and meets eligibility criteria that were approved in the order of the Commission, dated January 23, 2004, in Case 02-E-0780.

Customers With Designated Technologies who commence operation of their on-site generation facility between July 29, 2003 and May 31, 2015, will be billed under their Otherwise Applicable Rate, unless the customer makes a one-time election in writing, no less than 30 days before commencing operation of their on-site generation facility, to be billed at the Standby Service Rates. Billing at the Standby Service Rates will commence with the customer's first full billing cycle following notification, subject to the availability of interval metering.

SERVICE CLASSIFICATION NO. 25 (Continued)

SPECIAL PROVISIONS: (Continued)

(E) The Company may enter into individually negotiated agreements for standby service with the following;

(1) Customers that can demonstrate to the Company's satisfaction that they can economically isolate from the Company's system by installing and operating back-up generation at a lower cost than paying for standby service at the applicable rates and charges of this Service Classification, and would do so without the negotiated rate alternative;

(2) Customers that are currently isolated from the Company's system and rely on on-site generating facilities to meet their electrical requirements and would continue to do so without the negotiated rate alternative; and

(3) Customers with on-site generating equipment having a total nameplate rating of 50 MW or greater, where no less than 90 percent of the site's energy output, net of station power requirements, is sold into the market place or a third party, The rates and charges negotiated will reflect, when applicable, the characteristics of the specific interconnection arrangements, including, but not limited to, the voltage level of the interconnection, whether the interconnection is bi-directional, and the nature of the Company's facility where the generator is interconnected with the Company's system.

At a minimum, the negotiated rate agreement must provide for a reasonable contribution to the Company's recovery of fixed costs.

The Company shall respond to a customer application for a negotiated agreement within 60 days of its receipt, with a negotiated agreement offer or a written explanation for its rejection of the application.

(F) All requests for service under this Service Classification must be made in writing.

SERVICE CLASSIFICATION NO. 25 (Continued)

RESERVED FOR FUTURE USE

SERVICE CLASSIFICATION NO. 25 (Continued)

RESERVED FOR FUTURE USE

SERVICE CLASSIFICATION NO. 25 (Continued)

RESERVED FOR FUTURE USE

Orange and Rockland Utilities, Inc.
Gas Rate Case
Proposed Tariff Leaves effective January 1, 2015

P.S.C. No. 4 Gas

4th	Revised Leaf No.	2	6th	Revised Leaf No.	122.2
2nd	Revised Leaf No.	4.1	2nd	Revised Leaf No.	122.3
6th	Revised Leaf No.	5	5th	Revised Leaf No.	126
1st	Revised Leaf No.	20	8th	Revised Leaf No.	127
	Original Leaf No.	20.1	22nd	Revised Leaf No.	130
14th	Revised Leaf No.	33.3	4th	Revised Leaf No.	130.1
6th	Revised Leaf No.	47	11th	Revised Leaf No.	131
	Original Leaf No.	47.1	11th	Revised Leaf No.	132
15th	Revised Leaf No.	72	24th	Revised Leaf No.	133
18th	Revised Leaf No.	73	6th	Revised Leaf No.	134
8th	Revised Leaf No.	74	3rd	Revised Leaf No.	135
9th	Revised Leaf No.	75	2nd	Revised Leaf No.	136
8th	Revised Leaf No.	76	10th	Revised Leaf No.	137
12th	Revised Leaf No.	77	12th	Revised Leaf No.	137.1
3rd	Revised Leaf No.	77.1	10th	Revised Leaf No.	137.2
6th	Revised Leaf No.	79.1	16th	Revised Leaf No.	138
4th	Revised Leaf No.	79.2	15th	Revised Leaf No.	138.1
13th	Revised Leaf No.	80	2nd	Revised Leaf No.	141.1.1
15th	Revised Leaf No.	80.1	7th	Revised Leaf No.	141.2
7th	Revised Leaf No.	80.3.2	10th	Revised Leaf No.	141.3
6th	Revised Leaf No.	80.4	6th	Revised Leaf No.	141.4
9th	Revised Leaf No.	81.1	3rd	Revised Leaf No.	148
15th	Revised Leaf No.	82	3rd	Revised Leaf No.	149
4th	Revised Leaf No.	93	8th	Revised Leaf No.	150
9th	Revised Leaf No.	94.9	4th	Revised Leaf No.	151
9th	Revised Leaf No.	94.10	3rd	Revised Leaf No.	151.1
12th	Revised Leaf No.	94.16	3rd	Revised Leaf No.	151.2
6th	Revised Leaf No.	94.18	5th	Revised Leaf No.	152.3
2nd	Revised Leaf No.	94.25	12th	Revised Leaf No.	153
11th	Revised Leaf No.	112	6th	Revised Leaf No.	154.1
4th	Revised Leaf No.	113.1	16th	Revised Leaf No.	155
5th	Revised Leaf No.	113.2	9th	Revised Leaf No.	183
2nd	Revised Leaf No.	113.4	3rd	Revised Leaf No.	183.1
22nd	Revised Leaf No.	114	5th	Revised Leaf No.	184
15th	Revised Leaf No.	115	2nd	Revised Leaf No.	185.1
25th	Revised Leaf No.	116	2nd	Revised Leaf No.	190
13th	Revised Leaf No.	117	3rd	Revised Leaf No.	191
10th	Revised Leaf No.	118	2nd	Revised Leaf No.	191.1
9th	Revised Leaf No.	119	2nd	Revised Leaf No.	191.2
8th	Revised Leaf No.	120	2nd	Revised Leaf No.	192
8th	Revised Leaf No.	121	3rd	Revised Leaf No.	193
7th	Revised Leaf No.	122		Original Leaf No.	193.1
6th	Revised Leaf No.	122.1	3rd	Revised Leaf No.	197
2nd	Revised Leaf No.	122.1.1	2nd	Revised Leaf No.	197.1

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GENERAL INFORMATION

3. HOW TO OBTAIN SERVICE (Cont'd)

3.7 PROVISIONS OF GAS SERVICE (Cont'd.)

(B) Residential Applicant -- Heating

up to 200 feet of main, including appurtenant facilities, and service line measured from the centerline of the public right-of-way (or the main if it is closer to the customer and development will be limited to one side of the right-of-way for at least 10 years), service connections and appurtenant facilities, but not less than the length of service line necessary to reach the edge of the public right-of-way; and

(C) Non-Residential Applicant

up to 100 feet of main and appurtenant facilities, and any service line, service connections and appurtenant facilities located in the public right-of-way.

The Company will extend its facilities and provide service to non-residential customers who have installed dual fuel capability when:

(1) customer has paid to the Company the total estimated cost of all new facilities required to provide service; and

(2) customer agrees to pay to the Company any actual costs above such estimated costs (Company agrees to refund to customer the difference between actual costs and estimated costs when actual costs are lower); or

(3) customer makes other arrangements satisfactory to the Company to guarantee that the Company's investment in new facilities will be recovered, including return, depreciation, taxes and maintenance, and such arrangements are acceptable and approved by the Commission.

GENERAL INFORMATION

3. HOW TO OBTAIN SERVICE (Cont'd)

3.7 PROVISIONS OF GAS SERVICE (Cont'd.)

(D) Aggregation of Entitlements for Multiple Applicants

The Company will allow residential heating applicants, residential non-heating applicants, and non-residential applicants to aggregate their entitlements (i.e., costs to be paid by the Company) for gas extensions on active main construction projects subject to the following rules:

(1) There must be a minimum of five customers with signed gas commitment letters to aggregate entitlements.

(2) Aggregation of entitlements can only be used in active main construction projects. Once the construction of the main extension is completed, there will no longer be aggregation allowed.

(3) The total entitlement shall be equal to the greater of: (a) the cost associated with the sum of the individual customer footage entitlements determined pursuant to General Information Sections 3.7(A), 3.7(B), and 3.7(C) above; or (b) the lesser of the cost of the main extension or 2.5 times the annual adjusted gas revenue associated with customers for which entitlements are aggregated.

3.8 CHARGES FOR ADDITIONAL FACILITIES

(A) Surcharge for Additional Facilities

If, in order to provide service to an applicant, the Company must install mains and appurtenant facilities in addition to those to be provided without charge, as provided for above, the Company shall impose a surcharge subject to the following provisions:

GENERAL INFORMATION

6. METERING AND BILLING (Cont'd.)

6.5 RENDERING OF BILLS (Cont'd.)

(2) Transportation Customer Billing Options (Cont'd.)

(B) Utility Single Billing Service

A Marketer requesting that its charges be included on a Utility Single Bill must execute the Company’s Consolidated Billing and Assignment Agreement.

Under Utility Single Billing Service, the Company shall purchase the Marketer’s receivables. That is, the Marketer assigns to the Company its rights in all amounts due from all of its customers participating in the Company’s Retail Access Program and receiving a Utility Single Bill. By the 20th of each month (or the next business day if the 20th falls on a Saturday, Sunday, or public holiday), the Company shall remit to the Marketer all undisputed Marketer charges billed to its customers in the previous calendar month, reduced by the Purchase of Receivables (“POR”) Discount Percentage as described below.

The POR Discount Percentage shall consist of an Uncollectibles Percentage, Credit and Collections Costs and a Risk Factor. The Uncollectibles Percentage shall be set annually, effective each November 1, based on the Company's actual uncollectibles experience applicable to all gas and electric POR-eligible customers for the twelve-month period ended the previous June 30. The Credit and Collections Component will be determined by dividing the Company’s credit and collection expenses attributable to retail access customers whose Marketers participate in the Company’s POR program by the estimated gas supply costs to be billed on the Marketers’ behalf. The percentage for credit and collections to be included in the POR Discount Percentage will be determined annually based on the forecast of commodity costs to be billed on behalf of Marketers through the POR program. The Risk Factor shall also be reset annually and shall be equal to 20 percent of the Uncollectibles Percentage. The POR Discount Percentage for the twelve month period commencing November 1, 2014 is 1.221 percent. The POR Discount Percentage shall be reset each November 1.

The Company will collect and process customers’ payments and perform collection activities in accordance with the Home Energy Fair Practices Act.

GENERAL INFORMATION

6. METERING AND BILLING (Cont'd.)

6.15 SHARED METERS

(1) In accordance with 16 NYCRR Sections 11.30 through 11.39, and Section 52 of the Public Service Law, when a tenant's service meter also registers utility service use outside the tenant's dwelling, the tenant is not required to pay the charges for that service. The Company will establish an account in the owner's name for all service registered on the shared meter after that date and will rebill for past service in accordance with 16 NYCRR Part 11.34. A customer may request a copy of the entire rules governing shared meters from the Company's office.

(2) "Shared Meter" means any utility meter that measures gas service provided to a tenant's dwelling and also measures service to other space outside that dwelling. "Service to other space" includes service to equipment, such as space-conditioning or water heating equipment, operated for the benefit of common areas of the building or other dwelling units.

6.16 LOW-INCOME PROGRAM

Any customer receiving a grant under the Home Energy Assistance Program (“HEAP”) shall receive a monthly bill credit for twelve consecutive months. The monthly bill credit will be $11.63 excluding applicable taxes. The Company will commence posting the monthly bill credits to a customer’s account within 60 days of receiving notification from the New York State Office of Temporary Disability (or its successor) of a customer’s receipt of a HEAP grant.

6.17 AMI AND AMR METER OPT OUT FEES

Any customer who requests that the transmitter of an AMI meter be disabled or requests an AMR meter be removed, will be classified as having opted out of AMI or AMR metering and will be required to submit an application and agreement with the Company.

Customers who opt out of AMI or AMR metering will be subject to the following.

(1) Access to Premises

Customers who opt out of AMI or AMR metering must provide reasonable access for meter reading and meter maintenance. If the customer fails to provide access for two months in a twelve-month period, then the customer will be required to: (a) pay the Company to relocate the metering equipment to an external location; or (b) permit the Company to reinstall an AMR meter or enable the AMI meter transmitter feature.

GENERAL INFORMATION

6. METERING AND BILLING (Cont'd.)

6.17 AMI AND AMR METER OPT OUT FEES (Cont’d.)

(2) Manual Meter Reading Fee

A monthly fee of $15 will apply to any customer who: refuses to allow the Company to install an AMI or AMR meter; requests that the transmitter of an AMI meter be disabled; or requests that an AMR meter be removed.

(3) Meter Change Out Fee

(A) A one-time meter change fee will apply for a customer who requests the change-out of an AMR meter. Such fee will be $225 for a customer who receives both electric and gas service from the Company, or $100 for a customer who receives only gas service from the Company.

(B) A customer that has a non-transmitting AMI gas meter, who elects to switch back to AMI metering, will be charged $55 to reactivate the transmitter.

(C) A customer who elects to switch back to AMI or AMR metering after requesting the removal of such meter will be reassessed the meter change out fee.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS

12.1 GAS SUPPLY CHARGE

The Gas Supply Charge is applicable to customers taking service under Service Classification Nos. 1 and 2.

The rate for the Gas Supply Charge shall be equal to the Average Cost of Gas used in retail gas operations of Orange and Rockland Utilities, Inc. multiplied by the Factor of Adjustment and rounded to the nearest 0.001 cents per Ccf. The Gas Supply Charge shall also include a surcharge or refund to recover Gas Supply Charge under-recoveries or refund Gas Supply Charge over-collections. Such surcharge or refund shall be calculated in accordance with (E) below.

(A) Factor of Adjustment

The Factor of Adjustment, used to adjust the cost of gas to reflect lost and unaccounted for gas, will be updated for each twelve-month period commencing November 1 based upon the average of actual line losses for the preceding five twelve-month periods ending August 31 (“Five Year Average”).

(B) Conversion Factor

The conversion factor, used to convert the average cost of gas calculated on a Dth basis to an Mcf basis, shall be the estimated Btu content of the gas delivered each month.

(C) Average Cost of Gas

Pursuant to the Settlement Agreement adopted by the Commission in its Order Authorizing Merger, issued and effective April 2, 1999 and Confirming Order, issued and effective April 14, 1999 in Case No. 98-M-0961, gas will be purchased under a common supply arrangement for both Consolidated Edison Company of New York and Orange and Rockland Utilities ("Companies"). The arrangement will be administered by a single corporate department or entity for the benefit of the Companies. The department or entity will purchase gas and services for the Companies in a manner that minimizes their total cost.

The Company's monthly average cost of gas applicable to the rates under Service Classification Nos. 1 and 2 shall be based upon the Company's apportioned share of fixed and variable costs and shall be computed as follows:

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(C) Average Cost of Gas (Cont'd.)

(1) Fixed Cost

Fixed gas costs include pipeline demand charges, capacity costs associated with Mandatory Capacity Release Service under Service Classification No. 11, supplier gas inventory charges, storage demand charges, and any similar charges that do not vary with the volume of gas purchased except for balancing costs as described in General Information Section No. 12.2(I).

The fixed gas cost of the Companies associated with pipeline capacity, storage capacity, and purchased gas contract entitlements, except costs associated with balancing service, shall be allocated to each company using fixed percentages. The fixed percentages are based on ratios of each Company's forecasted winter peak day capacity requirement to the total forecasted peak day capacity requirement of the Companies. The fixed percentages shall be revised at least annually to become effective each November 1. The Company shall be permitted to make interim revisions to the fixed percentages, if necessary, to reflect a significant shift in peak day capacity requirements between the Companies. The Company shall advise Commission Staff on or before October 1 of each year of any changes to the fixed percentages to be implemented the following November 1.

The Company's apportioned share of fixed costs, determined in the manner set forth above, shall then be reduced by annual estimates of the revenues, fees and charges set forth below and then divided by the forecast quantities of gas to be taken for delivery to the Company's firm sales customers for the 12 calendar months ending the following August 31:

(a) Revenues from off-system sales, less any associated gas costs;

(b) Capacity related revenues associated with Service Classification No. 9;

(c) Transition Surcharge revenues; and

(d) Revenues associated with the Capacity Release Service Adjustment assessed under General Information Section No. 12.2(F).

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(C) Average Cost of Gas (Cont'd.)

(2) Variable Cost

Variable gas costs include purchased gas cost, storage gas cost, alternate gas supplies, i.e., liquefied natural gas, liquefied propane gas, and propane-air, variable transportation costs, applicable surcharges and taxes, the commodity cost of gas associated with bundled purchases made by the Company including bundled purchases associated with Service Classification No, 11, and the costs associated with risk management programs.

The variable cost of the Companies shall be determined by:

(i) applying the variable rates and charges of the transporters, storage and peaking providers, and suppliers to the billing determinates associated with transportation, storage and peaking, bundled purchases, and gas supply for the forecasted weather normalized quantities of gas to be taken for delivery to the Companies' firm sales customers during the month in which the gas supply charge will be in effect, adjusted further for the costs associated with risk management programs; and

(ii) applying the average unit cost of gas in storage at the date of computation to the quantities of gas estimated to be withdrawn from storage for the Companies' firm sales customers during the month in which the gas supply charge will be in effect.

The variable cost shall be allocated between the companies in proportion to their respective monthly firm sales sendout quantities.

The Company's share of the variable cost shall be adjusted as follows:

(a) The Company's share of the variable cost shall be reduced by all gas costs recovered via the rates and charges for service under Service Classification No. 9 of this Schedule.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(C) Average Cost of Gas (Cont'd.)

(2) Variable Cost (Cont'd.)

(b) The Company's share of the variable cost shall be increased by the replacement cost of fuel established as compensation, under Section 11.1(E)(1) of this Schedule, to customers resulting from the diversion of gas from non-core customers to core customers.

The Company's share of the variable cost, adjusted as described above, shall be divided by the forecasted weather normalized quantities of gas to be taken for delivery to the Company's firm sales customers during the month in which the gas supply charge will be in effect.

(3) Average Cost of Gas

The Average Cost of Gas is the sum of the unit amounts determined in (1) fixed cost and (2) variable cost.

(4) Mcf Conversion

The Average Cost of Gas shall be multiplied by the Conversion Factor in (B) to convert the cost per Dth to a cost per Mcf.

(D) Annual Reconciliation

Actual gas cost recoveries shall be reconciled with actual gas expenses each year, and a surcharge or refund to recover Gas Supply Charge under-recoveries or refund Gas Supply Charge over-collections shall be computed as follows:

(1) taking the cost of gas, adjusted for supplier refunds, revenues from off-system sales net of any associated gas costs; capacity-related revenues associated with Service Classification No. 9; liquefied propane consumed; Transition Surcharge revenues; and any Over- and Under-delivery Charges assessed under Service Classification Nos. 8 and 13 and the Charge for Unauthorized Use of Gas assessed under Service Classification No. 8; any penalty charges, cash out costs/recoveries and Winter Bundled Sales (“WBS”) Service Option recoveries, excluding carrying charges on the cost of WBS gas, associated with Service Classification No. 11;

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(D) Annual Reconciliation (Cont’d.)

(1) (Cont’d.)

and Peak Shaving Supply Fees assessed under Service Classification No. 6 as recorded on the Company’s books during the determination period, adjusting that cost to reflect a level of purchased gas commensurate with actual sales and the fixed factor of adjustment as described below:

(a) If the absolute value of the difference between the actual line loss factor (“actual LLF”) and Five Year Average (as defined in 12.1(A) above) is less than two standard deviations (“SD”) from the Five-Year Average, there is no adjustment to the cost of gas.

(b) If the actual LLF is greater than the Five-Year Average plus two SD (“Dead Band Upper Limit” or “DBUL”), the cost of gas will be adjusted by the ratio of a Factor of Adjustment (“FOA”) based on a LLF equal to the DBUL and the lesser of the Actual FOA or the FOA equal to the DBUL plus two SD, as shown in the following formula:

$$\text{Adjusted Cost of Gas} = \text{Cost of Gas} \times \frac{\text{FOA based on DBUL}}{\text{Lesser of Actual FOA or FOA based on DBUL} + 2 * \text{SD}}$$

(c) If the actual LLF is less than the Five-Year Average minus two SD (“Dead Band Lower Limit” or “DBLL”), the cost of gas will be adjusted by the ratio of a FOA based on a LLF equal to the DBLL and the greater of the Actual FOA or the FOA equal to the DBLL minus two SD, as shown in the following formula:

$$\text{Adjusted Cost of Gas} = \text{Cost of Gas} \times \frac{\text{FOA based on DBLL}}{\text{Greater of Actual FOA or FOA based on DBLL} - 2 * \text{SD}}$$

In no event shall the FOA based on DBLL or FOA based on DBLL minus 2 SD be less than 1 for purposes of the above calculation.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(D) Annual Reconciliation (Cont'd.)

(2) The amount derived in paragraph (1) of this subdivision shall be adjusted by subtracting therefrom an amount equal to:

(a) Gas Supply Charge revenues recorded during the determination period, adjusted to eliminate associated revenue tax recoveries;

(b) costs recorded during the determination period assignable to gas sold to customers not subject to the Gas Supply Charge; and

(c) (i) the previous year's over-collection including interest, to the extent not refunded, or

(ii) adding the previous year's under-collection including interest, to the extent not recovered.

(3) The amount derived in paragraph (2) of this subdivision shall be divided by the quantities of gas to be sold by the Company to its customers during the surcharge/refund period.

(4) Surcharge or refund amounts shall bear interest, at a rate prescribed by the Commission, on unamortized balances.

(5) The determination period to be used in the computation of the surcharge or refund shall be the 12 months ended August 31 of each year. The computation shall be filed with the Commission on or before October 15, and the resulting surcharge or refund shall be effective with the first January billing cycle date.

(6) Revisions to the annual surcharge/refund adjustment will be permitted during the 12 month period ended August 31 for the purpose of preventing large over-collection or under-collection balances from accruing at August 31, subject to Commission approval.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.1 GAS SUPPLY CHARGE (Cont'd.)

(E) Statement of Gas Supply Charge

(1) The Gas Supply Charge computed as herein provided, shall be effective for service rendered on and after the first day of the calendar month following the computation date and shall continue in effect until changed. Gas Supply Charges will be prorated based on the number of days each Gas Supply Charge is in effect during a billing period.

(2) The Statement of Gas Supply Charge shall be filed with the Public Service Commission and apart from this Rate Schedule not less than three days prior to the date on which it is proposed to be effective. Such Statement will be available to the public at Company offices at which applications for service may be made. Each Statement shall contain:

(a) an identification of the schedules and service classifications to which they apply;

(b) the date when the rates shall become effective and the period such rates will remain in effect;

(c) the present average cost to the utility of gas purchased to serve customers subject to the Gas Supply Charge;

(d) the date at which, and the period for which, the average was determined;

(e) the present factor of adjustment;

(f) the amount per unit of consumption affected;

(g) a summary of refunds or surcharges to be applied to the Gas Supply Charge; and

(h) the net amount per unit of consumption affected.

(3) A new statement may be filed on one day's notice to become effective not more than five days after the effective date of the initial statement if the replacement of cost estimates in the initial statement with actual figures results in a change in the average cost of gas of more than five percent.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(B) Transition Adjustment for Competitive Services

(1) Applicability

A Transition Adjustment for Competitive Services ("TACS")is applicable to customers taking service under Service Classification Nos. 1, 2, and 6 of this Rate Schedule. Such customers will be assessed the TACS on a per Ccf basis as set forth in the Statement of Monthly Gas Adjustment. The TACS shall be reset annually effective November 1 of each year.

(2) Definitions for Purposes of the TACS

"Merchant Function Charge Fixed Component Lost Revenue" shall be equal to a target of $2,085,890 attributable to the Merchant Function Charge ("MFC") Fixed Components consisting of a) commodity procurement costs (including commodity revenue based allocation of information resources and education and outreach costs); and b) credit and collections costs portions of the MFC, minus the revenues received through the MFC relating to such MFC Fixed Components.

"Billing and Payment Processing Lost Revenue" shall be equal to the total of billing and payment processing charges avoided by retail access customers less billing service charges assessed on Marketers participating in the Company's Gas Transportation Service program and electing the Utility Single Bill Option, less the Company's avoided costs associated with Marketers participating in the Company's Gas Transportation Service Program and electing the Marketer Single Bill Option.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(B) Transition Adjustment for Competitive Services (Cont'd.)

(2) Definitions for Purposes of the TACS (Cont'd.)

"Credit and Collections Lost Revenue Associated with Retail Access" shall be equal to a target of $598,479 attributable to credit and collections costs reflected in the POR discount minus revenues received through the credits and collections component of the POR discount.

"Prior Period Reconciliation" represents the difference between the amount to be recovered through the TACS and the actual amount recovered through the TACS. Any under-recovery or over-recovery resulting from such reconciliation, plus interest (calculated at the Other Customer Capital Rate), shall be included in the calculation of the subsequent year's TACS.

(3) Calculation of the TACS

The TACS shall be determined by dividing the sum of the MFC Fixed Component Lost Revenue, Billing and Payment Processing Lost Revenue, Credit and Collections Lost Revenue Associated with Retail Access, and the Prior Period Reconciliation by the forecasted Ccf deliveries to Service Classification Nos. 1, 2, and 6 customers for the twelve-month period for which the TACS is to be effective.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(C) Credit/Surcharge for Sharing of Benefits (applicable to Service Classification Nos. 1, 2 and 6)

The Monthly Gas Adjustment applicable to Service Classification ("S.C.") Nos. 1, 2, and 6 shall be adjusted to reflect the net benefits from 1) interruptible (S.C. No. 8) sales and transportation, firm withdrawable transportation and sales (S.C. No. 9), and firm dual fuel (S.C. No. 5) service (collectively "Interruptible Benefits")and 2) transfer of gas to electric generating facilities previously owned by the Company ("Power Generation Benefits"). Such benefits shall be determined as follows:

(1) Interruptible Benefits

Interruptible Benefits shall be defined as (1) total interruptible revenues from S.C. No. 8 minus any associated gas costs and revenue tax surcharge revenues; (2) total firm withdrawable delivery revenues from S.C. No. 9 minus any associated gas costs and revenue tax surcharge revenues; and (3) total firm dual fuel revenues from S.C. No. 5 minus gas costs and revenue tax surcharge revenues.

For each twelve-month period ending October 31, a base rate revenue imputation of $2,300,000 relating to the Interruptible Benefits described above shall be in effect. Any variance between the actual total Interruptible Benefits and the base rate revenue imputation for each twelve-month period shall be shared 80 percent/20 percent between customers and the Company respectively, in accordance with Appendix L of the Joint Proposal, dated June 29, 2009, and adopted by the Commission in its Order issued and effective October 16, 2009, in Case No. 08-G-1398.

Customers' share of the Interruptible Benefits so determined shall be credited (or surcharged if negative) to S.C. Nos. 1, 2, and 6 customers. The rate of credit (or surcharge) shall be determined by dividing the estimated customer share available to S.C. Nos. 1, 2, and 6 customers for the twelve-month period ending October 31 of each year by the S.C. Nos. 1, 2, and 6 deliveries estimated for that period.

The Company's share of Interruptible Benefits, if any, shall be retained by the Company and shall be excluded from any determination of Company earnings in excess of the level allowed by the Public Service Commission as any of the

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(C) Credit/Surcharge for Sharing of Benefits (applicable to Service Classification Nos. 1, 2 and 6) (Cont'd.)

(1) Interruptible Benefits (Cont'd)

provisions of Section 66, subsection 20 of the Public Service Law of the State of New York.

(2) Power Generation Benefits

Power Generation Benefits from the transfer of gas to electric generating facilities previously owned by the Company shall be defined as the amount received for the transfer of gas to such facilities, less any associated gas costs.

For each twelve-month period ending October 31, a power generation base rate revenue imputation of $650,000 shall be in effect. Any variance between the actual total Power Generation Benefits and the power generation base rate revenue imputation for each twelve-month period shall be credited (or surcharged if negative) to S.C. Nos. 1, 2, and 6 customers. The rate of credit (or surcharge) shall be determined by dividing the estimated power generation benefits available to S.C. Nos. 1, 2, and 6 customers for the twelve-month period ending October 31 of each year by the S.C. Nos. 1, 2, and 6 deliveries estimated for that period.

The unit rates as determined in (1) and (2) above will be applied to the Monthly Gas Adjustment. At the end of the fiscal year, the Company will determine the actual benefits accrued and compare this amount to the benefits disbursed to (or recovered from) S.C. Nos. 1, 2, and 6 customers during the fiscal year.

Any difference between the benefits accrued and the benefits disbursed (or recovered) shall be reflected in the estimated credits (or surcharges) for the next fiscal year.

The Company shall modify the unit rates determined as described above if a significant change to its estimates of benefits and/or sales volumes occurs during a fiscal year.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(I) Balancing Charge (applicable to Service Classification Nos. 1, 2 and 6) (Cont'd)

The Company's share of balancing costs shall be divided by the forecast quantities of gas to be taken for delivery to the Company's firm sales and firm transportation customers for the 12 calendar months ending the following August 31. The resulting balancing charge shall be adjusted by an uncollectibles percentage ("UC Percentage") as follows:

Balancing Charge = Balancing Cost / 12 Month Ccf / (1-UC Percentage).

The UC Percentage shall be reset annually effective November 1, based on the Company's actual uncollectibles experience for the twelve-month period ended the previous June 30.

At the end of each twelve-month period commencing November 1, Balancing Charge recoveries, excluding recoveries attributable to the UC Percentage, shall be reconciled with actual balancing costs and any over- or under-recovery shall be refunded or recovered through the Balancing Charge during the next twelve-month period commencing November 1.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.3 WEATHER NORMALIZATION ADJUSTMENT

A Weather Normalization Adjustment shall be effective for all Service Classification Nos. 1 and 6 - Space Heating Customers and for Service Classification No. 2 - General Service Master Metered Multiple Dwellings, General Service Commercial and General Service Industrial Customers. The Weather Normalization Adjustment will be applied to total gas usage during the period October 1 through May 31 of each year.

(A) Definitions

(1) PBR or pure base rate is the tail block delivery charge set forth in Service Classification Nos. 1, 2 and 6.

(2) BD or billing days is the actual number of days for which service is being billed.

(3) HDD or heating degree days are the difference between 63 degrees F. and the average outdoor dry bulb temperature for a day based on readings made every hour on the hour throughout the day. HDD are always zero when that average temperature is above 63 degrees F.

(4) Commencing November 1, 2015, NHDD or normal heating degree days shall be 4,938 heating degree days, the average for the 10-years ended December 31, 2013.

(5) AHDD or actual heating degree days are the actual difference between 63 degrees F. and the average outdoor dry bulb temperature for a particular day or days based on readings made every hour on the hour throughout the day. AHDD are always zero when that average temperature is above 63 degrees F.

(6) HDDF or heating degree day factor is the estimated number of ccf per customer needed to provide space heating for each degree of a degree day based on average usage by customers to which this adjustment applies. The HDDF shall be determined separately for each customer rate classification and shall be revised annually. The HDDF shall be submitted to Staff on or before August 31 for inclusion in the October 1 start date of each year's Weather Normalization Adjustment.

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.4 Merchant Function Charge (MFC)

(A) Applicability

Customers taking service under Service Classification Nos. 1 and 2 of this Rate Schedule shall be subject to a Merchant Function Charge ("MFC"). Separate MFCs will be determined for Service Classification No. 1 and for Service Classification No. 2 of this Rate Schedule and will be applied to all gas volumes sold under such service classifications to recover the costs associated with commodity-related competitive services. Commodity-related costs include commodity procurement costs (including commodity revenue-based allocation of information resources and education and outreach costs), credit and collections costs, gas in storage working capital costs related to firm sales, and commodity-related uncollectibles.

(B) Fixed MFC Components

The fixed components of the MFC are as follows:

	Cents per Ccf		
Service Classification	Commodity Procurement, IR, and Education And Outreach	Credit and Collections	Total
Commencing November 1, 2015			
SC No. 1	2.172	0.526	2.698
SC No. 2	0.707	0.165	0.872

GENERAL INFORMATION

12. ADJUSTMENT OF RATES IN ACCORDANCE WITH CHANGES IN THE COST OF GAS (Cont'd.)

12.4 Merchant Function Charge (MFC) (Cont'd.)

(B) Fixed MFC Components (Cont'd.)

These fixed MFC components shall remain in effect until changed by an order of the Commission.

(C) Determination of MFCs

The MFCs applicable to Service Classification Nos. 1 and 2 customers shall be the sum of (1) the applicable fixed MFC components set forth; (2) a per Ccf charge, determined in accordance with General Information Section 12.2 (D) of this Rate Schedule, to recover gas in storage working capital costs associated with firm sales customers; and (3) the applicable monthly uncollectibles charge ("UC charge") per Ccf to recover the cost of commodity-related uncollectibles.

The monthly UC charge component of the MFC described in (3) above shall be based on the Gas Supply Charge ("GSC") determined in accordance with General Information Section 12.1 of this Rate Schedule, and the uncollectibles percentage ("UC percentage") applicable to Service Classification No. 1 and the UC percentage applicable to Service Classification No. 2. The UC percentages shall be reset annually effective November 1 based on the Company's actual uncollectibles experience applicable to all electric and gas customers eligible for the Company's Purchase of Receivables Program for the twelve-month period ended the previous June 30. The UC charge component of the MFC shall be determined using the following formula rounding to the nearest 0.001 cents per Ccf:

UC Charge = GSC/(1-applicable UC percentage) - GSC

(D) Reconciliation of Fixed MFC Components

Revenues associated with the fixed MFC components shall be reconciled annually in accordance with the operation of the Transition Adjustment for Competitive Services, as set forth in General Information Section 12.2 (B) of this Rate Schedule.

GENERAL INFORMATION

15.0 INCREASE IN RATES APPLICABLE IN MUNICIPALITY WHERE SERVICE IS SUPPLIED (Cont'd.)

15.4 **New York State Tax Law Section 186-a (Gross Receipts Tax), Section 20-b of the General City Law, and Section 5-530 of the Village Law** - For the purpose of this provision, the following definitions apply. The term "commodity rates and charges" shall mean the "Gas Supply Charge" as set forth in General Information Section 12.1 of this Rate Schedule applicable to customers taking service under Service Classifications Nos. 1 and 2 of this Rate Schedule; the "Average Commodity Cost of Gas" used in establishing the "Minimum Allowable Unit Charge" as set forth under Service Classification Nos. 5 and 7 of this Rate Schedule; the "Over- and Under-delivery Charges", the "Penalty Charge", the "Emergency Service Charge", the "Marginal Cost Charge", and the "Real-time Value Component" as set under Service Classifications Nos. 8, 9, and 14 of this Rate Schedule, as applicable; all of the charges set forth under Service Classifications Nos. 11 and 13 of this Rate Schedule; and the special charges set forth in the General Information Section of this Rate Schedule. The term "delivery rates and charges" shall mean all other rates and charges.

The tax expense shall be recovered through separate residential and non-residential surcharge factors applicable to the delivery rates and charges and surcharge factors applicable to the commodity rates and charges. The commodity and delivery rates and charges shall be divided by the applicable surcharge factors for the appropriate municipality.

15.5 **Statement of Increase in Rates and Charges** - The applicable tax surcharge factors shall be set forth on the "Statement of Increase in Rates and Charges" (the "Statement") filed with the Commission. Whenever there is a change in a rate of tax imposed on the Company or the amount to be collected or reconciled, the Company shall file with the Commission a new Statement reflecting such new surcharge factors. Such Statement shall be filed not less than fifteen (15) business days before the date on which the Statement is proposed to be effective, which shall be no sooner than the date of the tax enactment to which the Statement responds, and no sooner than the date when the tax enactment is filed with the Secretary of State. Such new surcharge factors shall apply to bills that are rendered on and after the effective date of the Statement. Such Statements shall be canceled not more than five (5) business days after the tax enactment either ceases to be effective or is modified so as to reduce the tax rate. Such Statement will be available to the public at Company offices at which application for service may be made.

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER B (Continued)

ELIGIBILITY: (Continued)

service under this Rider in less than one year. Such allowance will be contingent on the customer reasonably demonstrating to the Company's satisfaction that the condition(s)that prevented the customer from maintaining an Annual Load Factor of at least 50 percent has been corrected and/or is not likely to recur in the next annual determination period.

RATE - MONTHLY:

Customers served under Rate Schedule I or Rate Schedule II of this Rider will be subject to the higher of the Delivery Charges or the Monthly Minimum Charge determined in the manner set forth below.

(1) Delivery Charges

Rate Schedule I – Applicable to customers whose Distributed Generation Facility has a rated capacity of less than 5 MegaWatts.

Rate IA – Applicable to customers whose Distributed Generation Facility has a rated capacity of 0.25 MegaWatt or less.

Usage Charge	Summer Months*	Winter Months*
First 3 Ccf or less…………@	$148.31	$148.31
Over 3 Ccf……………………………@	23.118 ¢ per Ccf	28.697 ¢ per Ccf

Rate IB – Applicable to customers whose Distributed Generation Facility has a rated capacity greater than 0.25 MegaWatt but less than or equal to 1 MegaWatt.

Usage Charge	Summer Months*	Winter Months*
First 3 Ccf or less……………@	$251.86	$251.86
Over 3 Ccf………………………………@	23.118 ¢ per Ccf	28.697 ¢ per Ccf

*Summer Months are April through October, inclusive; Winter Months are November through March, inclusive.

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER B (Continued)

RATE - MONTHLY: (Continued)

(1) Delivery Charges (Continued)

Rate IC – Applicable to customers whose Distributed Generation Facility has a rated capacity greater than 1 MegaWatt but less than or equal to 2 MegaWatts.

Usage Charge	Summer Months*	Winter Months*
First 3 Ccf or less……………@	$383.38	$383.38
Over 3 Ccf………………………………@	23.118 ¢ per Ccf	28.697 ¢ per Ccf

Rate ID – Applicable to customers whose Distributed Generation Facility has a rated capacity greater than 2 MegaWatts but less than 5 MegaWatts.

Usage Charge	Summer Months*	Winter Months*
First 3 Ccf or less……………@	$486.93	$486.93
Over 3 Ccf………………………………@	23.118 ¢ per Ccf	28.697 ¢ per Ccf

Rate Schedule II – Applicable to customers whose Distributed Generation Facility has a rated capacity of 5 MegaWatts or greater, but less than 50 MegaWatts.

Usage Charge	Summer Months*	Winter Months*
First 3 Ccf or less……………@	$ 55.97	$ 55.97
Over 3 Ccf…………………………………@	4.623 ¢ per Ccf	5.740 ¢ per Ccf

Contract Demand Charge – per Ccf of contract demand, as described in the "Determination of Contract Demand" section of this Rider.

Contract Demand Ccf…………@ $40.89 per Ccf

*Summer Months are April through October, inclusive; Winter Months are November through March, inclusive.

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER C (Continued)

ELIGIBILITY:

Available to any residential customer who is eligible to take service under Service Classification Nos. 1 or 6 of this Rate Schedule, upon written application and acceptance by the Company, subject to the provisions of this Rider and the applicable provisions of the customer's otherwise applicable service classification.

Prior to the commencement of service hereunder, the customer shall provide the Company with a reasonable estimate of customer's Winter Peak Day Gas Usage and the customer's annual gas usage during the first year of operation of the customer's Distributed Generation Facility, with the first year commencing after a three-month start-up phase ("the first year"). In the event a customer does not provide the Company with the required information, the Company will attempt to estimate the customer's Annual Load Factor using the best available information.

The customer's Annual Load Factor shall be computed after the first fifteen monthly billing periods hereunder (based on the most recent 12 monthly billing periods) and annually thereafter for the purpose of data collection and reporting requirements of the Commission.

RATE - MONTHLY:

The rates and charges set forth below will apply to the customer's total monthly-metered gas usage.

(1) Delivery Charges

Usage Charge

First 3 Ccf or less……………@ $38.18
Over 3 Ccf…………………………………@ 21.655 ¢ per Ccf

(2) Other Applicable Charges

In addition to the above Delivery Charges, the applicable rate and other provisions of the customer's otherwise applicable service classification shall apply to service rendered hereunder.

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER D

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY LOAN INSTALLMENT PROGRAM

Applicable to Service Classification Nos. 1, 2, 5, 6, 8, and 9

Pursuant to the Power New York ("PNY") Act of 2011 (L. 2011, c.388), the New York State Energy Research and Development Authority or its designated agent ("NYSERDA") will administer a loan program for qualifying residential and non-residential customers for the installation of qualified energy efficiency services (as that term is defined in subsection 1891(12) of the Public Authorities Law) on a customer's property. Beginning no later than May 30, 2012, installments for such loans will be shown on and collected through the customer's utility bill except as provided below. Customers shall repay the loan installment amounts on their utility cycle bills.

ELIGIBILITY:

As set forth in the PNY Act of 2011, the Company will bill and collect NYSERDA Loan Installment amounts on a customer's utility bill when notified by NYSERDA that these NYSERDA Loan Installments apply to the customer's utility account. Unless otherwise precluded by law, participation in the NYSERDA Loan Installment program shall not affect a customer's eligibility for any rebate or incentive offered by the Company. In order to comply with the requirements set forth in the PNY Act of 2011, the Company will provide NYSERDA, or its agents, certain customer information and take other actions for purposes of the NYSERDA Loan Installment Program.

Customers will be eligible on a first-come, first-served basis, provided that the number of customers taking service under this Rider does not exceed one-half of one percent of the total 2011 customer population as reported to the Commission for purposes of calculating the Company's complaint performance rate as of December 31, 2011.

BILLING, COLLECTIONS, AND PAYMENT:

Beginning no later than the second cycle bill after the Company receives from NYSERDA a valid customer account number, monthly NYSERDA loan installment amount, and number of loan installment amounts to be billed, each cycle bill issued to the customer shall include the monthly loan installment amount until the number of loan installments billed equals the number of loan installment amounts to be billed or the account is closed, whichever occurs first.

GENERAL INFORMATION

SERVICE CLASSIFICATION RIDERS:

RIDER E

EXCELSIOR JOBS PROGRAM (Continued)

RATES: (Continued)

For purposes of this Rider, percentage reductions will be applied to monthly Service Classification No. 2 and Service Classification No. 6 Rate Schedule IB and II delivery charges, before application of the Increase in Rates and Charges (described in General Information Section No. 16).

Incremental Billing Determinants for EJP customers are not subject to the Revenue Decoupling Mechanism Adjustment (described in General Information Section No. 25).

The Company will bill the EJP customer based on the lower results of using the discounts below or the standard rates that would otherwise be applicable notwithstanding participation in EJP. For customers who commenced service under Rider E prior to November 1, 2015, the EJP discount is 0 percent. For customers commencing service under Rider E on or after November 1, 2015, the EJP discount is 13.4%.

To the extent that marginal delivery costs change over time, the Company may file amended discounts with the Commission for its review and approval.

TERM:

Customers will be eligible for EJP rates specified under this Rider for up to ten consecutive twelve month periods. Customers who discontinue service under this Rider to commence service under Rider B will not be eligible thereafter to receive service under this Rider.

GENERAL INFORMATION

23. System Benefits Charge ("SBC")

The SBC will be applied to the Ccf usage on the bills of all customers taking service under Service Classification Nos. 1, 2 and 6 of this Schedule. The SBC will be determined annually and be designed to recover the costs of programs approved for SBC funding by the Commission.

Pursuant to the Commission's June 23, 2008 Order in Case No. 07-M-0548, the SBC shall be established to collect $116,755 for the fourth quarter of 2008, and $467,019 for each of the three years beginning 2009. In addition, pursuant to the Commission's Orders dated October 23, 2009 and January 4, 2010 in Case 08-E-1127 et al., Order dated June 24, 2010 in Case 07-M-0548, Order dated December 30, 2010 in Case Nos. 10-M-0457 and 05-M-0090, and Order dated October 25, 2011 in Case 07-M-0548, the SBC is expected to collect the following amounts during the years 2010 through 2018:

2010	$1,318,203	2015	$3,058,217
2011	2,297,462	2016	1,875,895
2012	636,001	2017	998,183
2013	1,445,534	2018	1,074,336
2014	2,893,018		

A reconciliation of annual SBC program costs and recoveries through the SBC (eleven months actual, one month forecast) will be submitted by the Company to the Commission on or before December 15 of each year. Any over- or under-collections for each calendar year through 2017 will be reconciled and included in the subsequent year's amount to be collected, commencing January 1 of each year. Any over- or under-collections during 2018 will be reconciled and credited to or collected from customers as directed by the Commission.

Not less than fifteen days prior to a proposed change in the SBC, a Statement showing the SBC and the effective date will be filed with the Commission apart from this Schedule. Such Statement will be available to the public at Company offices at which applications for service may be made. The SBC will remain in effect until changed as authorized by the Commission.

GENERAL INFORMATION

25. REVENUE DECOUPLING MECHANISM (“RDM”) ADJUSTMENT

Actual delivery revenues for certain customer classes are subject to reconciliation through an RDM Adjustment based on a revenue per customer (“RPC”) methodology. Under the RPC methodology, Actual Delivery Revenue is compared, on an annual basis, with an annual Delivery Revenue Target equal to the product of the average number of customers and an annual RPC Target for each customer group subject to the RDM.

(A) Applicability

The RDM Adjustment is applicable to Service Classification Nos. 1, 2, and 6. For RDM purposes, these service classifications shall be assigned to service classification groups as follows:

Group A – Service Classification No. 1 and Service Classification No. 6 Rate Schedule IA customers.

Group B – Service Classification No. 2 and Service Classification No. 6 Rate Schedule IB and Rate Schedule II customers.

The RDM is not applicable to customers taking service under Riders B and C, and usage above the Baseline Billing Determinants for customers taking service under Rider E.

(B) Actual Delivery Revenue

Actual Delivery Revenue, determined for each customer group, will be calculated as the sum of billed revenue derived from: a) delivery charges as defined in Service Classification Nos. 1 and 2; b) transportation charges as defined in Service Classification No. 6; and c) the Weather Normalization Adjustment as described in General Information Section 12.3. Actual Delivery Revenues will not include revenues derived from the RDM Adjustment described below. Actual Delivery Revenues in November 2015 will be adjusted upward to reverse the effect of proration between old and new rates in the actual revenues.

(C) Delivery Revenue Targets

RPC Targets are set for the 12-month periods beginning every November 1 based on the respective period’s total (billed and unbilled) delivery revenues (revenues associated with delivery charges as defined in Service Classification Nos. 1 and 2 and revenues associated with transportation charges as defined in Service Classification No. 6)

GENERAL INFORMATION

25. REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT (Continued)

(C) Delivery Revenue Targets (Continued)

divided by the average number of customers for the period. The RPC Targets for each customer group included in the RDM are listed below.

	Group A	Group B
Effective November 1, 2015	$966.15	$3,291.88

At the conclusion of each 12-month period ending October 31, a Delivery Revenue Target for each customer group will be computed by multiplying the RPC Target by the actual average number of customers for the period.

Adjustments to the Delivery Revenue Targets may be necessary if new legislation or regulation results in a change in delivery revenues for some or all service classifications included in the RDM.

GENERAL INFORMATION

25. REVENUE DECOUPLING MECHANISM ("RDM") ADJUSTMENT (Continued)

(E) Interim RDM Adjustment

The Company will track delivery revenue excess/shortfalls on a monthly basis and may implement Interim RDM Adjustments at any time in order to minimize the annual RDM Adjustment. The procedures for the Interim RDM Adjustments will follow the same procedures for interim Gas Supply Charge adjustments. Revenues associated with Interim RDM Adjustments will be included in the annual RDM reconciliation.

(F) Partial Year RDM

If the Company files for new base rates to be effective on a date other than November 1 of any year beyond 2016, then for purposes of reconciling the RDM, Adjusted RPC Targets for the partial rate year will be determined as follows. Actual Delivery Revenues for each customer group for the months comprising the partial rate year period will be divided by the Actual Delivery Revenues for the twelve-month period ended in the same month as the partial rate year period. This creates a factor for each customer group that is multiplied by the RPC Target for the group to create an Adjusted RPC Target. For each customer group, the Adjusted RPC Target will then be multiplied by the average number of customers for the partial rate year to determine the Delivery Revenue Target for the partial rate year. For each customer group, Actual Delivery Revenue for the partial rate year will be compared with the partial rate year Delivery Revenue Target to determine the delivery revenue excess or shortfall to be refunded to or recovered from customers through the RDM Adjustment.

SERVICE CLASSIFICATION NO. 1

APPLICABLE TO USE OF SERVICE FOR:

Residential and Space Heating service in the entire territory subject to the restrictions described in General Information Section 11. The total hourly input of a Commercial or Industrial Customer's space heating equipment shall not be more than 500,000 Btu except that the upper limit may be 1,000,000 Btu in the case of space heating service to Churches, Schools and Hospitals.

CHARACTER OF SERVICE:

Continuous; natural gas (or, in the case of emergency or for economy of operation, a mixture of natural and liquefied petroleum gas) of a Btu content per cubic foot of not less than 1,000 Btu on a monthly average, supplied at pressures within the limits prescribed in Title 16 Public Service, Part 255.60, the official compilation, Codes, Rules and Regulations of the State of New York.

RATE - MONTHLY:

(1) Delivery Charge

First 3 Ccf or less.......@	$26.00
Next 47 Ccf...............@	61.330 ¢ per Ccf
All over 50 Ccf...........@	59.028 ¢ per Ccf

(2) Gas Supply Charge

The Gas Supply Charge as described in General Information Section 12.1 shall apply to all gas sold under this Service Classification.

(3) Merchant Function Charge

The Merchant Function Charge as described in General Information Section 12.4 shall apply to all gas sold under this Service Classification.

(4) Monthly Gas Adjustment

The Monthly Gas Adjustment as described in General Information Section 12.2 shall apply to all gas sold under this Service Classification.

(5) Unauthorized Use of Gas

As explained in General Information Section 11.1.

(6) Billing and Payment Processing Charge

A billing and payment charge shall be assessed in accordance with General Information Section 6.5.

SERVICE CLASSIFICATION NO. 1 (Cont'd.)

RATE - MONTHLY: **(Continued)**

(7) System Benefits Charge
The System Benefits Charge as described in General Information Section 23 shall apply to all gas sold under this Service Classification.

(8) Temporary State Assessment Surcharge
The Temporary State Assessment Surcharge as described in General Information Section 24 shall apply to all gas sold under this Service Classification.

(9) Revenue Decoupling Mechanism Adjustment
The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section 25 shall apply to gas sold under this Service Classification.

(10) Increase in Rates and Charges
The rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

TERMS OF PAYMENT:

Bills are due when rendered, subject to late payment charge in accordance with provisions of General Information Section 6.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section 9.1 and 9.2.

TERM:

Terminable at any time unless a specified period is required under a main extension agreement.

SPECIAL PROVISIONS:

Budget Billing (Optional)
Any residential customer or customer who is a condominium association or cooperative housing corporation taking service hereunder, and any other customer who has taken service hereunder for at least twelve months, may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 6 of this tariff.

SERVICE CLASSIFICATION NO. 2

APPLICABLE TO USE OF SERVICE FOR:

General service in the entire territory subject to the restrictions described in General Information Section 11.

CHARACTER OF SERVICE:

Continuous; natural gas (or, in the case of emergency or for economy of operation, a mixture of natural and liquefied petroleum gas) of a Btu content per cubic foot of not less than 1,000 Btu on a monthly average, supplied at pressures within the limits prescribed in Title 16 Public Service, Part 255.60, the official compilation, Codes, Rules and Regulations of the State of New York.

RATE - MONTHLY:

(1) Delivery Charge

First 3 Ccf or less.......@	$40.00
Next 47 Ccf...............@	43.526 ¢ per Ccf
Next 4,950 Ccf...............@	41.790 ¢ per Ccf
All over 5,000 Ccf...........@	36.955 ¢ per Ccf

(2) Gas Supply Charge

The Gas Supply Charge as described in General Information Section 12.1 shall apply to all gas sold under this service classification.

(3) Merchant Function Charge

The Merchant Function Charge as described in General Information Section 12.4 shall apply to all gas sold under this Service Classification.

(4) Monthly Gas Adjustment

The Monthly Gas Adjustment as described in General Information Section 12.2 shall apply to all gas sold under this Service Classification.

(5) Unauthorized Use of Gas

As explained in General Information Section 11.1.

(6) Billing and Payment Processing Charge

A billing and payment charge shall be assessed in accordance with General Information Section 6.5.

SERVICE CLASSIFICATION NO. 2 (Cont'd.)

RATE - MONTHLY: (Continued)

(7) System Benefits Charge

The System Benefits Charge as described in General Information Section 23 shall apply to all gas sold under this Service Classification.

(8) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section 24 shall apply to all gas sold under this Service Classification.

(9) Revenue Decoupling Mechanism Adjustment

The provisions of the Company's Revenue Decoupling Mechanism Adjustment as described in General Information Section 25 shall apply to gas sold under this Service Classification.

(10) Increase in Rates and Charges

The rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

TERMS OF PAYMENT:

Bills are due when rendered, subject to late payment charge in accordance with provisions of General Information Section 6.6. If bill is not paid, service may be discontinued in accordance with provisions of General Information Section 9.1 and 9.2.

TERM:

Terminable at any time unless a specified period is required under a main extension agreement.

SPECIAL PROVISIONS:

Budget Billing (Optional)

Any condominium association or cooperative housing corporation taking service hereunder, and any other customer who has taken service hereunder for at least twelve months, may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 6 of this tariff.

SERVICE CLASSIFICATION NO. 3

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 3 (Cont'd.)

(Service Classification No. 3 is hereby canceled)

SERVICE CLASSIFICATION NO. 5

APPLICABLE TO USE OF SERVICE FOR:

General service in the entire territory to any customer with installed dual-fuel capability sufficient to serve customer's entire needs, subject to the restrictions provided for in General Information Section 11. (See Special Provision A)

CHARACTER OF SERVICE:

Continuous; natural gas (or in the case of emergency or for economy of operation, a mixture of natural and liquefied petroleum gas) of a Btu content per cubic foot of not less than 1,000 Btu on a monthly average, supplied at pressure within the limits prescribed in Title 16 Public Service, Part 255.60, the official compilation, Codes, Rules and Regulations of the State of New York.

RATE - MONTHLY:

(1) Unit Charge

A rate per 100 cubic feet (Ccf) shall be established for each of the dual fuel customer categories, at the Company's discretion, each month and shall be applied to all gas sold under each category of this Service Classification. The dual fuel customer categories are based on the customer's alternate fuel type as follows:

Category A - No. 6 Oil, 2% sulfur content or higher
Category B - No. 6 Oil, less than 2% sulfur content
Category C - All Other

The rates shall be filed with the Commission and be available for public inspection, at Company offices where applications for service may be made, at least three working days prior to the first day of the billing period for which the rates shall apply.

The Unit Charge shall not be less than the "Average Cost of Gas" times the "Factor of Adjustment," both as defined in General Information Section 12.1 of this tariff.

SERVICE CLASSIFICATION NO. 5 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(1) Unit Charge (Cont'd.)

The Unit Charge shall not be greater than the sum of (i) the lowest per unit delivery charge for service under Service Classification No. 2, plus (ii) the gas supply charge, monthly gas adjustment, and merchant function charge applicable to Service Classification No. 2, exclusive of any supplier refunds.

(2) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section 24 shall apply to all gas delivered under this Service Classification.

(3) Increase in Rates and Charges

The rates and charges under this Service Classification, including the unit charge and the minimum charge will be increased by a tax factor pursuant to General Information Section 15.

STATEMENT OF DUAL FUEL GAS RATE:

Not less than three working days prior to the first day of each billing period, the Company shall file with the Commission a statement showing the Maximum Allowable Unit Charge, Minimum Allowable Unit Charge, the actual Unit Charges to the billed, any Refunds, the Net Billing Rate, and the Effective Charges including Part (2) of RATE - MONTHLY as provided for above.

MINIMUM CHARGE:

$420 for the initial term and $35 per month thereafter, plus revenue tax surcharges for both the initial term and thereafter.

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - MONTHLY:

(1) Transportation Charge

Rate Schedule IA: Applicable to any customer otherwise eligible for Service Classification No. 1 and:

a) is a member of an aggregated group, or
b) is an individual customer whose annual usage is less than 5,000 Mcf.

First	3 Ccf or less..............@	$26.00
Next	47 Ccf......................@	61.330 ¢ per Ccf
Over	50 Ccf......................@	59.028 ¢ per Ccf

Rate Schedule IB: Applicable to any customer otherwise eligible for Service Classification No. 2 and:

a) is a member of an aggregated group, or
b) is an individual customer whose annual usage is less than 5,000 Mcf.

First	3 Ccf or less..............@	$40.00
Next	47 Ccf......................@	43.526 ¢ per Ccf
Next	4950 Ccf......................@	41.790 ¢ per Ccf
Over	5,000 Ccf......................@	36.955 ¢ per Ccf

Rate Schedule II:

Applicable to any customer that is not a member of an aggregated group and whose usage exceeds 5,000 Mcf in the previous consecutive twelve-month period. Customers using less than 5,000 Mcf in a consecutive twelve-month period shall be transferred to Rate Schedule I.

First	100 Ccf or less..............@	$255.18
Over	100 Ccf......................@	36.955 ¢ per Ccf

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - MONTHLY:

(2) Standard Service Option or Winter Bundled Sales Service Option

Upon applying for firm transportation service under Service Classification No. 6, a customer must elect either the Standard Service Option or Winter Bundled Sales Service Option.

(A) Standard Service Option

The Standard Service Option provides for a Seller to deliver gas to the Company's citygate on behalf of all of its customers in the Seller's Aggregation Group based on the customers' average daily usage for the same month last year, weather normalized and restated on a calendar month basis, with the Company redelivering the gas to the Seller's customers on an as needed basis.

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(2) Standard Service Option or Winter Bundled Sales Service Option (Cont'd.)

(B) Winter Bundled Sales Service Option

The Winter Bundled Sales Service Option provides for a Seller to deliver gas to the Company's citygate on behalf of all customers in the Seller's Aggregation Group based on the customers' average daily usage for the same month last year, weather-normalized, with the Company redelivering the gas to the Seller's customers on an as-needed basis, except that a portion of the Seller's customers total gas requirements during the period November through March (winter period) shall include an amount of WBS gas purchased by the Seller from the Company in accordance with and at the rates set forth in Service Classification No. 11 of this Rate Schedule.

(C) Peak Shaving Supply Fee

Customers that elect either the Standard Service Option or the Winter Bundled Sales Service Option will be assessed the Peak Shaving Supply Fee when propane is used by the Company to meet the system requirements of all firm sales and transportation customers. Customers will be assessed the Peak Shaving Supply Fee based on the customer's Ccfs of annual usage to recover the cost of any propane used by the Company. The Peak Shaving Supply Fee shall be determined by dividing the cost of propane used in any twelve-month (12) period by the quantity of gas delivered to Service Classification Nos. 1, 2, 5 and 6, during the same period, all as set forth in the determination of the Company's Monthly Gas Adjustment.

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(2) Standard Service Option or Winter Bundled Sales Service Option (Cont'd.)

(D) The Peak Shaving Supply Fee in 2(C) shall be shown as a separate line item in the Statement of Statement of Monthly Gas Adjustments as filed with the Commission each month.

(3) Revenue Decoupling Mechanism Adjustment

The provisions of the Company’s Revenue Decoupling Mechanism Adjustment as described in General Information Section 25 shall apply to gas delivered under this Service Classification.

(4) Increase in Rates and Charges

(A) The provisions of the Company’s Monthly Gas Adjustment as described in General Information Section No. 12 shall apply to all volumes delivered under this Service Classification.

(B) During the period October 1 through May 31 of each year, all volumes of gas used under this Service Classification shall be assessed the Weather Normalization Adjustment pursuant to General Information Section 12.3.

SERVICE CLASSIFICATION NO. 6 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(4) Increase in Rates and Charges (Cont'd.)

(C) A billing and payment processing charge of $1.02 per billing cycle shall apply to customers electing the Two Separate Bills billing option under General Information Section 6.5 (2)(B) of this Rate Schedule. This charge will be applied only once to a dual service customer bill.

(D) The System Benefits Charge as described in General Information Section 23 shall apply to all gas volumes delivered under this Service Classification.

(E) The Temporary State Assessment Surcharge as described in General Information Section 24 shall apply to all gas delivered under this Service Classification.

(F) All rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

SERVICE CLASSIFICATION NO. 7

APPLICABLE TO USE OF SERVICE FOR:

Service in the entire territory to any customer for the sole purpose of fueling motor vehicles subject to interruption at any time at the Company's option upon not less than one hour's notice. Service for uncompressed gas shall be separately metered from all other service taken and shall not be combined with use under any other Service Classification of this Schedule.

CHARACTER OF SERVICE:

Interruptible; natural gas of a Btu content per cubic foot of not less than 1,000 Btu on a monthly average, supplied at pressures available at customer's location and within the limits prescribed in Title 16 Public Service, Part 255.60, the official compilation, Codes, Rules and Regulations of the State of New York. Interruptible; compressed gas for fueling motor vehicles at Company locations.

RATE - MONTHLY:

(1) Unit Charge

Rate I – Uncompressed Gas Vehicle Rate

Charges per 100 cubic feet (Ccf) shall be established each month and shall be applied to gas sold hereunder. The charges shall be filed with the Commission and be available for public inspection, at Company offices where applications for service may be made, not less than three working days prior to the beginning of the billing period for which the charges shall be effective.

The unit charges, in cents per 100 cubic feet, shall be (i) the average price in cents per gallon paid by the Company for unleaded gasoline during the second previous month, minus (ii) all taxes included in that average price, minus (iii) a differential as provided for below, divided by (iv) a factor of 1.100 Ccf per gallon except that:

(a) the unit charges shall not be less than the Supplemental Sales Supply Charge as set forth on the “Statement of Interruptible Transportation and Supplemental Sales” filed with the Commission each month plus 5.000 cents per Ccf; and

(b) the unit charges shall not be greater than the sum of (1) the lowest per unit delivery charge for service under Service Classification No. 2 of this Schedule, plus (ii) the gas supply charge and monthly gas adjustment applicable to Service Classification No. 2.

The differential for service during the initial term shall be 35.000 cents per gallon. Thereafter, the differential shall be 25.000 cents per gallon.

SERVICE CLASSIFICATION NO. 7 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

Rate II – Compressed Gas Vehicle Rate

This rate is applicable to customers who purchase Compressed Natural Gas (CNG) at compression stations owned and operated by the Company.

Rate II will be established monthly at the discretion of the Company and published in the Statement of Gas Vehicle Rate, as described below. At no time shall Rate II be less than the cost of gas applicable to firm customers and the sum of the compressor electric running costs and one cent per Ccf.

(2) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section 24 shall apply to all gas delivered under this Service Classification.

(3) Increase in Rates and Charges

(a) The rates and charges under this Service Classification, including the Unit Charge and the Minimum Charge, will be increased by a tax factor pursuant to General Information Section 15.

(b) Any Federal, State and/or local taxes required to be collected by the Company on sales of natural gas for use in motor vehicles shall be charged for all sales made hereunder.

STATEMENT OF GAS VEHICLE RATE:

Not later than three working days prior to the beginning of each billing period, the Company shall file with the Commission a statement showing the average price paid by the Company for gasoline during the previous month, the Unit Charges, the Minimum and Maximum Allowable Unit Charges and the Effective Charges, including the Revenue Tax Surcharges provided for in Part 3(a) of RATE – MONTHLY, and the Compressed Gas Vehicle Rate.

SERVICE CLASSIFICATION NO. 7 (Cont'd.)

TERMS OF PAYMENT:

Bills are due when rendered, subject to a late payment charge in accordance with the provisions of General Information Section 6.6.

TERM:

The initial term shall be five years. Thereafter, service shall be terminable at any time upon thirty days written notice by the customer or the Company.

SPECIAL PROVISIONS:

(A) Budget Billing

The Company's budget billing plan is not available to customers taking service hereunder.

(B) Notification of Use of Liquified Petroleum Gas

At certain times the Company introduces liquified petroleum gas into its system at various points.

The Company will notify a designated representative of each customer whose operation may be affected by the introduction of liquified petroleum gas of the planned introduction and will notify said representative when the introduction has ceased.

Each customer assumes full responsibility for any injuries and damages resulting from such customer's continued operation after notification of the planned introduction of liquid petroleum gas into the Company's system. The Company will not be liable for any injury, casualty or damage resulting in any way from a customer's continued operation after notification of a planned introduction of liquid petroleum into the Company's system, except injuries or damages resulting from the negligence of the Company.

SERVICE CLASSIFICATION NO. 8

APPLICABLE TO USE OF SERVICE FOR:

Interruptible transportation service for customer-owned gas from a receipt point to the customer's facilities. Customers commencing service hereunder on or after November 1, 2006 are subject to the gas usage eligibility requirement set forth in Special Provision I of this Service Classification. A receipt point is an agreed upon pipeline delivery point that interconnects with the Company's distribution system. The customer or a customer's gas Seller is responsible for transporting the gas to the receipt point including an amount to compensate the Company for losses incurred in transporting customer’s gas. Customers electing interruptible transportation service under this Service Classification must be located adjacent to the Company's existing gas distribution mains having adequate capacity to supply customer's prospective requirements, in addition to the requirements of other present or prospective customers taking firm or interruptible service from such distribution mains or who agree to pay to the Company, prior to construction, the estimated cost of expanding its distribution system to make it adequate for service hereunder and who agree to:

(a) interruption of service at any time at the Company's option on not less than four hours notice;

(b) install and maintain facilities for using alternate fuels during interruptions to the extent applicable; and

(c) not use service supplied hereunder in any equipment which is supplied with gas service under any other Service Classification except as specified herein.

CHARACTER OF SERVICE:

(A) Interruptible transportation of natural gas owned by a customer which the customer has arranged to have transported to a receipt point which interconnects with the Company's gas distribution system. Such gas will be transported from that receipt point to the customer's facilities. The Company shall control the dispatch of such gas, and dispatch will be provided as requested by the customer, except that the volume of gas delivered shall be conditioned upon the availability of distribution system capacity not then being used by Orange and Rockland's customers being served under Service Classification Nos. 1, 2, 5, 6, 7 and 9.

(B) Customers have the option, in lieu of the interruptible transportation service provided in (A) above, to purchase Supplemental Sales Service on a monthly basis. Supplemental Sales Service is the sale of interruptible natural gas owned by the Company having a heating value of not less than 1,000 Btu per cubic foot delivered at a pressure agreed upon by the customer and the Company, but not in excess of the available pressure at the point of delivery, as determined by the Company. To purchase Supplemental Sales Service, a customer must notify the Company by the twenty-fifth day of any month to commence Supplemental Sales

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

CHARACTER OF SERVICE: (Cont'd.)

(B) (Cont'd.)

Service on the first calendar day of the following month. Customers electing Supplemental Sales Service will be precluded from transporting gas under this Service Classification commencing with the first day of the calendar month following such notification requesting Supplemental Sales Service until the customer submits a subsequent notification by the twenty-fifth day of any calendar month to resume transportation service under this Service Classification commencing on the first day of the calendar month following such notification.

(C) A customer transporting under this Service Classification is required to (a) balance the volumes delivered to the Company with actual usage each day and monthly within the tolerances specified in section "Rate - Monthly", Item 2, "Over- and Under-Delivery Charges", or (b) elect to have a gas seller or broker approved by the Company, hereinafter defined as a Qualified Seller, perform the balancing service pursuant to Service Classification No. 13. For customers electing (b) above, the over-delivery and under-delivery charges specified in "Rate - Monthly", Item 2, will be billed to their Qualified Sellers and the Qualified Sellers will be primarily responsible for such charges. If for any reason a Qualified Seller does not pay the under-delivery or over-delivery charges, however, the Company retains the right to bill the customer for such charges.

(D) A customer transporting gas under this Service Classification is required to (a) nominate and schedule the volumes to be delivered to the Company's citygate each day or (b) elect to have a gas seller or broker approved by the Company, hereinafter defined as a Qualified Seller, perform the nominating and scheduling service pursuant to Service Classification No. 13.

(E) If during periods of interruption by the Company, the Company continues to accept a customer's gas at the receipt points, the Company will waive any over-delivery charges and will coordinate with the customer to adjust future deliveries at the receipt point to eliminate the over-delivered volumes.

RATE - MONTHLY:

Customers shall be subject to the monthly rates and charges set forth below and shall also be subject to the charges set forth in Special Provision G of this Service Classification.

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

RATE - MONTHLY: (Cont'd)

(1) Transportation Charge

First	100	Ccf or less $122.00 per monthly billing period
Next	49,900	Ccf at the Base Charge plus 5.0 cents per Ccf
Next	50,000	Ccf at the Base Charge plus 2.5 cents per Ccf
Next	100,000	Ccf at the Base Charge
Over	200,000	Ccf at the Tail Block Charge

The Base Charge and Tail Block Charge per 100 cubic feet (Ccf) shall be established each month at the Company's discretion, not less than three working days prior to the first day of the billing period for which such charges are to be effective.

The Base Charge and Tail Block Charge shall not be less than $0.010 per Ccf.

The Base Charge and Tail Block Charge shall not be greater than (i) the lowest per unit delivery charge for service under Service Classification No. 6 of this Schedule minus (ii) 5.0 cents per Ccf.

(2) Over and Under-delivery Charges

If the amount of gas delivered to the Company by a customer electing interruptible transportation service varies from the amount of gas used by the customer on a daily basis, (adjusted for losses as defined in Special Provision D "Loss Adjusted Usage"), the customer will have an over-delivery or an under-delivery. If on any day the over-delivery or under-delivery is less than 10% of a customer's actual daily Loss Adjusted Usage, the customer may adjust subsequent daily deliveries to the Company by an amount not to exceed 10% of any day's Loss Adjusted Usage to eliminate any over- or under-deliveries by the end of the month. Any over- or under-delivery remaining at the end of each month will be cashed out. To cash out over- or under-deliveries, the customer must sell the over-delivered volumes to the Company or purchase the under-delivered volumes from the Company as specified below.

(a) Over-deliveries - Daily

If on any day a customer's over-delivery is greater than 10% of a customer's actual Loss Adjusted Usage, the over-delivered volumes in excess of 10% will be purchased by the Company at the rates set forth below. The Index Price used to determine the applicable rate shall be equal to the

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(2) Over and Under-delivery Charges (Cont'd.)

(a) Over-deliveries – Daily (Cont'd.)

highest "Midpoint" rate of the "Louisiana-Onshore South", "Tennessee" receipt points for the applicable day as published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

For Over-deliveries	Rate
>10% up to and including 15%	90% of Index Price
>15% up to and including 20%	85% of Index Price
>20% - Winter	60% of Index Price
>20% - Summer	70% of Index Price

(b) Over-deliveries - Monthly

If there is an over-delivery at the end of the month, the over-delivered volumes will be purchased by the Company at a rate equal to 95% of the monthly average of the highest daily "Midpoint" rates of the "Louisiana-Onshore South", "Tennessee" receipt points for the month published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

(c) Under-deliveries - Daily

If on any day a customer's under-delivery is greater than 10% of a customer's actual Loss Adjusted Usage, the under-delivered volumes in excess of 10% will be sold to the customer by the Company at the rates set forth below. The Index Price used to determine the applicable rate shall be equal to the highest daily "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipt points for the applicable day as published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

For Under-deliveries	Rate
>10% up to and including 15%	110% of Index Price
>15% up to and including 20%	115% of Index Price
>20% - Winter	140% of Index Price
>20% - Summer	130% of Index Price

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(2) Over and Under-delivery Charges (Cont'd.)

(d) Under-deliveries - Monthly

If there is an under-delivery at the end of the month, the under-delivered volumes will be sold to the customer by the Company at a rate equal to 105% of the monthly average of the highest daily "Midpoint" rates of the "Louisiana - Onshore South", "Tennessee" receipt points for the month published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

(3) Supplemental Sales Service Charge

All Mcf delivered to a customer as Supplemental Sales Service shall be subject to Parts (1), (4), and (5) of RATE – MONTHLY plus the Supplemental Sales Supply Charge set forth on the "Statement of Interruptible Transportation and Supplemental Sales Charges" filed with the Commission each month.

(4) Temporary State Assessment Surcharge

The Temporary State Assessment Surcharge as described in General Information Section 24 shall apply to all gas delivered under this Service Classification.

(5) Increase in Rates and Charges

The rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

STATEMENT OF INTERRUPTIBLE TRANSPORTATION AND SUPPLEMENTAL SALES CHARGES

Not less than three working days prior to the first day of each billing period, the Company shall file with the Commission a statement showing the Maximum Allowable Base Charge, the Minimum Allowable Base Charge, the Base Charge and the Transportation Charges effective for service rendered during the billing period. Such statements will be made available for public inspection at Company offices where applications for service may be made.

TERMS OF PAYMENT:

Bills are due when rendered, subject to a late payment charge in accordance with the provisions of General Information Section 6.6.

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

SPECIAL PROVISIONS: (Cont'd.)

(G) Provisions Relating Interruptions (Cont'd.)

(1) Failure to Interrupt (Cont'd.)

On one occasion during each Winter Period, a customer’s failure to interrupt the use of gas due to documented inoperable alternate fuel or alternate energy facilities will not be counted as a violation toward the two-violation rule, provided that the Customer (i) notifies the Company within one hour of the failure of its equipment; (ii) repairs and makes operable its equipment within forty-eight hours of the equipment’s failure; and (iii) provides the Company with an affidavit or other sufficient documentation that it has repaired and made operable its alternate fuel or alternate energy equipment and immediately complies with the earlier of the ongoing interruption or a separate planned interruption. The Company will extend the one-time forty-eight hour repair deadline to a period not to exceed seven days provided the customer demonstrates, to the Company’s satisfaction, that such extension was necessary due to the unavailability of a part and its installation during such forty-eight hour repair period. All three conditions set forth above must be satisfied for this exception to the two-violation rule to apply. During the forty-eight hour repair period, or, if applicable, the extended seven day repair period, the customer will be subject to all applicable charges of this Service Classification for all gas consumed, except for the charge for inoperable alternate fuel/energy facilities or inadequate fuel reserves set forth in Special Provision (G)(3), provided that the customer makes operable its alternate fuel/energy facilities within the forty-eight hour or seven day repair period, whichever is applicable. This exemption does not apply to customers taking service under Special Provision F (3) (Shut-Down Option).

(2) Charge for Unauthorized Use of Gas

All gas consumed by a customer during a period of interruption in excess of its Firm Base Load volume shall be subject to a charge equal to the greater of a) two times the sum of (i) the cost of gas delivered to the Company’s citygate on the day of the violation, as defined below, plus (ii) the applicable interruptible transportation rate determined in accordance with this Service Classification and as set forth in the “Statement of Interruptible Transportation and Supplemental Sales Charges" for the month in which the violation occurred or b) nine times the Supplemental Sales Service Charge

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

SPECIAL PROVISIONS: (Cont'd.)

(G) Provisions Relating Interruptions (Cont'd.)

(2) Charge for Unauthorized Use of Gas (Cont'd.)

for the month in which the violation occurred. For the purposes of this provision, the cost of gas shall be equal to the highest daily "Midpoint" rate of the "Louisiana-Onshore South", "Tennessee" receipt points for the appropriate day as published in Gas Daily in the table "Daily Price Survey" plus the Company's weighted average cost of transportation (WACOT) and fuel losses at 100% load factor.

(3) Charge for Inoperable Alternate Fuel/Energy Facilities or Inadequate Fuel Reserves

Customers, other than those taking service under Special Provision F (3), Shut-Down Option, that fail to comply with the requirements set forth in Special Provision F above shall be subject to a charge equal to the greater of a) 130% of the cost of its alternate fuel, as established with reference to appropriate fuel price indices as determined in accordance with the Company's Gas Transportation Operating Procedures or b) 130% of the Supplemental Sales Service Charge, minus the rates paid by the customer under this Service Classification. This additional charge shall be applied to all gas consumed during the billing period, excluding any Firm Base Load volumes, in which there is non-compliance and for any subsequent billing periods during which the non-compliance continues. This charge shall be assessed in addition to the Charge for Unauthorized Use of Gas.

(H) Imbalance Trading

Direct Customers shall be permitted to trade imbalances with other Direct Customers and Qualified Sellers taking service under Service Classification No. 13 on both a daily and monthly basis in accordance with the provisions below. For the purposes of this provision, the term "Seller" shall refer to both Qualified Sellers and Direct Customers.

(1) Daily Imbalance Trading

The Company shall post imbalance information on its Retail Access Internet site. The posting will include a list of Sellers with telephone and e-mail information, the pipeline on which the imbalance occurred, and a plus or minus sign to indicate the direction of each Seller's imbalance for that

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

SPECIAL PROVISIONS: (Cont'd.)

(H) Imbalance Trading (Cont'd.)

(1) Daily Imbalance Trading (Cont'd.)

given day. The actual daily imbalance for each Seller listed will not be disclosed. It will be the responsibility of the Seller to review the imbalance site and to contact those Sellers with whom a daily imbalance trade appears feasible. Imbalance information will be posted by 4:00 p.m. Monday through Friday for gas days ending on a business day. Imbalance information for gas days ending on Saturday, Sunday or on a Company-observed holiday will be posted on the following business day. Sellers will have three business days from the time of the posting to contact the Company, via an Internet application, with their imbalance trading results. Imbalance trading results must be authorized by both trading partners in order to be considered valid by the Company. The Company will not process any trading results that are received after the three business day period.

Daily imbalance volumes traded must be from the same gas day and delivering pipeline to the Company's system.

Any volumes not traded on a daily basis shall be subject to Over- and Under-delivery Charges in accordance with Part (2) of RATE - MONTHLY.

A fee of $5.00 shall be assessed per party, per trade. If two parties engage in, and provide the Company with a single notice of, up to three daily trades during a single 72 hour notification imbalance trading period, such trades shall be considered a single trade for the purpose of assessing the $5.00 fee.

(2) Monthly Imbalance Trading

By 4:00 p.m. on the second business day of each month, the Company will post monthly imbalance information from the previous month on its Retail Access Internet site. The posting will include a list of Sellers with telephone and e-mail information, the pipeline on which the imbalance occurred, and a plus or minus sign to indicate the direction of each Seller's imbalance for the prior month. The actual monthly imbalances of Sellers will not be disclosed. It will be the responsibility of the Seller to review the imbalance site and

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

SPECIAL PROVISIONS: (Cont'd.)

(H) Imbalance Trading (Cont'd.)

(2) Monthly Imbalance Trading (Cont'd.)

to contact Sellers with whom a monthly imbalance trade appears feasible. Sellers will have three business days from the time of the posting to contact the Company with their imbalance trading results. Imbalance trading results will be communicated back to the Company via an Internet application. Imbalance trading results must be authorized by both trading partners in order to be considered valid by the Company. Trading results not received within the three business day period will not be processed by the Company.

Any volumes not traded on a monthly basis shall be subject to Over- and Under-delivery Charges in accordance with Part (2) of RATE - MONTHLY.

(I) New Interruptible Customer Eligibility Requirement

Customers commencing service under this Service Classification on or after November 1, 2006, must, in addition to the other requirements of this Service Classification, demonstrate to the Company’s satisfaction annual gas consumption of at least 100,000 Ccf at a single meter.

Unless the Company possesses sufficient usage history to determine eligibility for service under this Service Classification, the customer shall provide the Company with a reasonable estimate of the customer’s annual gas usage. In the event a customer does not provide the Company with the required information to determine the customer’s eligibility for service hereunder, the Company will attempt to estimate the customer’s annual gas usage using the best available information. A customer may be denied service under this Service Classification if the customer fails to supply the information required to determine initial eligibility.

(J) Prepayment for Facilities

A customer taking firm service with the Company who switches to this Service Classification after taking firm service for less than five years, may, at the Company’s sole discretion, be required to pay all or a portion of the facility costs previously incurred for the customer.

SERVICE CLASSIFICATION NO. 10

(Service Classification No. 10 is hereby canceled)

SERVICE CLASSIFICATION NO. 10 (Cont'd.)

(Service Classification No. 10 is hereby canceled)

SERVICE CLASSIFICATION NO. 10 (Cont'd.)

(Service Classification No. 10 is hereby canceled)

SERVICE CLASSIFICATION NO. 10 (Cont'd.)

(Service Classification No. 10 is hereby canceled)

SERVICE CLASSIFICATION NO. 10 (Cont'd.)

(Service Classification No. 10 is hereby canceled)

SERVICE CLASSIFICATION NO. 10 (Cont'd.)

(Service Classification No. 10 is hereby canceled)

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

STANDARD SERVICE OPTION:

For Standard Service Option customers, the DCQ for each calendar month shall be calculated by the Company by dividing each customer's weather-normalized usage for each month of the most recent twelve billing months by the total number of days in each billing month and restating the billing month usage on a calendar month basis. The Company may adjust each customer's DCQs during the year due to changes in the customer's gas equipment or pattern of usage. For new customers, the initial monthly DCQ will be estimated by the Company based on the rating of the customer's gas-fired equipment and the expected utilization of such equipment.

The daily DCQs determined, as set forth above, reported on a volumetric basis shall be aggregated by month for each of the twelve months for all Standard Service Option customers within a Seller's Aggregation Group. The result obtained shall be the monthly ADCQ. The monthly ADCQ shall be multiplied by the Company's factor of adjustment as defined in General Information Section 12 and then converted to an energy basis by using the conversion factor shown in the Statement of Monthly Gas Adjustment. The highest ADCQ determined in the twelve-month period is the ("MAX ADCQ"). Seller shall be obligated to deliver the ADCQ each day during the month.

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

STANDARD SERVICE OPTION: (Cont'd.)

Monthly Cash-out

For each month the Company will calculate the difference between the Seller's Standard Service Option customer's actual usage and the ADCQ multiplied by the number of days in the billing period. If there is an imbalance at the end of the month, the over-delivered volumes will be purchased by the Company from the Seller and the under-delivered volumes will be sold by the Company to the Seller at a rate equal to the monthly average of the highest daily "Midpoint" rate of the "Louisiana – Onshore South", "Tennessee" receipts points for such month as published in Gas Daily in the table "Daily Price Survey", plus the Company's Adjusted WACOT for such month and fuel losses calculated at 100% load factor.

The MAX ADCQ shall be the amount of daily pipeline capacity to be obtained by the Seller. The ADCQ is the amount of gas that Seller must deliver to the Company daily. If Seller is also serving customers that have elected the Winter Bundled Sales Service Option, the ADCQ and the MAX ADCQ determined for the Winter Bundled Sales Service Option shall be added to the ADCQ and MAX ADCQs determined herein.

WINTER BUNDLED SALES SERVICE OPTION:

For customers electing the Winter Bundled Sales ("WBS") Service Option pursuant to Service Classification No. 6, the Company will provide to the Seller the Winter Bundled Sales Volume ("WBSV"), the ADCQ, and the MAX ADCQ for its customers as defined and determined in the manner set forth below:

a) The WBSV shall be equal to the sum of the WBS gas allocated to each customer in Seller's Aggregation Group multiplied by the Company's factor of adjustment as defined in General Information Section 12 and then converted to an energy basis by using the conversion factor shown in the Statement of Monthly Gas Adjustments. The Seller is required to purchase the WBSV from the Company during the period November through March (winter period) in accordance with the provisions set forth below. Each customer will be allocated a portion of the WBSV based on the percentage of the Company's system gas requirements that are served by storage service. If there is a change in the percentage of the Company's system requirements that are met through storage service, the new percentage will be used to re-determine the allocated volume of WBSV the following April. WBSV is to be measured in Dths.

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

WINTER BUNDLED SALES SERVICE OPTION: (Cont'd.)

Monthly Cash-out

For each month the Company will calculate the difference between the Seller's Winter Bundles Sales Service Option customer's actual usage and the ADCQ, adjusted for WBS volumes, multiplied by the number of days in the billing period. If there is an imbalance at the end of the month, the over-delivered volumes will be purchased by the Company from the Seller and the under-delivered volumes will be sold by the Company to the Seller at a rate equal to the monthly average of the highest daily "Midpoint" rate of the "Louisiana – Onshore South", "Tennessee" receipts points for such month as published in Gas Daily in the table "Daily Price Survey", plus the Company's Adjusted WACOT for such month and fuel losses calculated at 100% load factor.

SERVICE CLASSIFICATION NO. 11 (Cont'd.)

WINTER BUNDLED SALES SERVICE OPTION: (Cont'd.)

RATE - MONTHLY

In addition to any applicable charges for released capacity, Seller's monthly cost for each customer in the Seller's Aggregation Group electing the Winter Bundled Sales Service Option shall be:

(1) a monthly charge for WBS gas purchased consisting of a commodity charge, storage charges, and carrying charges on the cost of WBS gas, which shall be determined by using the effective Other Customer Capital Rate prescribed by the Commission. Storage charges shall consist of demand and associated charges for space, deliverability, and injection and withdrawal charges for pipeline storage facilities for the period at the applicable rates and charges of each applicable pipeline. All commodity costs used in determining the WBS rate are described in the Company's Gas Sales and Transportation Operating Procedures.

(2) all rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

The rate for WBS gas purchases shall be as set forth in the Statement of Rates to Qualified Sellers and Firm Transporters of Gas, Service Classification No. 11 filed with the Commission each month.

<u>Termination of Winter Bundled Sales Service Option</u>

If during a winter month a customer terminates Winter Bundled Sales Service Option, the customer's Seller shall be reimbursed at the WBS gas rate in effect for the month in which the Seller purchased such excess gas.

SERVICE CLASSIFICATION NO. 13

APPLICABLE TO USE OF SERVICE FOR:

Qualified Sellers ("Sellers") of natural gas or Direct Customers who transport natural gas to various agreed upon pipeline delivery points that interconnect with the Company's distribution system, herein after called the receipt point(s). The Company will accept the gas at the receipt point(s) on an interruptible basis and redeliver the gas on an interruptible basis to Seller's customer(s) pursuant to Service Classification Nos. 8 and 9. Seller is responsible for (1) transporting the gas to the receipt point including an amount to compensate the Company for losses incurred in transporting customer's gas and (2) balancing the deliveries to the Company at the receipt point(s) with the actual Loss Adjusted Usage (as defined in Special Provision F of this Service Classification) of Seller's customers on a daily and monthly basis. The Company will aggregate a Seller's deliveries and Seller's customers' actual Loss Adjusted Usage for purposes of determining any over- or under-deliveries pursuant to this Service Classification. Service is provided in accordance with the provisions of this Service Classification and the provisions of the UBP. In the event of any conflict between the provisions of this Service Classification and the provisions of the UBP, the UBP shall control. Seller must meet the eligibility and creditworthiness requirements set forth in the UBP and must execute an application for service under this tariff. The Company may cease to provide service to a Seller in accordance with the Company's Gas Transportation Operating Procedures and for any reason specified in the UBP.

CHARACTER OF SERVICE:

Interruptible receipt of Sellers' gas at receipt point(s) for subsequent interruptible delivery by the Company to customers taking service under Service Classification Nos. 8 and 9.

RATE - MONTHLY:

(1) Over- and Under-delivery Charges

If the amount of gas delivered to the Company by Seller varies from the total Loss Adjusted Usage of customers in a Seller's aggregation group on a daily basis, (i.e., the total of all of Seller's Service Classification No. 8 customers that elected this service), the Seller will have an over-delivery or an under-delivery. If on any day the over-delivery or under-delivery is less than 10% of a Seller's aggregation group's actual daily Loss Adjusted Usage, the Seller may adjust subsequent daily deliveries to the Company by an amount not to exceed 10% of any day's Loss Adjusted Usage to eliminate any over- or under-deliveries by the end of the month. Any over- or under-delivery remaining at the end of each month will be cashed out. To cash out over- or under-deliveries, Seller must sell the over-delivered volumes to the Company or purchase the under-delivered volumes from the Company as specified below.

SERVICE CLASSIFICATION NO. 13 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(1) Over- and Under-delivery Charges (Cont'd.)

(A) Over-deliveries - Daily

If on any day a Seller's over-delivery is greater than 10% of a Seller's aggregation group's actual Loss Adjusted Usage, the over-delivered volumes in excess of 10% will be purchased by the Company at the rates set forth below. The Index Price used to determine the applicable rate shall be equal to the highest "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipt points for the applicable day as published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

For Over-deliveries	Rate
>10% up to and including 15%	90% of Index Price
>15% up to and including 20%	85% of Index Price
>20% - Winter	60% of Index Price
>20 - Summer	70% of Index Price

(B) Over-deliveries - Monthly

If there is an over-delivery at the end of the month, the over-delivered volumes will be purchased by the Company at a rate equal to 95% of the monthly average of the highest daily "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipt points for the month as published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

(C) Under-deliveries - Daily

If on any day a Seller's under-delivery is greater than 10% of a Seller's aggregation group's actual Loss Adjusted Usage, the under-delivered volumes in excess of 10% will be sold to the Seller by the Company at the rates set forth below. The Index Price used to determine the applicable rate shall be equal to the highest daily "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipt points for the applicable day as published in Gas Daily in the table.

SERVICE CLASSIFICATION NO. 13 (Cont'd.)

RATE - MONTHLY: (Cont'd.)

(1) Over- and Under-delivery Charges (Cont'd.)

(C) Under-deliveries – Daily (Cont'd.)

"Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

For Under-deliveries	Rate
>10% up to and including 15%	110% of Index Price
>15% up to and including 20%	115% of Index Price
>20% - Winter	140% of Index Price
>20 - Summer	130% of Index Price

(D) Under-deliveries – Monthly

If there is an under-delivery at the end of the month, the under-delivered volumes will be sold to the Seller by the Company at a rate equal to 105% of the monthly average of the highest daily "Midpoint" rate of the "Louisiana - Onshore South", "Tennessee" receipt points for the month published in Gas Daily in the table "Daily Price Survey", plus the Company's weighted average cost of transportation (WACOT) and fuel losses calculated at 100% load factor.

(2) Increase in Rates and Charges

All rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

INTERRUPTION OF SERVICE:

If Seller interrupts deliveries to the receipt point, Seller must notify Seller's customer(s) of such interruption. If the Company interrupts service to Seller's customers, the Company must notify Seller's customers. If during periods of interruption by the Company, the Company continues to accept Seller's gas at the receipt points, the Company will waive any over-delivery charges and will coordinate with Seller to adjust future deliveries at the receipt point to eliminate the over-delivered volumes.

SERVICE CLASSIFICATION NO. 13 (Cont'd.)

(1) Daily Imbalance Trading (Cont'd.)

through Friday for gas days ending on a business day. Imbalance information for gas days ending on Saturday, Sunday or on a Company-observed holiday will be posted on the following business day. Sellers will have three business days from the time of the posting to contact the Company, via an internet application, with their imbalance trading results. Imbalance trading results must be authorized by both trading partners in order to be considered valid by the Company. The Company will not process any trading results that are received after the three business day period.

Daily imbalance volumes traded must be from the same gas day and delivering pipeline to the Company's system.

Any volumes not traded on a daily basis shall be subject to Over- and Under-delivery Charges in accordance with Part (1) of RATE - MONTHLY.

A fee of $5.00 shall be assessed per party, per trade. If two parties engage in, and provide the Company with a single notice of, up to three daily trades during a single 72 hour notification imbalance trading period, such trades shall be considered a single trade for the purpose of assessing the $5.00 fee.

(2) Monthly Imbalance Trading

By 4:00 p.m. on the second business day of each month, the Company will post monthly imbalance information from the previous month on its Retail Access Internet site. The posting will include a list of Sellers with telephone and e-mail information, the pipeline on which the imbalance occurred, and a + or – sign to indicate the direction of each Seller's imbalance for the prior month. The actual monthly imbalances of Sellers will not be disclosed. It will be the responsibility of the Seller to review the imbalance site and to contact Sellers with whom a monthly imbalance trade appears feasible. Sellers will have three business days from the time of the posting to contact the Company with their imbalance trading results. Imbalance trading results will be communicated back to the Company via an internet application. Imbalance trading results must be authorized by both trading partners in order to be considered valid by the Company. Trading results not received within the three business day period will not be processed by the Company.

Any volumes not traded on a monthly basis shall be subject to Over- and Under-delivery Charges in accordance with Part (1) of RATE - MONTHLY.

SERVICE CLASSIFICATION NO. 14

SERVICE AGREEMENT:

The Company and customer shall execute a service agreement prior to the commencement of service hereunder. A standard service agreement shall include all terms and conditions contained in this Service Classification. The Company may, at its sole discretion, enter into a negotiated service agreement with the customer which includes different terms and conditions. Rates and terms offered to one customer in a negotiated service agreement will be made available to other similarly situated customers on a non-discriminatory basis. The Company will make available, on request, the criteria it will use to determine which customers are similarly situated. Negotiated service agreements between the Company and its customers will be filed with the Commission at least 30 days before becoming effective.

The service agreement shall contain all information necessary for the Company to supply service to the customer, including but not limited to:

(a) the exact character of service including volumes, pressures and customer's equipment to be served;

(b) receipt and/or delivery points, upstream pipelines and suppliers;

(c) additional facilities to be constructed or installed;

(d) the maximum annual volume as calculated under MINIMUM ANNUAL BILL below; and

(e) all terms and conditions which deviate from those contained in this Service Classification.

RATE - MONTHLY:

(1) Transportation Charge

A Transportation Charge of $0.10 per Dth shall be assessed on all gas actually delivered to the electric generating facility each day during the month to or for the account of customer.

(2) Marginal Cost Charge

A Marginal Cost Charge of $0.05 per Dth shall be assessed on the gas actually delivered each month.

(3) Value Added Charge ("VAC")

A Value Added Charge per Dth shall be assessed on the gas actually delivered each month. The VAC shall consist of an Estimated Value Added Charge plus a Reconciliation Adjustment. The VAC shall be determined as set forth below.

SERVICE CLASSIFICATION NO. 14

RATE - MONTHLY: (Continued)

(3) Value Added Charge ("VAC") (Continued)

DEFINITIONS

Actual Value Added Charge - The Value Added Charges that the customer would have been billed during the Effective Period if the Value Added Charge had been calculated based on the actual Spark Spreads during the Effective Period. The Actual Value Added Charge includes the prior period Reconciliation Adjustment.

Base Year – The first full year of the operation of the New York Independent System Operator ("NYISO") starting December 1, 1999.

Base Year Spark Spread - The simple average of the Spark Spread for all 8,784 hours of the Base Year. The Base Year Spark Spread for each respective Heat Rate Tier Level is as follows:

Tier 1	$(34.78)	per MWH
Tier 2	$(6.76)	per MWH
Tier 3	$(2.45)	per MWH
Tier 4	$ 8.76	per MWH

Customer's Heat Rate - The Heat rate expressed in MMBtu/MWH in the Heat Rate Tier Level that applies to the customer's equipment.

Customer's MWH Generated Output - The hourly Dth consumption divided by the customer's heat rate expressed in MWH.

Daily Market Gas Cost - The Daily Market Gas Cost per Dth is the market cost of gas reported in Platt's "Gas Daily" for Transco Zone 6 (NY) or, if gas is delivered to the Company's system from another gas pipeline, the cost of gas as reported in the Gas Daily for that pipeline delivery point. Such cost of gas shall be the average of the midpoint and the high price for the day of flow.

Effective Period - The period May 1st through April 30th of the following year.

Fuel Cost of Generation – The applicable Daily Market Gas Cost multiplied by the customer's Heat Rate Tier Level expressed in $/MWH.

SERVICE CLASSIFICATION NO. 14

RATE - MONTHLY: (Continued)

(3) Value Added Charge ("VAC") (Continued)

DEFINITIONS (Continued)

Heat Rate Tier Level – the heat rate tier level based on the technology of the unit:

Tier 1	17.5	MMBTU/MWH	Old simple cycle peaking units that commenced operation prior to December 31, 1998
Tier 2	11.0	MMBTU/MWH	Rankine cycle steam units
Tier 3	10.0	MMBTU/MWH	New simple cycle peaking units
Tier 4	7.4	MMBTU/MWH	Combination cycle plants

Market Electric Price – The Real-Time Locational Based Marginal Price (LBMP), expressed in $/MWH, for Zone G and for each applicable hour as set forth on the ("NYISO") web site.

Reconciliation Adjustment: The Reconciliation Adjustment is an adjustment that will be made prospectively for any Value Added Charge over/under collected. This adjustment is the difference between the sum of the Value Added Charges billed to the customer in the Test Year and the customer's Actual Value Added Charges in the Test Year.

Spark Spread – The Spark Spread is the Market Electric Price minus the Fuel Cost of Generation, expressed in $/MWH.

Test Year - The Test Year is the calendar year prior to the Effective Period.

Estimated Value Added Charge ($/Dth)

The Estimated Value Added Charge is a unitized per Dth rate, derived from the increase in Spark Spread from the Base Year to the Test Year. An Estimated Value Added Charge shall be determined for each customer taking service under this service classification and applied to every Dth delivered to such customer under this Service Classification, commencing May 1, 2006.

SERVICE CLASSIFICATION NO. 14

RATE - MONTHLY: (Continued)

(3) Value Added Charge ("VAC") (Continued)

Estimated Value Added Charge ($/Dth) (Continued)

A Monthly Total Value Added Charge shall be determined for each customer for each month of the Test Year. Such monthly amount shall be determined by (1) subtracting the Base Year Spark Spread from the Spark Spread determined for each hour in the respective month of the Test Year that the customer received natural gas; (2) multiplying five percent of the difference determined in (1) by the customer’s MWH Generated Output during such Test Year hour; and (3) summing the amounts determined in (2). The amount determined in (3) is the Monthly Total Value Added Charge, unless such amount is less than or equal to zero. In such case, the Monthly Total Value Added Charge shall be zero. The customer's Annual Total Value Added Charge shall be the sum of the customer's Monthly Total Value Added Charges for the Test Year.

The Estimated Value Added Charge shall be the customer's Annual Total Value Added Charge for the Test Year, including any applicable Reconciliation Adjustment, divided by the number of Dth delivered to such customer during the Test Year. If a customer does not have twelve months of consumption data for the Test Year, that customer will be assigned a Value Added Charge equal to the average of all the customers’ Value Added Charge within the applicable heat rate tier level.

For each customer taking service under this Service Classification, the Company will file by March 1 of each year the Estimated Value Added Charge applicable to such customer to become effective May 1 of that year.

The Value Added Charge is a unitized per Dth rate, derived from the increase from the Base Year Spark Spread, adjusted for prior period Reconciliation Adjustment.

(4) Over and Under-delivery Charges

If the amount of gas delivered to the boundary of the Company's service area on behalf of a customer varies from the amount of gas used by the customer on a daily basis, the customer will have an over-delivery or an under-delivery.

SERVICE CLASSIFICATION NO. 14

RATE - MONTHLY: (Continued)

(4) Over and Under-delivery Charges (Continued)

Over- and under-deliveries shall be determined as specified below. However, if the pipeline transporting gas to the Company's system boundary imposes more stringent over- or under-delivery limits or purchase or sales rates on the Company, such limits and rates shall apply to the customer and will supersede those contained herein. Additionally, a customer transporting gas on more than one pipeline serving the Company shall have over- or under-deliveries calculated on each transporting pipeline. The over- or under-delivery shall be allocated proportionally to each pipeline based on the nominated volumes.

If on any day the over-delivery or under-delivery is less than 2% of a customer's actual daily usage, the customer may adjust subsequent daily deliveries to the Company by an amount not to exceed 2% of any day's usage to eliminate any over- or under-deliveries by the end of the month. Any over- or under-delivery remaining at the end of each month will be cashed out. To cash out over- or under-deliveries, the customer must sell the over-delivered volumes to the Company or purchase the under-delivered volumes from the Company as specified below.

(a) Over-deliveries - Daily

If on any day a customer's over-delivery is greater than 2% of a customer's actual usage, the over-delivered volumes in excess of 2% will be purchased by the Company at the rates set forth below.

For Over-deliveries	Rate
>2% up to and including 5%	90% of Index Price
>5% up to and including 10%	80% of Index Price
>10%	70% of Index Price

The Index Price for daily over-deliveries shall be equal to the simple average of the daily Algonquin, city-gates and Millennium-East midpoint price index on the day in which the over-delivery occurs.

(b) Over-deliveries - Monthly

If there is an over-delivery at the end of the month, the over-delivered volumes will be purchased at a rate equal to the lower of the monthly average of the daily Algonquin, City gates and Millennium-East midpoint prices or the average of the Algonquin, city-gates and Millennium-East First-of-Month Low Range Price as published in Platt’s Gas Daily.

SERVICE CLASSIFICATION NO. 14

RATE - MONTHLY: (Continued)

(4) Over and Under-delivery Charges (Continued)

(c) Under-deliveries – Daily

If on any day a customer's under-delivery is greater than 2% of a customer's actual usage, the under-delivered volumes in excess of 2% will be sold to the customer at the rates shown below.

For Under-deliveries	Rate
>2% up to and including 5%	110% of Index Price
>5% up to and including 10%	120% of Index Price
>10%	130% of Index Price

The Index Price for daily under-deliveries shall be equal to the simple average of the daily Algonquin, city-gates and Millennium-East midpoint price index on the day in which the under-delivery occurs.

(d) Under-deliveries - Monthly

If there is an under-delivery at the end of the month, the under-delivered volumes will be sold to the customer by the Company at a rate equal to the higher of the monthly average of the Algonquin, city-gates and Millennium-East midpoint prices or the average of the Algonquin, city-gates and Millennium-East First-of-Month High Range Price as published in Platt’s Gas Daily.

(5) Penalty Charge

All gas used by a customer during periods in which the Company has requested customer to discontinue usage of gas service shall be subject to a minimum penalty equal to the higher of a) 120% of the wholesale electric market price at the time of non-compliance converted to a gas price in accordance with the Company's Gas Transportation Operating Procedures or b) $25.00 per Dth plus the cost of gas or c) $45.00 per Dth, or any penalty the Company may incur from a pipeline due to customer's unauthorized takes that is greater than the minimum penalty. The Company may, at its option, waive this penalty during emergencies. For the purposes of this provision, the cost of gas shall be equal to the highest daily "Midpoint" rate of the "Louisiana-Onshore South", "Tennessee" receipt points for the appropriate day as published in Gas Daily in the table "Daily Price Survey" plus the Company's weighted average cost of transportation (WACOT) and fuel losses at 100% load factor.

SERVICE CLASSIFICATION NO. 14

RATE - MONTHLY: (Continued)

(6) Variable Balancing Charge

The customer will pay a monthly variable balancing charge of on all volumes recorded as delivered and burned. The monthly Variable Balancing Charge shall be determined by November 1 of each year based on the allocated costs of assets used to balance customers under this Service Classification.

(7) Increase in Rates and Charges

All rates and charges under this Service Classification will be increased pursuant to General Information Section 15 of this Schedule.

SERVICE CLASSIFICATION NO. 14

SPECIAL PROVISIONS: (Cont'd.)

(F) Customer Responsibilities (Cont'd.)

The customer shall immediately: (i) notify the Company of any condition that would prevent the required discontinuance of gas service or prevent the Company from determining whether the customer is using gas during a period in which the Company withdraws service, (ii) take immediate action to correct such condition, and (iii) notify the Company when such condition has been corrected. If the customer does not correct such condition within 10 days from when the condition is first reported by the customer or from when first discovered by the Company with notice to the customer, whichever is earlier, the customer shall be billed an additional charge equal to the greater of a) 130% of the cost of its alternate fuel, as established with reference to appropriate fuel price indices as determined in accordance with the Company's Gas Transportation Operating Procedures or b) 130% of the Service Classification No. 8 Supplemental Sales Service Charge, minus the rates paid by the customer under this Service Classification. This additional charge shall be applied to all gas consumed during the billing period in which there is non-compliance and for any subsequent billing periods during which the non-compliance continues.

The customer must comply with an annual inspection of its alternate fuel or alternate energy facilities, at a date and time determined by the Company, to determine whether such facilities are operable. In addition, the Company shall have the right to require a test of the customer's alternate fuel or alternate energy facilities. The customer must comply with any such test.

SERVICE CLASSIFICATION NO. 14 (Cont'd.)

SPECIAL PROVISIONS: (Cont'd.)

(G) Reserve Requirements

Prior to November 1 of each year, customers are required to demonstrate to the Company that they have adequate reserves of alternate fuel based on peak winter period requirements and in accordance with the provisions below.

(1) All Distillate Users shall have a five days supply of alternate fuel. If the customer does not have five days storage capability on site, the customer must fill available on-site storage and prove, to the Company's satisfaction, that a relationship exists with an alternate fuel provider to supply the customer for the difference between its on-site supply and the five days of required alternate fuel supply.

For the purposes of this provision, Distillate Users are those customers using No. 2 fuel oil, diesel fuel or kerosene as their alternate fuel source.

(2) Other withdrawable customers must maintain reserve levels acceptable to the Company.

A customer with an inadequate alternate fuel reserve that fails to discontinue gas service at any time during the first five days in which the Company has requested customer to discontinue usage of gas service in any winter season shall be billed an additional charge equal to the greater of a) 130% of the cost of its alternate fuel, as established with reference to a published distillate fuel index price as determined in accordance with the Company's Gas Transportation Operating Procedures or b) 130% of the Service Classification No. 8 Supplemental Sales Service Charge, minus the rates paid by the customer under this Service Classification. Any customer with an inadequate alternate fuel reserve as of November 1 of each year will similarly be subject to the same additional charge. This additional charge shall be applied to all gas consumed during the billing period in which there is non-compliance and for any subsequent billing periods during which the non-compliance continues.

ORANGE AND ROCKLAND UTILITIES, INC.

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending October 31, 2016 *
(Based on Billed Sales and Revenues)

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,608,664	192,183	313,689	333,481	19,791	6.3%
SC19	81,534	3,589	14,534	15,396	862	5.9%
Total Res	1,690,198	195,772	328,223	348,877	20,654	6.3%
SC2 Sec	865,136	27,896	145,453	153,449	7,996	5.5%
SC20	74,749	443	10,293	10,718	425	4.1%
Total Secondary	939,885	28,339	155,746	164,167	8,421	5.4%
SC2 Pri	36,560	155	5,376	5,526	149	2.8%
SC3	368,538	267	48,231	50,037	1,806	3.8%
SC21	38,578	26	5,036	5,227	191	3.8%
Total Primary	443,676	448	58,643	60,790	2,147	3.7%
Total Sec & Pri	1,383,561	28,786	214,389	224,957	10,568	4.9%
SC9 (Commercial)	408,086	47	48,197	49,157	960	2.0%
SC22 (Industrial)	344,926	33	39,377	40,406	1,029	2.6%
Total SC9 & SC22	753,012	80	87,573	89,563	1,990	2.3%
SC4	15,144	73	5,679	5,762	83	1.5%
SC5	2,983	498	570	570	0	0.0%
SC6	4,219	2	699	733	34	4.8%
SC 16 -dusk-to-dawn	9,684	2,273	4,663	4,681	18	0.4%
SC 16 - energy only	3,824	430	729	763	34	4.6%
SC16 - Total	13,508	2,703	5,392	5,444	52	1.0%
Total Lighting	35,854	3,276	12,340	12,509	169	1.4%
Total	3,862,625	227,914	642,526	675,906	33,380	5.2%

* 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.

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending October 31, 2016 *
(Based on Billed Sales and Revenues)

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	13,369,015	121,071	171,679.3	205,364.9	33,685.6	19.6%
1	Non Residential	695,059	3,746	8,377.9	9,928.6	1,550.7	18.5%
2 / 6 IB	Commercial	4,197,353	8,115	44,193.9	48,606.0	4,412.1	10.0%
6 II	Large Commercial	1,506,734	110	14,681.6	15,744.0	1,062.4	7.2%
	Total Firm	19,768,161	133,042	238,932.8	279,643.5	40,710.7	17.0%
5	Firm Dual Fuel	0	0	0.0	0.0	0.0	0.0%
7	NGV	0	0	0.0	0.0	0.0	0.0%
8	Interruptible Trans	1,974,196	93	2,099.0	2,099.0	0.0	0.0%
9	Withdrawable Trans	2,248,900	1	799.0	799.0	0.0	0.0%
	Total	23,991,257	133,136	241,830.7	282,541.5	40,710.7	16.8%

* For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.

NYS DEPARTMENT OF STATE

Notice of Proposed Rule Making

Public Service Commission
(SUBMITTING AGENCY)

NOTE: Typing and submission instructions are at the end of this form. Please be sure to COMPLETE ALL ITEMS. Incomplete forms and nonscannable text attachments will be cause for rejection of this notice.

Pursuant to the provisions of the State Administrative Procedure Act (SAPA), NOTICE is hereby given of the following agency action:

1. Proposed action:

   The Public Service Commission (the "PSC") is considering whether to approve, reject, in whole or in part, or modify a proposal filed by Orange and Rockland Utilities, Inc. (the "Company") to make various changes in the charges, rules, and regulations contained in its Schedule for Electric service, P.S.C. No. 3 – ELECTRICITY and in its Schedule for Gas Service – P.S.C. No. 4 – GAS, effective January 1, 2015.

2. Statutory authority under which rule is proposed:

   n/a

3. Subject of rule:

   Tariff leaves reflecting increases in the rates and charges contained in Orange and Rockland's Schedule for Electric Service, P.S.C. No. 3 – ELECTRICITY and P.S.C. No. 4 – GAS.

4. Purpose of rule:

   Consideration of tariff changes reflecting a revenue requirement for the rate year, the twelve months ending October 31, 2016, of approximately $33.4 million for electric and $40.7 million for gas. In addition, proposals have been made in the tariffs for various provisions.

5. Terms of rule (check applicable box):

   [ ] The rule contains 2,000 words or less. An original copy of the text in scannable format is attached to this form.

   [ ] The rule contains more than 2,000 words. Therefore, an original copy of a summary the text (in scannable format) is attached to this form.

   [X] Pursuant to SAPA § 202(7)(b), the agency elects to print a description of the subject, purpose and substance of the rule containing less than 2,000 words. The original text in scannable format is attached to this form.

6. The text of the rule and any required statements or analyses may be obtained from:

Name of agency contact: Margaret Maguire, Clerk II
Office address: Three Empire State Plaza
Albany, New York 12223
Telephone number: (518) 474-3204

7. Regulatory Impact Statement (RIS) (check applicable box):

[ ] A RIS of 2,000 words or less is submitted with this notice.

[ ] A summary of the RIS is submitted with this notice because the full text exceeds 2,000 words.

[ ] A consolidated RIS is submitted with this notice because:

[ ] the rule is one of a series of closely related and simultaneously proposed rules.

[ ] the rule is one of a series of virtually identical rules proposed during the same year.

[ ] An RIS is not submitted because this rule is a technical amendment and, therefore, exempt from SAPA § 202-a. Attached to this notice is a statement of the reason(s) for claiming this exemption.

[ ] An RIS is not submitted because this rule is subject to a consolidated RIS printed in the Register under a notice of proposed rule making ID No. PSC-_______; Register date: _________.

[X] An RIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

8. Regulatory Flexibility Analysis for Small Businesses (RFASB) (check applicable box):

[ ] An RFASB of 2,000 words or less is submitted with this notice.

[ ] A summary RFASB is submitted with this notice because the full text exceed 2,000 words.

[ ] A consolidated RFASB is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject of the same analysis.

[ ] An RFASB is not submitted because this rule will not impose any adverse economic impact or reporting, recordkeeping or other compliance requirements on small businesses. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse economic impact or compliance requirements on small businesses.

[ ] An RFASB is not submitted because this rule is subject to a consolidated RFASB printed in the Register under a notice of proposed rule making, ID No. _______; Register date: _________.

[X] An RFASB is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

9. Rural Area Flexibility Analysis (RAFA) (check applicable box):

[ ] An RAFA of 2,000 words or less is submitted with this notice.

[ ] A summary RAFA is submitted with this notice because the full text exceeds 2,000 words.

[ ] A consolidated RAFA is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject to the same analysis.

[ ] An RAFA is not submitted because this rule will not impose any adverse impact or reporting, recordkeeping or other compliance requirements on public or private entities in rural areas. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse impact or compliance requirements on rural areas.

[ ] An RAFA is not submitted because this rule is subject to a consolidated RAFA printed in the Register under a notice of proposed rule making, ID No. ______; Register date: _________.

[X] An RAFA is not submitted because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

10. Job Impact Statement (JIS) (check applicable box):

[ ] A JIS of 2,000 words or less is submitted with this notice.

[ ] A summary JIS is submitted with this notice because the full text exceeds 2,000 words.

[ ] A JIS/Request for Assistance is submitted with this notice.

[ ] A consolidated JIS is submitted with this notice because this rule is the first of a series of closely related rules that will be subject to the same analysis.

[ ] A JIS is not submitted because it is apparent from the nature and purpose of the rule that it will not have a substantial adverse impact on jobs and employment opportunities. A statement is attached setting forth this agency's finding that the rule will have a positive impact or no impact on jobs and employment opportunities; except when it is evident from the subject matter of the rule that it could only have a positive impact or no impact on jobs and employment opportunities, the statement shall include a summary of the information and methodology underlying that determination.

[ ] A JIS is not submitted because this rule is subject to a consolidated JIS printed in the **Register** in a notice of proposed rule making ID No. _________; Register date: _________.

[X] A JIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

[ ] A JIS is not submitted because this rule is proposed by the State Comptroller or Attorney General.

11. Prior emergency rule making for this action was previously published in the ______ issue of the Register, I.D. No. _ __________.

12. Expiration Date (check only if applicable):

    [X] This proposal will not expire in 180 days because it is for a "rate making" as defined in SAPA § 102(2)(a)(ii).

13. Public Hearings (check box and complete as applicable)

    [ ] A public hearing is required by law and will be held at __ a.m./p.m. on ________, 19__, at
    ____
    ____

    [ ] A public hearing is not required by law, and has not been scheduled.

    [ ] A public hearing is not required by law, but will be held at __ a.m./p.m. on _______, 19 __, at
    ____
    ____

14. Interpreter Service (check only if a public hearing is scheduled):

    [ ] Interpreter services will be made available to hearing impaired persons, at no charge, upon written request submitted within a reasonable time prior to the scheduled hearing. Requests must be addressed to the agency contact designated in this notice.

15. Accessibility (check appropriate box only if a public hearing is scheduled):

    [ ] All public hearings have been scheduled at places reasonably accessible to persons with a mobility impairment.

    [ ] All public hearings except the following have been scheduled at places reasonably accessible to persons with a mobility impairment:
    1. ____
    2. ____
    3. ____

    [ ] None of the scheduled public hearings are at places that are reasonably accessible to persons with a mobility impairment.

    [ ] An **optional** explanation is being submitted regarding the nonaccessibility of one or more hearing sites.

16. Submit data, views or arguments to (complete only if different than previously named agency contact):

    Name of agency contact: Kathleen H. Burgess, Secretary
    Office address: Three Empire State Plaza
    Albany, New York 12223
    Telephone number: (518) 474-6530

17. Additional matter required by statute:

    [X] Check box if NOT applicable.

18. Public comment will be received until:

    [ ] 45 days after publication of this notice (MINIMUM, public comment period).

    [ ] 5 days after the last scheduled public hearing required by statue (MINIMUM, with required hearing).

    [ ] Other: (specify) ___________________.

19. Regulatory Agenda: (**The Division of Housing and Community Renewal; Workers Compensation Board; and the departments of Agriculture and Markets, Banking, Education, Environmental Conservation, Health, Insurance, Labor and Social Services** and any other department specified by the governor or his designee must complete this item. If your agency had an optional agenda published, that should also be indicated below):

    [ ] This action was listed as a Regulatory Agenda item in the first January issue of the Register, 19_.

    [ ] This action was listed as a Regulatory Agenda item in the last June issue of the Register, 19_.

    [ ] This action was not under consideration at the time this agency's Regulatory Agenda was submitted for publication in the Register.

AGENCY CERTIFICATION (To be completed by the person who PREPARED the notice)

I have reviewed this form and the information submitted with it. The information contained in this notice is correct to the best of my knowledge.

I have reviewed Article 2 of SAPA and Parts 260 through 263 of 19 NYCRR, and I hereby certify that this notice complies with all applicable provisions.

Name ____________________________ Signature ____
Address ____
Date ____________________________ Telephone ____

Please read before submitting this notice:

1. Except for this form itself, all text must be typed in scannable format as described in the Department of State's "NYS Register Procedures Manual."

2. Submit the **orginal notice and scanner copy** collated as (1) form; (2) text or summary of rule; and if any, (3) regulatory impact statement, (4) regulatory flexibility analysis for small businesses, (5) rural area flexibility analysis, (6) job impact statement **- and ONE copy of that set.**

3. **Hand deliver to:** DOS Office of Information Services, 41 State Street (3rd Floor), Albany
   Address mail to: Register/NYCRR unit, Department of State, Albany, NY 12231

Method of Service

Name:	John L. Carley
Company/Organization:	Orange and Rockland Utilities, Inc.
Mailing Address:	4 Irving Place, Room 1815-S, New York, NY 10003
Company/Organization you represent, if different from above:	
E-Mail Address:	carleyj@coned.com
Case/Matter Number:	

Request Type

- ■ New Petition/Application - I am filing a new petition/application which requires action by the Commission.
- ☐ Service List request – I request to be on the service list for the matter/case.
- ☐ Other – Type of request ____

Service Information *(Select one option below)*

- ■ Electronic Service and Waiver – Consent in Case/Matter Identified Above
  As duly authorized by the Participant identified above that I represent, I knowingly waive on behalf of that Participant any right under PSL §23(1) to be served personally or by regular mail with Commission orders that affect that Participant and will receive all orders by electronic means in the above Case. If participating individually, I knowingly waive any PSL §23(1) right to service of orders personally or by regular mail and will receive all orders by electronic means in the above Case. This consent remains in effect until revoked.

- ☐ Electronic Service and Waiver – Global Consent in All Cases/Matters
  As duly authorized by the Participant identified above that I represent, I knowingly waive on behalf of that Participant any right under PSL §23(1) to be served personally or by regular mail with Commission orders that affect that Participant and will receive all orders by electronic means in all Cases where it participates. If participating individually, I knowingly waive any PSL §23(1) right to service of orders personally or by regular mail, and will receive all orders by electronic means in all Cases where I participate. This consent remains in effect until revoked.
  Note*: Due to the design of our system, this consent attaches to the individual named here and not to the party that may be represented by that individual. Therefore, individuals who represent multiple parties should be aware that a global consent will affect all matters in which they appear on behalf of any party.*

- ☐ I do **not** consent to receive orders electronically

E-Mail Preference *(Select one option below) – For Case specific request*
E-Mail notifications include a link to filed and issued documents.

- ☐ Notify me of Commission Issued Documents in this case/matter.
- ■ Notify me of Both Commission Issued Documents and Filings in this case/matter
- ☐ Do not send me any notifications of filed or issued documents

Submitted by: John L. Carley	Date: November 14, 2014

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ACCOUNTING PANEL

TABLE OF CONTENTS

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ACCOUNTING PANEL

I. INTRODUCTION

Q. Would the members of the Accounting Panel please state your names and business addresses?

A. Kenneth A. Kosior, One Blue Hill Plaza, Pearl River, New York 10965. Jack C. Deem, 4 Irving Place, New York, New York 10003. Wenqi Wang. 4 Irving Place, New York, New York, 10003.

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

A. **(Kosior)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R", or the "Company") where I hold the position of Director – Financial Services.

(Deem) I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I hold the position of Department Manager - Regulatory Policy.

(Wang) I am also employed by Con Edison. I hold the position of Department Manager - Regulatory Accounting and Revenue Requirements.

Q. Please explain your educational background, work experience and current general responsibilities.

A. **(Kosior)** I graduated from Pace University in 1976 with a Bachelor of Business Administration degree, having majored in Accounting. In June 1980, I received a Masters of Business Administration degree from Fairleigh Dickinson University, having majored in Accounting and Finance. After graduation from Pace, I was employed by Homa Company as a staff accountant. I joined Orange and Rockland in July 1979 as an Associate

Accountant advancing to Supervisor-Payroll, Supervisor & Manager-General Accounting where I had the responsibility of administering and supervising all employee related payroll records and subsequently the books and records of Orange and Rockland and its subsidiaries. In June 1989, I was promoted to Manager-Budgets and was responsible for the development and management of the operating and capital budgets. My additional duties included forecasting and analyzing the corporate financial statements. I was named Strategic Analysis Principal in October 1994 and became responsible for developing, analyzing and evaluating corporate direction and business opportunities. In June 1995, I was promoted to Director of Accounting, where I was responsible for the accounting functions of Orange and Rockland and its subsidiaries, including the consolidated financial statements. In July 1999, as a result of the merger of Con Edison and Orange and Rockland, I was appointed Director-Financial Planning and Administration, now called Financial Services, at Orange and Rockland responsible for providing the coordination for administration, financial, budget and regulatory activities between Con Edison and Orange and Rockland. I have been a member of various accounting and finance committees of the Edison Electric Institute and the Pennsylvania Electric Association. In addition, I am a past Chairperson of the New Jersey Utilities Association Accounting and Finance Committee.

(Deem) In December 1990, I received a Bachelor of Science Degree in Policy & Management from Carnegie Mellon University in Pittsburgh, Pennsylvania. I earned a Masters of Business Administration degree from Carnegie Mellon in June of 1996. Before returning to Carnegie Mellon for my MBA, I worked as an analyst with Barakat & Chamberlin, Inc. where I was responsible for planning and evaluating demand-side management ("DSM") programs for various utilities. In that role, I performed cost effectiveness screening and market penetration analysis of DSM measures and programs, prepared testimony entered on behalf of utilities during DSM cost recovery hearings, and implemented DSM tracking systems. After receiving my MBA, I worked as a consultant with Deloitte Consulting for 14 years. With Deloitte, I assisted companies to improve operations by leading the implementation of finance process, system, control, and organizational improvements. Specific areas of experience include finance transformation strategy and implementation, shared services, post-merger finance integration, financial closing and reporting optimization, finance talent management, Enterprise Resource Planning ("ERP") financial module implementation, Sarbanes-Oxley compliance, and activity-based management. While a majority of my consulting clients were electric and gas utilities, I also served clients in the health care, life sciences, financial services, and not-for-profit industries. I joined Con Edison in June 2010 as Business & Solution Architect for the implementation of the Oracle Finance and Supply Chain system. I transitioned to my current role of Department Manager for Regulatory Policy in May 2014.

(Wang) In June 1999, I received a Bachelor of Science Degree in Accounting from the University at Albany, State University of New York. I began my employment with Con Edison in July 1999 as a Management Intern. I worked in Corporate Accounting Department from July 2000 until April 2014 primarily in the General Accounts section starting as a Staff Accountant, then

Supervisor and ultimately reaching the Department Manger level. In May 2014, I assumed my current position as Department Manger of Regulatory Accounting and Revenue Requirements.

Q. Have any members of the Accounting Panel previously testified before the New York Public Service Commission ("NYPSC" or "Commission")?

A. **(Kosior)** Yes. I testified before the Commission in Case 95-E-0491, Case 99-G-1695, Case 02-G-1553, Case 05-G-1494, Case 06-E-1433, Case 07-E-0949, Case 08-G-1398, Case 10-E-0362 and Case 11-E-0480.

(Deem) No.

(Wang) No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. Our testimony primarily covers the following topics:

- An overview of the costs driving the need for electric and gas rate relief for the twelve months ending October 31, 2016 ("Rate Year"), along with the Company's efforts to mitigate the cost of providing gas and electric service;
- Projected deferred cost and credit balances as of November 1, 2015, which is the start of the Rate Year, resulting from deferral accounting or reconciliation provisions contained in the Company's current electric and gas rate plans;
- Historic financial statements and statistical data as required by the Commission;

- Rate base for the twelve months ended June 30, 2014 ("Historic Year") through the Rate Year;
- A comparison of the projected revenues, expenses and rate base for the Rate Year to the Historic Year;
- Certain revenues, operation and maintenance ("O&M") expenses and other operating deductions including labor expense and the need for certain additional employees;
- Common utility plant capital expenditures;
- Cost allocation procedures;
- The Company's requests related to certain deferral accounting and reconciliation mechanisms;
- The general inflation factor, sources and uses of funds and interest coverage ratios; and
- The Company's interest in pursuing multi-year rate plans in settlement discussions.

As we explain more fully later in our direct testimony, the Company is not proposing a multi-year rate plan in its filing. However, in addition to providing projections for the Rate Year, the Company has included forecasted financial information for two annual periods beyond the Rate Year, *i.e.*, the twelve month periods ending October 31, 2017 and October 31, 2018 (which we and other Company witnesses will refer to as "RY2" and "RY3", respectively, for ease of reference).

Q. Please identify any exhibits to your testimony.

A. We are presenting the following exhibits. All of the exhibits were prepared under our supervision and direction but some of them contain various parts or schedules sponsored by various other Company witnesses, as is indicated in the exhibits.

Description of Exhibit	**Exhibit No.**
Electric Historical Financial Data	AP-E1
Gas Historical Financial Data	AP-G1
Electric Rate Base	AP-E2
Gas Rate Base	AP-G2
Electric Operating Income and Rate of Return	AP-E3
Gas Operating Income and Rate of Return	AP-G3
Electric Operating Expenses	AP-E4
Gas Operating Expenses	AP-G4
Electric and Common Plant Forecast	AP-E5
Gas and Common Plant Forecast	AP-G5
Electric Multi-Year Forecast	AP-E6
Gas Multi-Year Forecast	AP-G6
Management Audit Report	AP-E7 and AP-G7

III. <u>THE NEED FOR RATE RELIEF AND COST MITIGATION MEASURES</u>

A. Costs Driving the Need for Rate Relief

Q. Please explain why the Company is filing for increased electric and gas rates to become effective November 1, 2015?

A. The Company's current electric rates were set by the Commission's *Order Adopting Terms of Joint Proposal, With Modification, and Establishing*

Electric Rate Plan, issued June 15, 2012, in Case No. 11-E-0408 ("2012 Rate Order"). The 2012 Rate Order established a three-year electric rate plan under which the last rate change became effective July1, 2014. The Company did not file for new base electric rates to become effective immediately following the third rate year of that rate plan. Assuming the Commission's usual 11-month rate case process, there will be 16 months between electric base rate changes.

For the Company's gas service, the time between base rate changes will be much longer. The Company's current gas rates were set by the Commission's *Order Adopting Joint Proposal and Implementing a Three-Year Rate Plan*, issued October 16, 2009, in Case 08-G-1398 ("2009 Rate Order"). The 2009 Rate Order established a three-year gas rate plan under which the last rate change became effective November 1, 2011. The Company did not file for new gas base rates to become effective immediately following the third rate year of that rate plan. Consequently, assuming the Commission's usual 11-month rate case process, there will be four years between gas base rate changes.

The Company has faced and continues to face a number of significant cost increases in its electric and gas operations that make the rate increase requests necessary. This is despite, as described throughout this filing, the Company's successful efforts to mitigate costs and achieve efficiencies and productivity gains. However, these efforts do not fully offset the effects of rising costs, resulting in net cost increases that cannot be absorbed without significantly curtailing or eliminating necessary programs and impairing the Company's ability to provide safe and reliable service or cover its cost of capital.

Q. What amount of rate relief is the Company requesting?

A. For electric, the Company is requesting approximately $33.4 million of rate relief for the Rate Year. That amount equates to approximately a 5.2% overall increase in customer bills and approximately an 11.5% increase on a delivery bill basis.

For gas, the Company is requesting approximately $40.7 million of rate relief for the Rate Year. That amount equates to approximately a 16.8% overall increase in customer bills and approximately a 35.1% increase on a delivery bill basis.

Q. What are the specific drivers of the requested rate increases?

A. There are several, including: (1) the need for infrastructure investment so that the Company can continue to provide safe and reliable service to its customers; (2) increases in costs largely outside the Company's control (*e.g.*, property taxes and major storm costs); (3) the cost of capital; (4) increases in operating expenses due to changes in the level of activities; and (5) projected costs increases. The following table summarizes the cost and other components driving the need for increased electric and gas base rate revenues:

	Electric	Gas
	($ millions)	
Infrastructure Investment	$7.2	$10.7
Depreciation	7.3	5.7
Total Carrying Costs	$14.5	$16.4

Property Taxes	13.2	20.6
Operating Expenses	3.8	7.0
Cost of capital	3.0	(3.9)
Payroll and other taxes	0.5	2.3
Sales and other revenues	(1.6)	(1.7)
Net Increase	$33.4	$40.7
Increase in Total Bill	5.2%	16.8%

Q. Please discuss the Infrastructure Investment item shown in the above table.

A. One of the primary drivers of the requested rate increases is the continued need to upgrade, reinforce, rebuild and invest in the Company's infrastructure. The carrying cost of this new investment (*i.e.*, cost of capital and depreciation) in the Rate Year is $14.5 million for electric and $16.4 million for gas. The Electric Infrastructure and Operations Panel, the Smart Grid Panel, and Company witnesses Hehir, Banker and Scerbo explain these needs in greater detail. As discussed by the Company's Depreciation Panel, the depreciation component of those increased costs results only from the increased plant investment, as the Company is not proposing any increase to depreciation rates.

Q. Please identify some of the costs that are outside of the Company's direct control.

A. The Company is faced with a number of costs which it cannot directly control. For example, as discussed by the Property Tax Panel, the level of electric property taxes forecast for the Rate Year is approximately $41 million, or 31%, higher than the level provided in current electric rates. For gas, the figures are $24 million, or 114% higher than the level provided in current gas rates. In addition, past rate allowances for property taxes have proven to be insufficient and the Company is seeking to recover, over five years, deferred property tax under-collections of $16 million from electric customers and $36 million from gas customers.

The effect of storms on the Company's electric system must also be recognized here. As discussed later in our testimony, the Company is not seeking to increase the funding level for the major storm reserve reflected in this filing. However, the recovery of deferred major storm costs is $12 million, or 75%, higher than provided in current electric rates.

Q. What are the major elements of O&M expenses that contribute to the need for a rate increase?

A. Increases in O&M expenses due to changes in the level of activities, new required programs, as well as projected cost increases, are discussed by various Company witnesses and account for $3.8 million of the increase for electric and $7.0 million for gas. The more significant increases are the recovery of storm costs for electric and damage prevention and other safety programs for gas. Pension and other post-employment benefits ("OPEB") costs tend to be quite variable and the Company is projecting a reduction in those costs which apply to electric and gas.

Q. What impact does the return on equity ("ROE") and projected interest cost have in this rate request?

A. For electric, the 2012 Rate Order authorized overall rates of return and ROEs that varied by rate year. For the third rate year, and as reflected in current electric rates, the overall rate of return is 7.48%, including a ROE of 9.6%. The weighted cost of long-term debt included is 5.64%. For gas, the 2009 Rate Order authorized an overall rate of return of 8.49%, including a ROE of 10.4% for all rate years. The weighted cost of long-term debt included is 6.81%. As discussed in the direct testimony of Company witnesses Hevert and Saegusa, the electric and gas revenue requirements in this case reflect an overall rate of return of 7.80%, based on a 9.75% ROE and a weighted cost of long-term debt of 6.08%. As discussed in his direct testimony, Company witness Hevert provided a range of ROE estimates, *i.e.*, from 9.75% to 10.5%, as being appropriate for the Company. Approximately $3 million of the electric revenue requirement increase is attributable to the higher financing costs, including the cost of capital associated with growth in rate base. The gas revenue requirement reflects an approximately $3.9 million decrease in the cost of capital that is attributable to the lower financing costs despite the growth in rate base.

Q. What effects do projected sales and other revenues have on the proposed revenue requirements?

A. For electric, net sales revenues are projected to decrease by $5.4 million, while other operating revenues are projected to increase by $7.0 million producing a net decrease of the need for rate relief of $1.6. For gas, net sales revenues are projected to increase by $0.4 million, and other operating revenues are projected to increase by $1.3 million producing a combined $1.7 million decrease of the need for rate relief.

Q. Do any of your exhibits address in further detail the elements of the revenue requirement you have summarized?

A. Yes, Exhibit AP-E3, Schedule 1, page 1 of 2, for electric and Exhibit AP-G3, Schedule 1, page 1 of 2, for gas do so.

B. Mitigation of the Rate Increases

Q. Please describe the rate mitigation efforts taken by the Company in developing the electric and gas revenue requirements for these filings.

A. Our initial calculations resulted in rate increases of $47.7 million for electric and $45.6 million for gas. The measures we have taken to mitigate these increases can be summarized as follows:

	Electric	Gas
	($ millions)	
Rate Increase before Mitigation	$47.7	$45.6
Extend Recovery of Deferred Property Taxes	(2.2)	(4.9)
Extend Recovery of Deferred Storm Charges	(8.1)	-
Eliminate Increase to Storm Allowance	(4.0)	-
Rate Increase after Mitigation	$33.4	$40.7

In order to mitigate the rate increases, the Company extended the amortizations of its two largest deferrals, property taxes and storm costs from three years to five years. The Company also has not proposed to increase the annual storm recovery allowance contained in electric base rates, even though the Company's experience with major storms over the past few years would justify such an increase.

Q. Does the Company intend to waive any rights by employing these mitigation measures in this filing?

A. No. The Company's revenue requirement needs are as reflected in the "unmitigated" rate request, as supported by the testimony and exhibits of the Company's witnesses. To the extent the Commission rejects or modifies any, all or any part of one or more of the Company's mitigation proposals, the Company's rate request should be adjusted upwards by the amount of mitigation that is eliminated. For example, if the Commission were to disagree with the Company's proposal to extend the recovery of property taxes from three to five years, the Commission should adjust the electric revenue requirement upwards by $2.2 million and the gas revenue requirement by $4.9 million. A similar upward adjustment would be required if the Commission were to accelerate the recovery of a particular cost that the filing has assumed would be recovered over a period of years or at a later date. Accordingly, the Company waives neither its right to recover all deferred costs nor its right to an increase in revenue requirement beyond the level filed by the Company should the Commission determine to depart from one or more (in whole or part) of the mitigation approaches used by the Company and to prescribe a quicker or greater recovery of mitigated costs. No waiver is intended and none should be inferred.

Q. You stated above that Company witness Hevert provided a range of ROE estimates, *i.e.*, from 9.75% to 10.5%, as being appropriate for the Company. Why did the Company choose the lower end of the range?

A. The Company selected the lower end of the reasonable range of ROE in order to minimize the issues in controversy in this proceeding and facilitate reaching a multi-year rate plan through settlement. Similarly, as noted by Company witness Saegusa, the Company selected an equity ratio of 48% in lieu of the Company's actual equity ratio of 48.45%. Should the Commission assign greater risks to the Company, the Company does not waive its right to a higher return corresponding to such greater risks. Should the Commission exclude costs in the calculation of the revenue requirement that lower the "mitigated" revenue requirement, the Company does not waive its rights to a reasonable return (*i.e.*, greater than 9.75 percent common equity return reflected in the "mitigated" revenue requirement and in the range identified by Company witness Hevert) consistent with the Company's non-mitigated revenue requirement or, if the revenue requirement is adjusted upwards for any reason, consistent with such increased revenue requirement.

Q. Has the Company taken any other steps to mitigate its requested rate relief?

A. Yes. The Company has taken significant steps to keep costs at the lowest practical level without adversely affecting service quality or reliability. This includes instilling a cost-management culture that pervades all aspects of the Company's operations starting with long range planning, project prioritization and optimization continuing to short term budgeting and culminating in daily implementation as is addressed by many Company witnesses. It is a Company-wide imperative to proactively seek ways to responsibly reduce costs. As described throughout this filing, the Company continues to mitigate costs – some to be realized in the short-term and some in the longer-term –

some that can be more specifically quantified or estimated than others, and some that are avoided increases rather than savings from current levels. Efforts to avoid unnecessary costs are described by various Company witnesses including the Electric Infrastructure and Operations Panel, Company witness Hehir as to gas infrastructure and operations, the Compensation and Benefits Panel, the Property Tax Panel, Company witness McCormick as to environmental costs, Company witness Work as to the project delivery and capital project management model, Company witness Carnavos as to gas supply costs, and the Electric Supply Panel.

Q. Are all the Company's cost mitigation efforts quantifiable?

A. No. Sometimes cost mitigation results may not be quantifiable or may not be subject to estimation with significant confidence and some result in avoided increases rather than savings from current levels. One significant example is the implementation of management audit recommendations. Although the Company has not been the subject of a stand-alone Commission management audit in many years, in its *Order Establishing Rates for Electric Service*, issued June 17, 2011, in Case 10-E-0362, the Commission directed the Company to produce a report detailing its implementation of those recommendations contained in the Liberty Management Audit of Con Edison, released in June 2009 ("Liberty Audit"), that were applicable to the Company. Orange and Rockland submitted an implementation report dated October 17, 2011 to the Commission and then submitted an updated implementation report dated June 14, 2014 to the Commission, a copy of which is presented in Exhibit (AP-E7 and AP-G7). As noted in the updated implementation report (p. 1), of the 92 separate recommendations contained in the Liberty Audit, the Company identified 41 as Shared Services recommendations, 41 as O&R Specific recommendations, and ten recommendations as not being applicable to the Company. The Company has implemented all the Liberty Audit recommendations applicable to Orange and Rockland.

Cost savings associated with the implementation of the Liberty Audit recommendations are reflected in this rate case filing, although many of these recommendations are qualitative in nature and not conducive to cost savings quantification. As noted above, 41 of the Liberty Audit recommendations are Shared Services recommendations, for which Con Edison has primary implementation responsibility. Cost savings associated with the implementation of these recommendations would be reflected in lower support services billings during the Historic Year. For example, to the extent that Con Edison was able to achieve costs savings by consolidating duplicative Energy Management operations in the electric and gas hedging functions (Recommendation 79), a portion of those savings would automatically be flowed through to the Company in the form of lower support services billings during the Historic Year. In addition, certain of the other Company witnesses, including Company witness Work, will discuss the implementation of specific Liberty Audit recommendations and the associated cost savings.

Along with the project management efforts discussed by the Company witness Work, and consistent with Liberty Audit Recommendations 45 and 46, the Company's cost management initiative continues to be a major focus throughout all levels of management. The Company received approval to hire three cost management analysts and a Project Management Cost Administrator in the 2012 Rate Order. Orange and Rockland hired these three analysts in April, September and December 2012 and the Project Management Cost Administrator in April 2013. These additional cost management professionals along with the continued development and understanding of the new financial reporting system referred to as Project One, which we will address more fully later in our testimony, has assisted the Company in improving reporting and analysis efficiency and standardizing responsibilities and duties across financial analysis positions in Orange and Rockland. These cost management professionals have enabled operational and staff organizations to provide a more in-depth focus on the costs within the respective departments. This has contributed to the Company's ability to maintain O&M and capital budgets within targets and reduce incurred overtime. More detailed cost reports by section and department support the managers in understanding and monitoring O&M and capital spending.

In addition, and consistent with Liberty Audit Recommendation Number 61, Orange and Rockland's annual budget process now requires a standardized focus on overtime as a percentage of straight time by organization. A corporate guidance document was approved on October 7, 2011. The document is to be used across the Company and outlines a philosophy to provide management with effective tools to administer and control overtime. The annual budget process requires that all organizations review historical trends and implement projected improvements necessary to optimize overtime.

The cost reductions or avoided costs associated with all of the foregoing with respect to implementing the Liberty Audit recommendations are not specifically quantifiable and in many cases not subject to confident estimation. To the extent they have been realized, however, they are reflected in the Company's revenue requirement calculations in these proceedings.

Furthermore, management continually reviews the proper utilization of in-house and contractor resources. Although cost can be a driver of the decision to utilize in-house or contractor resources, scheduling, length and frequency of the type of work, availability of trained workers, skill sets, productivity and changed circumstances are some of the additional factors that may be part of the decision to utilize in-house or contractor resources. Some operational functions are performed by contractors because decisions were made in the past that such skills were not core skills that the utility should train, develop or maintain internally. More complex core skills and functions have been retained within the Company while less skilled functions have been contracted out. Some examples of functions that have been contracted include cafeteria and cleaning services, as well as security, copy machines repairs and landscaping services. With regard to operations, flaggers, trenching, and tree trimming have been outsourced. Similar examples include civil work. Heavy civil construction work is not a core skill set that the Company seeks to maintain. Local skilled trade labor is familiar with and readily available for this type of work.

At other times O&R may supplement its in-house resources with contractor resources. The Company may wish to staff short-term projects to address peaks in workload. There may be projects that require an extensive amount of work, but with only a short time period to complete it. For example, in the past O&R has augmented its leak repair efforts with single contract crews to enable it to reduce the number of leaks to a level manageable with internal resources. Another example is the Company bringing on-board a third party vendor to assist the Company's in-house customer service organization during major storms. The Company has formally adopted this process as part of its Storm Recovery plan because call volume generated during a storm usually exceeds the Company's in-house staffing levels. The Company believes these various uses of in-house and contractor resources enable the Company to effectively manage and balance its operational resources.

As with cost reductions or avoided costs associated with respect to implementing the Liberty Audit recommendations, those associated with the workforce management approach we have described are not specifically quantifiable and in many cases not subject to confident estimation. To the extent they have been realized, however, they are reflected in the Company's revenue requirement calculations in these proceedings.

Q. You earlier referred to Project One. Please elaborate.

A. Project One, also referred to as the Finance and Supply Chain Enterprise Resource Project or ERP, is a technology project to modernize and improve a wide range of financial-related systems. It is an integrated system for Con Edison's and Orange and Rockland's finance, supply chain and management reporting activities. The scope of Project One included integrating Procurement, Inventory Management, Accounts Payable, Miscellaneous

Accounts Receivable, Projects Accounting, Treasury, General Ledger, Consolidations, Budgeting and Financial Forecasting, and Management Reporting systems onto one common, centralized platform for financial budgeting and reporting. Project One "went live" in July 2012. The project was fully vetted and cost recovery commenced for Con Edison in Case 09-E-0428. O&R's share of the cost is approximately 7%. Cost recovery of the electric portion of O&R's share of the cost began in Case 10-E-0362. Cost recovery of the gas portion of O&R's share of the cost has not yet begun but it will in the Rate Year.

Project One is a prime example of a project for which cost mitigation results may not be quantifiable or may not be subject to estimation with significant confidence and that results in avoided cost increases rather than savings from current levels. For example, enhanced information for management is intended to result in better management decisions but it is not possible to ascertain what decisions would have been made absent the enhanced information. In addition, the integration of the various systems under Project One reduces the risk of error but it is not possible to know what errors would have been made absent that integration. Moreover, Project One will reduce financial reporting risk. Con Edison could experience a loss of confidence from the financial community as a result of material error on its financial statements. Should that happen, the consequences to Orange and Rockland and its customers are uncertain but clearly they would not be beneficial. Project One reduces the risk of that happening.

IV. HISTORICAL FINANCIAL AND STATISTICAL INFORMATION

Q. Are you familiar with the Company's accounting books and records?

A. Yes.

Q. Are the accounts of the Company kept in accordance with the Uniform System of Accounts prescribed by the Commission?

A. Yes.

Q. Does this filing include the historic financial and statistical information required by the Commission?

A. Yes. The required information for electric is included in Exhibit AP-E1 entitled "Historical Financial Data - Electric" and the required information for gas is included in Exhibit AP-G1 entitled "Historical Financial Data – Gas." Each of those exhibits includes ten supporting schedules.

- Schedules 1 through 5 are balance sheets and supporting schedules as of December 31, 2010, 2011, 2012 and 2013 and June 30, 2014.
- Schedules 6 through 10 are income statements and supporting schedules for the twelve months ended December 31, 2011, 2012 and 2013 and June 30, 2014.

The data on these schedules have been taken directly from the books and records of the Company except for the average plant per customer amounts on Schedule 5 and the unit cost figures on Schedules 8 and 10, which have been computed for the purpose of the respective exhibits. It should be noted that Schedules 1, 2, and 6 reflect total Company operations for electric and gas but not the operations of its subsidiaries. More specifically, the schedules in Exhibit AP-E1 and Exhibit AP-G1 are as follows:

- Schedule 1 shows comparative balance sheets at December 31, 2010, 2011, 2012, and 2013 and June 30, 2014.
- Schedule 2 is a statement of retained earnings at December 31, 2010, 2011, 2012, and 2013 and June 30, 2014.
- Schedule 3 shows the net book value of electric or gas plant in service by primary account at December 31, 2010, 2011, 2012, and 2013 and June 30, 2014.
- Schedule 4 shows the net book value of common plant in service at December 31, 2010, 2011, 2012, and 2013 and June 30, 2014.
- Schedule 5 shows electric or gas plant in service and the average cost per customer at December 31, 2010, 2011, 2012, and 2013 and June 30, 2014.
- Schedule 6 shows income statements for the twelve months ended December 31, 2011, 2012, 2013 and June 30, 2014.
- Schedule 7 is a statement of electric or gas O&M expenses for the twelve months ended December 31, 2011, 2012, 2013 and June 30, 2014.
- Schedule 8 of Exhibit AP-E1 shows electric operating expenses per kWh sold for the twelve months ended December 31, 2011, 2012, 2013 and June 30, 2014. Schedule 8 of Exhibit AP-G1 shows gas operating expenses per Mcf sold for those same periods.
- Schedule 9 is a statement of electric or gas operating taxes, other than income taxes, for the twelve months ended December 31, 2011, 2012, 2013 and June 30, 2014.

- Schedule 10 of Exhibit AP-E1 is a statement of electric operating revenues per kWh of electricity sold for the twelve months ended December 31, 2011, 2012, 2013 and June 30, 2014. Schedule 10 of Exhibit AP-G1 is a statement of gas operating revenues per Mcf of gas sold for those same periods.

V. RATE BASE

Q. What exhibits support the Company's electric and gas rate base amounts in this filing?

A. Exhibit AP-E2 for electric and Exhibit AP-G2 for gas contain summaries and details of the Company's rate base for the Historic Year per books and also the forecasted rate base for the Rate Year.

Q. Are the components of the rate base amounts in Exhibit AP-E2 for electric and Exhibit AP-G2 for gas the same?

A. While there are some differences within some of the components of rate base, many of the components of rate base are the same for electric and gas. The rate base amounts in Exhibit AP-E2 for electric and Exhibit AP-G2 for gas include electric or gas utility plant in service, the allocated portion of common utility plant, electric or gas plant held for future use and that portion of construction work in progress not subject to the Allowance for Funds Used During Construction ("AFUDC"). There are also electric and gas rate base deductions for the accumulated provision for depreciation relating to plant in service including that for the allocated portion of common utility plant, plant held for future use as well as customer advances for construction. Net electric and gas accumulated deferred income taxes and accumulated deferred investment tax credits are also rate base deductions. The twelve-month average balance of regulatory assets is a rate base addition and for regulatory liabilities is a deduction. Electric and gas rate base also include an allowance for working capital requirements and each includes its allocated portion of the Earnings Base / Capitalization adjustment ("E/B Cap Adjustment").

Q. Please identify the derivation of the amounts for the rate base components shown on Exhibit AP-E2, Summary, and Exhibit AP-G2, Summary.

A. The rate base components shown on Exhibit AP-E2, Summary, and Exhibit AP-G2, Summary, are supported by Schedules 1 through 10 of those exhibits. The schedules are as follows:

Schedule 1 shows the monthly balances of utility plant and other balance sheet items used to compute electric rate base for the Historic Year.

Schedule 2 shows the projected monthly balances of utility plant for each month of the linking period (*i.e.*, July 1, 2014 through October 31, 2015).

Schedule 3 shows the projected monthly balances of utility plant for the Rate Year. The forecast of accumulated deferred income taxes has been derived from the forecast of plant-in-service using the appropriate book and tax depreciation factors.

Schedule 4 shows the projected monthly plant in service and plant held for future use amounts for the months from the end of the Historic Year (June 30, 2014) through the Rate Year. The projected amounts include the major plant additions shown on Schedules 2 and 4 of Exhibit AP-E5 and of Exhibit AP-G5 which we address more fully later in our testimony. The forecast for electric or gas plant held for future use assumes no change in that component of rate base beyond the end of the Historic Year.

Schedule 5 shows the forecast of the various components of the accumulated reserve for depreciation from the end of the Historic Year through the Rate Year. The depreciation rates utilized in calculating reserve for depreciation are those previously authorized by the Commission.

Schedule 6 of Exhibit AP-E2 and Exhibit AP-G2 is the first of four schedules showing the development of the working capital requirements element of rate base. The working capital requirements element of rate base has three components: cash working capital, materials and supplies and prepayments. Schedule 6 summarizes those components and the next three schedules in Exhibit AP-E2 and Exhibit AP-G2 each address one of the three components.

Schedule 7 shows the development of the cash working capital component of the working capital element of rate base. The approach is referred to as the FERC Working Capital Formula ("FERC Formula") that the Commission has employed for many years. The cash working capital requirement under the FERC Formula is primarily an amount equal to 1/8 of annual O&M expenses. As shown on Schedule 7, the starting point is the total annual O&M expense shown on Exhibit AP-E6, Summary, for electric and Exhibit AP-G6, Summary, for gas. As also shown on Schedule 7, we then deducted certain expenses from the total. The reasons for the deductions vary with the principal reason being that the expenses do not require funding by working capital because they are non-cash expenses (*e.g.*, uncollectible accounts expense and regulatory costs and certain amortization of regulatory assets and liabilities.

We also deducted the System Benefits Charge ("SBC") in the electric and gas calculations and Renewable Portfolio Standard ("RPS") expenses in the electric calculation to avoid any revenue requirement impact from these items. For electric, we deducted purchased power costs as well because under the FERC Formula, they are treated in a manner that differs from the treatment of other O&M expenses We then took 1/8 of the remaining O&M expenses in accordance with the FERC Formula as the cash working capital requirement to which, for electric, we added a percentage of purchased power expense as indicated on Schedule 7 also in accordance with the FERC Formula.

Schedule 8 of Exhibit AP-E2 and Exhibit AP-G2 relates to the materials and supplies component of working capital rate base. Schedule 8 shows the monthly and average balances of materials and stores general expense for the Historic Year along with projected Rate Year balance. We escalated the Historic Year average balance by the general inflation factor we discuss later in our testimony to arrive at the Rate Year allowance for that component of working capital.

Schedule 9 of Exhibit AP-E2 and Exhibit AP-G2 relates to the prepayments component of working capital rate base and lists the various prepayment items we have included. The average balance of each item for the Historic Year is shown along with the projected balance for the Rate Year. Prepaid property taxes, the predominant prepayment item, were forecasted to increase based on the projected level of property tax bills. The remaining items were projected at the Historic Year levels plus general inflation.

Schedule 10, the final schedule of Exhibit AP-E2 and Exhibit AP-G2, is the calculation of the E/B Cap Adjustment to rate base. This adjustment has been required by the Commission in numerous rate cases over many years. The purpose of the adjustment is to synchronize rate base plus interest bearing items (what is often referred to as the earnings base) with the total capitalization employed in providing utility service. The EB/Cap Adjustment originated, in part, because of concerns that the FERC Formula for the cash working capital allowance did not measure the working capital devoted to providing utility service to a sufficient degree of accuracy.

Schedule 10 shows the average earnings base and capitalization for the Historic Year for electric and gas operations. The Company's average capitalization balance was developed by first calculating O&R's average equity and long-term debt balances for the Historic Year. This figure was then increased for other funds that are available to support the earnings base and reduced by amounts of capitalization that are not devoted to the support of the earnings base. This method is the same as has consistently been used in previous rate cases.

As shown on Schedule 10, earnings base exceeds the capitalization and the amount of this excess that is attributable to electric operations is $27.86 million and the amount attributable to gas operations is $15.24 million. Given the nature and purpose of the EB/Cap Adjustment as we explained, rate base for electric and gas operations for the Rate Year must be reduced by those amounts. These adjustments have been reflected in rate base on Exhibit AP-E3 and Exhibit AP-G3 at Schedule 2, Page 1, and in the calculation of the Company's earned return on Page 2.

Q. Referring to the rate base items shown on Exhibit AP-E2, Summary, and Exhibit AP-G2, Summary, under the caption Regulatory Assets and Other Rate Base Additions, please briefly explain each item, how the Rate Year balance was developed and state any disposition of the balance the Company proposes in these proceedings.

A. There are considerably more items in the Regulatory Assets and Other Rate Base Additions category on Exhibit AP-E2, Summary, for electric than on Exhibit AP-G2, Summary, for gas. Consequently, we will first address the items on Exhibit AP-E2, Summary, and indicate which of the items pertain to gas as well. We will then address the remaining items for gas on Exhibit AP-G2, Summary. In addition, we note that the balances for these items shown on Exhibit AP-E2, Summary and Exhibit AP-G2, Summary, are net of any related deferred income taxes.

Line 13 in both electric and gas, Unbilled Revenues represents the accrual of unmetered revenues that have not been billed to customers but have historically been reflected in rates. The Historic Year levels of unbilled revenues were carried forward to the Rate Year. This item pertains to gas as well as electric.

Line 14 in electric, Deferred Purchased Power represents the average over- or under-collection of average balance related to such costs. For the Rate Year, we reflected the three-year average of the balance. This item pertains to electric only.

Line 15 in electric and line 14 in gas, Deferred MTA Surtax represents the average balance of the MTA surcharge paid but not yet collected from customers, net of income taxes. MTA taxes are collected from customers on a one year lag. We used the Historic Year level for the Rate Year rate base amount. This item pertains to gas as well as electric.

Line 16 in electric, Deferred MTA Mobility Tax represents the average unamortized balance of the payroll tax surcharge that was reflected in the 2012 Rate Order. We held the monthly balance constant through the end of the amortization period. This item pertains to electric only.

Line 17 in electric and line 16 in gas, Deferred MFC Credit and Collection represents the average deferred Merchant Function Charge balance for the Historic Year net of income taxes. Due to a lower level of actual sales than the level included in rates, we assumed the current balance would continue through the end of the linking period and the Company would recover the balance in the Rate Year. This item pertains to gas as well as electric.

Line 18 in electric, Deferred Storm Reserve Expenditures represents the under-recovery of major storm costs under the major storm reserve accounting authorized by the Commission. We updated the deferred balance as of the end of the Historic Year to the start of the Rate Year reflecting continued recovery pursuant to the 2012 Rate Order. As we discuss more fully later in our testimony, the Company proposes that the five-year amortization period be continued at a level based on the projected balance as of the start of the Rate Year. This item pertains to electric only.

Line 19 in electric, Interest on Provision for Storm Damages represents the average balance of interest on deferred storm expenses, net of income taxes. The Company proposes that a three-year amortization established by the 2012 Rate Order be continued at a level based on the projected balance as of the start of the Rate Year. This item pertains to electric only.

Line 20 in electric and line 17 in gas, Deferred Environmental Expenditures represent the average deferred balance for Site Investigation and Remediation ("SIR") costs net of accruals and insurance recoveries and income tax. The Rate Year balance was projected by starting with the balance as of the end of the Historic Year, adding projected expenditures and deducting amortization of the cost. This item pertains to gas as well as electric.

Line 21 in electric and line 18 in gas, represents the average deferred balance for interest variations on Pollution Control Debt, net of income taxes. The Company proposes that the current three-year amortization period be continued at a level based on the projected expenditures and deducting amortization of the costs. This item pertains to gas as well as electric.

Line 22 in electric and line 20 in gas, represents the average deferred balance for - Property Tax under recovery, net of income taxes. The projected balance along with the forecast spending for the Rate Year reflects a five-year amortization period. This item pertains to gas as well as electric.

Line 23 in electric, represents the average deferred balance for Smart Grid Project maintenance costs, net of taxes. The projected balance for the Rate Year reflects a three-year amortization period consistent with the 2012 Rate Order. This item pertains to electric only.

Line 24 in electric and line 21 in gas, represents the average deferred balance of Rate Case Costs. The costs allowed for recovery in the 2012 Rate Order are being amortized over three years in conformance with the 2012 Rate Order. Estimated costs for this filing are reflected as being amortized over three-years as well. This item pertains to gas as well as electric.

Q. Are there any items in the Regulatory Assets and Other Rate Base additions category on Exhibit AP-G2, Summary for gas that you have not yet addressed?

A. Yes, there is such item that pertains only to gas. That is as follows:
Line 15 in Gas, represents the average balance of deferred Economic Development Enhancement pilot program expenses, net of income taxes. The projected balance for the Rate Year reflects a three-year amortization period. This item pertains to gas only.

Q. Referring again to the rate base items shown on Exhibit AP-E2, Summary, and Exhibit AP-G2, Summary, but this time to those under the caption Regulatory Liabilities and Other Rate Base Deductions, please briefly explain each item, how the Rate Year balance was developed and state any disposition of the balance the Company proposes in these proceedings.

A. As with Regulatory Assets and Other Rate Base Additions, there are considerably more items in the category of Regulatory Liabilities and Other Rate Base Deductions on Exhibit AP-E2, Summary, for electric than on Exhibit AP-G2, Summary, for gas. Consequently, we will first address the items on Exhibit AP-E2, Summary, and indicate which of the items pertain to gas as well. We will then address the remaining items for gas on Exhibit AP-G2, Summary. In addition, we note that the balances for these items shown on

Exhibit AP-E2, Summary and Exhibit AP-G2, Summary are net of any related deferred income taxes.

Line 25 in electric, represents O&R's share of the average deferred oil supplier refunds, net of income taxes. The balance was projected to be zero at the beginning of the Rate Year. This item pertains to electric only.

Line 26 in electric, CATV billings represents the average deferred balance for the revenue increase related to rate change for the pole attachment rates applicable to the cable system operator and the telecommunication carriers, net of income taxes. We are projecting that the balance will be zero at the beginning of the Rate Year. This item pertains to electric only.

Line 27 in electric and line 23 in Gas, represents the average deferred balance for Performance Reliability Revenue Adjustments, net of income taxes. We are projecting that the balance will be zero at the beginning of the Rate Year. This item pertains to gas as well as electric.

Line 28 in electric and line 19 in Gas, represents the average deferred balance for the Company's Low-income Program costs, net of income taxes. The projected balance for the Rate Year reflects the three-year amortization schedule reflected in the 2012 Rate Order. This item pertains to gas as well as electric.

Line 29 in electric and line 22 & 27 in Gas, represents the average deferred balance for R&D Expenditures, net of income taxes. The projected balance for the Rate Year reflects the three-year amortization reflected in the 2012 Rate Order. This item pertains to gas as well as electric.

Line 30 in electric and line 25 in Gas, represents the average deferred balance for Conservation Costs, net of income taxes. This fund was originally established for energy efficiency programs. For purposes of this filing, we have reflected a three-year amortization of the remaining balance. This item pertains to gas as well as electric.

Line 31 in electric and line 30 in Gas, represents the average deferred balance for deferred Property Tax Refunds, net of income taxes. The projected balance for the Rate Year reflects a three-year amortization period for crediting the refunds to customers. This item pertains to gas as well as electric.

Lines 32 in both electric and gas, represents the average deferred balance for tax savings resulting from a decrease in the New York State corporate income tax rates. The projected balance for the Rate Year reflects the three-year amortization period. This item pertains to gas as well as electric.

Line 33 in electric, Net Plant Reconciliation represents the average deferred balance for carrying charges deferred on T&D plant additions that were lower than the level included in rates, net of income taxes. The projected balance for the Rate Year reflects the continuation of the three-year period for crediting the amount of those carrying charges to customers as reflected in the 2012 Rate Order. This item pertains to electric only.

Lines 34 in electric, represents the average deferred Reactive Power Balance net of income tax. The projected balance for the Rate Year reflects the three-year amortization period reflected in the 2012 Rate Order. This item pertains to electric only.

Line 35 in electric line 31 in Gas, represents the average balance of deferred Carrying Charge on Tax liabilities in rate base under the rate plan adopted by the Commission in the 2012 Rate Order, net of income taxes. The projected balance for the Rate Year reflects the continuation of the three-year period for crediting the amount of those carrying charges to customers as reflected in the 2012 Rate Order. This item pertains to gas as well as electric.

Line 36 in electric and line 28 in Gas, represents the average deferred balance for Interest Deferred on a change of accounting for Repair Allowance. The projected balance for the Rate Year reflects a three-year amortization period. This item pertains to gas as well as electric.

Line 37 in electric and line 29 in Gas, represents the average deferred balance for carrying charges on deferred Environmental Costs, net of income taxes. The projected balance for the Rate Year reflects a three-year amortization period. This item pertains to gas as well as electric.

Line 38 in electric, represents the average deferred balance for Stray Voltage expenses, net of income taxes. The projected balance for the Rate Year reflects a three-year amortization period. This item pertains to electric only.

Line 39 in electric, represents the average deferred balance of deferred Tree Trimming revenues, net of income taxes resulting from the currently effective reconciliation mechanism. The projected balance for the Rate Year reflects a three-year amortization of the deferred over-collection. This item pertains to electric only.

Line 40 in electric, represents the average deferred balance of the customers' share of the net proceeds from the Sale of Property in Warwick, net of income taxes. The projected balance for the Rate Year reflects a three-year amortization period. This item pertains to electric only.

Q. Are there any items in the Regulatory Liabilities and Other Rate Base Deductions category on Exhibit AP-G2, Summary, for gas that you have not yet addressed?

A. Yes, there are two such items that pertain only to gas. They are as follows:

Line 24 in gas, represents the average deferred balance for Accumulated Provision for Rate Refund on Prior SIT rate changes, net of income taxes. The balance is projected to be zero at the beginning of the first Rate Year. This item pertains to gas only.

Line 26 in gas, represents the average deferred balance for Customer Outreach expenses, net of income taxes. The projected balance for the Rate Year reflects a three-year amortization of the deferred balance. This item pertains to gas only.

Q. Turning now to the category of Accumulated Deferred Income Taxes on Exhibit AP-E2, Summary for electric and Exhibit AP-G2, Summary for gas, please explain what these items are and how the deferred tax balances were calculated.

A. All of the items result from the normalization of tax benefits as required by the Commission. Each deferred tax balance was calculated in a manner that tracks the projection of related revenues and costs. They relate to items such as (1) federal income tax and the normalization of tax benefits of tax deprecation under various accelerated depreciation methods including ACRS, ADR and MACRS; (2) federal income tax benefits related to mixed services cost and capitalized overheads under Section 263A of the IRS Code; (3) repair allowance; (4) New York State income taxes related to a variety of tax benefits subject to normalization;- (5) New York City (MTA) taxes; and (6) deferred Investment Tax Credits being amortized over the average service lives of the property that generated the tax credits. In addition removal cost, accelerated depreciation and lien date property tax deduction are items that result from the normalization of the tax benefit proposed by the company.

We note that all of the deferred income tax items on Exhibit AP-E2, Summary for electric also pertain to gas and appear on Exhibit AP-G2, Summary as well. There are no gas-only items of this nature.

VI. <u>CAPITAL EXPENDITURES AND PLANT ADDITIONS</u>

Q. Please describe the Company's presentation of its capital expenditure projections and related plant additions.

A. Schedule 1 of Exhibit AP-E5 presents the Company's forecasted electric transmission and distribution capital expenditures from the end of the Historic Year through the Rate Year and for later periods and Schedule 2 presents the forecasted electric transmission and distribution plant additions for those same periods. Supporting testimony is provided by the Company's Electric Infrastructure and Operations Panel. Corresponding information for gas is presented on Schedules 1 and 2 of Exhibit AP-G5 with supporting testimony by Company witness Hehir and the Advanced Metering Infrastructure Panel. Common plant capital expenditures and plant additions are presented on Schedules 3 and 4, respectively, of Exhibit AP-E5 and of Exhibit AP-G5. The capital expenditures and plant additions are at 100%, meaning they are shown before their allocation to electric and gas operations. We will describe the allocation procedure later in our testimony. We will provide the supporting testimony for the common expenditures and additions. We will do so by the two major categories of common plant: common general plant and other common plant.

Q. What is the forecasted amount of plant additions during the Rate Year for common general plant and for other common plant?

A. The common plant expenditures for the Rate Year include general common plant, or "blanket," expenditures of $7.7 million and other common plant project additions of $7.3 million, for a total of $15 million.

Q. Please provide a description of the blanket expenditures.

A. Blanket expenditures consist of equipment purchases, replacements and minor construction necessary to provide ongoing service to customers, provide for the safety of employees and support the day-to-day functioning of the Company and its employees. Blankets are an accounting convention, long accepted by the Commission and its Staff, whereby for the sake of convenience, the costs of certain recurring labor and equipment are grouped together. Purchases and replacements are primarily required due to aging, obsolescence or as technology changes. The projected spending levels are relatively consistent with historical levels. The following is a description of each major blanket category:

(1) **Transportation Equipment:** This blanket category, which amounts to $4.7 million for the Rate Year, includes the replacement of vehicles and equipment to support operations. The Company has a methodology for

selecting equipment to be replaced based on age, maintenance, and reliability. The Company performs an analysis each year to determine which assets to replace. Using a method referred to as the 'life cycle' method, the Company uses historical actual maintenance data and expected maintenance data as well as cost-of-money considerations to determine a point at which it is most economical to replace an asset rather than face increasing maintenance costs and reduced reliability. This optimizes the Company's overall cost to own and maintain these assets.

(2) **Communications Equipment**: This category includes the funds for equipment purchases and replacements that support the Company-owned and operated private communications infrastructure which includes the fiber optic and microwave communications backbone, two-way radio communications and tower sites, local area and wide area networks, telephone system infrastructure, telephone, data and conferencing equipment, cable support systems as well as network alarm monitoring and testing equipment. The Rate Year funding for this category is $0.7 million.

(3) **Computer Equipment**: This category includes the purchase and replacement of computing equipment and servers amounting to expenditures of $0.6 million in the Rate Year. In order to maintain the most efficient and dependable computing and processing power to support the Company's day-to-day functions and work force operations, personal computers, laptops and ruggedized field laptops, replacement standards require a five year turnaround. In addition, computer server purchases and replacements support the growing

demand for storage capacity and centralized backup capabilities in order to minimize downtime and facilitate quick recovery in the event of a disaster.

(4) **Furniture Replacements and Building Improvements**: This category includes the purchase and replacement of the Company's office furniture and work equipment that support the work force and maintain the buildings and grounds, as well as minor building and grounds construction and replacement capital improvements, such as for lighting systems, plumbing systems, flooring, and fencing, The expenditure included in the Rate Year is $1.0 million.

(5) **Security Equipment**: This category includes the purchase and replacement of electronic equipment and systems to support and protect Company property and assets and to provide a safe and secure environment for employees, amounting to expenditures of $0.2 million in the Rate Year. Equipment primarily includes closed circuit televisions, intrusion detection systems, and facility card access systems.

(6) **All Other**: This category encompasses all remaining general plant equipment blanket purchases and replacements for storerooms, protective equipment, safety equipment and audiovisual/graphics equipment amounting to expenditures of $0.5 million in the Rate Year.

Q. Please provide a description of other common general plant addition projects.

A. Other general plant addition projects primarily include the cost of the following six projects: New Business system enhancement, Blooming Grove Fuel Station Upgrade, Storm Communication Software Upgrade, Upgrade

Middletown workout location and Upgrade Spring Valley Distribution Center, and Radio System Upgrade.

1) **New Business System Enhancement:** The Company's New Business organization seeks to upgrade the in-house project management software to enhance the management of new residential subdivisions. The new process will fully automate the handoff of work from the project management system (NUCON) to the Company's work management system. This automation will eliminate some time consuming manual efforts the customer currently experiences and is expected to increase the overall customer experience. From the Company's perspective, there will be an enhancement to the "checklist" process in NUCON that will allow New Business project managers to identify the next steps in projects in a clearer more efficient manner. In addition, the system will provide the Joint Use department access to NUCON to process their own power supply projects for cable television orders. This will eliminate duplicate Company processes and allow the Joint Use department to process their own service orders. Rate Year 1 funding includes $0.7 million.

2) **Blooming Grove Fuel Station Upgrade**: This project replaces aging and obsolete equipment at the Company's Blooming Grove Operating Center. The Company conducted an engineering study to evaluate the Company's fueling stations and to determine what upgrades and/or replacements would be required to improve reliability and reduce environmental risk. Recommendations were based on existing conditions of the tanks and equipment, as well as historical maintenance costs. The Blooming Grove

fuel station has a single wall fiberglass tank that was installed in 1983. The engineering study recommended that single wall tanks be replaced with new double-wall fiberglass underground storage tanks that meet current fuel station regulations. The scope of the project includes the replacement of a fueling island, gas and diesel dispensing equipment, the single wall tank and associated hardware. In addition, the Company's gas dispensing card reader system (GasBoy) will be replaced with state-of-the-art technology. Rate Year funding includes $1.7 million.

3) **Storm Communication Software Upgrade:** Over the years, the Company has developed and deployed numerous tools that aid in communicating customer outage information during storms. Some of these tools have supported only internal users while some have supported both internal users and customers. After Superstorm Sandy, O&R undertook a project to develop proactive notifications to customers regarding outage information via text, email and phone calls. In addition the Company also implemented functionality that allows for two way texting between customers and the Company. During the development of these projects, a new architecture strategy was developed that centralizes outage data from the Company's Outage Management System ("OMS") into a centralized data repository that is linked to the Company's Customer Information Management System ("CIMS"). The Company proposes to take the centralized data repository and expand it to be utilized by the customer communication channels that currently interact directly with OMS. By utilizing the new data repository OMS core function, providing service outage and estimated time to repair information,

will be increased during large storm events and the secondary functionality will be performed by the data repository in CIMS. This will provide a single reference point for all customer storm communications via the Customer Service Representative's terminal, on the ORU.com web page, the ORU Mobile Web, the ORU Mobile APP and through SMS (short message service) texting. Rate Year funding includes $0.8 million.

4) **Upgrade Middletown workout location and 5) Upgrade Spring Valley Distribution Center:** Both of these sites are integral locations for the Operations and Customer Service needs for the Company's gas and electric services. The initiatives associated with these capital projects are programs that will ensure these two facilities continue to be maintained in a safe, secure and efficient manner. Examples of the programs identified in these capital additions include upgrading a building's heating, ventilation and air conditioning (HVAC) systems, replacing old windows and lights with new energy efficient ones, restacking buildings to maximize office space, enhancing fencing, lighting, cameras and card swipe systems for increased protection of Company assets and employees, rebuilding loading docks that are deteriorated and improving yard efficiency. Rate Year funding for the Middletown workout locations includes $0.6 million. The Rate Year funding level for the Spring Valley Distribution Center is $0.8 million.

6) **Radio System Upgrade:** Due to technology restrictions of the Company's existing and aging private radio system, the Company has a program in place to purchase new Storm Emergency Radios for use during Storm Restoration and Emergency conditions. These radios are being purchased using capital

funding and will be used only during emergency conditions. O&R does not own the frequencies in which these new radios operate on and since O&M usage charges would apply; use will be limited to emergency situations only. Purchases of the new storm emergency radios are critical for electric restoration efforts, as the existing low-band radio system were not able to support the heavy demand of past storms. Additionally, these radios are compatible with the Company's future plans for replacing its low-band radio system, with a new leased radio solution. The Rate Year funding includes $0.8 million.

VII. INCOME STATEMENTS AND RATES OF RETURN

Q. Please describe how the Company's forecasted cost of service was developed.

A. Exhibit AP-E3, Schedule 2, Page 1, is a summary of the electric cost of service for the Historic Year and the Rate Year. Exhibit AP-G3, Schedule 2, Page 1, is a summary of the gas cost of service for the Historic Year and the Rate Year. Column 1 of these schedules contains the actual per books amounts for the Historic Year. Operating revenues have been detailed by sales to the public, sales for resale, and other operating revenues. The operating expenses have been broken down into elements of cost, some of which are forecasted individually and others of which are included in a grouping that was escalated by the general inflation rates developed for this proceeding. Various components of income taxes are also shown. The Historic Year contains items not specifically related to actual Historic Year operations or which may be considered non-recurring. These items are adjusted through various normalizing adjustments, as set forth in column 3 of the exhibits. The adjusted results for the Historic Year are summarized in column 4. Column 6 reflects conditions in the Rate Year and various rate case adjustments. Column 7 reflects the Rate Year absent a rate change and the rate change is reflected in column 8. Column 9, which is a summation of columns 7 and 8, shows operating income, average rate base and rate of return for the Rate Year.

Q. Were the data for the Rate Year derived from the historical per books data shown in the first column?

A. Yes. Each element of cost has been analyzed to further subdivide the basic elements into necessary components for purposes of forecasting the various changes in that cost element for the forecast period. Schedules 3 through 10 of Exhibit AP-E3 and Exhibit AP-G4, support the cost of service components related to sales and revenues, amortization of regulatory deferrals, other operating revenues, depreciation, taxes other than income taxes, state and federal income taxes and interest synchronization. O&M expenses reflected in the cost of service are presented in Exhibit AP-E4 for electric and Exhibit AP-G4 for gas.

A. Sales and Revenues

Q. What was your source for the Rate Year projection of sales and delivery revenues?

A. The Company's Electric Forecasting Panel and Gas Forecasting Panel provided us with the projections of sales and delivery revenues. The amounts are shown on Exhibit EFP-E1 and Exhibit GFP-G1, as well as Schedule 3 of Exhibit AP-E3 and Exhibit AP-G3.

B. Amortization of Deferred Charges and Credits

Q. Please summarize the Company's proposals with respect to the disposition of deferred charges and deferred credits.

A. With limited exceptions, the Company proposes that all projected deferred charge and deferred credit balances as of the start of the Rate Year be amortized over three years. The exceptions are the deferred balances related to property taxes, major storms, SIR costs, and the lien date property tax deduction. For those items, with the exception of Lien date property tax deduction the Company proposes an amortization period of five years in order to mitigate the proposed rate increases. As for the lien date property tax deduction the Company proposes using the remaining life of the related plant assets as the amortization period which is 34 years for electric and 46 years for gas. This proposal is supported by the direct testimony of the Income Tax Panel and Exhibit ITP-2, Schedule 1.

The individual deferred charges and credits are listed on Schedule 4 of Exhibit AP-E3 for electric and Exhibit AP-G3 for gas. Also shown are the actual deferred balances as of the end of the Historic Year and the projected deferred balances as of the start of the Rate Year. Some of the amortizations are charged or credited to the appropriate expense item. Other miscellaneous amortizations are charged or credited to Other Operating Revenues. The amortization amounts for the Rate Year relating to Other Operating Revenues are shown on Schedule 5 of Exhibit AP-E3 and Exhibit AP-G3 and the amortization amounts for the Rate Year relating to O&M expenses, with the exception of property taxes and the sale of Warwick property, are shown on the various Schedules of Exhibit AP-E4 and Exhibit AP-G4. The amortization amounts for the Rate Year relating to property taxes are shown on the Schedule 7 of Exhibit AP-E3 and Exhibit AP-G3. The amortization amounts for the Rate Year relating to the sale of Warwick property is shown on Schedule 2 of Exhibit AP-E3. The amortization amounts for the Rate Year relating to the lien date property tax deduction are shown on the Schedule 9 of Exhibit AP-E3 and Exhibit AP-G3.

For electric, the net deferred balance is a charge of $70.096 million and the net amortization for the Rate Year is a charge of $10.446 million. For gas, the net deferred balance is a charge of $39.483 million and the net amortization for the Rate Year is a charge of $6.702 million.

1. Applicable to Electric and Gas

Q. Do all of the deferred charges and deferred credits pertain to both electric and gas?

A. No. Although many of the deferred charges and deferred credits pertain to both electric and gas and appear on Schedules 4 and 5 of Exhibit AP-E3 and of Exhibit AP-G3 and on various Schedules of Exhibit AP-E4 and of Exhibit AP-G4, some pertain only to electric and some only to gas.

Q. Please identify and explain the deferred charges and deferred credits that pertain to both electric and gas.

A. The deferred items that pertain to both electric and gas and therefore appear on Schedules 4 and 5 of Exhibit AP-E3 and of Exhibit AP-G3 and on various Schedules of Exhibit AP-E4 and of Exhibit AP-G4 are as follows:

Interest on Pollution Control Debt represents the deferral of interest amounts to be recovered related to the Company's pollution control facility financings that were subject to reconciliation pursuant to the 2011 Rate Order.

Interest Repair Allowance/Bonus Depreciation represents the amounts to pass-back to customers relating to the rate base carrying charges avoided as a result of additional income tax deductions the Company was able to secure for (bonus) depreciation and the repair allowance deduction.

NYSIT Rate Change represents the amounts to refund to customers relating the change in New York State Income Tax rate from 7.1% to 6.5%.

Deferred Tax Liabilities Carrying Charge represents the amounts to pass-back to customers relating to interest deferred on the difference between the actual deferred Section 263A and tax depreciation reflected in rate base and the actual tax deduction allowed by the IRS.

Property Tax Refunds reflects the amount to refund to customers related to various property tax refunds secured by the Company.

Environmental Carrying Charge represents interest to refund to customers on environmental spending under-runs in accordance with the environmental expense reconciliation mechanism.

Lien Date Property Tax Deduction is reflected in Exhibit AP-E3 and Exhibit AP-G3, Schedule 9N, and will be discussed by the Income Tax Panel.

Property Taxes are reflected in Exhibit AP-E3 and Exhibit AP-G3, Schedule 7, will be discussed in the Taxes Other Than Income Taxes section of our direct testimony.

R&D, MGP Sites & Environmental Programs, Rate Case Costs, Low Income, and Pensions / OPEBs and Medicare are reflected in Exhibit AP-E4 and Exhibit AP-G4, in various schedules and will be discussed in the O&M expense section of our direct testimony.

2. Applicable to Electric Only

Q. Please identify and explain the deferred assets and liabilities that pertain only to electric.

A. The deferred charge items that pertain only to electric and appear on Schedules 4 and 5 of Exhibit AP-E3 and various Schedules of Exhibit AP-E4 and of Exhibit AP-G4 are as follows:

Interest on Storm Reserve represents the deferral of interest amounts to be recovered from customers in accordance with the Company’s major storm cost recovery mechanism.

Smart Grid represents the deferred carrying cost to be recovered relating to two Smart Grid projects, the distribution capacitor bank project and the Company’s share of the NYISO capacitor bank installation project. Deferral of such carrying costs was authorized by the Commission in Case 09-E-0310.

Conservation Cost / MHP represents the deferral of $53,000 to be recovered from customers because in the last Company electric rate proceeding such amount was inadvertently credited to customers twice. Appendix I to the Joint Proposal adopted by the Commission in Case 11-E-0048 shows the refund of $53,000 for a regulatory liability referred to as Conservation Cost. However, this amount was actually part of the Mandatory Hourly Pricing Program and was therefore also refunded to customers through the ECA.

Reactive Power represents the amounts to pass-back to customers relating to the reactive power demand charge.

Plant Reconciliation reflects the amount of estimated carrying charges to be recovered from customers in accordance with the net plant reconciliation mechanism under the current electric rate plan.

Stray Voltage Savings represents the amount to refund to customers resulting from stray voltage inspection cost savings as required by the Commission Order dated March 22, 2013 in Case 04-M-0159.

Tree Trimming represents the amounts to pass-back to customers for differences between tree trimming costs provided for in rates and the actual expense under the tree trimming reconciliation mechanism under the current electric rate plan.

Sale of Warwick represents the customer's share of the gain from the sale of property in accordance with the Commission's Order dated July 28, 2014 in Case 14-E-0099.

Storm Reserve represents amounts to be recovered from customers under the major storm costs reconciliation mechanism which will be discussed further in the O&M expense section of our direct testimony.

3. Applicable to Gas Only

Q. Please identify and explain the deferred charges that pertain only to gas.

A. The deferred asset and liabilities that pertain only to gas and appear on Schedules 4 and 5 of Exhibit G-4 are as follows:

Gas Economic Development Enhancement Pilot Program represents the deferred amount to be recovered from customers under a reconciliation mechanism related to spending on programs to encourage economic development in the Company's service territory.

Customer Outreach represents the amount to refund to customers for customer outreach and education program materials underspending under a related reconciliation mechanism.

Damage Prevention Penalty represents the refund to customers associated with a penalty incurred by the Company in 2007.

C. Other Operating Revenues

Q. Please identify and explain how you projected the elements of Other Operating Revenues shown on Schedule 5 of Exhibit AP-E3 and Exhibit AP-G3 in addition to the deferred charge and deferred credit items you have already addressed.

A. Following the same approach we used for the deferred charges and credits, we will first address the remaining elements of Other Operating Revenues that pertain to both electric and gas followed by those that pertain to electric only and then those related to gas only.

1. Applicable to Electric and Gas

The remaining elements of Other Operating Revenues that pertain to both electric and gas and appear on Schedule 5 of Exhibit AP-E3 and Exhibit AP-G3 are as follows:

Late Payment Charge ("LPC") Revenues were forecasted by multiplying an LPC factor of 0.65% for electric and an LPC factor of 0.45% for gas to the Rate Year sales revenues. The LPC factor represents the ratio of actual LPCs to actual total sales revenues in the Historic Year.

Customer Reconnect Fees, Shared Meter Assessment, and POR Discount were forecasted by carrying forward the Historic Year level.

Joint Use Rents relates to carrying charges billed for facilities such as the Spring Valley Operating and Distribution Centers, Blooming Grove and Middletown that provide benefits to the Company's subsidiaries Rockland Electric Company ("Rockland Electric") and Pike County Light & Power Company ("Pike"). This item was forecasted by annualizing the current monthly carrying charge level. The electric rents were then adjusted to reflect the 9.75% return on equity that the Company used in setting the revenue requirement.

All items listed in the section titled **Revenues Offset in Sales, Energy Clauses or O&M** were normalized to zero for the Rate Year because the Forecasting Panel included them in their sales revenues forecast or because they are collected from or credited to customers through a separate surcharge.

All items in the **Regulatory Accounting (Reconciliations / Amortizations)** sections were normalized to zero for the Rate Year. These amounts reflect the amounts deferred netted by amortizations for reconcilable items in the Historic Year. These amounts were normalized because they are not applicable to the Rate Year. The Rate Year estimates for reconcilable items were discussed earlier in our direct testimony.

Regulatory Accounting - Recoveries / Refunds are the new deferrals for items we discussed in the above section labeled "Amortization of Deferred Charges and Credits".

2. Applicable to Electric Only

The remaining elements of Other Operating Revenues that pertain only to electric and shown on Schedule 5 of Exhibit E-4 are as follows:

Collection Charges, Bad Check Charge, Agency Checks Dishonored, and Other were forecasted by carrying forward the Historic Year level for those items.

Acceller Inc. – When a new customer or existing customer who is moving calls the Company to start service, the Company asks them if they wish to be transferred to Acceller to have their cable and telephone connected also. This provides the customer with one stop shopping when they move or enter the service territory. The Company is paid $10 for every customer it transfers to Acceller whether the customer connects cable or phone service or not. These revenues were projected based on escalating the Historic Year level by the general escalation factor.

NYSERDA - When homeowners obtain a loan from NYSERDA, they can repay the loan through their utility bill by using the on-bill recovery financing program. The Company then remits the money to NYSERDA. NYSERDA pays the Company a one-time fee of $100 for each loan and a fee of 1% of the amount of each loan to defray costs directly associated with implementing the program. These revenues were projected based on escalating the Historic Year level by the general escalation factor.

Other Rents relates to rent received from parties due to their use of electric property owned by the Company such as poles and transformers. We projected the amount for the Rate Year by escalating the Historic Year level by the general escalation factor.

3. Applicable to Gas Only

The remaining elements of Other Operating Revenues that pertain only to gas and shown on Schedule 5 of Exhibit G-4 are as follows:

Access Fines refer to monies collected from customers because the Company was unable to access meters**.** We forecasted the Rate Year level to be the same as the Historic Year level.

R&D Ventures refer to royalties received from a joint R&D venture with other gas utilities**.** We forecasted the Rate Year level to be the same as the Historic Year level.

D. Depreciation

Q. Please describe Schedule 6 of Exhibit AP-E3 and Exhibit AP-G3 regarding depreciation.

A. Schedule 6 of Exhibit AP-E3 for electric and of Exhibit AP-G3 for gas contains two pages. The first page shows the monthly calculation of depreciation expense for electric and common plant or for gas and common plant for the period from July 1, 2014 (the beginning of the linking period) through October 31, 2015 (the end of the linking period). The second page shows the monthly calculation of depreciation expense for electric and common plant or for gas and common plant for the Rate Year at depreciation rates established by the 2012 Rate Order and 2009 Rate Order.

E. Taxes Other Than Income Taxes

Q. Please describe the development of Taxes Other than Income Taxes.

A. Schedule 7 of Exhibit AP-E3 for electric and Schedule 7 of Exhibit AP-G3 for gas present taxes other than income taxes for the Historic Year and for the Rate Year. Taxes other than income taxes include property taxes, payroll taxes, revenue taxes, and other taxes.

Payroll taxes were determined by applying effective payroll tax rates to the forecasted direct labor expense. Revenue taxes were determined based on the estimated revenue multiplied by the effective tax rates. We have assumed that the Historic Year level of other miscellaneous taxes will be representative of the Rate Year level. Finally, we normalized the sales and use tax refunds because the balance in the historical period was not consistent with prior periods.

Q. Please continue with the development of property taxes as identified on Exhibit AP-E3, Schedule 7 and Exhibit AP-G3, Schedule 7.

A. The property tax forecast is addressed by the Company's Property Tax Panel. The amortization of property tax deferral amounts identified on Schedule 7 of Exhibit AP-E3 and Exhibit AP-G3, represent a five year recovery of the under-collection of property taxes under the reconciliation mechanisms included in the Company's current electric and gas rate plans.

F. Income Taxes

Q. Please describe how the calculations of State and federal income tax expenses were performed.

A. We will begin with the computation of State income tax, which is shown on Schedule 8 of Exhibit AP-E3 and Exhibit AP-G3. Starting with operating income before State income taxes for the Historic Year and the various columns for normalizing adjustments and rate case adjustments, we then show the various required tax adjustments to operating income per books to determine taxable income. We then compute the amount of tax payable using a blended rate of 6.60%. We developed the blended rate by using the current applicable statutory rate of 6.5% for the ten months of January 1 through October 31, 2016 and the previously applicable statutory rate of 7.1% for the two months of November and December of 2015 to track the related change in State tax law. We note the calculations exclude the MTA surcharge rate of 1.53% which is recovered as part of the current MTA surcharge mechanism. The last column represents the State income tax for the Rate Year.

Schedule 9 of Exhibit AP-E3 and Exhibit AP-G3 detail the federal income tax computation for electric and gas, respectively. Starting with operating income before federal income tax for the Historic Year and the columns for normalizing adjustments and rate case adjustments, we then show the various required tax adjustments to book operating income to determine taxable income and compute the amount of tax payable using the applicable statutory rate of 35%. We then reflect certain items as adjustments to taxable income as well as amortizations for items to be normalized in the Rate Year or that have been normalized in prior periods to arrive at the final federal income tax expense.

Q. Are the federal income tax normalization proposals for plant-related items and property taxes presented by the Income Tax Panel reflected in your exhibits?

A. Yes, they are reflected on Schedule 9N of Exhibit AP-E3 and of Exhibit AP-G3. For comparison purposes, we also included the calculation using the flow through accounting method as reflected on Schedule 9 of Exhibit AP-E3 and Exhibit AP-G3.

G. Interest Synchronization

Q. Please explain Schedule 10 of Exhibit AP-E3 and of Exhibit AP-G3.

A. Schedule 10 shows the calculation of the interest deduction included in Schedules 8 and 9 of those exhibits. The majority of long-term debt has been issued by Orange and Rockland for itself and its subsidiary utility affiliates RECO and Pike. This "synchronization" adjustment is necessary in order to allocate the proper level of interest expense to each company. The adjustment we have made has been calculated in the same manner as has been employed in previous O&R rate cases.

VIII. OPERATION AND MAINTENANCE EXPENSES

Q. O&M expenses reflected in the cost of service shown in Exhibit AP-E3 for electric are addressed in Exhibit AP-E4 and those reflected in the cost of service shown in Exhibit AP-G3 for gas are addressed in Exhibit AP-G4. Is that correct?

A. Yes.

A. Purchased Power and Purchased Gas

Q. Please explain the cost elements of purchased power shown on Exhibit AP-E4, Schedule 1 and purchased gas shown on Exhibit AP-G4, Schedule 1.

A. The purchased power cost element reflects the actual and forecast purchased power costs for O&R for the Historic Year and the Rate Year. This cost is matched with the Market Supply Charge ("MSC") and Sales for Resale (Power Supply Agreement ("PSA") Energy Charges) recoveries shown on Exhibit AP-

E3, Schedule 3. Company witness Briscese discusses the Company's historical and projected wholesale electricity supply purchases for the Company's full service customers in its testimony.

The purchased gas cost element reflects the actual and forecast purchased gas costs for O&R for the Historic Year and the Rate Year. This cost is matched with the Gas Supply Charge ("GSC") and Monthly Gas Adjustment ("MGA") recoveries shown on Exhibit AP-G3, Schedule 3. Company witness Carnavos discusses the Company's historical and projected wholesale gas supply purchases for the Company's full service customers in his testimony.

B. Labor Expense

Q. Please describe Schedule 2 of Exhibit AP-E4 and Exhibit AP-G4 related to the Company's labor expense.

A. Schedule 2 of Exhibit AP-E4 for electric and Schedule 2 of ExhibitAP-G4 for gas, each contain two pages. Both schedules represent O&R's actual labor expense for the Historic Year, projected labor costs for the linking period (July 1, 2014 through October 31, 2015) and the Rate Year. Page 1 of the exhibits represents the amount of total labor charged to electric (Exhibit AP-E4) or gas expense (Exhibit AP-G4) (as derived on page 2) for each service, based on account guideline classifications such as production and purchase power, transmission, distribution, customer accounts and service and administrative and general expenses. Schedule 2, Page 2 of each exhibit represents total labor costs according to the employee classifications of those paid weekly and those paid monthly and the total labor cost by functional cost categories such as electric expense, gas expense and construction.

Q. Please describe how you projected direct labor expense for the Rate Year as shown on Exhibit AP-E4, Schedule 2, Page 1 of 2 for electric and as shown on Exhibit AP-G4, Schedule 2, Page 1 of 2 for gas.

A. We began by detailing the labor costs for the Historic Year according to the classifications we mentioned and others as shown in the exhibits. We then calculated any necessary normalizing adjustments applicable to the Historic Year in order to derive total normalized labor costs for that period. We then escalated the normalized Historic Year costs through the linking period and through the Rate Year. This calculation included the labor costs associated with any normalizing adjustments and program changes anticipated between the end of the Historic Year and the end of the Rate Year. The result is the expected labor expense by the various categories shown on page 1 of Schedule 2 for the Rate Year.

Q. Please describe the normalizing adjustments to the Historic Year labor expense in your labor cost calculations?

A. The normalizing adjustments are of two types. The first is the exclusion of certain labor costs from the calculation of the revenue requirements as has been the practice in past Company rate cases despite the costs being part of an overall reasonable compensation package. The second relates to the labor cost for employees who were hired during the Historic Test Year or will be hired during the linking period. This calculation included the labor cost associated with any normalizing adjustments between the end of the Test Year and the end of the Rate Year.

Q. Please describe the first exclusion to the labor expense cost calculation.

A. We excluded from the Test Year, the Company's compensation expenses associated with its Annual Team Incentive Plan ("ATIP") for its officers, which amounted to a reduction of $ $398,351 in electric labor expense and a reduction of $164,965 in gas labor expense. We note, however, that the exclusion of these items in these proceedings is not intended to be, and should not be construed to be, precedential regarding the inclusion of these costs in rates in the future.

Q. Please describe the second normalization adjustment to the labor expense cost calculation.

A. As noted above, the second normalization represents labor costs for weekly and monthly employees who were hired during the Historic Test Year or will be hired during the linking period. Listings of all normalizing adjustments are shown in Attachment A to our testimony.

Q. Please describe the normalizing adjustments more fully.

A. Attachment A, page 1 under the heading "Electric Normalizing Adjustments" and page 2 under the heading "Gas Normalizing Adjustments" lists the 14 electric and 12 gas positions that we have normalized in calculating the Company's labor costs. The 14 electrical positions listed on page 1 include:

- Operations administrative coordinator that was hired in September 2014; and
- Underground engineer for Distribution Engineering department that was hired in September 2014;

The duties and responsibilities associated with these two positions are discussed in more detail in the direct testimony of Company witness Banker.

- Two Smart Grid engineers that were hired in October 2014;
- Smart Grid senior system analyst that was hired in January 2015;
- Two analysts for the Central Information Group in the Company's Electrical Control Center that were hired in June and September 2014 respectively; and
- Distribution Control Center trainer to be added in January 2015;

The duties and responsibilities associated with these six positions are discussed in more detail in the direct testimony of the Company's Smart Grid Panel.

- Operations System Support manager that was hired in December 2013; and
- Five Operations System Support business analysts – two hired in February 2014, one hired in March 2014 and two hired in August 2014.

The costs associated with these six positions are charged on a basis of 57.05% and 23.59% between the Company's electric and gas services respectively. The duties and responsibilities associated with these positions are discussed in more detail below.

Q. Please continue with the 12 normalizing adjustments for gas.

A. The 12 gas positions listed on page 2 of Attachment A that we have normalized in calculating the Company's labor costs include:

- Three union gas locators hired in October 2013;

- A locating operating supervisor hired in March 2014; and
- Two senior planning analysts for the Gas Mobile Dispatch system who will transition from charging capital expenditures to O&M in January 2015.

The duties and responsibilities associated with these six positions are discussed in more detail in the direct testimony of Company witness Hehir.

As discussed above, 23.59% of costs attributed to the following five positions are charged to the Company's gas service and these positions are discussed in more detail below.

- Operations System Support manager that was hired in December 2013; and
- Five Operations System Support business analysts – two hired in February 2014, one hired in March 2014 and two hired in August 2014.

Q. Please discuss the Operations System Support manager and the five Operations System Support business analysts and the duties and responsibilities they will have to support both the electric and gas services.

A. As a result of Hurricane Irene, the October 2011 snow storm and Superstorm Sandy (collectively, the "Major Storms"), the Company undertook various improvements in the accuracy of outage response planning and also enabling efficient and effective outage response performance tracking. Improved outage response planning will enable O&R to better meet customers' needs by providing them with more accurate estimates of when their service will be restored during storms. Effective tracking of outage response performance will enable O&R to adjust outage response plans more efficiently so as to improve communication and information with our operators, field crews, and customers as it relates to ETRs. Performance tracking will also enable O&R to more effectively identify and rectify inefficiencies in its work plan development and restoration processes. By reviewing and tracking this data, the Company can review its ETR accuracy and make necessary changes in its processes to meet the ETRs provided. This will enable more granular correlation between outage response plans and specific outage incidents tracked by OMS.

Currently, O&R is analyzing historical outage event data in order to establish metrics and information to support and improve outage restoration planning activities. The Company will use such metrics and information to design and implement an internal outage restoration planning and performance tracking tool, including the software associated with such tool. This internal performance tracking tool will enable O&R to efficiently and effectively monitor restoration progress against the inputted plan and modify the plan according to the availability of updated information. It will allow proper tracking and monitoring of ETRs to verify that the Company is meeting the expected restoration times it is providing to its customers.

Q. Please discuss the staffing requirements associated with the Company's system enhancement efforts.

A. Timely, efficient and effective storm preparation, restoration and response are a top priority of the Company. In reviewing the Company's preparation for and response to the Major Storms, the Company implemented various system enhancement efforts. To support these efforts and to support the needs of our key stakeholders, the Company added a team comprised of the following six positions: four Operations System Support Specialist Business Analysts, one Operations System Support Senior Specialist Regulatory Support and an Operations Support System manager for the organization.

The team is assigned to address and support the implementation of the Company's system enhancements, as well as regulatory requirements and process initiatives. The team will be critical to the Company's efforts to interact with key internal and external stakeholders in a consistent and timely manner. These positions necessary to staff this effort are more fully described below.

<u>Operations System Support Specialist Business Analysts:</u>

To support the Company's various systems and storm process related initiatives, the Company requires four additional business analysts. The work load to support these initiatives has increased significantly in recent years due to regulatory requirements, increased Company focus and awareness and improved processes and communications with stakeholders. These four analysts will be responsible for analyzing, documenting and implementation of storm related business processes to determine key process improvements, change management, training and communication. Based on the business requirements, these process improvements may result in new system implementation initiatives or existing process and system enhancements. These individuals will also facilitate business requirements, serve as the liaison between the business users and technical teams, and manage testing and user training.

<u>Operations System Support Senior Specialist Regulatory Support:</u>

Since the Major Storms, there have been many new storm related PSC reporting requirements. In this more demanding environment, it is critical that the Company address and effectively manage the requirements and expectations of our regulators and key stakeholders. The Company requires a regulatory analyst in order to manage and track regulatory initiatives and coordination. This new position will serve as a single point of contact for all regulatory related requests, orders and collaborations. This individual will assist in the overall planning and tracking of the deliverables and status, defining resources, providing direction and support to the responders, and improving efficiencies in how the Company coordinates and tracks data, as well providing consistent and accurate responses and information. In addition, this position will serve as a liaison between regulators, municipalities, customers and appropriate Company departments.

<u>Operations System Support manager:</u>

The manager of the Operations System Support organization reports directly to O&R's Vice President – Operations, and is responsible for overseeing and managing the process improvements and enhancements to the Company's outage response performance tracking.

Q. Please explain the labor costs included under the heading "Proposed Electric New Employees" and "Proposed Gas New Employees" on pages 3 and 4 of Attachment A.

A. Program changes include the cost of an additional 14 employee positions for the Company's electric organization and nine employees for the Company's gas organization. All of these proposed positions address specific areas in which the Company must provide additional operational resources that either address the Company's ongoing projects to harden the energy delivery system, provide greater safety in the operation of the natural gas delivery system, project administration for new distributed generation electric programs; customer outreach initiatives for gas conversion programs and to remain in compliance with various Federal and state regulations. The 14 electric positions, which are summarized on page 3 of Attachment A, include:

- Four union equipment technicians;
- Smart grid engineering supervisor; and
- Two Smart Grid engineers.

The duties and responsibilities associated with these seven positions are discussed in more detail in the direct testimony of the Company's Smart Grid Panel.

- Permitting specialist; and
- Estimator/Scheduler specialist.

The duties and responsibilities associated with these two positions are discussed in more detail in the direct testimony of Company witness Work.

- Senior Specialist – NERC Compliance Program;
- Senior Specialist – Substations Compliance; and
- Senior Specialist – Control Center Compliance.

The duties and responsibilities associated with these three positions are discussed in more detail in the direct testimony of Company's BES Panel.

- Chief Construction Specialist – Vegetation Management.

The duties and responsibilities associated with this position are discussed in more detail in the direct testimony of the Electric Infrastructure and Operations Panel.

- Distributed Generation Resource Specialist.

The duties and responsibilities associated with this position are discussed in more detail in the direct electric testimony of Company witness Scerbo.

Q. Please continue with the detail of the Proposed Gas New Employees information on page 4 of Attachment A.

A. The Company is proposing an additional nine employees for various gas related responsibilities. The positions include the following:

- Union gas locator;
- Two union Gas Fitters for the Company's Northern division;
- Two union Gas Troubleshooters for the Company's Northern division; and
- Two compliance supervisor for the Northern and Eastern Division respectively.

The duties and responsibilities associated with these positions are discussed in more detail in the direct testimony of Company witness Hehir.

- Two Gas Marketing Resource specialists;

The duties and responsibilities associated with these positions are discussed in more detail in the direct gas testimony of Company witness Scerbo.

Q. Do you have any additional comments regarding the Company's plans to add employees?

A. Yes. The Company is well aware of the impact all these additional employees have on the proposed electric and gas revenue requirements. The Company does not take lightly any staffing decision that has the effect of contributing toward the Company's need to increase rates. Company management is very conscious of mitigating customer bill impacts and the proposal of these positions were the result of a prioritization and cost management process in which need and workload to support new or existing programs, as explained here in this testimony and the testimony of other Company witnesses and Panels. The Company believes the need for these positions and the roles and responsibilities of all these positions are properly justified throughout this filing and in the long-term best interests of customers.

Q. Please describe the labor cost escalation factors used in your projections.

A. On June 12, 2014, the employees of the Company's bargaining unit, Local 503 of the International Brotherhood of Electrical Workers ("Local 503"), ratified a new collective bargaining agreement between the Company and Local 503. The agreement will be in effect for a period of three years, i.e., from June 1, 2014 through May 31, 2017. The agreement provided, among other things, for the following general wage increases: 2.25% upon ratification; 0.50% on January 1, 2015; 2.25% on June 1, 2015; 0.50% on January 1, 2016; 2.25% on June 1, 2016; and 0.50% on January 1, 2017. Notwithstanding the Company's obligation with respect to such percentage wage increases under the collective bargaining agreement, in recognition of the Company's ongoing efforts to manage costs and implement productivity improvements, projected labor costs reflect wage escalation rates of 1% less than those called for by the collective bargaining agreement. Accordingly, the escalation rates used in our labor cost projection calculations, and reflecting the normalizing adjustments and program changes we explained earlier, for employees paid weekly are as follows from the end of the Historic Year through the Rate Year: 2.25% from July 2014 through December 2014, 2.75% from January 2015 through May 2015; 2.25% for June 2015 through December 2015, 1.75% increase from January 2016 through May 2016; and 1.25% from June 2016 through October 2016.

The labor costs for employees paid monthly, including escalation applicable to the normalizing adjustments and program changes explained earlier, were calculated for by first applying a salary increase of 3.00% per year effective April 1, 2014**.** As with the employees paid weekly, the labor escalation rate for employees paid monthly was reduced by a 1.00% productivity factor from the beginning of the Rate Year for revenue requirement purposes.

C. Shared Services Expense

Q. Please explain the Shared Services cost element shown on Exhibit AP-E4, Schedule 3 and Exhibit AP-G4, Schedule 3.

A. The shared services cost element reflects the allocation of costs from Con Edison and Consolidated Edison, Inc. for administrative and general services provided to Orange and Rockland, such as accounting, treasury, and tax services. These costs are detailed according to labor, fringe benefits and other cost components on Schedule 3 of these exhibits.

Q. What is the basis for the billing of shared services to O&R?

A. O&R is billed a share of the total costs of Con Edison operating the various departments that provide services to the Company. In addition, the Company is billed for 100% of other services provided solely on its behalf by Con Edison. These charges are then allocated to O&R's electric and gas operations and subsidiaries by use of the common expense allocations.

Q. How did you develop the shared service expense for the Rate Year?

A. We started with the total actual shared services expense billed to O&R during the Historic Year of $18.284 million and identified the portions of that amount according to labor, fringe benefits, direct charges to O&R, etc., as is shown on page 2 of Schedule 3 of Exhibit AP-E4 and Exhibit AP-G4. We then determined for each type of shared service expense, the portions of the total billing that were applicable to O&R electric and O&R gas using the Company's common expense allocation factors. That resulted in $10.410 million of the $18.284 million being allocated to O&R electric operations and $4.304 million to O&R gas operations. We then escalated the Historic Year labor component of the shared service billing by 6.65% over the 16-month period starting at the end of the Historic Year and continuing to the start of the Rate Year, or 3.00% on an annual basis which is the labor cost escalation factor we describe later in our testimony. We escalated the Historic Year amounts for fringe benefit and the other components of the billing by the general inflation factor of 4.12% over the same 16-month period to arrive at expense total O&R expense of $ 19.162 million for the Rate Year which we allocated $11.238 million to electric and $4.631 million to gas.

D. Employee Insurance and Other Employee Costs

Q. Please describe the amounts included in the item "Health Insurance Costs" set forth on Exhibit AP-E4, Schedule 4, and Exhibit AP-G3, Schedule 4.

A. The first line item on Schedule 4 of those exhibits includes the electric or gas, as applicable, share of all amounts related to medical, dental, prescription drug, vision and health maintenance organization coverage. The amounts are net of reimbursements pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985 (commonly referred to as “COBRA”), employee and retiree contributions, capitalized amounts and recovered amounts.

The amounts shown reflect the projected health insurance expenses for the Rate Year, less an amount equal to a “negative escalation” of 1% to reflect a productivity adjustment that the Commission has imputed in prior rate cases. We note that reflecting the productivity adjustment in these proceedings is without prejudice to the Company taking a different position in any subsequent rate case.

Q. Please describe the costs included in the item "Life Insurance Costs" set forth on Schedule 4 of Exhibit AP-E4 and of Exhibit AP-G3.

A. The amounts shown represent the electric and gas shares of the net premiums for life insurance, disability and accidental death and dismemberment coverage. The amounts shown reflect the projected expenses for the Rate Year, less an amount equal to a “negative escalation” of 1% to reflect a productivity adjustment that the Commission has imputed in prior rate cases. We note that reflecting the productivity adjustment in these proceedings is without prejudice to the Company taking a different position in any subsequent rate case.

Q. Please describe in greater detail how the Rate Year amounts for health and life insurance expense was calculated.

A. We first adjusted the Historic Year costs to reflect program change amounts of $2,226,000 for electric health insurance, $442,000 for electric life insurance, $919,000 for gas health insurance, and $183,000 for gas life insurance to reflect the projected costs for the Rate Year. We then subtracted the productivity savings imputation of 1% from the adjusted amounts to arrive at the Rate Year amounts. We note that reflecting the productivity adjustment in these proceedings is without prejudice to the Company taking a different position in any subsequent rate case.

We also reduced the health and life insurance program change amounts by $774,000 for electric and $307,000 for gas to reflect the capitalized and recovered benefit costs. The capitalized and recovered benefit costs were projected using the Historic Year relationship of those credits to the Historic Year level of expense and applying that percentage to the program change amounts. A reverse productivity imputation of 1% was also applied to the adjusted amount to arrive at the Rate Year capitalized and recovered benefit costs amount.

As has been the practice in past Company rate cases, this item will be updated at the time of the Company's rebuttal and update filing to reflect any known insurance premium changes.

Q. Do any of the health and life insurance benefits you have been discussing pertain to retirees?

A. Yes, benefits such as health and life insurance, prescription drug coverage and Medicare Part B payments pertain to retirees; however, all pay-as-you-go costs for retiree claim payments made by the Company are excluded from Schedule 4 of Exhibit AP-E4 and Exhibit AP-G4. The pay-as-you-go costs for retirees are now treated as a direct reduction to a liability account (for pre-1995 retirees) or as a receivable from the VEBA Benefit Trust (for post-1995 retirees).

Q. Please describe Other Employee Benefit Costs shown on Exhibit AP-E4, Schedule 4, and Exhibit AP-G4, Schedule 4.

A. Other Employee Benefit Costs relate to costs for items such as employee training, tuition reimbursement, safety shoes, employee physicals and administrative fees to manage the employee stock purchase plans and other benefit plans. The Rate Year level is based on the Historic Year level escalated using the general inflation factor.

Q. Please describe Officers Restricted Stock item shown on Exhibit AP-E4, Schedule 4, and Exhibit AP-G4, Schedule 4.

A. Officers Restricted Stock relates to the cost of stock awards to officers under the Company's restricted stock program. We normalized the Historic Year expense to exclude such costs from our filing and will not be seeking rate relief for this item at this time. We note that excluding this cost from the revenue requirement in these proceedings is without prejudice to the Company taking a different position in any subsequent rate case.

E. Insurance, Workers' Compensation and Injuries and Damages Expense

Q. How did you develop the rate allowance for property insurance expense?

A. Property insurance expense shown on Schedule 4 of Exhibit AP-E4 for electric and Exhibit AP-G4 for gas represents O&R's share of policies that are administered by Con Edison. We developed the Rate Year amounts by applying the general escalation factor to the Historic Year level of expense. As has been the practice in past Company rate cases, this item will be updated at the time of the Company's rebuttal and update filing to reflect any known insurance premium changes.

Q. Please explain what is meant by the term "workers' compensation" with respect to the expense reflected in your revenue requirement calculations.

A. Workers compensation expense shown on Schedule 4 of Exhibit AP-E4 for electric and Exhibit AP-G4 for gas represents a combination of assessments paid to the New York State Workers' Compensation Board and amounts accrued to the workers' compensation reserve by the Company with respect to employees' work-related injuries or illnesses as well as exposure to asbestos at formerly-owned electric generating stations.

Q. Please explain how you developed the Rate Year expense amount for workers' compensation.

A. For electric and gas, normalizing adjustments of $129,000 and $53,000, respectively, were made to include costs written-off during the Historic Year but were related to a prior period adjustment for over-accrued costs related to workers' compensation assessments. The adjusted level of expense was then escalated at the labor escalation factor and further adjusted by a 1% productivity adjustment to arrive at the Rate Year level of expense. We note that reflecting the productivity adjustment in these proceedings is without prejudice to the Company taking a different position in any subsequent rate case.

A change in law resulting from the State's 2013-2014 budget requires the Workers' Compensation Board to consolidate the existing multiple statutory assessments into a single assessment, which would provide funding of the workers' compensation system for all New York State employers. The new single assessment went into effect on January 1, 2014. Based on the new assessment methodology, we anticipate that O&R's "single assessment" total for 2014 will be approximately $174,200. This is $42,431 less than the total assessments paid in 2013. Please note, the legislation did not affect the workers' compensation assessment under Section 50-5 for self-insured employers, which continues in effect. In addition, the legislation also repealed the Fund for Reopened Cases (25-a Fund) effective January 1, 2014 to all new claims. This repeal means that the liability for certain claims that would otherwise be transferred to the Fund for Reopened Cases will remain with the employer and this increase in costs may partially offset the savings resulting from the single assessment. Therefore, without historical experience on reopened cases costs, we have not normalized any such costs out of the Historic Year costs.

Q. Please explain what is meant by the term "injuries and damages" with respect to the expense reflected in your revenue requirement calculations.

A. Injuries and damages expense shown on Schedule 4 of Exhibit AP-E4 and Exhibit AP-G4 represents a combination of insurance premiums and amounts accrued to the injuries and damages reserve by the Company with respect to various claims and lawsuits for personal injury, property damage or asbestos litigation.

Q. Please explain how you developed the Rate Year expense amount for injuries and damages.

A. For electric, a normalizing adjustment of $250,000 was made to add back an accrual reversal made during the Historic Year for asbestos litigation cases that was to correct a prior period error. The adjusted level of expense was then escalated at the general inflation rate to arrive at the Rate Year level of expense. For gas, the Historic Year level of expense was escalated at the general inflation rate to arrive at the Rate Year level of expense.

F. Research & Development

Q. Please explain the bases of the amounts for Research and Development (“R&D”) expense included in Exhibit AP-E4, Schedule 5 for electric, and Exhibit AP-G4, Schedule 5 for gas.

A. In accordance with previous Commission decisions in Company rate cases and the Commission’s 1980 Technical Release regarding accounting for and rate recovery of R&D expenditures, the Company reconciles electric and gas R&D expense amounts included in rates and the actual expenditures. Electric and gas R&D costs primarily reflect the Company’s share of R&D costs included in the Commission’s annual assessment, the cost of projects undertaken by

O&R and the electric and gas portions of the R&D costs allocated to Orange and Rockland as a shared service by Con Edison.

For electric, in the 2012 Rate Order, the Commission approved a two-year amortization of under-collected R&D costs at $522,000 per year, which ceased as of June 30, 2014. As of June 30, 2014, the Company had a credit deferred balance of $883,000. The Company proposes to refund this amount to customers over three years, or at $294,000 per year. Also included is projected Rate Year R&D expenditures of $844,000 based on the Historic Year level escalated using the general escalation factor.

For gas, in the 2009 Rate Order, the Commission approved a three-year amortization of under-collected R&D costs at $20,000 per year, which ceased as of October 31, 2012. As of June 30, 2014, the Company had a credit deferred balance of $131,000. The Company proposes to refund this amount to customers over three years, or at $44,000 per year. Also included is projected Rate Year R&D expenditures of $253,000 based on the Historic Year level escalated using the general escalation factor.

We note that the majority of the Company's R&D expenditures ($624,000 out of the total of $1,097,000, or approximately 57%) are for the NYSERDA assessment.

G. Negative Net Salvage Caps - Amortization of Gas Mains

Q. Please explain the bases of the amount of Amortization of Gas Mains expense included in Exhibit AP-G4, Schedule 5 for gas.

A. As discussed by the Depreciation Panel, O&R has been required for many years, beginning with Case 92-G-0050, to limit the negative net salvage factor included in the depreciation rates for Account 376 (gas mains) and Account 380 (gas services) to negative 40% and negative 80%, respectively. Any negative net salvage incurred beyond these thresholds is included in O&M expense for accounting and ratemaking purposes. The Company is proposing to continue the O&M expense rate allowance of $300,000 per year that was approved in the 2009 Rate Order.

H. Low Income Program

Q. Please explain the bases for the amount of Low Income Program expense included in Exhibit AP-E4, Schedule 5 for electric and Exhibit AP-G4, Schedule 5 for gas.

A. For electric, in the 2012 Rate Order, the Commission approved an expense allowance of $1,825,000 for the third rate year of the electric rate plan regarding the Company's low income program to fund the discounts or bill credits given to low-income customers. In this filing Company witness Cigliano is proposing to decrease the funding level from $1,825,000 to $1.3 million. The 2012 Rate Order provided for a two-year amortization of deferred under collected low-income program costs at $163,000 per year which ceased as of June 30, 2014. As of June 30, 2014, the discounts or bill credits given to low-income customers were below the level provided in rates by $528,000. This balance is projected to grow to $1,503,000 by the start of the Rate Year. The Company proposes to refund this amount to customers over three years, or at $501,000 per year.

For gas, in the 2009 Rate Order, the Commission approved an expense allowance of $878,000 for the third rate year of the gas rate plan regarding the

Company's low-income program to fund the discounts or bill credits given to low-income customers. In this filing Company witness Cigliano is proposing to increase the funding level from $878,000 to $1.4 million. As of June 30, 2014, the discounts or bill credits given to low-income customers exceeded the level provided in rates by $1,172,000. This balance is projected to grow to $1,757,000 by the start of the Rate Year. The Company proposes to recover this deferred balance over three years, or at $586,000 per year.

Q. Do the Company's revenue requirements, as reflected in Exhibit AP-E3 and Exhibit AP-G4 include the impacts of the changes discussed by Company witness Cigliano?

A. No, the Company wishes to discuss this matter with Staff and other interested parties prior to reflecting any changes to the revenue requirements.

I. Pension and OPEB Costs

Q. Please describe the accounting procedures followed by the Company to record pension costs included in Exhibit AP-E4, Schedule 6, and ExhibitAP-G4, Schedule 6.

A. The Company's pension expense has been calculated in accordance with the provisions of ASC 715 (formerly SFAS No. 87) and the Commission's *Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions*, issued and effective September 7, 1993, in Case 91-M-0890 ("Policy Statement"). The Company defers any difference, including the income tax effect, between the allowance provided in current rates for pension costs and the corresponding book expense recorded under the provisions of ASC 715.

Assumptions used to calculate the Company's ASC 715 expenses are listed and described in the study prepared by the Company's actuarial consultant, Buck Consultants, submitted in support of Exhibit AP-E4, Schedule 6, and Exhibit AP-G4, Schedule 6. We note that a new study will be performed and the results will be available approximately March 31, 2015. The Company will provide that later study to Staff and the result of that study should be used in the final determination of pension and OPEB expense in these proceedings.

For electric, in the 2012 Rate Order, the Company was allowed to recover a deferred balance of $10.262 million, representing an under-recovery of the Company's ASC 715 pension expense, over three years at $3.421 million per year commencing July 1, 2012. That amortization will expire as of the start of the Rate Year. Based on the latest forecast, we are projecting a further under-recovery of costs of $3.374 million as of the start of the Rate Year that we propose to amortize over three years, or at $1.125 million per year.

For gas, in the 2009 Rate Order, the Company was allowed to recover a deferred balance of $2.679 million, representing an under-recovery of the Company's ASC 715 pension expense, over three years at $893,000 per year commencing November 1, 2009. Although the recovery expired on October 31, 2012, we have and will continue to recover $893,000 per year until rates are reset. Based on the latest forecast, we are projecting a further under-recovery of costs of $3.053 million as of the start of the Rate Year that we propose to amortize over three years, or at $1.018 million per year.

Q. How is the Company accounting for any difference between the rate base deductions reflected in rates and the actual deferred balance of pension costs?

A. The Policy Statement (pp. 19-20) requires the Company to accrue carrying charges on the pension recoveries not deposited into an external fund, in excess of the Company's imputed rate base deduction.

For electric, in Case 07-E-0949, the imputed rate base deduction was $6.4 million and the deduction continued in Case 10-E-0362. In recent years, the Company has had an under-recovery of its pension cost and has also funded its actual pension obligation at levels above the annual rate recoveries. As a result, this rate base deduction for pensions was eliminated beginning in Case 11-E-0408.

For gas, the 2009 Rate Order established a refund to customers of $450,000 over three years at $150,000 per year commencing November 1, 2009 of accrued carrying charges on the pension cost recoveries not deposited into an external fund in excess of the Company's imputed rate base deduction. Although the refund expired on October 31, 2012, we have and will continue to refund to customers $150,000 per year until rates are reset. In recent years, the Company has had an under-recovery of its pension cost and has also funded its actual pension obligation at levels above the annual rate recoveries. As a result, we propose to eliminate this rate base deduction as of the start of the Rate Year.

Q. How did you project the expense for the Company's 401(k) plan that is included in pension expense on Schedule 6 of Exhibit AP-G4 and Exhibit AP-G4?

A. We escalated the Historic Year amount using the wage escalation factor that we discuss later in our testimony.

Q. Please describe the accounting procedures followed by the Company to record OPEB costs.

A. Since the adoption of Statement of Financial Accounting Standards No. 106 (now ASC 715-60) on January 1, 1992, the Company has calculated its OPEB obligation accordingly and in accordance with the Policy Statement.

Assumptions used to calculate the Company's OPEB expense are listed and described in workpapers submitted in support of Exhibit AP-E4, Schedule 6 and Exhibit AP-G4, Schedule 6.

For electric, in the 2012 Rate Order, the Company was allowed to recover a deferred balance, excluding the transitional obligation, of $5.974 million representing an under-recovery of the Company's ASC 715-60 OPEB expense, over three years at $1.991 million per year commencing July 1, 2012. That amortization will expire as of the start of the Rate Year. Based on the latest forecast, we are projecting a further over-collection of costs, excluding the transitional obligation, as of the start of the Rate Year of $9.351 million that we propose to amortize over three years, or at $3.117 million per year.

The 2012 Rate Order also allowed the Company to recover an OPEB transitional obligation deferred balance of $909,000 over the twelve months ended June 30, 2013. We are currently not projecting any OPEB transitional obligation for the Rate Year.

For gas, in the 2009 Rate Order the Company was allowed to recover a deferred balance, excluding the transitional obligation, of $801,000 representing an under-recovery of the Company's ASC 715-60 OPEB expense over three years at $267,000 per year commencing November 1, 2009. Based on the latest forecast, we are projecting a further over-collection of costs, excluding the transitional obligation, of $6.867 million as of the start of the Rate Year that we propose to amortize over three years, or at $2.289 million per year. The 2009 Rate Order also allowed the Company to recover an OPEB transitional obligation deferred balance of $1,602,000 over three years at $534,000 per year commencing November 1, 2009. We are currently not projecting any OPEB transitional obligation for the Rate Year.

Consistent with the Policy Statement, interest is only calculated when OPEB recoveries exceed funding. Since the Company has been able to fully utilize rate recoveries in a tax effective manner to fund its OPEB obligation, no interest was accrued during the Historic Year.

As with pension costs, the Company expects a new study for OPEB costs by approximately March 31, 2015.

Q. Please explain the Medicare Part D Tax Benefit Deferral included in OPEB expense in Exhibit AP-E4, Schedule 6 and Exhibit AP-G4, Schedule 6.

A. Medicare legislation was enacted in 2004 that granted Medicare recipients a partial reimbursement of prescription drug costs starting in 2006. The projected reimbursement applicable to Company employees and retirees was factored into the estimated OPEB costs calculated by the Company's actuaries. Federal legislation enacted in 2010 made the Medicare Part D reimbursements taxable starting in 2012. In addition, accrued Medicare Part D benefits deducted by the Company and passed back to customers that have not been paid will be taxable in the future. As a result, the Company will update its filing to reflect the impact of the lost tax deduction as the actual 2014 amounts become known. For purposes of the filing, the Company has not reflected any ongoing tax benefits in the State and federal income tax calculations shown on Schedules 8 and 9 of Exhibit AP-E3 and Exhibit AP-G3.

For electric, in the 2012 Rate Order, the Company was allowed to recover a deferred balance of $1.078 million representing an under-recovery of the Company's Medicare Part D expense, over three years at $413,000 per year commencing July 1, 2012. That amortization will expire as of the start of the Rate Year. Based on the latest forecast, we are projecting an over-recovery of costs of $84,000 as of the start of the Rate Year that we propose to amortize over three years, at $28,000 per year.

For gas, the 2009 Rate Order established the refund to customers of a credit deferred balance of $1.371 million, representing an over-recovery of the Company's Medicare Part D expense over three years, or at $457,000 per year commencing November 1, 2009. Although the refund expired on October 31, 2012, we have and will continue to refund to customers $457,000 per year until rates are reset.

Based on the latest forecast, we are projecting an under-recovery of costs of $4.074 million as of the start of the Rate Year that we propose to amortize over three years, or at $1.358 million per year.

Q. Which Company witness discusses the steps the Company has taken to control OPEB Costs?

A. The Company's Compensation and Benefits Panel addresses that subject.

J. Uncollectible Accounts

Q. Please explain the Uncollectible Accounts item shown on Exhibit AP-E4, Schedule 7 and Exhibit AP-G4, Schedule 7.

A. Schedule 7 of those exhibits reflects the projected customer uncollectible accounts expense. The projections are based on the ratio of bad debt customer account write-offs, net of collections, to sales to customers for the twelve month period ended July 31, 2014 during which $0.54 for each $100 of revenue billed to electric and gas customers was written off as uncollectible. This ratio was applied to projected revenues from sales to customers during the Rate Year to develop the Rate Year expense.

Also presented is the projected sundry uncollectible expense. The projections for the Rate Year are based the average annual actual net sundry write-offs, net of collections, for the 24 months ended June 30, 2014, totaling $415,000. The amount allocated to electric is $293,000, or 70.75%, and the amount allocated to gas is $122,000, or 29.25%.

K. Environmental Costs

Q. Please describe the Company's proposals regarding the recovery of SIR costs associated with former manufactured gas plant ("MGP") and non-MGP sites reflected on Exhibit AP-E4, Schedule 8 and Exhibit AP-G4, Schedule 8.

A. Taking into account the SIR cost projections provided by Company witness McCormick as well as the current electric deferred balance and the amortization approved under the 2012 Electric Rate Order, we estimate that the Company will have an under-recovery of the electric allocation of SIR expenditures at the start of the Rate Year of $9,555,000. The Company proposes to recover this amount from customers over five years, or at $1,911,000 per year.

For gas, in the 2009 Rate Order the Commission approved the recovery over three years of $4,090,000 of SIR costs at the Company's MGP and non-MGP sites.

We have assumed the continuation of that recovery until the start of the Rate Year. Taking into account the SIR cost projections provided by Company witness McCormick, we estimate that the Company will have an under-recovery of the gas allocation of SIR expenditures at the start of the Rate Year of $5,770,000. The Company proposes to recover this amount from customers over five years, or at $1,154,000 per year.

L. Tree Trimming

Q. Please explain the development of tree trimming expense for the Rate Year as shown on Exhibit AP-E-4, Schedule 9.

A. We made a normalizing adjustment to tree trimming expense during the Historic Year to reflect the expense allowance reflected in the 2012 Rate Order. We then applied general inflation escalation rate of 4.12% to the normalized Historic Year expense. Under the 2012 Rate Order, the Company agreed to defer for the benefit of customers any cumulative shortfall between actual expenditures for the Company's transmission and distribution tree trimming program, including the danger tree programs, and the levels provide in rates. Although the Company is currently short of meeting the targets established in the 2012 Rate Plan, and will be passing back to customers a benefit for this shortfall, we believe that not changing the current spending level is appropriate. The latest actual expenditures for the tree trimming program will be provided at the time of the Company's update filing.

M. Stray Voltage

Q. Please explain the development of stray voltage expense for the Rate Year as shown on Exhibit AP-E-4, Schedule 9.

A. For the Stray Voltage expenses, we made a similar normalizing adjustment to the Historic Test Year to reflect the expense allowance approved by the Commission in the 2012 Rate Plan. As is the case with Tree Trimming, the Company believes the current level in rates is sufficient to meet the on-going responsibilities for performing stray voltage inspections throughout the service territory.

N. NY Reliability – Pole Inspection/Replacement/Lightning

Q. Please explain the NY Reliability – Pole Inspection, Replacement and Lightning expense cost element on Exhibit AP-E4, Schedule 9.

A. This cost element includes the pole inspection program recommended by the National Electric Safety Code to replace or reinforce defective poles as they are identified. We escalated the expense during the Historic Year by the general inflation factor to arrive at the Rate Year estimate.

O. NY Infra-Red Program (Thermovision)

Q. Please explain the NY Infra-Red Program (Thermovision) expense cost element on Exhibit AP-E4, Schedule 9.

A. This cost element includes an annual study to identify system conditions that could lead to failure on the transmission and distribution system. We escalated the expense during the Historic Year by the general inflation factor to arrive at the Rate Year estimate.

P. Aerial Patrol

Q. Please explain the NY Aerial Patrol expense cost element on Exhibit AP-E4, Schedule 9.

A. This cost element includes helicopter patrols on North American Electric Reliability Corporation ("NERC") transmission corridors on a monthly basis and other transmission corridors on a bimonthly basis to identify encroachments, vegetation growth, trespassing, corridors and facility conditions. We escalated the expense during the Historic Year by the general inflation factor to arrive at the Rate Year estimate.

Q. Damage Prevention

Q. Please explain the Damage Prevention expense cost element on Exhibit AP-G4, Schedule 9.

A. This cost element includes preventing damage to the Company's underground lines and pipes during excavation projects such as repairing or installing a water line, sewer line, planting a tree, or re-grading a driveway and the "marking" of underground facilities.

Company Witness Hehir discusses a program change carrying incremental costs for such activities. We otherwise escalated the Historic Year expenses by the general inflation factor to arrive at the Rate Year estimates.

R. Other Transmission & Distribution

Q. Please explain the Other Transmission & Distribution expense cost element on Exhibit AP-E4, Schedule 9 and Exhibit AP-G4, Schedule 9.

A. This cost element includes transmission and distribution expenses related to electric and gas operations that do not fall into other categories of expense within Schedule 9 of Exhibit AP-E4 or Exhibit AP-G4. For electric, the Electric Infrastructure Operations Panel discusses some program changes related to the Electric and Gas Map Conflation, the Tower Leg Remediation Program, the Storm Hardening Program and the Spare Equipment Initiative. We otherwise escalated the Historic Year expenses by the general inflation factor to arrive at the Rate Year estimates.

S. Major Storm Costs

1. Deferred Major Storm Cost Recovery

Q. Please define the term "major storm."

A. 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.

Q. Please explain the Company's proposal with respect to recovery of previously deferred major storm costs shown on Exhibit AP-E4, Schedule 9, Page 2 of 2.

A. The 2012 Rate Order provided for recovery of deferred storm charges of $6,864,500 for the second and third rate years of the current electric rate plan ended June 30, 2014 and 2015, respectively. The Company is proposing that the recovery of previously incurred costs related to major storms be increased by $5,169,000 for an annual amortization of $12,034,000 based on a five-year amortization period.

Q. What is the basis for annual recovery amount of $12,034,000?

A. As of June 30, 2014, the Company had a deferred storm reserve balance of $74,810,000. Taking into account remaining recoveries under the current rate plan of $14,102,000 and $568,000 to offset the increase to the Energy Cost Adjustment (“ECA”) and assuming no additional deferred major storm costs in the interim, the Company will have unrecovered deferred storm charges of $60,170,000 at the start of the Rate Year. The Company proposes to recover the projected deferred storm cost balance from customers over five years, or $12,034,000 per year.

Q. Please discuss the $568,000 relating to the ECA?

A. The 2011 Rate Order stated that if new electric base delivery rates did not go into effect immediately following the end of Rate Year 3 (June 30, 2015), the ECA 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. Because the Company proposes the new base rates to be effective beginning November 2015, we calculated the expected ECA revenue for four months July 2015 through October 2015 to be approximately $568,000.

Q. Please discuss the impact that Superstorm Sandy had on the Company’s deferred major storm costs?

A. Superstorm Sandy had a devastating impact on the Company’s service territory. Eighty-three percent, or approximately 250,000 of the Company’s total customer base of 300,000 lost power. Superstorm Sandy damaged 27 transmission lines, 17 substations and almost all of the Company’s 280 distributions circuits. The Company experienced distribution damages at more than 10,000 separate locations. The Company was able to restore service to 88% of the 250,000 customers within seven days, and completed the balance in an additional four days. Resources came from 31 States and Canada. Additionally, assistance was received from the Air Force through the airlifting of equipment and personnel to our area, and from the National Guard which mobilized troops to assist New York State utilities. Over the course of the storm, more than 2,800 additional field personnel arrived and worked in the O&R service territory to supplement the roughly 1,100 Company employees who were engaged full in the Company's storm response and restoration activities.

Approximately $57,200,000 of the $74,810,000 deferred storm reserve balance as of the end of the Historic Year is the result of Superstorm Sandy. For the past several months the Company has been working with members of Staff's Office of Accounting, Audits and Finance to review Superstorm Sandy charges.

Q. Were there any major storms in addition to Superstorm Sandy since the Company's last electric rate case?

A. Yes, the Company experienced two additional major storms.

Q. Please describe those two major storms.

A. First, on July 26, 2012, an evening thunderstorm ripped through the Company's service territory. The quick moving thunderstorm brought with it damaging wind and lightning and although the impact was felt across all areas, O&R's Western Division suffered the most damage. On July 27, 2012, line crews from all Company divisions, contractor crews and Con Edison mutual assistance crews from Bronx and Westchester worked throughout the day to restore power to customers. In total, over 150 crews worked to repair lines, remove fallen tree limbs from equipment, assess damage and secure downed wires. A total of 22,028 New York customers were affected and the Company deferred costs of approximately $600,500.

Second, on September 12, 2013 violent thunderstorms, rain and damaging wind whipped through the Company's service territory. O&R's field forces, mutual aid and contractor crews worked around the clock to assist in the restoration effort. The Company and contractor line crews from Con Edison's Bronx/Westchester and Brooklyn/Queens divisions helped make repairs to the distribution system and restore power to customers by September 13, 2013. A total of 18,199 New York customers were affected and the Company deferred costs of approximately $1,081,000.

2. Major Storm Reserve Funding

Q. Please explain the Storm Reserve – Current Spending item shown on Exhibit AP-E4, Schedule 9.

A. The amount shown, $3,786,000, is the annual funding amount the Company is requesting to provide for future major storm costs. The 2012 Rate Order allowed the Company the continuation of reserve accounting to provide funding for major storm costs of $3,563,000 in RY1, $3,636,000 in RY2, and $3,712,000 in RY3. In an effort to mitigate the proposed revenue requirement and related bill impacts, the Company has elected to forgo requesting an increase to the annual funding amount currently reflected in rates except to adjust for the effect of general inflation which increases the rate allowance by only $150,000.

T. Regulatory Commission Expense & Rate Case Costs

Q. Please explain the regulatory commission expense cost element on Exhibit AP-E4, Schedule 10, and Exhibit AP-G4, Schedule 10.

A. This cost element includes the annual assessment by the Commission, the 18-a assessments and the amortization of deferred rate case costs. For the Rate Year projection for the Commission's assessment, we first normalized the Historic Year level of expense to reflect the most recent bill and then escalated that amount using the general inflation factor. For the 18-a assessment, which is recovered via a surcharge, we normalized this cost as well as the associated revenues out of the calculation of the revenue requirements to avoid any rate base impact that might result from the expense being captured in the cash working capital component of rate base.

With respect to electric rate case costs, under the 2012 Rate Order, the Company was allowed to recover a deferred balance of $300,000 over a three-year period commencing July 1, 2012. An annual amortization amount of $66,667 was approved for the third rate year and we have assumed the continuation of this recovery until the start of the Rate Year. As of June 30, 2014, the Company had a deferred balance of $66,000 representing the amount to be amortized during the third rate year of the current electric rate plan. Taking into account the continuing amortization and new estimated rate case costs of $251,000 (the electric share of an estimated $388,000 in total for outside consulting, printing and other expenses) the deferred balance is projected to net to $228,000 by the start of the Rate Year which the Company proposes to amortize over three years, or at $76,000 per year.

With respect to gas rate case costs, under the 2009 Rate Order, the Company was allowed to recover rate case costs of $54,000 over a three-year period commencing November 1, 2009. The amortization ceased as of October 2012. As of June 30, 2014, the Company had a zero deferred balance. Taking into account the new estimated rate case costs of $137,000 (the gas share of an estimated $388,000 in total for outside consulting, printing and other expenses) the deferred balance is projected to be $137,000 by the start of the Rate Year which the Company proposes to amortize over three years, or at $46,000 per year.

The estimated costs for these proceedings exceeds those for the previous 2010 electric rate filing and 2008 gas rate filing primarily due to the need to retain an outside compensation expert to demonstrate through a compensation study the reasonableness of its overall compensation levels.

U. System Benefits Charge and Renewable Portfolio Standard

Q. Do the revenue requirements you have calculated include expenses for the SBC or the RPS?

A. No. Exhibit AP-E4, Schedule 11, shows amounts representing electric expense for annual payments to the New York State Energy Research and Development Authority for the SBC and the RPC and Schedule 11 of Exhibit AP-G4 shows gas expense for payments for the SBC only. The costs are recovered by a separate surcharge. The forecasted expenses and the surcharges to be billed to customers included in delivery revenues are set at equal amounts to avoid any revenue requirement impact or rate base impact that might result from the expense being captured in the cash working capital component of rate base.

V. Other O&M Expenses

Q. Please identify any remaining categories of expense reflected in the revenue requirements you have calculated and explain how the expense amounts for the Rate Year were developed.

A. The remaining categories of expense are shown on Schedule 12 of Exhibit AP-E4 and Exhibit AP-G4. We will address each in turn.

Advertising Expense pertains to what is generally referred to as "informational advertising" directed to customers. We developed the Rate Year amount by applying the general inflation factor to the Historic Year level of expense.

Corporate and Fiscal Expense pertains to miscellaneous financing costs, fees and services for the Company's expected increase in financing needs to support its increased capital and operating costs as testified to by various witnesses in this proceeding, as well as various fees paid to the rating agencies. A program change of $5,000 ($4,000 allocated to electric and $1,000 allocated to gas) was added to reflect annual maintenance costs for an incremental bond to be issued during the Rate Year. We otherwise escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Facilities Expense relates to building maintenance services such as janitorial, security and administrative services. It also includes the monthly rental expense for the building at Blue Hill. We otherwise escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Information Technology Solutions Expense pertains to items such as technology support, software maintenance and application services related to the CIMS system as well as mainframe computers in general. Company witness Melvin discusses a program change related to the CIMS system. We otherwise escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

The Company, along with Con Edison, implemented a major new computer system called Project One in July 2012. The annual Oracle support and license fees are approximately \$7.2 million, of which O&R's portion is 7.3% or \$528,000. The O&R portion benefits all of its New York, New Jersey and Pennsylvania customers. The portion related to O&R's electric customers is approximately \$293,000 and the portion related to O&R's gas customers is approximately \$235,000. The annual support fees to Oracle provides for priority technical support services. It allows the Company to receive software fixes and enhancements. Additionally, it provides access to Oracle's support teams to resolve specific issues and questions and grants the Company access to Oracle's online knowledge base.

Legal and Other Professional Services Expense includes the cost of outside legal counsel, the Company's outside independent auditors (PricewaterhouseCoopers) and other consulting expenses. The annual levels of services vary over time. We developed the Rate Year amount by applying the general inflation factor to the Historic Year level of expense.

Materials and Supplies Expense pertains to cost of materials purchased to be used for operation and maintenance purposes. We escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Rent Expense relates to items such as Ramapo substation rent, rent for the open position on 345kV Transmission Line 77 used to construct Transmission Line 28, the Port Jervis office rent, rent for a communicators tower in the Town of Clarkstown, and right-of-way rent rents paid to railroad companies for transmission and distribution lines. The Rate Year level of expense was forecasted based on existing rental agreements and escalation for Ramapo and Transmission Line 28 was at 3%.

Telecommunications Expense pertains to items such as landlines/network and PC maintenance costs. We discuss program changes related to new telephone and PC costs for maintenance to support the Corporate Communications Transmission Network ("CCTN"), and a new low-band radio system later in our direct testimony. We otherwise escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Transportation Expense is separated into two parts – vehicle depreciation and other transportation expenses. We developed the Rate Year level of expense for the vehicle depreciation based on monthly calculation of depreciation expense at depreciation rates established by the 2012 Rate Order and 2009 Rate Order.

The other portion of Transportation Expense relates to items such as fuel, parts and garage non-labor indirect costs. For that portion of the expense, we escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Manhour Expense pertains to non-labor indirect support charges related to facilities, transportation, telecommunications and material and supplies expenses. We escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Other Customer and Administrative Expense includes miscellaneous customer and administrative and general expenses that did not fit into other categories of expense discussed above. We discuss program changes related to the corporate security programs, increased O&M costs associated with MyAccount web functionality and app, gas marketing, education, and outreach to customers to foster conversions from alternate fuels to natural gas, as well as rebates for customers who elect to do gas conversion later in our direct testimony. We otherwise escalated the electric and gas expenses during the Historic Year by the general inflation factor to arrive at Rate Year estimates.

Q. Please discuss the Company's proposals for the CCTN and the low band radio system.

A. Program changes for O&M expenses related to the Company's CCTN and low band radio system expansions and upgrades are represented in the line item "Telecom – PC – Monthly Charge" in Exhibit __ (AP-E4), Schedule 12, and Exhibit __ (AP-G4), Schedule 12. The total O&M program request for the CCTN and the low band radio system totals $732,000. As discussed below, both of these program changes benefit the Company's electric and gas organizations. The cost of the CCTN program is $272,000; $206.000 allocated to electric and $66,000 allocated to gas. The total cost for leasing a new digital radio system is $4,090,900 over a seven year lease term agreement, with a year one O&M cost of $460,000; $348,000 allocated to electric and $112,000 allocated to gas.

Q. Please describe the significance of the Company's CCTN.

A. The CCTN is integral to the Company's data communications networks, security video surveillance, and emergency communications requirements. The CCTN provides a reliable, secure and redundant communications system, which is vital to maintaining electric and gas services, particularly when public telecommunications carriers may not be able to meet Company requirements due to their own system limitations or other emergency conditions.

Q. Have there been any changes that have occurred or will be occurring with respect to the Company's CCTN?

A. The Company is in the process of expanding and upgrading the existing CCTN in order to better protect key cyber assets and mission critical communications.

Q. Please describe the Company's efforts to expand the CCTN.

A. The CCTN expansion includes the Company's microwave, radio and fiber optic networks. New CCTN facilities will be installed at the Company's West Nyack substation and the leased Wurtsboro radio facility. Both of these sites support critical communication and are currently connected by telephone circuits, which are both a security and reliability concern.

Q. In addition to expansion efforts, are there also plans to upgrade CCTN facilities?

A. Yes, upgrades are planned for the Company's Greeneville and Middletown CCTN facilities. This will include replacing older low-speed equipment with new state-of-the-art equipment, providing a high-capacity solution. Both of these facilities are part of the fiber optic network, so upgrading the microwave allows for high speed redundant links (fiber and microwave) for added reliability and redundancy.

Q. What impact, if any, will these expansion and upgrade efforts have on the Company's CCTN maintenance costs?

A. The expansion to new facilities and upgrades of existing CCTN sites are resulting in increased maintenance on the Company's fiber and microwave networks. Additionally, new equipment has been placed into service at eight master radio towers in support of the Company's Smart Grid and Distribution Automation initiatives. The new master radios, along with 269 remote radios, will increase costs under the Company's radio maintenance contract, along with increased leased costs at non-Company owned tower sites. More specifically, increases in tower lease contracts will be seen at Clarkstown, NY and Wurtsboro, NY, due to new antenna attachments. The Company is also looking to expand its Smart Grid network to the Highland Falls/West Point New York area, where a new tower lease will be required.

Q. Are there any other maintenance costs you wish to discuss?

A. Yes, the Company's proposal also includes additional maintenance and support for two emergency generators the Company will be purchasing, one for the

Wurtsboro facility and another mobile unit for deployment as needed. The mobile unit will be stored and maintained at the Company's Radio Maintenance shop.

Q. What is the Company proposing with respect to its low band radio system?

A. The Company seeks to replace its current two-way analog radio system with a new leased high band-width data capable communications network. The current two-way radio system, utilized by both the electric and gas departments, operates in a range of frequencies (or spectrum) that was commonly designed for private radio systems during the 1940's through 1960's. The frequencies, in the 37 MHz to 50 MHz range, are termed "low-band", *i.e.*, the lowest of all licensed mobile radio frequencies available. Newer systems built over the past twenty-five years operate at higher spectrum ranges, and have the capability of supporting both voice and data. The Company's existing low band system is a voice only radio system.

Due to limited functionality of the low-band frequencies, combined with technology advancements in higher frequency bands, availability of equipment for maintaining our low-band system has become increasingly difficult. Many suppliers no longer manufacture low-band base stations and radios because they have migrated their manufacturing to newer state-of-the-art technology.

The Company proposes to lease a new digital radio communications network given the cost associated with purchasing and owning a new system. The cost of leasing a system is $4.1 million compared with the cost of purchasing a similar system at $33.0 million.

Q. Is there any other benefit, aside from the cost savings, of leasing rather than purchasing a new high band-width data capable communications network?

A. Yes. Leasing allows the Company greater flexibility for the Company to upgrade to a more efficient spectrum and advanced equipment, or other technologies, should they become available. The Company will not be locked into a system that may become outdated and inferior to other potential alternatives. Maintaining flexibility is particularly important in light of the ongoing national initiative for building an advanced and secure Private Radio Network for first responders and emergency personnel. Leasing offers a cost-effective immediate solution to obtain a state of the art communication tool, while continuing to monitor the ever changing wireless telecommunications systems. The Company may have the opportunity to one day partner with local first responders in a future national communications initiative. Leasing a new radio system provides O&R with a low cost solution that can bridge the gap to a potentially future long term solution.

Q. Please discuss the Company's Other Expenses – Customer & Administrative request in Exhibit_ (AP-E4), Schedule 12, and Exhibit _ (AP-G4), Schedule 12.

A. The electric request of $188,000 in Exhibit_ (AP-E4), Schedule 12, is comprised of a request for (i) $45,000 for the electric allocation of the expansion of the Company's MyAccount digital mobile application, and (ii) $143,000 for the electric allocation of the security upgrades the Company is seeking to install. The gas request of $238,000 in Exhibit _ (AP-G4), Schedule 12, is comprised of a request for (i) $18,000 for the gas allocation of the expansion of the Company's MyAccount digital mobile application, (ii) $18,000 for the gas allocation of the security upgrades measures the Company is seeking to install, and (iii) $75,000 for natural gas safety customer outreach and education programs. As discussed in the direct testimony of Company witness Scerbo, the remaining $127,000 is comprised of (i) $57,500 for additional gas conversion rebates, (ii) $45,000 for natural gas conversion outreach and education programs.

Q. Please discuss the Company's initiative to expand the MyAccount mobile application.

A. The Company's MyAccount application allows our customers to interact with the Company through their mobile communication devices. More and more customers are seeking to communicate with the Company through smart phone technology. Customers want the ability to pay bills on-line through their smart phone and obtain service restoration times electronically during storm outages. The incremental funding request will be used for maintenance and support costs to expand the MyAccount functionality to handle e-mail informational blasts to our customers and allow customers to access the Company's outage map through their smart phones.

Q. What are the current limitations of the MyAccount application and why does the Company wish to expand the application?

A. The MyAccount application is currently limited to certain transactions that are storm or outage related. An upgrade to the system will allow the Company to employ an e-mail service company to provide us with robust e-mail deliverability services to our customers and stakeholders. With this e-mail service company, the Company can target emails to specific customers (*e.g.*, by customer type, counties, towns, zip codes and streets), allowing the Company to send e-mails with more specific and relevant information. The services provided by the upgrade include: account services; monthly platform licensing fee; HTML and text e-mail execution; customer service set up and testing; creative services and technical deployment.

Customers are demanding real time information and updates when the Company is experiencing service outages or interruptions. As smart phone technology becomes more prevalent and sophisticated, customers require their service providers to interact and communicate with them immediately and in a technologically sophisticated manner. The advancements we are requesting to the MyAccount mobile application will allow the Company to meet these customer expectations.

Q. Please discuss the Company's request for an additional $161,000 of funding for security upgrades.

A. The Company is requesting additional funding to upgrade its existing video security and intrusion systems for its gas and electric services. To adequately safeguard its gas and electric facilities, O&R continues to incorporate comprehensive security processes to protect the Company, its employees and its assets. The security platform we have implemented to date consists of CCTV, intrusion detection, card access and DVR equipment. The Company continues to add facilities where we have these systems into our Security Operations Center ("SOC") where we monitor them, on a 24 hour, seven day per week basis. The SOC provides a central point for coordinating response protocols for security events and alarms. The Company needs to upgrade outdated equipment and video and security applications to advance security technology for many Company locations, including gas and electric infrastructure.

Q. Please discuss some of the security upgrades the Company seeks to implement.

A. Security concerns and risks are evolving on a daily basis. What was once considered either state of the art technology or a location that was sufficiently protected may now be under-protected or a potentially exposed location. For example, previous generations of security camera technology may only offer a limited line of sight review of the protected location. Current security requirements require an expanded and broader view of infrastructure assets and locations. The installation of advanced camera and security technology will allow for an expanded security perimeter.

Q. Please discuss the Company's request to fund an additional $75,000 in natural gas safety customer outreach and education programs.

A. The Company has adopted the Natural Gas Association's ("NGA") regional Pipeline Public Awareness Program and also has a natural gas outreach and education plan that is submitted annually to the DPS Office of Consumer Policy. The requested additional funding will allow the Company to expand its outreach.

Q. What type of additional activities does the Company propose?

A. The Company proposes to add radio and television advertising placements in order to reach more customers.

Q. What are the Company's current methods for relaying gas safety messages?

A. The Company takes advantage of bill inserts to communicate gas safety messages to our customers. In 2014, O&R placed gas safety messages in four out of five issues of *@home*, the Company's newsletter included in bill inserts. O&R has also included the message in customer buckslip inserts that also addressed the *Call 811 Before You Dig* message. Three natural gas safety brochures also were included with customers' bills. These brochures covered topics such as how to detect a gas leak and how to report a gas leak. In October 2014, the Company inserted in customers' bills a "Smell Gas. Act Fast" odorant card. These cards are also being inserted in new customers' bills.

Q. Please continue.

A. In addition, O&R continuously takes advantage of promoting gas safety through postings on the Company's social media, Facebook, Twitter, You Tube, and website. The Company distributes e-mail blasts to customers and gas safety materials at home shows in the region. O&R places advertising in local print publications, as well as on local radio stations. The Company participates in the NGA Regional Public Awareness media campaign for two weeks of radio spots and eight weeks of television spots which offer general messages on gas safety and offer us the ability to use a logo to identify our company.

Q. What areas of natural gas safety outreach need enhancements?

A. Based on focus groups and telephone surveys that were conducted in conjunction with Con Edison, O&R learned that that many customers are aware of the smell of natural gas and have an understanding of leak detection, however, they may be reluctant to respond to a gas leak or to report it. The Company seeks to propel consumer awareness of the smell of gas into action and have adopted a slogan “Smell Gas. Act Fast.” To change customer behavior, O&R needs more aggressive ad placements to supplement and support our current outreach activities. The Company currently advertises in local weekly papers and have banner ads on one local online news channel. Radio spots run on small stations within the service territory. Our current print and electronic communication channels have a “niche” local following, but O&R seeks to expand our reach. O&R’s goal is to advertise with Pamal Broadcasting on WHUD, the largest radio station with the strongest frequency serving our geographic area in the Lower Hudson Valley. As an example, one of our smaller stations, WJGK, has an average market share of 2.3, while WHUD’s is at 7.2. The Company would also advertise on Cablevision, placing television ads on our local cable news channel, as well as other channels that fit our demographic and budget.

Q. Why do you need the additional funding?

A. Our goal is to advertise with the largest radio station with the strongest frequency serving our geographic area in the Lower Hudson Valley. We also seek to place television ads on our local cable news channel, as well as other channels that within our service territory. These additional channels have good audience penetration in our communities, but are not as expensive as the channels and networks serving the larger New York City market.

Our current total outreach budget for gas safety is $147,000. The additional $75,000 for TV and radio will increase our audience penetration and contribute to our goal of having more people know how to detect a gas leak and what to do.

IX. GENERAL INFLATION FACTOR

Q. Please describe the general escalation rate you mentioned earlier in your testimony and how it was applied in developing projected revenue requirements.

A. The general escalation rate is applied to historic costs that are anticipated to increase at the rate of inflation as measured by the Gross Domestic Product ("GDP") price deflator. The labor component was removed from each element of expense and then the residual amounts were escalated by the GDP price deflator for most elements of expense subject to escalation. For certain expenses the escalation factor is specifically tailored to the particular expense item such as medical insurance costs as addressed by the Company's Compensation and Benefits Panel.

The actual GDP deflator used to escalate various elements of the cost of service as addressed throughout our testimony and the testimony of other witnesses was published on July 30, 2014 by the Bureau of Economic Activity. The quarterly forecasts for 2014 and 2015 are from the Blue Chip Economic Indicators dated July 10, 2014. The annual forecast for 2016 is from the Blue Chip Economic Indicators dated March 10, 2014. Utilizing these forecasts, the projected cumulative effect of inflation from the average of the Historic Year through the average of the Rate Year is 4.12%. Details supporting this percentage are shown on Schedule 13 of Exhibit AP-E3 and Exhibit AP-G3.

As with past practice in Orange and Rockland rate cases, the inflation factors should be updated to reflect the latest available inflation forecasts in the final revenue requirements in these proceedings.

X. COST ALLOCATIONS

Q. Please describe the cost allocation procedures currently used by Orange and Rockland to assign or allocate costs to its utility subsidiaries and between the Company's electric and gas operations.

A. Orange and Rockland's wholly owned utility subsidiaries are Pike, which provides electric and gas service in Pennsylvania, and Rockland Electric, which provides electric service in New Jersey. The Company charges costs that it incurs for labor, material and services directly to the responsible utility (*i.e.*, Orange and Rockland, Pike, or Rockland Electric) to the extent practically identifiable, through the use of time sheet reporting and Company specific account numbers. In those instances where work performed is for the common benefit of two or more of the utilities, costs are allocated through the use of common expense clearing accounts and allocations.

Historically, the common expense or cost allocations among Orange and Rockland, Rockland Electric, and Pike for electric and gas O&M costs, customer expenses, administrative and general expenses and carrying costs on the Company's net utility plant investment have been pursuant to the contractual terms of Joint Operating Agreements between Orange and Rockland and Pike, and Orange and Rockland and Rockland Electric, respectively. The Commission has reviewed and approved these Joint Operating Agreements.

The Joint Operating Agreement between Pike and O&R was updated during 2014 in connection with a recommendation in a management and operations audit of Pike by the Pennsylvania Public Utility Commission. The update was to reflect the current corporate structure within Consolidated Edison, Inc., affiliate relationships and cost allocation methodologies. The updated AIA has been filed with the Commission and the Company has consulted with the Office of Accounting, Audits and Finance. No ratemaking consequences of the updated AIA are expected.

As approved by the Commission in Case 99-G-1695 and as applied in all subsequent O&R gas and electric rate cases, the methodology followed by the Company in this proceeding to allocate total common costs between Orange and Rockland's electric and gas operations is based on a formula that factors in utility plant investment, O&M expenses, and payroll expenses.

XI. RECONCILIATIONS AND DEFERRED ACCOUNTING

Q. Does the Company currently employ the use of deferred accounting as permitted under Accounting Standards Codification 980, Regulated Operations (formerly SFAS No. 71)?

A. Yes, the Commission has authorized the Company to utilize deferred accounting to match the recognition of expenditures with the recovery of certain costs when the costs are either beyond the Company's direct control and therefore not subject to reasonable estimation, the timing of the actual expenditure is not certain, or in furtherance of Commission policy objectives such as the reconciliation mechanisms for SBC and Energy Efficiency Portfolio Standard charges. The Commission similarly employs deferral accounting regarding the Company's actual, potential or unexpected receipts of various revenues and credits. This approach is intended to protect the interests of customers and investors by avoiding a “windfall” for one or the other and the amortization of deferred costs and credits over subsequent periods serves to mitigate rate volatility.

Q. Is the Company proposing to continue the use of deferral accounting for the cost and revenue items that the Commission has previously authorized and are currently in effect?

A. Aside from those limited exceptions discussed below, the Company proposes to continue all deferred accounting and reconciliation mechanisms (some with modifications) that are in effect under the Company’s current electric and gas rate plans. The reconciliation mechanisms that the Company proposes to continue include, but are not limited to, the existing supply rider provisions such as the MSC, ECA, GSC and MGA, reserve accounting for major storm costs (addressed earlier in our testimony) and reconciliation mechanisms for pensions and OPEBs, SIR costs, low-income program costs, property taxes and that related to legislative, regulatory and related actions. The Company also proposes to continue the reconciliation mechanism for tree trimming costs, which is a downward-only reconciliation mechanism in favor of customers. The Company also proposes to continue the implementation of the electric and gas revenue decoupling mechanisms in effect under the current electric and gas rate plans with certain modifications to the electric mechanism as explained by the Company’s Electric Rate Panel.

For all mechanisms based on established targets, the target levels in effect under the current electric and gas rate plans should be updated to reflect those established in these proceedings.

Q. Why is the Company proposing, with very limited exceptions and modifications, to continue the existing reconciliation mechanisms?

A. Those related to costs that are significant, highly variable even in the near term and not subject to reasonable estimation, protect the interests of customers and investors and are appropriate. For example, the Company is subject to the Commission's Policy Statement on Pensions and Other Postretirement Benefits and is required to true-up its annual pension and OPEB costs to the levels provided in base rates "to protect companies and ratepayers from potential volatility." Other reconciliation mechanisms, such as those related to the SBC and low-income program benefits and the supply rider mechanisms, are in furtherance of public policy objectives. Moreover, continuing these true-ups in connection with a one-year rate determination could enable the Company to delay the need for rate relief at the expiration of the Rate Year.

Q. You mentioned earlier that the Company proposes to continue a property tax reconciliation mechanism. Is the Company proposing to continue the reconciliation mechanism as it is currently designed?

A. No. The Company is proposing that the property tax reconciliation mechanism be modified.

Q. Please describe the currently effective property tax reconciliation mechanism.

A. The reconciliation mechanism, which is similar for electric and gas, is a partial true-up of property tax expense. The mechanism provides for an 86% / 14% (customer / Company) sharing of variations in tax expense that are due to higher or lower property tax assessments than were forecast when setting the property tax rate allowance. Variations in property tax expense caused by differences between actual property tax rates and those forecast when setting the property tax rate allowance are fully deferred.

Q. Is the Company proposing a change to the reconciliation mechanism?

A. Yes.

Q. Please explain the Company's proposed modifications to the property tax reconciliation mechanism.

A. The Company believes that a full and symmetrical property tax mechanism would be appropriate and should be established. The Company's Property Tax Panel explains at length why property taxes are not subject to reasonable estimation. These reasons include, but are not limited to, the Company's property taxes being subject to the vagaries of municipal management, economic circumstances, and political influences.

Absent a full and symmetrical reconciliation mechanism, these circumstances create the potential for a significant windfall for either customers or the Company at the expense of the other. There should be no such opportunity and the current sharing mechanism does not foreclose the possibility. As the Company's Property Tax Panel explains, the Company has historically sought to minimize its taxes and that continues on an ongoing basis – it is a normal course of business for the Company.

In addition, it should also be noted that regardless of the process by which the current rate cases are concluded (litigated or settled), a large portion of the Company's property taxes for the Rate Year will most likely be unknown in time to be reflected in the final revenue requirements.

The difficulty in forecasting property taxes even for a single rate year is evidenced by the significant first rate year variation that occurred under the Company's current electric and gas rate plans. Under the current gas rate plan, the rate allowance for property taxes was $10,051,000 for the first rate year of the twelve months ended October 31, 2010. Actual gas property tax expense for that period was $11,600,000, a variation of $1,549,000, or 15.4%. Under the current electric rate plan, the rate allowance for property taxes was $28,060,000 for the first rate year of the twelve months ended June 30, 2013. Actual electric property tax expense for that period was $29,736,000, a variation of $1,676,000, or 6.0%. Those variations are also significant when viewed from the perspective of return on equity. With no reconciliation mechanism in place under the rate plans, the under collection of property taxes in the first rate year would have reduced the earned return on common equity by approximately 70 basis points for gas and approximately 30 basis points for electric.

Q. What portion of Rate Year property taxes will not be known in time for them to be reflected in the final revenue requirements in these proceedings?

A. We assume and support the customary practice of updating to use the latest known property taxes at a time when it is reasonable for final revenue requirement calculations to reflect them.

Even in that event, however, we estimate that County and Town ("CT") taxes will be known for only the first two months (November and December 2015) of the Rate Year. CT taxes for the remaining ten months of the Rate Year will not be known in time to be reflected in the final revenue requirements in these proceedings because they will not be known until approximately January 2016 when the Company will pay its CT tax bills for the 2016 calendar (fiscal) year. With respect to school taxes, which are on a fiscal year from July through June, the Company's actual taxes for only two-thirds of the Rate Year might possibly, but unlikely will, be known. That is because the school taxes for the July 2015 – June 2016 fiscal year will not be known until approximately October 2015 when the Company will pay school tax bills – a time likely to be too late to be taken into account in the final revenue requirements.

Q. Should there be a concern that a full and symmetrical property tax mechanism will lessen the Company's incentive to take action to minimize its property tax expense?

A. No, not even in the context of a single-year rate plan. There should be no concern that full reconciliation would diminish the Company's incentive to minimize its property taxes and there is no reason to not provide for it because a rate case does not result in a multi-year rate plan. The Commission has addressed those matters.

In Case 08-E-0539 the Commission set rates for Con Edison outside the context of a multi-year rate plan and provided for a full and symmetrical reconciliation of property taxes. Addressing the disincentive issue on pages 106-107 of its April 24, 2009 order in that case, the Commission said:

> We share DPS Staff's concern about removing an incentive for the Company to minimize its property tax expenses. However, the record in these cases shows that the Company has aggressively sought to minimize its property tax assessments. Indeed, there is no assertion to the contrary. Moreover, our long standing policy is that a utility will be allowed to retain a share of property tax refunds, frequently in the 10-15% range, to the extent it can be established conclusively that the utility's efforts contributed to that outcome. Taking these two factors

> into account, we conclude that the Company already has and will retain an incentive to minimize its property tax assessments.
>
> Given the magnitude of the Company's property taxes, the relative uncertainty about the impacts of the economic downturn that we consider unique, and that the Company will continue to have an incentive to minimize its property tax assessments, we are adopting the judges' recommendation for full or bilateral reconciliation of property taxes. (footnotes omitted)

The Commission's explanation of why a full reconciliation mechanism was appropriate in Case 08-E-0539 remains applicable here in the context of a single rate year filing. The Company has continued to aggressively pursue minimization of its property taxes. Although economic circumstances the Commission referred to as "unique" are not indicative of today's economic environment, it can hardly be said that taxing entities no longer face fiscal stress or uncertainty, which prevents the ability to forecast future tax responsibility with any degree of certainty.

Q. What do you propose regarding the sharing between the Company and its customers of any property tax savings the Company might obtain?

A. The Commission should continue the 86% customer / 14% Company sharing mechanism for property tax refunds and assessment reductions (net of costs incurred to achieve them) that the Company secures, that exists under the current electric and gas rate plans. The sharing mechanism is consistent with established Commission practice to incent utilities to pursue property tax reductions as the Commission noted in the 2012 Rate Order (p. 30). Moreover, as explained by the Company's Property Tax Panel, the Company's efforts in this regard have produced material benefits for customers.

Q. Are there any other deferral or reconciliation mechanisms that are currently in effect that the Company proposes be modified?

A. Yes. The Company proposes that modifications be made to the deferral or reconciliation mechanism related to R&D expenses. The Company's proposal with regard to R&D expenses is offered primarily for simplification purposes. The Commission has long provided for the reconciliation of R&D expenses, as demonstrated by its Technical Release 16 issued February 6, 1980. The Company's current gas rate plan provides for a full, symmetrical reconciliation of R&D expenses using the complicated revenue matching approach described in Technical Release 16. In contrast, the Company's current electric rate plan provides for full, symmetrical reconciliation by simply comparing the actual expense to the rate allowance. This is the approach employed for reconciliation mechanisms related to other, and much larger, expenses. The Company proposes to continue the R&D expense reconciliation mechanism contained in the Company's current electric rate plan and that the same reconciliation mechanism be adopted for gas R&D expense.

In addition, the Company's Income Tax Panel explains Company proposals related to accounting and rate treatment of income tax benefits associated with plant-related items and property taxes.

Q. Which deferral or reconciliation mechanisms that are currently in effect does the Company propose be terminated?

A. The Company proposes that the deferral or reconciliation mechanisms that are currently in effect related to Section 263A of the IRS Code, Bonus

Depreciation, long-term debt costs, gas stimulus project O&M expenses, "hyper-inflation" and net plant rate base be terminated.

Q. Please explain the Company's proposal to terminate the deferral or reconciliation mechanism related to Section 263 of the IRS Code.

A. The mechanism, which is currently in effect for both electric and gas, provides that the difference between the actual rate base effect of deferred taxes related to deductions under Section 263A of the IRS Code and the rate base amount reflected in rates is subject to carrying charges. Such carrying charges are either payable to or recoverable from customers based on the amount by which the rate base reduction for this item reflected in rates is either more or less than the actual rate base amount. The mechanism should cease because it is no longer necessary. The issue between the Company and the IRS giving rise to the mechanism in past rate cases has been resolved.

Q. Please explain the Company's proposal to terminate the deferral or reconciliation mechanism related to Bonus Depreciation.

A. The mechanism, which is currently in effect for both electric and gas, provides that the difference between the actual rate base effect of deferred taxes related to depreciation deductions using the highly accelerated Bonus Depreciation rates and the rate base amount reflected in rates is subject to carrying charges. Such carrying charges are either payable to or recoverable from customers based on the amount by which the rate base reduction for this item reflected in rates is either more or less than the actual rate base amount. The availability of Bonus Depreciation expired December 31, 2013 according to federal tax law. For purposes of this filing, the Company has assumed that Bonus Depreciation will not be available after that date. Because the rate base effects of Bonus Depreciation as of the time it expired are actual, known amounts, continuation of the reconciliation mechanism is not necessary. Should Bonus Depreciation again be authorized during the course of this proceeding in time to be reflected in the final revenue requirements, the Company would not oppose continuation of the reconciliation mechanism. In such event, the Company will provide Staff with a recalculation of federal income tax expense, deferred tax liabilities and the cash flow impact of the avoided federal tax payments. Should Bonus Depreciation again be authorized but not at a time so that it could be reflected in the final revenue requirements, the Company would not oppose continuation of the reconciliation mechanism. In such event, the Company proposes that the mechanism be continued.

Q. Please explain the Company's proposal to terminate the deferral or reconciliation mechanism related to long-term debt costs.

A. In general terms, the Company's current gas rate plan provides for the reconciliation of the cost of variable rate and fixed rate long-term debt costs. In contrast, the Company's current electric rate plan provides for the reconciliation of variable rate long-term debt costs but not fixed rate long-term debt costs. As explained by Company witness Saegusa, the Company's existing variable rate debt matures shortly before the start of the Rate Year making the reconciliation of variable rate long-term debt costs unnecessary. Given the reasonably stable environment of fixed long-term debt rates, the Company sees no need for the reconciliation of fixed long-term debt costs. As such, the currently effective mechanisms for gas and electric may reasonably be terminated.

Q. Please explain the Company's proposal to terminate the deferral or reconciliation mechanism related to gas stimulus project O&M expenses.

A. In general terms, the Company's current gas rate plan provides for the deferral of incremental gas O&M expenses resulting from municipal projects funded under federal economic stimulus programs. The Company has had no occasion during the years the gas rate plan has been effect to record any such deferrals and does not contemplate the need to do so during the Rate Year making termination of the deferral mechanism reasonable.

Q. Please explain the Company's proposal to terminate the deferral or reconciliation mechanism related to "hyper-inflation."

A. The Company's current electric and gas rate plans each contain a provision that, in general terms, provides for the deferral of the effect on certain Company expenses of inflation in excess of a stated inflation threshold. The Company believes that such a provision warrants consideration in the event parties to these proceedings engage in settlement discussions regarding a multi-year rate plan but given that the Company's filing seeks approval of what is commonly referred to as one-year rates and the Company's current assessment that near term inflation rates will be modest, the Company is willing to forgo the protection of a "hyper–inflation" deferral mechanism.

Q. Please describe the deferral or reconciliation mechanism related to net plant rate base that the Company proposes be terminated.

A. The Company's current electric and gas rate plans each contain a mechanism that, in general terms, calls for the Company to pay back to customers carrying charges collected on net plant investment to the extent the actual net plant investment is less than that in the rate base reflected in current rates. The electric mechanism also provides for carrying charges on net plant investment to be collected from customers on the amount of electric net plant in excess of the rate base amount in a limited circumstance. The Company may collect carrying charges from customers for a net plant overage only to the extent of any net plant investment resulting from the amount of capital expenditures initially forecasted by the Company in that electric rate case but excluded from the development of net plant rate base. Both of these mechanisms should be terminated.

Q. Why should the current electric and gas net plant reconciliation mechanisms be terminated?

A. There should be a reasonable basis for establishing any reconciliation mechanism. Most reconciliation mechanisms are premised on the underlying costs being outside the Company's control and/or not subject to reasonable estimation. Such mechanisms are usually bilateral in nature.

Downward-only reconciliation mechanisms merely serve to limit discrete aspects of the Company's overall cost structure to actual expenditures up to a cap and therefore limit the Company's flexibility to effectively manage its operations and shift resources as needed. Downward-only reconciliation is also inherently inequitable because it addresses only the potential for forecasts being too high, while not reasonably addressing the just as likely potential for forecasts being too low. The net plant reconciliation mechanisms also do not recognize the potential for offsetting spending effects of certain projects above or below forecasts where the net result is within the capital expenditure forecast but actual net plant rate base differs from used when rates were set. For example, actual net plant rate base may exceed that used in setting rates not because the Company has overspent the rate case capital expenditure forecast but, rather, because the facilities entered service sooner than projected, thereby providing earlier than expected benefits to customers.

It is important to note that the Company's proposal to terminate the net plant mechanisms is accompanied in this filing by the Company's willingness to continue the current downward-only reconciliation mechanism for tree trimming expense and the Company's proposal, discussed below, to establish a new downward-only reconciliation mechanism related to ATIP expense.

Q. Does the Company propose that any deferral or reconciliation mechanisms not currently in effect be established?

A. Yes. First, as explained in the testimony of the Company's Compensation and Benefits Panel, the Company proposes to defer for customer benefit the amount by which expense for payments under ATIP, the variable component of the non-officer management pay plan are less than the rate allowance for this expense. Next, we note that the Company's REV Panel proposes a cost recovery mechanism related to future REV investments that entails the use of deferral accounting.

Q. Are there any other subjects you would like to address regarding the use of deferral accounting or reconciliation mechanisms?

A. Yes. It must be recognized that there are large-scale changes to the operation of the utility industry in the State under consideration by the Commission. In Case 12-M-0476 and related cases regarding the competitive retail energy mass markets subjects being addressed include, but are not limited to, customer enrollment, net metering, data availability, facilitation of energy-related value-added services, ESCO eligibility and POR programs. Wider-scale, fundamental changes are under consideration in the Reforming the Energy Vision proceeding (Case 14-M-0101). These proceedings make the Company's future operating costs subject to great uncertainty in amount, form and timing. The Company does not consider the instant electric and gas rate cases to be the proper forum for projecting the outcome of those pending generic policy proceedings and the effect of them, including attendant costs, on the Company. Neither should these instant rate cases result in the Company being at risk of harm because the outcomes of those proceedings were not captured in these rate cases. The Commission should take appropriate action here to produce that result.

XII. MULTI-YEAR RATE PLAN

Q. Has the Company included forecasted financial information for periods beyond the Rate Year in its filing?

A. Yes. The Company has included, for illustrative purposes only, financial information for two annual periods beyond the Rate Year. Exhibit AP-E6 for electric and Exhibit AP-G6 for gas present details of the revenue requirement for the Rate Year and the two following twelve-month periods ending October 31, 2017 and October 31, 2018. The Company's filing also includes capital expenditure projections that extend beyond the Rate Year. Those projections are for calendar years 2014 through 2018

Q. What is the basis of the financial information presented in Exhibit AP-E6 and Exhibit AP-G6?

A. Various Company witnesses have presented forecasts extending beyond the Rate Year. There are also proposals by various witnesses, including the Accounting Panel that would affect periods beyond the Rate Year such as amortization periods for deferred costs and credits.

Q. Is the Company proposing a multi-year rate plan for adoption by the Commission?

A. No. This filing seeks Commission approval of what is commonly referred to as one-year rates. The Company is, however, interested in pursuing, through settlement discussions with Staff and the parties, a multi-year rate plan. The financial information presented, along with the Company's thoughts on some possible features of a multi-year plan, could form a basis for discussions to address the myriad of details and complexities that must be addressed to establish a multi-year rate plan that fairly considers the interests of all stakeholders.

The Company believes that there is considerable merit to exploring a mechanism that would enable the rate plan to be extended beyond the initial multi-year term if certain agreed-upon circumstances exist. This would go beyond the "continuation provision" commonly included in multi-year rate plans. It could reach to automatic modifications of the rate plan that become effective at the end of the stated multi-year term. Examples of the type of mechanism would be a tracking mechanism for increasing plant investment or the effects of inflation. The rate plan might also provide for changes in the level of recovery of net regulatory assets.

Q. Does the three-year revenue requirement you present reflect a stay-out premium?

A. For purposes of illustration, the revenue requirements for the twelve-month periods ending October 31, 2017 and October 31, 2018 reflect an ROE of 9.85% and 9.95%, respectively (as compared to 9.75% for the Rate Year).

XII. FUND REQUIREMENTS AND SOURCES

Q. Are the Company's projected sources and applications of funds presented in the Company's filing?

A. Yes. Exhibit AP-E3, Schedule 11, presents a statement of sources and application of funds for the Rate Year for electric operations and Exhibit AP-G3, Schedule 11, does so for gas operations. Sources of funds are separated into internal and external sources. Internal sources would generally include the change in retained earnings during the Rate Year, depreciation, amortizations and deferred taxes. External sources would generally include long-term debt and common stock equity. The primary use of funds would generally be for construction and the retirement of debt. These exhibits identify those projected for the Rate Year.

XIII. FINANCIAL RATIOS

Q. Please describe Schedule 12 of Exhibit AP-E3 and Exhibit AP-G3.

A. Schedule 12 of those exhibits presents the historical and forecast interest coverage ratios for Orange and Rockland.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.

Normalizing Adjustments	Responsible Witness	Number of Positions	Hire Date	Annual Salary Per Man	Salary Total Base	O&R Electric O&M Exp,
Weekly Positions						
Operations Administrative Coordinator	Wayne Banker	1	Sep-14	$ 65,600	$ 65,600	$ 48,472
Subtotal		1			65,600	48,472
Monthly Positions						
Smart Grid Engineer	Smart Grid Panel	1	Oct-14	142,100	142,100	104,998
Smart Grid Engineer	Smart Grid Panel	1	Oct-14	142,100	142,100	104,998
Senior Systems Analyst (Smart Grid)	Smart Grid Panel	1	Jan-15	110,000	110,000	81,279
Central Information Group	Smart Grid Panel	1	Jun-14	76,000	76,000	56,156
Central Information Group	Smart Grid Panel	1	Sep-14	90,000	90,000	66,501
DCC Trainer	Smart Grid Panel	1	Jan-15	108,000	108,000	79,801
Operations System Support Specialist Business Analyst	Accounting Panel	1	Feb-14	80,000	80,000	45,640
Operations System Support Specialist Business Analyst	Accounting Panel	1	Mar-14	75,000	75,000	42,788
Operations System Support Specialist Business Analyst	Accounting Panel	1	Aug-14	80,000	80,000	45,640
Operations System Support Specialist Business Analyst	Accounting Panel	1	Aug-14	70,000	70,000	39,935
Operations System Support Senior Specialist Regulatory Support	Accounting Panel	1	Feb-14	88,100	88,100	50,261
Operations System Support Manager	Accounting Panel	1	Dec-13	141,500	141,500	80,726
Underground Engineer for Distribution Engineering Dept.	Wayne Banker	1	Aug-14	160,000	160,000	18,916
Subtotal		13			1,362,800	817,638
Total Normalizing Positions		**14**			**$ 1,428,400**	**$ 866,110**

Normalizing Adjustments	Responsible Witness	Number of Positions	Hire Date	Annual Salary Per Man	Salary Total Base	O&R Gas O&M Exp,
Weekly Positions						
Locator	Flannan Hehir	1	Oct-13	$ 47,154	$ 47,154	$ 47,154
Locator	Flannan Hehir	1	Oct-13	47,154	47,154	47,154
Locator	Flannan Hehir	1	Oct-13	47,154	47,154	47,154
Subtotal		3			141,462	141,462
Monthly Positions						
Locating Operating Supervisor	Flannan Hehir	1	Mar-14	93,400	93,400	93,400
Gas Mobile Systems Management	Flannan Hehir	1	Jan-15	100,000	100,000	100,000
Gas Mobile Systems Management	Flannan Hehir	1	Jan-15	100,000	100,000	100,000
Operations System Support Specialist Business Analyst	Accounting Panel	1	Feb-14	80,000	80,000	18,872
Operations System Support Specialist Business Analyst	Accounting Panel	1	Mar-14	75,000	75,000	17,693
Operations System Support Specialist Business Analyst	Accounting Panel	1	Aug-14	80,000	80,000	18,872
Operations System Support Specialist Business Analyst	Accounting Panel	1	Aug-14	70,000	70,000	16,513
Operations System Support Senior Specialist Regulatory Support	Accounting Panel	1	Feb-14	88,100	88,100	20,783
Operations System Support Manager	Accounting Panel	1	Dec-13	141,500	141,500	33,380
Subtotal		9			828,000	419,512
Total Normalizing Positions		**12**			**$ 969,462**	**$ 560,974**

Proposed Incremental Positions	Responsible Witness	Union/ Mgmt	Number	When Added Date	Annl Salary per Man	Salary Total Base	O&R Electric O&M Exp
New Proposed Incremental Positions							
Weekly Positions							
Distribution Equipment Technicians	Smart Grid	Union	4	Jul-15	$ 106,700	$ 426,800	$ 252,290
		Subtotal	4				
Monthly Positions							
Distribution Equipment Supervisor	Smart Grid	Mgmt	1	Jul-15	125,000	125,000	92,363
Smart Grid Engineers	Smart Grid	Mgmt	2	Jul-15	115,000	230,000	169,947
Permitting Specialist	Dave V. Work	Mgmt	1	Jul-15	105,000	105,000	19,396
Estimator / Scheduler Specialist	Dave V. Work	Mgmt	1	Jul-15	105,000	105,000	19,396
Distributed Generation Resource	Keith Scerbo	Mgmt	1	Aug-15	85,000	85,000	85,000
Sr. Specialist - NERC Compliance Program	BES Compliance Panel	Mgmt	1	Oct-15	110,000	110,000	88,000
Sr. Specialist - Compliance, Substation Operations	BES Compliance Panel	Mgmt	1	Oct-15	110,000	110,000	88,000
Sr. Specialist - Compliance, Control Center Operations	BES Compliance Panel	Mgmt	1	Oct-15	110,000	110,000	88,000
Chief Construction Inspector - Vegetation Mgt.	Electrical Infrastructure and Operations Panel	Mgmt	1	Jul-15	100,000	100,000	73,890
		Subtotal	10			1,080,000	723,992
		Grand Total	**14**			**$ 1,506,800**	**$ 976,282**

Proposed Incremental Positions	Responsible Witness	Union/ Mgmt	Number	When Added Date	Annl Salary per Man	Salary Total Base	O&R Gas O&M Exp
New Proposed Incremental Positions							
Weekly							
Locator	Flannan Hehir	Union	1	Nov-15	$ 85,387	$ 85,387	$ 85,387
Gas Fitter - Northern Division	Flannan Hehir	Union	1	Jul-15	65,666	65,666	65,666
Gas Fitter - Northern Division	Flannan Hehir	Union	1	Jul-15	65,666	65,666	65,666
Gas Troubleshooter - Northern Division	Flannan Hehir	Union	1	Jan-16	89,253	89,253	89,253
Gas Troubleshooter - Northern Division	Flannan Hehir	Union	1	Jan-16	89,253	89,253	89,253
		Subtotal	5			395,225	395,225
Management							
Compliance Supervisor - Northern Division	Flannan Hehir	Mgmt	1	Jul-15	100,000	100,000	100,000
Compliance Supervisor - Eastern Davison	Flannan Hehir	Mgmt	1	Jul-15	100,000	100,000	100,000
Gas Marketing Resources Program	Keith Scerbo	Mgmt	1	Aug-15	90,050	90,050	90,050
Gas Marketing Resources Program	Keith Scerbo	Mgmt	1	Aug-15	90,050	90,050	90,050
		Subtotal	4			380,100	380,100
		Grand Total	**9**			**$ 775,325**	**$ 775,325**

Q. Would the members of the Advanced Metering Infrastructure ("AMI") Panel ("Panel") please state their names and business addresses.

A. James L. Burke, 500 Route 208, Monroe, New York 10950; Donald E. Kennedy, Allisyn Glasser, Charmaine Cigliano, and Joe N. White, 390 West Route 59, Spring Valley, New York 10977.

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

A. **(Burke)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R" or the "Company"), where I hold the position of Director – Customer Meter Operations.

(Kennedy) I am employed by Orange and Rockland, where I hold the position of Director – Customer Energy Services.

(Glasser) I am employed by Orange and Rockland, where I hold the position of Project Manager – Operations System Support.

(Cigliano) I am employed by Orange and Rockland, where I hold the position of Section Manager – Customer Energy Services.

(White) I am employed by Orange and Rockland, where I hold the position of Department Manager – Technology Engineering in the Smart Grid Department.

Q. Please briefly outline your educational and business experience.

A. **(Burke)** I received a BS in Business Management in 1994 from the State University of New York, Old Westbury and an MS in Energy Management from the New York Institute of Technology in 1997. I started my career at the Consolidated Edison Company of New York, Inc. ("Con Edison") in 1974 as a

General Utility Worker and held various union positions. In 1986, I was promoted to District Manager – Manhattan Energy Services. In 1992, I was promoted to Manager of Sales and Marketing and held that position until joining Orange and Rockland in 2001 as Director – Customer Meter Operations.

(Kennedy) I received a Bachelor of Science in Math and Science from Empire State College in 2003 and a Masters Degree in Business Administration from Walden University in 2010. I have worked for Orange and Rockland since 1982 and held positions with increasing responsibility as Manager - Customer Accounting, Director - Customer Assistance, and Director - New Construction prior to my current position as Director - Customer Energy Services.

(Glasser) I received a Bachelor of Science degree in Management Information Systems in 1994 from the University of Connecticut and a Masters of Business Administration degree in Project Management from DeVry University in 2007. I have worked for Con Edison, Con Edison Communications ("CEC") and Orange and Rockland since 1998 in various positions. I started with Con Edison as a Management Intern and have held positions as a Financial Business Analyst with CEC, Senior Financial Analyst in Treasury, Senior Planning Analyst in Shared Services, and Systems Manager in Information Resources with Con Edison prior to assuming my present position as Project Manager in Operations Systems Support at Orange and Rockland.

(Cigliano) I received a Bachelor of Science degree from the Binghamton University in 1988 with a double major in Mathematics and Computer Science. My first employment thereafter was with Orange and Rockland as an Analyst with the Economic Research Department where I held positions of increasing responsibility. In 1998, as a result of the merger between Con Edison and O&R, I was offered a position as a Senior Planning Analyst in Con Edison's Electric Forecasting Department and in 1999 I accepted a Senior Planning Analyst position in Con Edison's Rate Engineering Department. In 2000, I returned to O&R as the Customer Information Management System Billing Team Lead and in 2004 I was promoted to Manager of Retail Access. In 2008, I was promoted to Section Manager - Customer Energy Services. I am currently responsible for the design, implementation and evaluation of O&R's portfolio of Energy Efficiency Portfolio Standard ("EEPS"), demand response, targeted demand-side management ("DSM"), renewable and low-income programs. I am also a member of the E2 Advisory Group which supports EEPS efforts.

(White) I have a B.S. Degree in Electrical Engineering from Auburn University and 15 years of increasing responsibility in utility operations and engineering. Prior to coming to Orange and Rockland, I spent 14 years at Southern Company where I worked in various capacities at the subsidiaries of Alabama Power Company, Savannah Electric & Power Company, Mississippi Power Company and Georgia Power Company in electric transmission, distribution systems and resource policy and planning. I have a background in the areas of Transmission Area Maintenance, Transmission Line Design, Distribution Region Operations, and Distribution Material Standards. I served as the Lead Product Engineer for Insulators and Lighting Materials for all of Southern Company. Within the electric utility industry, I served on various regional committees as part of the Southeast Electric Exchange Working Groups for Overhead, Underground, Joint-Use, Transformers, NESC and Pole Line Hardware Committees.

I joined Orange and Rockland in 2013 as a Principal Engineer in the Reliability Department where I analyzed outage data, frequent customer complaints, and commission inquiries. I led teams to identify and address worst performing circuits within the service territory and helped select circuits that could benefit from storm hardening projects. In October 2014, I became Department Manager – Technology Engineering in the Company's Smart Grid Department.

Q. Have you previously submitted testimony before the New York State Public Service Commission ("NYPSC")?

A. **(Burke)** Yes. I have submitted testimony to the NYPSC in Case 11-E-0408.

(Kennedy) Yes. I have submitted testimony to the NYPSC in Case 08-G-1398.

(Glasser) No.

(Cigliano) Yes. I have submitted testimony to the NYPSC in Case 11-E-0408.

(White) No.

Q. What is the purpose of the Panel's direct testimony in this proceeding?

A. The Panel will address the Company's proposal to install AMI for both electric and gas customers throughout the Rockland County portion of the Company's service territory. This is the first phase of the Company's installation of AMI throughout all of its service territory.

Q. Please describe the Company's Phase One AMI proposal.

A. Commencing in 2016, O&R plans to install, over a five-year period, an AMI system in the Rockland County portion of O&R's service territory which will involve approximately 115,800 electric metering end-points and 91,200 gas metering end-points. The installation of an AMI system will allow the Company to meet developing customer expectations, assist the Company in facilitating the policy objectives articulated by the NYPSC in its Reforming the Energy Vision proceeding ("REV Proceeding").[1] The installation of an AMI system also will provide significant benefits to customers in the areas of: managing their energy use, participation in Energy Efficiency ("EE") and Demand Response ("DR") product offerings, improved electric outage detection and restoration, and enhanced system engineering and planning. In short, AMI is an enabling technology. It is also an investment that will reduce operating costs.

Q. How will the deployment of AMI facilitate meeting the NYPSC's REV-related policy objectives?

A. AMI is an integrated system of meters, communications networks, and data management systems that enable two-way communication between utilities and customers. It will play a critical role in the integration of new technologies and innovations across the electric grid, by monitoring energy moving in and out of customer premises. As the electric grid evolves into a broad platform for integrating new energy services and technologies, consistent with the NYPSC's REV-related policy objectives, the ability to connect legacy assets and systems and integrate new ones is critical. AMI supports this evolution. In addition, the

[1] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Instituting Proceeding* (issued April 25, 2014) ("REV Order").

data collected by AMI systems opens the door for greater integration of new resources and new energy services for customers. The Company supports the full rollout of AMI to all customers as a means to enable the mass market, by capturing customer information which can be used by utilities and third party suppliers to enhance customer services and further engage customers in programs to reduce energy consumption and become aware of energy price signals.

In addition, AMI will create a basis from which more granular data can be made available for all stakeholders. While enhancing customers' ability to manage their energy use and market options, thereby enabling increased levels of energy efficiency and demand reduction, AMI will facilitate the Company's efforts to provide enhanced opportunities for customer engagement through new rates (*e.g.*, time of use rates that accurately reflect the agreed upon cost of energy provided by different entities during discreet periods of time).

Similarly, AMI will allow the Company and other entities to provide more flexible billing options to customers. By allowing meters to be read at any time during the month, AMI allows for customized billing (*i.e.*, billing will no longer constrained by a given read date or trip date each month).

Q. Please continue.

A. AMI functionality also supports improvements in system-wide efficiency. Operational benefits include the capability to identify selective real time load and point monitoring to support fault detection, and to perform real time load control based on more granular information. AMI will enable the Distributed System Platform ("DSP") by providing an avenue through which the utility can monitor real time information relating to energy flowing in and out of the electric distribution system by source and location.

The Company would note that Staff's Straw Proposal on Phase One Issues, dated August 22, 2014, identifies market operations, grid operations and integrated system planning as three regulated monopoly functions of the DSP to be implemented under REV. AMI directly supports each of these functions. DSP market operations need to be transparent, flexible, scalable and efficient. AMI will facilitate market operations by providing all stakeholders with enhanced, useful levels of granular data. AMI supports grid operations by enhancing visibility into distribution networks and facilitating grid automation down to the meter level. A robust communication network, installed as part of AMI deployment, will enhance fault detection schemes, thereby strengthening system reliability. Finally, AMI functionality facilitates integrated system planning by providing an increased level of information regarding circuit loading and distribution level needs, which will assist in integrated distribution system planning.

Q. Are there any programs that O&R is proposing related to REV that an AMI deployment would support?

A. Yes. As discussed in the direct testimony of the Company's REV Panel and Electric Infrastructure and Operations Panel, the Company is seeking to defer the construction of a new Pomona Substation. Absent the Company's implementation of the proposed Distributed Energy Resource ("DER") demonstration program, the Company will need to commence construction of the new Pomona Substation by 2019, with construction completed by 2021.

In order to facilitate third party involvement in the DER demonstration program, the Company plans that the initial roll out of AMI will occur in the Pomona area. As discussed by the REV Panel, by providing developers and marketers with granular customer usage data, AMI will enhance their ability to offer customer-specific solutions. As its AMI system becomes operational, the Company will explore the feasibility and benefits of implementing tariffs to charge third parties for aggregated customer data (subject to all appropriate customer information protections).

Q. Please continue.

A. The Company's proposed DER demonstration program will focus on the implementation of lower cost DER alternatives in northwest Rockland County that will reduce peak demand, improve system reliability and resiliency, and allow for the postponement of substation construction. As discussed by the REV Panel, the Company will not retain a single contractor for the DER demonstration program, but rather will seek multiple solution providers so that numerous approaches and technologies can be evaluated to determine the best aggregate solutions. In other words, the Company will be acting as the aggregator of a variety of solutions, taking on a more proactive management and implementation role. The alternatives to be considered by O&R include:

- Targeted EE;
- Clean (*i.e.*, gas fired and solar) distributed generation ("DG");
- DSM (*i.e.*, a/c and appliance cycling);and
- Energy storage.

Q. Please describe how AMI will enable customer engagement in the management of their energy usage.

A. Advanced metering functionality provides transparency on how and when customers use energy. This information can be paired, when applicable, with corresponding price signals associated with that usage. Access to hourly usage and dynamic pricing data will allow for the development of value added services that will enable customers to better control their energy usage and bill. Once customers better understand their energy usage, they will be more likely to participate in product offerings that will increase their level of energy efficiency and demand response. With AMI, customers can see the positive impact of their energy conservation efforts real-time and increase their understanding of how they use energy on a daily, weekly and seasonal basis. Providing the tools to manage energy consumption fosters an environment where customers are both engaged and empowered to proactively optimize their energy cost choices in a more dynamic energy market. Customers with access to more granular data are more likely to reduce their energy usage. This was illustrated in a U.S. Department of Energy ("DOE") study released in January 2014, indicating that of the 3,000 pilot program participants in Central Maine Power's test group who received weekly usage and cost reports, 70% said they took action to reduce usage which resulted in 1.8% reduction in their electricity consumption.

Q. Please describe how AMI will provide the platform technology for customer participation in EE and DR product offerings.

A. AMI will provide the platform for EE and DR product offerings through real-time two-way communications. For example, AMI is a prerequisite to the Company providing a peak time rebate to those customers who reduce their energy usage during a peak period or emergency event. The Company is not aware of another viable, currently available technology that will confirm changes in use at the customer level and communicate them use to the utility on a real-time ongoing basis. Customers actively engaged in managing their usage can respond to a signal for an event by turning off non-essential equipment, raising the set point for cooling equipment, or postponing tasks until after the event. Similarly, a device like a smart thermostat can be programmed to respond to a peak price or critical event by automatically increasing the set temperature for cooling to reduce usage. Customers can see in real-time the effect that their actions had on lowering their usage. The Company can verify whether customers responded to the critical event and then reward the customers with a peak time rebate for that behavior. By providing customers with their own unique usage profile and the knowledge and tools to manage that profile, customers can ultimately lower their energy usage and better manage their energy bill.

Q. Please describe how the deployment of AMI would improve electric outage detection and restoration.

A. The deployment of AMI will enhance the Company’s storm restoration and response capabilities through integration of the AMI application with the Company’s Outage Management System (“OMS”). The interface between AMI and OMS will facilitate the integration of outage data from the AMI application. OMS will process this data and incorporate it into its predictive logic business rules to predict the root cause of outages. In addition to receiving outage data, OMS will be able to use the same interface to receive outage data on meters that are pinged within the AMI application. This data will be used to identify nested outages during the restoration process. A nested outage is a service interruption that remains for a particular premise or area subsequent to the restoration of service to the main lines of a circuit. The availability of this data will allow the Company to identify areas that still require restoration and confirm when all outages have been restored and in some cases avoid sending restoration crews to locations where service has already been restored. Additionally, on normal non-storm days or “blue-sky” days, AMI will enable Company personnel to ping a meter upon receipt of an outage report to verify if voltage is present at the customer’s premise. If voltage is present, the customer would be informed that the outage is due to an internal customer premise issue which will require that the customer obtain the services of an electrician and a crew will not be sent, unnecessarily, to the incident reported.

Q. How does having AMI data benefit engineering and planning?

A. Implementation of an AMI platform will enable the Company to obtain, store and analyze actual hourly energy usage data from its customers. By using this data as input for the Company’s Integrated System Model (“ISM”) and coupling it with the Company’s sophisticated analysis tools, a more accurate simulation of system electrical performance will be realized. This will benefit planning and operations by allowing decisions on prioritization of major capital expenditures to be made with a higher degree of confidence. When used in conjunction with analysis of real time systems, actual data provides the ability to better monitor the health of the system in a real-time snapshot. This monitoring will allow for improved transformer load management and system modeling.

Q. How does having AMI data improve transformer load management?

A. Currently transformer load modeling uses load research data derived from a sample population of load interval recorders installed at a customer's premises. KWHr to KW conversion factors, diversity curves and load profiles are derived based upon the class of customer (*i.e.*, residential, small commercial, and industrial). These statistics are generic to all customers within each rate class.

Actual usage for each customer is unique to the customer. For example, a 2,500 square foot single-family home with two people living in it can have a much different hourly load shape than a 2,500 square foot home occupied by four to six people, but the load research statistics and load profile used in the modeling is the same for both because both are in the residential rate class. Distribution transformer loading analysis uses the load research data in conjunction with the hourly load profile to determine the time varying loading of the transformer. By using actual data, it is expected that the economic loading of distribution transformers will improve by better matching load to transformer capacity which reduces transformer losses and insures that existing transformer capacity is optimally utilized. This minimizes transformer overloads that can cause low voltage conditions which adversely affect customer equipment and cause excessive transformer energy losses. Actual customer load data supports more accurate forecasting of distribution transformer loading, thereby enabling proactive identification and upgrade of transformers approaching their economic loading limits.

Q. Does having AMI data improve engineering system modeling?

A. Yes, system modeling is improved because actual distribution transformer time varying loading and load durations are known as opposed to having been derived from generic load research statistics. The higher degree of accuracy supported by the use of AMI data improves the precision of the modeling.

Q. Why is enhanced accuracy in system modeling important?

A. Enhanced accuracy in system modeling allows for increased confidence in the timing of capital expenditures, aligning them more closely to the timing of system needs while improving project prioritization and capital budgeting. Improved accuracy in system modeling allows circuitry to be more fully optimized through improved load balancing, optimal sizing and placement of fixed and switched shunt capacitors, minimizing system losses and enabling conservation voltage reduction ("CVR") techniques resulting in reduced energy consumption. Additionally, as DG is introduced to the ISM, AMI will accurately capture the generation profile of that resource and assist in developing the load profile not only for that premise, but the area in which the generator is essentially connected. With the AMI input, the entire system and generation profile can be integrated and reviewed for peaks, demand reduction contingencies and monitoring (and future controlling) capability of generation sources such as solar and micro grids. As these innovative technologies are implemented, AMI metering will enable the Company to closely monitor and model the load characteristics, so that these technologies are integrated and utilized for the benefit of both the consumer and the Company.

Q. Has the use of AMI and advanced metering technology expanded?

A. Yes, as discussed in a recent report from the Federal Energy Regulatory Commission ("FERC") on the "Assessment of Demand Response and Advanced Metering," issued in October 2013 ("Advanced Metering Report"), there has been a significant growth of AMI in the United States. The report indicated a penetration rate of 22.9 percent. Other sources report similar numbers. Data collected by the Institute for Electric Efficiency ("IEE") in May 2012 indicates that such meters represent approximately 23.5 percent of the 166.5 million meters installed. More recently, IEE, which has changed its name to Innovation Electricity Efficiency, released an August 2013 report indicating that as of July 2013 almost 46 million advanced meters have been installed in the United States. IEE's recent data implies a penetration rate of approximately 30 percent for these meters. Lastly, a report published in September 2014 from the Edison Foundation, Institute for Electric Innovation, indicates that over 50 million AMI Meters have been deployed in the United States, covering over 43 percent of U.S. homes.

Q. Has there been government support to increase AMI metering deployment?

A. Yes, there has been an increase in support for the deployment of AMI meters at the Federal level. The American Recovery and Reinvestment Act of 2009 ("ARRA") appropriated $4.5 billion to the DOE for grid modernization programs. Of that amount, $3.4 billion was devoted to the Smart Grid

Investment Grant ("SGIG") program, a public-private partnership initiative for leveraging investments in grid modernization. As of June 30, 2013, approximately 12.8 million AMI meters were installed and operational as a result of the SGIG program. Ultimately, 15.5 million AMI meters are expected to be installed and operational pursuant to the SGIG program. All SGIG projects are expected to reach completion by the end of 2014.

Q. Was there any other data cited in the FERC's Advanced Metering Report to support the Company's AMI proposal?

A. Yes, the report noted that with recent storm activity and extreme weather events, AMI has facilitated efficient restoration of electric service following outages caused by storm damage. Electric system outages can be the result of small, medium, and very large scale events spanning several states that often impact other infrastructure systems (*e.g.*, communication, financial, and health care). In addition, as indicated in the report, many state regulators and utilities continue to review system hardening and resiliency measures designed to combat and mitigate future storm damage and outages. The application of new information and communication technologies, including AMI meters, are now a featured component of storm response discussions. Also, some of the information provided in the FERC's Advanced Metering Report indicated how such meters integrated with other technologies have helped maintain reliable electric service and enabled faster service restorations during recent weather events. Interval usage data from AMI meters in conjunction with other enabling technologies can expand opportunities for demand response and energy efficiency programs.

Q. Besides FERC's Advanced Metering Report, has the Company reviewed other material related to AMI deployments to support the Company's AMI proposal?

A. Yes. As proposed in NYPSC's Smart Grid Policy Statement (issued in Case 10-E-0285), the Company has been reviewing published DOE reports to determine the results from ARRA funded programs at other utilities. Some of these include Operations and Maintenance Savings from Advanced Metering Infrastructure – December 2012; Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – July 2013; and Smart Meter Investments Yield Positive Results in Maine – January 2014.

Q. What conclusions did the Company draw from reviewing these DOE reports?

A. The Company concluded that many of the potential benefits derived from an AMI system were obtained as a result of deploying AMI systems at other utilities.

Q. What AMI technology is the Company proposing to deploy in Rockland County?

A. The Company plans to install an AMI system developed by Sensus called Flexnet. The Sensus technology uses a two-way point-to-point radio frequency communication technology protocol which will enable meters to converse directly with tower base radio systems. Meters will be able to send data directly to and from the Company's wide-area network into the Flexnet head-end system which communicates with Company systems, such as the Company's OMS and the Customer Information Management System.

Q. Why did the Company choose this particular system?

A. Since 2006, the Company has been assessing various AMI technologies. The considerations assessed by the Company included meter locations, meter density, topography, coverage, reliability, scalability, throughput, functionality and costs versus benefits derived. The Company concluded that Sensus was best suited to meet the Company's requirements based on these assessments.

Q. Did the Company retain an independent consultant as part of these assessments of AMI technologies?

A. Yes, in addition to conducting its own internal assessment, the Company retained the services of Accenture in 2013 to conduct an independent assessment. Accenture determined that the Sensus system was best suited for the Company's service territory and at the lowest cost for deployment.

Q. Does the Sensus system meet the minimal functionality for AMI systems established by the NYPSC?

A. Yes. The AMI system would meet or exceed the minimum functionality requirements for AMI systems identified by the NYPSC in its Order Adopting Minimum Functional Requirements for Advanced Metering Infrastructure Systems and Initiating an Inquiry into Benefit-Cost Methodologies, issued February 13, 2009 in Case 09-M-0074. These minimum functional requirements are as follows:

(a) AMI systems must be compliant with all applicable American National Standards Institute standards, NYPSC regulations and Federal standards, such as those set forth in the Federal Communication Commission's regulations.

(b) AMI systems must provide net metering.

(c) AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with an auxiliary device if it is the only means to provide a visual read of consumption data.

(d) AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.

(e) AMI meters must have sufficient on-board meter memory capability so that meter data is not lost in the event of an AMI system failure and that the previous and current billing period of billing data is stored on the meter.

(f) AMI systems must have the ability to provide customers direct, real-time access to electric meter data.

(g) AMI systems must have the ability to remotely read meters on-demand.

(h) At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.

(i) AMI systems must have two-way communications capability, including the ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.

(j) AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network to provide direct or customer-activated load control.

(k) AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.

(l) AMI systems must have the following security capabilities:

(i) Identification - uniquely identify all authorized users of the system to support individual accountability;

(ii) Authentication – authenticate all users prior to initially allowing access;

(iii) Access Control - assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated;

(iv) Integrity – prevent unauthorized modification of data, and provide detection and notification of unauthorized actions;

(v) Confidentiality - secure data stored, processed and transmitted by the system from unauthorized entities;

(vi) Non-repudiation - provide proof of transmission or reception of a communication between entities;

(vii) Availability - information stored, processed and transmitted by the system must be available and accessible when required;

(viii) Audit - provide an audit log for investigating any security-related event; and

(ix) Security Administration – provide tools for managing all of the above tasks by a designated security administrator.

Q. Did the Company assess the capability and sustainability of Sensus in the AMI market?

A. Yes. Sensus is the second leading provider of AMI deployments in the North American market. According to the 2013 Scott Report from Pike Research, Sensus has 20% of the entire U.S market share with over 12.5 million metering end-points deployed since 2007. They have also recently won a contract to install 16 million additional meter end-points in Great Britain.

Q. What does O&R estimate will be the cost of implementing the Sensus AMI system in Rockland County?

A. As set forth in Exhibit ___ (AMI-1), the Company's current best estimate is that the installation of the Sensus AMI system in Rockland County will cost approximately $ 43.3 million over a five-year period.

Q. Does the Company plan to seek competitive bids for its AMI system components?

A. Yes. The Company plans to seek competitive bids for meter purchases from various meter manufacturers who have Sensus technology as part of their standard metering offerings. The Company will also competitively bid field equipment, system hardware, and storage.

Q. Has the Company quantified the benefits of O&R implementing the Sensus AMI system?

A. As set forth in Exhibit ___ (AMI-1), the Company's current best estimate is that its installation of the Sensus AMI system will provide benefits totaling approximately $142.7 million over a 20-year period, with a net benefit of $86.8 million after accounting for recurring operation and maintenance costs of $55.9 million.

Q. Please describe these benefits.

A. First, are the storm restoration benefits discussed above, which include both operational savings and the impact of reduced outage restoration times for our customers. Second, are avoided capital expenditures that result from the AMI deployment related to meter purchases and installation costs, replacement of meter reading vehicles, replacement of the meter reading system and meters that would need to be replaced for Rate Engineering load study purposes. Third, are operational savings directly related to providing efficient meter reading services and other customer field activity services to our customers, such as connects and disconnects. Finally, AMI will produce operational savings by reducing costs associated with back-office operations required in handling customer inquiries, rebilling costs associated with actual read updates to estimated meter readings, and cost reductions resulting from earlier detection of metering problems.

Q. Are these savings reflected in the electric revenue requirement in this proceeding?

A. No, because any such savings will be realized after the Rate Year.

Q. Are there additional benefits that may be obtained from an AMI system that are not quantifiable at this time?

A. Yes. AMI provides a key benefit as the enabling technology for REV initiatives. As such the value to the customer of those initiatives, many of which have not yet been developed, stems in part from the availability of AMI. Further, an AMI system may be enhanced to provide other non-quantifiable benefits. An AMI system is a transformative technology in the way it will allow utilities to operate going forward. Many of the partially funded DOE AMI projects and other regulatory approved projects across the United States are just beginning to realize and quantify other benefits derived from deploying

AMI systems. For example, the ability to remotely upgrade metering firmware reduces the metering costs to change or institute new rates designs. AMI systems also afford utilities with the ability to collect more data, more frequently from the meters (*e.g.*, Kvar readings, voltages). In the area of EE and DR, the AMI communication network with Zigbee (*i.e.*, a low-cost, low-power, wireless mesh network standard) enables "beyond the meter" capabilities. Customers can start receiving signals such as critical peak, or voluntary load reductions on in-home displays or even to mobile devices thus allowing for better demand response programs. When customers are more aware of their usage either via their in-home displays or via the web, they often adjust their behavior and overall energy usage is reduced. The AMI communication network can also be leveraged to control load on premises if the utility is experiencing distribution network issues. A mature DR program can be developed considering DG solutions, renewables like solar on premise, load reduction by calling a DR event, and curtailing load by controlling such devices as thermostats and pool pumps. The work and equipment necessary to obtain such benefits and their associated costs would be determined after implementing the AMI system. Although they are not part of this proposal, the mechanism to store the additional data coming from an AMI system to enable these benefits in the future has been included in our cost estimate. Societal benefits also would be achieved by reducing environmental concerns through improved air quality from avoided generation and vehicle emissions. Lastly, improved outage management obtained through an AMI deployment would reduce the financial impacts incurred by both commercial and residential customers during an outage.

Q. Has the Company reflected its estimated costs and benefits in the current Rate Case filings?

A. Yes, the estimated costs and benefits are summarized in Exhibit ___ (AMI-1), and are reflected in the direct testimony of the Accounting Panel.

Q. How will the Company address individual customer questions and concerns regarding AMI meters?

A. The Company will address customer questions and concerns initially through outreach and education. The Company will develop a communication plan to explain the various benefits associated with the AMI system as discussed above. The communication plan will include the opportunity for customers to ask questions and discuss their concerns. Understanding that some individual customers may conclude that their concerns outweigh the benefits of having an AMI meter, the Company will provide electric and gas customers with the option of meters in which the data transmitter has been turned off. Customers that opt out of AMI metering will be required to submit an application and agreement to Orange and Rockland. As part of the agreement, customers with internal metering equipment must guarantee the Company access to manually read its meters on a monthly basis. If the customer fails to provide access for any two months during a consecutive twelve-month period, the customer will be required to relocate their metering equipment external to their home or facility and incur the cost for such relocation. If the customer fails to so relocate their metering equipment, the Company will enable the transmission capability of the customer's AMI meter and the customer will incur a fee to reactivate the transmission capability of any gas AMI equipped meters. The Company will charge any customer who opts out of AMI meter an incremental service fee to cover the cost of monthly meter reads. In addition, the customer must provide reasonable access for meter maintenance. Customers will be provided information about the Company's policy to opt out of AMI transmission after contacting the Company with AMI concerns. It is appropriate to charge incremental meter reading fees to customers electing to opt out of using AMI meter data transmission because this will charge customers an appropriate cost-based rate while ensuring that those customers understand and are responsible for costs associated with their decision to opt out. Additionally, these proposed incremental charges properly balance opt out customer's AMI related concerns, and other customers' interests in achieving optimally efficient utility operations.

Q. Has the Company calculated the incremental costs for manually reading the meter(s)?

A. Yes, any customer exercising an opt out agreement, will be charged a monthly service fee of $15 for one electric or one gas meter or the combination of both, to manually read their meter(s).

Q. Has the NYPSC allowed other utilities to charge similar fees to customers who opt out of using AMR equipped meters?

A. Yes. For example, the NYPSC has allowed Central Hudson Gas & Electric Corporation to charge such fees (*see*, Case 14-M-0196, Order Approving Proposed Tariff Amendments, issued September 8, 2014).

Q. Has the Company considered a similar approach for handling the concerns of customers who do not wish to have AMR meters used for their home or facility.

A. Yes, after discussion with the customer and completion of an application and agreement with the customer, the Company will provide any such customer with an AMI meter in which the data transmitter has been turned off, subject to the same terms and conditions explained above. In such cases, the Company proposes a one-time meter change fee of $225.00 for a combined gas and electric customer, $135.00 for an electric only customer and $100.00 for a gas only customer.

Q. Will the Company charge customers that have AMI equipped meters to reactivate the transmission capabilities?

A. The Company will not charge any electric customer to reactivate the AMI meter transmitter, because the Company can perform such reactivation remotely. It will, however, charge a gas AMI activation fee of $55.00 to cover the cost of the required field visit and programming of the gas AMI device.

Q. Does this conclude the Panel's direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
BULK ELELCTRIC SYSTEM COMPLIANCE PANEL

Q. Would the members of the BES Compliance Panel ("Panel) please state your names and business addresses.

A. Michele Hanebuth, 390 West Route 59, Spring Valley, New York 10977

Edward P. Bedder,One Blue Hill Plaza, Room 405, Pearl River, New York 10965.

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

A. **(Hanebuth)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R" or "the Company") as Director for the Control Center and Substation Operations. The Company's compliance program management is also within my scope of responsibility.

(Bedder) I am employed by Orange and Rockland as Program Manager – Compliance in O&R's Control Center Operations.

Q. Please briefly describe your educational and business experience.

A. **(Hanebuth)** I earned a Bachelor's of Engineering Degree in Electrical Engineering from Manhattan College in 1989 and a Master's of Science Degree in Management Science from Pace University in 1995. I was employed by Consolidated Edison Company of New York, Inc. ("Con Edison") for approximately 25 years. I held a variety of engineering and management positions throughout Operations during that time period. I have been in my current position since May 1, 2014.

(Bedder) I earned a Bachelor's of Science Degree in Business Administration from Mercy College in 1992 and a Master's of Science in Organizational Leadership from Mercy College in 2002. I was employed by Con Edison for approximately 25 years, during which I held a variety of positions throughout Operations, Customer Service and Security. Additionally, I have been in my current position at O&R for seven years.

Q. What is the purpose of the Panel's testimony in this proceeding?

A. The purpose of our testimony is to discuss the actions that the Company must take and the resources the Company must add in order to comply with Order No. 773, issued by the Federal Energy Regulatory Commission ("FERC") on December 20, 2012 in FERC Docket Nos. RM12-6-00 and RM12-7-00, as well as other regulatory requirements. In addition, we will discuss the resources the Company is requesting in order to maintain situational awareness in the Company's Bulk Electric System Control Room.

<u>Background</u>

Q. Please provide an overview of FERC Order No. 773?

A. In FERC Order No. 773, FERC approved a modification to the definition of the "Bulk Electric System" ("BES") developed by the North American Electric Reliability Corporation ("NERC"). The BES is the universe of facilities that must comply with mandatory FERC-approved reliability standards. The modification approved in Order No. 773 removed language allowing for regional discretion in the currently-effective BES definition and established a bright-line threshold that includes all facilities operated at or above 100 kV. Previously, NERC allowed each regional entity (in the Company's case the Northeast Power Coordinating Council or "NPCC") to define what constitutes the BES in its region. NPCC had set the threshold as those transmission facilities that are operated at or above 230 kV. Prior to the revised BES definition, the Company maintained BES compliance for its Primary Energy Control Center ("ECC") located at its Spring Valley, New York Operations Center, and its Alternate Control Center ("ACC"), located at the Company's Monroe New York Operations Center. The Company also maintained BES compliance for facilities associated with two Substations. Under the FERC-approved modification of BES, as discussed below, various regulatory requirements will now be applicable to 32 elements associated with 17 additional substations operated at or above 100 kV. Elements associated with these stations include 24 138kV circuits, five 345/138kV transformers, and three capacitor banks.

The modified definition developed by NERC also identified specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of BES. FERC has established an exception process whereby elements can be added to or removed from the definition of BES on a case-by-case basis.

Q. Has the Company submitted an exception request?

A. Yes. On August 25, 2014, the Company submitted an exception request to NERC in order to exclude all newly included BES elements from the definition of BES (*i.e.*, 32 facilities associated with 17 substations). It is uncertain whether NPCC and NERC will agree with the Company and grant the Company the exception requested. It also could take a year or longer for NERC to rule on the Company's exception request. Regardless of NERC's decision regarding the Company's exemption request, the Company must be fully compliant with the requirements of FERC Order No. 773, as discussed below, by the July 1, 2016 deadline, unless O&R can successfully negotiate a revised implementation schedule with NPCC.

Q. Please describe the impact FERC Order No.773 has on the Company.

A. Orange and Rockland has identified assets that will now be classified as BES elements. In addition, the Company will need to change its registrations with NERC. As a result of the new BES definition, O&R will need to register as a Transmission Operator ("TOP") and a Transmission Planner ("TP").

Q. Please describe the change in the number of assets that will be classified as BES elements.

A. Prior to the FERC Order No. 773, O&R had identified three 345kV Lines associated with two substations. Under FERC Order No.773, O&R will need to classify elements, including lines, capacitors, and transformers as BES elements. O&R will have an additional 17 substations (all operated at or above 100kV) classified as BES facilities. Elements associated with these stations include 24 138kV circuits, five 345/138kV transformers, and three capacitor banks.

Q. Please address the operational or regulatory impact resulting from the change in classification of these assets as BES elements.

A. As a result of the change of classification of these assets, Orange and Rockland will be impacted both operationally and on a regulatory/compliance basis. Operationally, Orange and Rockland will need to increase operating staff and training requirements. On the regulatory/compliance side, Orange and Rockland will need to increase staff, training, software and external consulting resources.

Q. Please describe the Critical Infrastructure Protection ("CIP") standards for cyber security and it's impacts to the Company?

A. The NERC CIP Standards have been revised and the Company must be fully compliant with CIP Version 5 in accordance with its implementation schedule. The Company has two control centers and one substation that must be in full compliance by April 1, 2016. The Company also has 18 substations that must be in full compliance by April 1, 2017. If our BES exception request is granted, then 17 of the 18 substations will not be required to be compliant with the CIP Version 5 standards.

Q. Please elaborate on the timing and overall impact of complying with the CIP standards as it relates to the redefinition of the BES?

A. The implementation schedules of CIP Version 5 and the revised BES present significant overlap, with both schedules having completion dates during the first half of 2016. Compliance with the CIP Version 5 Standards presents an incremental increase of requirement depth in our existing applicable facilities, specifically our ECC and ACC, which are categorized as High Impact Facilities. Additionally, O&R will now have one substation categorized as a Medium Impact Facility and 18 substations categorized as Low Impact Facilities. Included in the resource requirements outlined below are the cost impacts for both labor (three new positions described below) and non-labor (training/workshops), and consulting resource requirements that will facilitate compliance with these standards.

Q. Please describe the changes in NERC Entity Registration and NERC Certification as a result of FERC Order 773.

A. Prior to the FERC Order No. 773, O&R was registered as a Transmission Owner ("TO"), Distribution Provider ("DP") and Load Serving Entity ("LSE"). As a result of the additional assets included as part of the BES under FERC Order 773, O&R will be required to register as a TP and as a TOP and will also need to execute Coordinated Functional Registration ("CFR") agreements with the New

York State Independent System Operator ("NYISO"). The revised Entity Registration Model also will require O&R to obtain NERC Certification with NPCC as a TO.

Q. Please describe the changes to the number of NERC Reliability Standards and Standards Requirements that the Company will need to comply with as a result.

A. As a DP, LSE and TO, there are 46 standards and 423 requirements that are applicable to O&R. As a DP, LSE, TO, TP and TOP there will be 72 standards and 708 requirements that will be applicable to O&R.

Q. O&R is currently audited by NPCC for compliance with NERC reliability standards. What will be the impact of FERC Order No. 773 on the audit cycle?

A. As a TOP, O&R will have scheduled audits once every three years as compared with the current six-year period. In addition, the audits will be on-site versus the current off-site audits.

Q. Please describe the incremental resource requirements associated with compliance with the revised definition of the BES.

A. In order to comply with the expanded requirements associated with FERC Order No. 773 by the July 1, 2016 deadline, the Company is proposing to add the following three positions:

- Senior Specialist – Compliance (Control Center Operations);
- Senior Specialist – Compliance (Substation Operations); and
- Senior Specialist – NERC Compliance Program.

Q. Please discuss the need for and the responsibilities of each of these three proposed positions.

A. Senior Specialist – Compliance (Control Center Operations)

This position is required to meet the increased oversight and administration for compliance with mandatory NERC Reliability Standards, NPCC Criteria, and New York State Reliability Rules. As discussed above, this increase is the result of, and the impacts from, the adoption of the new NERC BES definition (*i.e.*, 100 kV). The Senior Specialist – Compliance (Control Center Operations) will be responsible for providing direct, daily, oversight and due diligence required to comply fully with all regulatory requirements that apply to Control Center Operations. These requirements include, but are not limited to, NERC Reliability Standards, NPCC Criteria, and New York State Reliability Rules. This position will represent Control Center Operations, and coordinate efforts through participation and attendance at NPCC, NERC, and NYISO compliance related activities. This position also will be responsible for the Control Center's Operations implementing and sustaining compliance associated with registration as a TOP.

Senior Specialist – Compliance (Substation Operations)

This position is required to meet the increased oversight and administration for compliance with mandatory NERC Reliability Standards, NPCC Criteria, and NY State Reliability Rules. As discussed above, this increase is the result of, and the impacts from, the adoption of the new NERC BES definition (*i.e.*, 100 kV). The Senior Specialist – Compliance (Substation Operations) will be responsible for providing direct, daily, oversight and due diligence required to comply fully with all regulatory requirements that apply to Substation Operations. Requirements include, but are not limited to, NERC Reliability Standards, NPCC Criteria, and New York State Reliability Rules. This position also will be responsible for Substation Operations implementing and sustaining compliance with CIP Version 5.

Senior Specialist – NERC Compliance Program

This position is required to meet the increased oversight and administration for compliance with mandatory NERC Reliability Standards, Critical Infrastructure Protection Standards, Transmission Operator requirements, Transmission Planner requirements, and the Commission's Chief Executive Officer certification process. As discussed above, this increase is the result of, and the impacts are from, the adoption of the new NERC BES definition (*i.e.*, 100 kV). The Senior Specialist-NERC Compliance Program will work with the Company's Compliance Group to oversee the Company's entire NERC compliance program. This program encompasses all NERC Standards, NPCC Criteria, and NYS Reliability Rules that apply to O&R as a registered NERC entity. The scope of compliance across O&R includes Control Center Operations, Critical Infrastructure Protection Group, Substation Operations, Transmission Engineering, Transmission Maintenance, and Security Services. This will include administration of self-certifications, audits, data submissions, and continued standards development. This position will be responsible for providing daily oversight to facilitate the necessary due diligence and timely reporting of mandatory compliance related activities. In addition, this position will be responsible for the review and analysis of pending and approved reliability standards and requirements, review of applicable standards requirements with appropriate subject matter experts ("SMEs") within the Company, solicitation of definitive statements of compliance and evidence for reporting purposes, and representing the Company through participation and attendance at NPCC and NERC standards related activities. As a result of NERC's Reliability Assurance Initiative ("RAI"), which pertains to compliance with and enforcement of NERC standards, this position also will be involved in the Company's Internal Control Program ("ICP") to provide more robust internal oversight of all compliance activities.

Q. When does the Company plan to fill these three proposed positions?

A. The Company currently does not have the funding for these positions. The Company has asked for, and expects the Commission to authorize, funding for these positions in this electric rate case. Accordingly, the Company expects to fill these positions in October 2015.

Q. What is the Company's funding request for each of these three proposed positions?

A. The Company proposes to pay each of these positions $110,000 on a calendar year basis.

Q. Please describe the basis for the incremental annual non-labor expense associated with complying with the NERC Reliability Standards, NPCC Criteria, and New York State Reliability Rules.

A. The Company will be retaining a consultant to provide guidance, gap analysis (*i.e.*, comparison of actual performance with potential or desired performance) and audit preparation for the new regulatory requirements of the NERC Standards associated with the new BES definition. This consultant will assist the Company's SMEs to comply with this expanded range and scope of implementation, including the Company registering as a TO and TOP.

Q. What is the Company's funding request for this consultant?

A. The Company projects that it will spend $70,000 annually during calendar years 2015, 2016 and 2017.

Q. Will the Company be retaining any other consultants?

A. Yes. The Company will be retaining a consultant to provide guidance, gap analysis and audit preparation for the new regulatory requirements associated with NERC's CIP Standards. NERC has completely revised the current nine CIP standards and established two new CIP standards, all of which require a complete rewrite of most of the Company's related processes and procedures. NERC has also created a third new CIP standard on physical security (CIP-014) that the Company will need to comply with. The scopes of these CIP standards have increased to include equipment outside of the Orange and Rockland Control Centers to include substations. The Company's SMEs will work with the consultant in order to comply with these various CIP standards

Q. What is the Company's funding request for this consultant?

A. The Company projects that it will spend $180,000 annually during calendar years 2015, and 2016 and $30,000 annually during calendar year 2017.

Q. Will the Company incur additional training and workshop costs relating to its expanded compliance obligations?

A. Yes, the Company's Compliance Program, System Operations, and Substation Operations personnel will attend regulatory conferences and training workshops in order to sustain working connectivity with NERC/NPCC/ regulatory organizations, ISOs, and NATF. Prior to the adoption of the new NERC BES definition, only the three personnel in the Company's compliance group typically traveled to most workshops. Prospectively, SMEs from each of the areas responsible for implementation, monitoring, and control of compliance at the operational level will need to be fully engaged in the compliance arena, including participating in training, and workshops. This may include up to seven to ten additional personnel interacting in regulatory work on an ongoing basis. The Company also will host internal meetings, training, and events for compliance purposes.

Q. What is the Company's funding request for this additional training and workshops?

A. The Company projects that it will spend $50,500 annually during calendar years 2015, 2016 and 2017.

Q. Please discuss the Company's renewal of its subscription to Direct Line 2 Compliance ("DL2C") Online Library.

A. Renewal of the Company's subscription to the DL2C Online Library provides the Company's SMEs with access to the entire library of NERC standards. The Library employs a color coded format that allows for translation of the NERC standards' requirements into clear, concise and actionable items. The Library is updated so as to reflect the latest NERC changes and directives.

Q. What is the Company's funding request for the DL2C Online Library?

A. The Company projects that it will spend $28,000 in 2015 and $31,000 in 2016.

Q. Please discuss the Company's use of Primate Technologies.

A. The Company is implementing a software tool to enhance Bulk Electric System Operators' situation awareness in the Control Center.

Q. What is the Company's funding request for Primate?

A. The Company projects that it will spend $20,000 in 2015, $20,000 in 2016 and $20,000 in 2017 in order to maintain this software tool, which is being installed in late 2014 and early 2015.

Q. Has Orange and Rockland reflected these incremental labor and non-labor expenses and the Company's ongoing labor and non-labor expenses in the revenue requirement proposed in this case?

A. Yes. The internal labor resource requirements were provided to the Company's Accounting Panel who included such requirements in the labor projection in determining revenue requirements. The reoccurring non-labor expenses have not been specifically provided for, however, these expenses are assumed to be included in the overall pool of expenses escalated by inflation based on the methodology employed to forecast those expenses.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
YUKARI SAEGUSA

Q. Please state your name and business address.

A. My name is Yukari Saegusa. I am the Treasurer of Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R" or the "Company"). I am also Director, Corporate Finance for Consolidated Edison Company of New York, Inc. ("Con Edison"). My business address is 4 Irving Place, New York, New York.

Q. Briefly describe your educational background.

A. I graduated from the University of Pennsylvania, Wharton School in 1989 and received a B.S. degree in Economics. I received an MBA from the MIT Sloan School of Management in 1995.

Q. Please summarize your professional background.

A. I joined Con Edison in March 2013. Prior to joining Con Edison, from 2004 to 2013 I was employed by Barclays as a Managing Director in Debt Capital Markets covering the United States utility and energy sectors. I was employed from 1995 to 2004 by Citigroup, also in Debt Capital Markets covering the United States utility sector. In my roles at Barclays and Citigroup, I was broadly responsible for advising utility clients on the design and execution of debt capital-raising and liability management strategies.

Q. Have you previously sponsored testimony before the New York State Public Service Commission ("Commission")?

A. No.

Q. What is the purpose of your testimony?

A. My testimony discusses (1) the current financial market environment, (2) O&R's historic and projected capital structure and cost of capital, and (3) O&R's financial challenges and the need to maintain access to financial markets at reasonable cost.

CURRENT FINANCIAL MARKET ENVIRONMENT

Q. Please describe the current state of the financial markets.

A. The financial markets have improved dramatically from the financial crisis in 2008 and early 2009. A large measure of this improvement can be attributed to the Federal Reserve System's ("Federal Reserve") monetary easing policy. Since the global financial crisis, the Federal Reserve has taken a number of unprecedented steps to keep interest rates low in an attempt to stabilize the financial markets and stimulate economic growth. These steps have included: (i) the purchase of mortgage-backed and Treasury securities and (ii) the flattening of the yield curve (i.e., lowering longer-term interest rates) through the purchase of Treasury bonds with 6-30 year maturities and selling bonds with maturities of three years or less. This policy has kept interest rates at artificially low levels and pushed the equity market above levels achieved prior to the financial crisis. However, starting in January 2014, the Federal Reserve began to gradually reduce the amount of its bond purchases and ended its purchases completely in October. Furthermore, in the June 2014 meeting of the Federal Open Markets Committee ("FOMC") meeting, the Federal Reserve signaled that it may begin to raise interest rates in 2015 and 2016 as the economy continues to recover, the unemployment rate declines and inflation remains below the Federal Reserve's long-term target of two percent. More recently, in September's FOMC meeting, a survey of the participants showed that 14 of 17 members expect the Federal Reserve to start raising rates in 2015 (versus 12 of 17 members in the

June FOMC). The survey also indicated a median expected fed funds rate of of 1.375% at the end of 2015 and 2.875% at the end of 2016. That compares to the current fed funds rate of 0.07% (as of October 30, 2014). Given the forward-looking nature of the financial markets, interest rates may rise earlier and rise quickly in anticipation of the Federal Reserve's action. As evidence of this, the mere hint of the Federal Reserve tapering off its easing policy in May 2013 sent ten-year Treasury rates higher by 46 basis points for the month. A 46 basis point move in one month (or 25% on a relative basis) has few precedents since 1990. To put this into perspective, on an absolute basis, this movement ranked in the top 95th percentile of changes in monthly ten-year Treasury rates since 1990 (*see*, Exhibit YS-2). And on a relative basis, a 25% move ranked in the top 99.5 percentile of changes in monthly ten-year Treasury rates since 1990. After three decades of steadily declining interest rates, we are likely at an inflection point with higher interest rates ahead. The Federal Reserve's stimulus programs have also had the effect of reducing market volatility. As discussed by Company witness Hevert, the decline in volatility is strongly correlated to the Federal Reserve's stimulus program. But as the Federal Reserve tapers its stimulus, we can logically and reasonably expect that volatility will increase. A rise in volatility would likely lead investors to require a higher return to compensate them for the additional risks that they will have to bear.

Q. What challenges do the financial market environment present?

A. In addition to the potential for higher interest rates and higher market volatility described above, the Company faces a potential increase to its cost to access the bank credit market. While capital availability and cost remain attractive today, the cost of our credit facilities is significantly higher than pre-financial crisis pricing – more than four times higher. Futhermore, the expectation is that, stricter capital guidelines imposed by financial institution regulators will lead to an increasing cost to access the bank credit market.

Q. Why are bank revolving-credit facilities important to the Company’s financing plan?

A. There are four purposes for bank credit facilities in funding a utility company like O&R. First, the facilities directly or indirectly provide the Company with the flexibility to raise long-term financing when desirable, not when it has to. The facilities thereby save customers money because they eliminate the need to pre-fund spending and allow the Company to fund at times of its choosing. Second, the facilities allow the Company to issue letters of credit as collateral for its operations including managing the portfolio of energy commodity purchases made on behalf of customers in the wholesale and financial markets. Third, the facilities are the source of liquidity that is required by purchasers of our commercial paper so that they will be repaid. This “back-up” function permits the Company to access a lower-cost source of funds for the day-to-day operation of its business. Finally, the facilities assure the rating agencies that the Company can meet its obligations even if it loses access to the capital markets for a period of time (and thus factors into the credit ratings for the Company).

CAPITALIZATION AND COST OF CAPITAL

Q. What capital structure do you recommend should be used in this proceeding?

A. I recommend the use of the stand-alone capitalization of O&R in this proceeding.

Q. Please describe the stand-alone capitalization.

A. The stand-alone capitalization refers to the actual capital structure of O&R, that is to say, the actual investment of capital required to provide services to O&R's customers.

Q. Does the initial actual capital structure plus projected financings represent the expected actual investment of capital in the Company during the rate year (*i.e.*, November 1, 2015 – October 31, 2016) ("Rate Year")?

A. Yes, it does.

Q. Has the Company prepared a rate of return required exhibit?

A. Yes. The document entitled "ORANGE AND ROCKLAND UTILITIES, INC. & SUBSIDIARIES -- RATE OF RETURN REQUIRED FOR THE RATE YEAR – THIRTEEN MONTH AVERAGE ENDING OCTOBER 31, 2016," is set forth as Exhibit YS-1, Schedule 1.

Q. Please describe any projected changes in O&R's long-term debt and how such changes have been incorporated into the rate of return required for the thirteen-month average ending October 31, 2016.

A. The Company expects to issue the following debentures:

- During the linking period (*i.e.*, July 1, 2014 through October 31, 2015): $100 million of Debentures, Series A 2015, 5.40% to be issued August 2015, due August 2045.
- During the Rate Year: $100 million of Debentures, Series B 2015, 5.40% to be issued November 2015, due November 2045 and $75 million of Debentures, Series A 2016, 6.10% to be issued September 2016, due September 2046.

Q. Please describe how you developed the cost of long-term debt.

A. Exhibit YS-1, Schedules 4 and 5, present the detailed calculation of the cost of the long-term debt at June 30, 2014 and for the thirteen-month average ending October 31, 2016, respectively. These schedules detail each issue of long-term debt outstanding and calculate an effective annual cost for each issue, taking into consideration the original net proceeds to the Company and annual interest costs. The sum of the effective annual cost for all issues is divided by the gross amount of debt outstanding to derive the weighted average cost of long-term debt.

Q. Did you provide the interest rate forecasts used as a basis for the cost of debt in this Exhibit?

A. Yes.

Q. What method have you used to develop the interest rate forecasts?

A. We have used forecasts of Treasury rates from the publication Blue Chip Financial Forecasts, plus a spread to Treasuries based on indicative quotes from financial institutions. The Blue Chip Financial Forecasts consist of the consensus forecast of approximately 50 economists. This approach provides more accurate forecast results than simply using the most current Treasury rates. At the update stage of this proceeding, I will revise Exhibit YS-1, Schedule 5 to reflect the most recent data available as well as any new or refinanced debt that the Company may have issued by that time.

Q. Are you recommending a true-up of interest costs for debt at this time?

A. No. Based on the Commission’s adoption of forecasted Treasury rates in the calculation of interest rate forecasts in Con Edison’s most recent base rate proceedings (*i.e.*, Cases 13-E-0030, 13-G-0031 and 13-S-0032), I am not recommending a true-up of interest costs of the Company’s fixed-rate debt portfolio. Additionally, I am not recommending a true-up of interest costs of the Company’s one outstanding variable rate debenture which will mature prior to the start of the Rate Year.

Q. Please describe the method used to project the Company’s equity balance through October 31, 2016.

A. The average consolidated equity of O&R at October 31, 2016, excluding all non-utility subsidiaries and Other

Comprehensive Income was projected from June 30, 2014 using the following steps:

1. The forecast earnings for June 30, 2014 to October 31, 2016 were added to the June 30, 2014 equity balance; and
2. The forecast dividends to Consolidated Edison, Inc. ("CEI") for June 30, 2014 to October 31, 2016 (*i.e.*, \$9.9 million for the six months ended December 31, 2014, \$41.0 million for for the twelve months ended December 31, 2015, and \$31.9 million for the nine months ended October, 31, 2016) were subtracted from the June 30, 2014 equity balance.

Q. What stand-alone capital structure for O&R results from the calculations that you described?

A. Exhibit YS-1, Schedule 1, shows the forecasted capital structure for the thirteen months ending October 31, 2016 of 50.66% long-term debt, 0.90% of customer deposits, and 48.45% common stock equity. O&R has no preferred stock outstanding and has no plans to issue preferred stock.

Q. Does Exhibit YS-1 also show the forecasted capital structure, based on a thirteen-point average, for the twelve months ending October 31, 2017 and October 31, 2018?

A. Yes. Schedules 2 and 3 of this exhibit show the capital structure for those periods. These schedules show that over those two years the debt ratios would decrease to 48.28% and 46.65% of the Company's capital structure, respectively, as new debt is issued. These schedules also show that the customer deposit ratio would stay the same and decrease modestly and the equity ratio would increase to 50.82% and 52.53% for the twelve-month periods ending October 2017 and 2018, respectively.

Q. Are you requesting that the capital structure, upon which the revenue requirements are calculated in the Company's contemporaneous electric and gas base rate filings, use an equity ratio of 48.45%?

A. No, for purposes of calculating the revenue requirements in the Company's contemporaneous rate filings, the Company is proposing to use a 48.00% common stock equity component. The Company is proposing an equity component lower than the standalone capital structure of O&R in order to minimize the controversial issues in this proceeding and facilitate reaching a multi-year rate plan through settlement.

Q. Is the Company waiving its rights to a reasonable common stock equity ratio?

A. No, it is not. The requested common stock equity component is slightly lower than the level the Company believes is a reasonable based on the Company's standalone capital structure.

Q. Please explain why the Company's proposed common stock equity ratio is reasonable.

A. As discussed in the direct testimony of Company witness Hevert, the proposed capital structure and proposed equity ratio are reasonable based on his analysis of the equity ratios of comparable operating utility companies. The analysis demonstrates that the Company's proposed equity ratio is below the mean equity ratio of the proxy group companies of 52.90%. I would note that Staff has argued, in the recent Con Edison rate proceedings (*i.e.*, Case 13-E-0030, 13-G-

0031 and 13-S-0032), that it is inappropriate to compare our capital structure to that of comparable operating utility companies because:

> *[The use of] proxy groups of electric utility holding companies to establish the Company's cost of equity, it is the financial performance of these electric utility holding companies that is the relevant peer comparison*

Q. Do you agree with Staff's position?

A No, I do not. Staff's argument against utility operating company comparisons (because the Company's cost of equity is established by analyzing a proxy group of utility holding companies) would suggest shortcomings with Staff's application of the Discounted Cash Flow model. It would seem that Staff's argument exposes the inconsistency of applying a market cost of equity derived at the utility holding company level to a book value of equity at the utility operating company level. The Company would argue that the market cost of equity would more appropriately be applied to the utility holding company's market value of equity.

Q. What are you proposing for the Company's return on equity?

A. We propose a 9.75% return on equity.

Q. Using this forecasted capital structure and cost of long-term debt and the return on equity, what overall rate of return results?

A. The overall rate of return is 7.80% as shown on Exhibit YS-1, Schedule 1).

CAPITAL NEEDS AND INVESTOR CONCERNS

Q. Please describe the financial challenges facing the Company during the Rate Year and beyond.

A. The Company faces the following four inter-related financial challenges: (A) the capital intensive nature of its business, (B) its unusually weak cash flows, (C) the restrictions that regulation places on its ability to respond to unfavorable developments in its environment, and (D) its dependence on the market to fund its capital needs.

Q. Please discuss (A) the capital intensive nature of the

Company's business.

A. The Company's business requires significant capital investment every year, its assets are long-lived and the underlying technology, facilities and customer base are mature.

Capital intensity is high for utilities. According to an IHS CERA presentation titled "Post Fukushima: If not nuclear, what energy mix?" (June 2011), the electric utility industry is second only to railroads in capital intensity. As shown on Exhibit YS-3, the Company's capital intensity can be demonstrated by the fact that its ratio of net fixed assets per dollar of revenues is $1.98 versus $0.76 for the average S&P 500 company and $0.19 for the median company. Capital intensity creates extra risk for investors because capital intensive businesses have to recover much larger fixed costs (interest and depreciation) before achieving a return.

O&R's assets also have extraordinarily long lives. Long-lived assets in the context of rate regulation present two financial challenges for the Company that are also risks for potential investors in the

Company's debt and shares. First, their investment horizons for capital recovery must be much longer. For debt investors, utility debt has much longer average maturities than other companies. Equity investors must wait for long-term repayment on their investment. Second, there is a regulatory risk in long-lived assets because United States rate regulation limits returns to a fraction of historic tangible book cost rather than replacement or current market value. The Company's depreciation recoveries, which reflect historic tangible net book values, are small relative to its current capital costs, returning only 42% of its capital expenditures in the form of depreciation in 2013.

Due to the long depreciation lives established in rates, this dynamic is likely to continue for many years. As shown on Exhibit YS-4, by way of comparison, the average S&P 500 company recovered 155% of its capital expenditures through depreciation and amortization. This would have placed O&R in the bottom 9% of companies in the S&P 500 that had meaningful recovery rates. CEI (which had a 37%

capital expenditure recovery rate) had the six-lowest recovery rate among the 30 utilities in the S&P 500 as shown on Exhibit YS-4. The average recovery rate for the utility companies in S&P 500 utilities was 51%. The Company’s large installed base of mature equipment requires a continuous investment in replacement assets. In other industries, a much larger portion of investment can be dedicated to new business (generating offsetting revenues) or new technology (lowering costs).

Mature assets raise operating costs and increase operating risks, particularly in an environment which requires the highest level of reliability and imposes regulatory penalties for failing to achieve it with no corresponding opportunities to earn rewards for superior performance.

The technology of the business is also mature, affording little opportunity to significantly reduce invested capital in the business through technological innovation. The need for continuous investment to maintain and improve the system with slight opportunities for demand growth and limited depreciation cash flow means that the Company must seek rate increases and raise new capital frequently to maintain its operations. Replacement capital needs alone substantially exceed the cash generated through depreciation recoveries for the Company.

Q. Please describe (B) how the Company's unusually weak cash flows present a financial challenge.

A. The Company will continue to be challenged by its unusually weak cash flows and lack of positive free cash flow. O&R's weak cash flow metrics will mean that O&R will be more dependent on external funding.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to my Exhibit YS-5.

Q. Please describe (C) how restrictions on the Company's business imposed by the Commission present a financial challenge.

A. The Company is subject to several regulatory restrictions that limit its ability to react to unfavorable circumstances. It must provide service as requested, even if doing so entails significant investment upon unfavorable terms. It cannot refuse to provide service to new or unprofitable customers.

It also is limited in its ability to reach beyond its franchise area to serve attractive new customers. The Company's assets are immovable; unlike those of most companies they cannot be used in a different location or business, their usefulness and profitability are tied to providing utility service in its New York service territory.

Unlike other companies, O&R has no meaningful ability to retain the advantages of its efforts to improve its efficiency and thus lower its costs of doing business for the benefit of its equity investors, as the Commission's rate orders remove a fixed percentage upfront through an imputed productivity adjustment. Moreover, any additional efficiencies achieved by management are fully allocated to customers each time rates are reset, given the capital recovery and cash flow parameters of historic cost-of-service rate making.

Additionally, on April 25, 2014, the Commission instituted a proceeding for Reforming the Energy Vision ("REV") (Case 14-M-0101). The goal of the REV proceeding is to achieve the Commission's energy policy objectives through aligning electric utility practices, tariffs, market design and incentive structures with technological advances. Since the REV proceeding is in its preliminary stages, it would be highly speculative to predict its final outcome. Although, it is plainly premature to judge the ultimate impact that the REV proceeding will have on the Company, O&R believes that the basic framework of an output/incentives-based rate model could provide challenges to the Company. These potential challenges include, but are not limited to: (i) increased volatility of cash flows due to lower allowed base returns and/or how expenditures are allocated between O&M and capital, (ii) long-term rate plans under the new framework can provide stability but the mechanisms by which the cost of debt and return on equity are adjusted over the rate period will factor significantly into investors' assessment of the new regulatory framework, and (iii) a greater emphasis on incentives through rigorous efficiency targets could pressure profitability and relative competitiveness which affect the assessment of business risk profile.

Taken together, these challenges could have the effect of putting upward pressure on the Company's credit ratings and cost of capital.

Q. Please describe (D) how the fact that the Company must continually raise capital increases risk for existing and prospective investors.

A. As mentioned earlier in my direct testimony, the Company must approach the markets for additional new debt capital on a frequent and recurring basis. O&R is forecasted to raise $200 million in 2015 and $75 million in 2016. O&R will need the backing of prospective cash flows and regulatory support to continue to market this debt.

Each time O&R markets its debt securities, investors will assess the risks they would bear upon investing in the Company due to the challenges identified above. Their assessment of these risks is, and will be, priced in to the cost of debt each time that the Company seeks new capital in the years ahead. To the extent that analysis of risk leads the market to reduce stock prices or raise interest rates, the existing investors are disadvantaged and other potential investors are made more wary. Through this cycle of investors assessing and pricing risks that the Company faces, customers are negatively impacted through increases in the cost of financing the Company.

Q. What is the implication of the above mentioned large capital needs?

A. To raise this capital at a reasonable cost, O&R and CEI must remain attractive investments to both debt and equity investors. To remain attractive to these investors, O&R must receive fair and reasonable treatment from its regulators.

Q. How much debt does the Company have outstanding and what type?

A. As of June 30, 2014 O&R had $603 million of long-term debt (including long-term debt due within one year), of which $535 million were unsecured taxable debentures, $3 million were first mortgage bonds, $20 million were transition bonds and $44 million was tax-exempt debt. O&R had letters of credit outstanding in an amount of $38 million. Additionally, O&R had $45 million of letters of credit backing O&R tax-exempt debt. Letters of credit represent an additional capital need which must be met, requiring O&R to compete for scarce funds in an increasingly regulated bank market.

Q. Who owns the Company’s debt?

A. Investment managers, insurance companies, pension plans, hedge funds, banks, trust companies and individuals.

Q. How do bond investors evaluate O&R?

A. For most investors, the credit ratings assigned by the nationally recognized statistical rating organizations (*i.e.*, Moody’s, S&P and Fitch), are the threshold basis for evaluating individual corporate credits such as O&R.

Q. What are the current ratings on O&R debt?

A. The long-term, senior unsecured debt ratings are A3, A-, and A- by Moody’s, Standard and Poor’s (“S&P”), and Fitch, respectively. The short-term debt is rated P-2, A-2, and F2, respectively. All ratings have a stable outlook.

Q. Are bond ratings the correct indicator of the risks to shareholders?

A. No. Shareholders, unlike bondholders, only have a residual claim to the resources and income of the Company, and thus face risks even in well-rated companies. If returns are inadequate, the bondholder may suffer a loss from a credit downgrade. The stockholder will suffer the loss directly. Efforts by the Commission to limit the upside potential of the shareholder through the elimination of incentives and other opportunities, combined with true-ups and implementation of enhanced penalties exacerbate the effect of lowered targeted returns.

Q. Why do companies such as O&R need a particularly strong financial condition?

A. Capital intensive companies with a duty to serve have to borrow in spite of the state of the market and need continuous access to capital. When they are forced to pay high rates, these rates will stay with the companies and their customers for as long as 30 years. On the short-end of the maturity spectrum, access to commercial paper and bank borrowing markets is key to allowing O&R to pay for energy that must be delivered, no matter the price. Only prime borrowers can maintain that status in all markets, a status that has become more tenuous for O&R due to its current A-2/P-2 (S&P’s/ Moody’s) rating for commercial paper. At the height of the financial crisis of 2008-2009, A-2/P-2 borrowers, if they had access, paid rates significantly higher than those paid by A-1/P-1 borrowers.

The seizing up of the commercial paper market was relieved only by the Federal government’s extraordinary decision to provide an effective backstop for the highest rated (A-1/P-1) commercial paper issuers, a solution that may not always be available, and may not extend to lower quality issuers such as O&R.

If O&R lost access to the commercial paper market, borrowing costs would increase as the Company would have to rely more upon long-term debt, which is more expensive. In addition, the Company could be forced to issue debt with less attractive terms because it lacked the flexibility to wait for better market conditions. The recent past has demonstrated the importance of maintaining a strong credit rating and investor confidence in our credit.

Q. Are there new factors which may serve to reinforce the need for and potentially limit the supply of, liquidity?

A. Yes. Globally, the Basel III regulations require more capital for banks and may lower capital available for lending and increase costs.

Revolving credit facilities are an alternate source of short-term borrowing. Compared to the period before the financial crisis, they are now a significantly more expensive source of funds, particularly for companies with lower credit ratings. For example, the Company entered into a new revolving credit facility in October 2011 with borrowing costs at more than four times the pricing in the Company's previous, *i.e.*, 2006, revolving credit agreement. Similarly, the penalty for having a lower credit rating (*i.e.*, the pricing premium between a borrower rated A- and BBB-) increased more than four times as compared to our previous revolving credit facility.

Q. Please explain why maintaining its current debt ratings is important for O&R.

The Company has a significant continuing construction program which must be met in large part by debt financing. Access to credit markets will be restrictive for lower quality creditors.

In addition, a part of O&R's financing program is made up of short-term borrowing through its commercial paper program. Such borrowing is highly sensitive to credit quality and credit market conditions.

Q. Who owns the Company?

A. O&R has one shareholder, CEI. CEI, in turn, is owned by approximately sixty thousand registered shareholders. Registered shareholders are the individuals or businesses whose names are listed on the shareholder register of CEI.

Q. What are the characteristics of the registered shareholders?

A. CEI's registered shareholders consist of individuals and institutional investors. Institutional investors often own shares for the benefit of others. These investors purchase CEI shares for the benefit of their investors who, in turn, may be pension funds and individual investors. Since pension funds exist for the benefit of the individual participants in their plans, it makes sense to think of the ultimate beneficiaries of share ownership in CEI and derivatively in O&R of being millions of individuals who may own shares directly, invest in U.S. stock mutual funds, or receive or expect benefits from pension plans or life insurance policies.

Q. What do these people who own the Company provide to it?

A. They provide the capital that the Company needs above and beyond what debt investors are willing to provide. Their capital allows the Company to use the goods, wages, services and borrowings that bring safe, reliable energy utility service to the Company's customers. Without these shareholders, the Company's customers would have to pay currently for all of the costs of the services they receive. Instead, customers can delay payment by promising to pay these investors a greater amount in the future. Therefore, instead of paying for a new substation as it is constructed, for example, customers can plan to pay for that asset over the subsequent decades during the time they benefit from its operation.

Q. What do these equity investors expect in return for the benefit customers receive from their capital investment?

A. They expect compensation either in the form of a periodic dividend payment or an increase in the value of the business, or both.

Q. How do equity investors in regulated utilities set their expectations for compensation?

A. The return expectations of equity investors in rate-regulated energy utilities are grounded in the bargain termed "the regulatory compact." The regulatory compact's essence is that equity investors forgo the monopoly earnings they would otherwise enjoy in return for the institutionalization of their monopoly in an exclusive franchise, and a fair and equitable return on the capital they have invested.

Q. What standards exist to help equity investors and regulators determine whether a rate-regulated utility offers a fair and equitable return?

A. The general standards for a fair and equitable return for investors in utility shares are well-established in the United States. The underlying requirement for fair treatment for equity investors has been recognized for years. As discussed in the testimony of Company witness Hevert, it dates back to the Bluefield and Hope cases. The United States Supreme Court in those cases established that in determining the fairness or reasonableness of a utility's allowed return on equity ("ROE"), one needed to look at the consistency of a utility's allowed ROE with the returns on equity investments in other businesses having similar or comparable risks. The key point is that in neither of these cases is there a specific limitation to looking only to the financial health of utilities when looking at enterprises with "similar or comparable risks." And, as has been pointed out many times in prior New York rate proceedings, comparisons to other utilities introduces an incurable circularity to the assessment of an appropriate level of returns.

Q. How would a potential equity investor evaluate the return limitations on New York utilities as to their magnitude, timing and probability?

A. There are four significant factors in an equity investor’s assessment of New York utility regulation: (1) headline rate of return on equity, (2) the likelihood of earning that return, (3) the symmetry of potential earned equity returns, and (4) the restrictions the regulator places on the scope of the business. To make this assessment, a potential equity investor will start with the basic parameters of the rate orders from the state.

Q. How do the Commission’s rate orders influence investors’ evaluation of the first identified return consideration?

A. The first factor, the level of returns on equity, is important for an equity investor because it provides the most visible indication in the rate order of the regulator’s willingness to balance the needs of investors and customers.

Q. How have the Commission’s authorized returns compared to those in other jurisdictions?

A. As we have stated in previous rate cases, the rates of allowed return granted in New York are well below those in other states. I have provided a comparison of allowed returns in New York versus other states (based on data from Regulatory Research Associates ("RRA")) to demonstrate the consistency of this practice (Exhibit YS-6).

In past cases, Staff has argued that each of the rate cases in the RRA database is unique, and therefore no meaningful conclusion can be drawn. While I would agree that each rate case is unique, it is equally obvious that the differences in the authorizations cannot always be such that New York companies should consistently and deservedly be permitted a chance to earn the lowest returns in the country.

Q. Can investors readily measure the degree to which a regulatory regime fairly rewards shareholders?

A. In New York, yes. The Commission has a clear and long-standing policy of setting returns relative to the historic tangible book value of the investors' shares. Information about returns on share book values for publicly-traded United States companies is readily available to investors from public sources as a basis for comparison.

Q. How does O&R compare to this universe of alternative investments?

A. It does not fare well in the comparison. When looking at 2013, O&R had a return on book equity that would have placed it in the bottom third of S&P companies with meaningful data. The return for the average S&P company was 16.5%.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to my Exhibit YS-7.

Q. Are companies typically valued by investors at their book value?

A. No, they are valued by investors based on their prospects. Exhibit YS-8 shows the five-year average market to book ratios for those S&P companies with positive book equity. CEI's market to book ratio is in the bottom 17% of this universe for this important measure of investor perception of prospects, even after a massive financial crisis which most severely affected the financial sector and other industries.

Valuation methods such as the Discounted Cash Flow ("DCF") model can be reasonable (if imperfect) methods for determining expected returns for investors when they apply market-derived data to the firm's market value of equity, assuming that data reasonably comports with the model's fundamental assumptions. The method and the application are then internally consistent and reward the equity-holder for what his or her stock investment is currently worth. In contrast, the current practice of applying market-derived returns to a much lower book value not only strips out the accumulation of improvements to the business and its assets, but it is not consistent with standard, corporate finance practice. The application of the Capital Asset Pricing Model ("CAPM") methodology suffers from similar flaws. Market-derived returns must be applied to market equity values. There is no theoretical basis to do otherwise.

In this proceeding, to remedy the flaw inherent in the application of a market-derived return to book value-based equity, the Commission should establish the Company's approved ROE at the level requested by the Company.

Q. How would an investor assess the second factor: the likelihood of a utility actually earning the headline equity return?

A. The investor would analyze the adjustments made to actual costs that are allowed to be recovered, imputed productivity that may or may not be achieved, and any arbitrary revenue adjustments. To the extent that such adjustments to real costs are made, the headline rate of return is unlikely to be achieved.

Q. How would an investor assess the third factor: the symmetry of potential returns?

A. There is ample opportunity through penalty-only performance mechanisms, an absence of any meaningful positive incentives and one-way true-ups of costs--burdens which have increasingly been imposed in New York rate decisions--to realize significantly worse returns than the headline authorized return. All of these aspects of New York rate orders create asymmetry in expected returns, which a rational potential equity investor would judge as reducing his or her expected return. Little evidence exists that these burdens are common in other jurisdictions in the country, where the peers that are the basis for the Commission's DCF and CAPM results operate.

Q. Have the shortcomings in the treatment of O&R been reflected in equity analysts' views of the Company?

A. Yes. As of October 24, 2014, Con Edison ranked as 485th of the 500 companies in the S&P 500 in terms of analyst buy/sell rankings Exhibit YS-9.

CONCLUSION

Q. Please summarize your testimony regarding the financial challenges facing the Company.

A. Company witness Hevert has presented the Company's calculation of a required equity return for O&R. My testimony concerns the financial challenges and the need to maintain access to financial markets at reasonable cost. Both equity and debt investors perceive that the New York regulatory environment is a difficult one in which to operate. Such a perception, if it continues, will make financing needed expenditures more expensive in normal times and less certain in times of financial crises. To avoid such an outcome, and to re-establish debt and equity investors' trust in the fairness of New York regulation, a fair and equitable rate of return, competitive with those available elsewhere in the market, and a reasonable chance to actually earn that return, are needed. And to achieve such, the Commission should grant the rate of return and capital structure requested by the Company.

Q. Does that conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ROBERT J. MELVIN – ELECTRIC & GAS

Q. Please state your name and business address.

A. Robert J. Melvin, 390 West Route 59, Spring Valley, New York 10977.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("O&R" or "the Company") as Section Manager of CIMS.

Q. Please briefly describe your educational and business experience.

A. I graduated from Hobart College in 1990 with the degree of Bachelor of Arts in Economics. In 1995, I graduated from Iona College with a Masters of Business Administration degree in Financial Economics. I was employed by the Company from 1990 through 1995. From 1995 through 2008, I was employed by International Business Machines Corporation ("IBM") in various financial management and operations positions within the IBM Global Services. In 2008, I returned to the Company where I was a Specialist in Customer Energy Services and the Retail Access Manager. In 2014, I assumed my present position.

Q. Have you previously testified before the Public Service Commission ("Commission")?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss certain Customer Information Management System ("CIMS") related projects that the Company proposes to implement during the Rate Year in this proceeding (*i.e.*, 12 months ending October 31, 2016)("Rate Year"). These projects are set forth in the chart below and include projects for 2015 and 2016 that support normalized costs for electric in Exhibit ___ (AP-E4), Schedule 12, and for gas in

Exhibit ___ (AP-G4), Schedule 12. I would note that the cost estimates are based on the Company's current best estimates and are subject to update.

		Total Project	NY Elec	NY Gas	Total NY
2015					
	Rate Verification Tool	$ 190.0	$ 106.3	$ 43.9	$ 150.2
	LPC Credits for Prolonged Outages	$ 260.0	$ 152.7	$ 63.2	$ 215.8
	NY Retail Access	$ 200.0	$ 111.9	$ 46.2	$ 158.1
		$ 650.0	$ 370.8	$ 153.3	$ 524.2
2016					
	CIMS Security Enhancements	$ 100.0	$ 55.9	$ 23.1	$ 79.1
	NY Retail Access	$ 100.0	$ 55.9	$ 23.1	$ 79.1
	ROPES	$ 100.0	$ 55.9	$ 23.1	$ 79.1
	Phantom Load Web Design	$ 100.0	$ 55.9	$ 23.1	$ 79.1
	Automate OBF Payments	$ 250.0	$ 147.1	$ 60.9	$ 207.9
		$ 650.0	$ 370.8	$ 153.3	$ 524.2

Q. Please describe each of these projects.

A. **Rate Verification Tool -** The Company's CIMS team will work in conjunction with the Customer Accounting and Rate Engineering departments to commence the development of an enhanced Rate Verification Tool to assist in the Company's monthly rates verification process. O&R currently has a manual monthly bill and rate verification process. The Company is automating this process to allow for the testing of larger samples in order to verify the accuracy of customer bills and to prepare for future rate designs that may be implemented as a result of developments in the Reforming the Energy Vision ("REV") proceeding.

<u>Late Payment Charges ("LPCs") for Prolonged Outages</u> - After Hurricane Irene and Superstorm Sandy, the Commission requested that utilities temporarily waive the imposition of late payment charges in the aftermath of major storm events (*see*, Order Granting Temporary Waiver and Suspension of Late Payment Charges, issued November 2, 2012 in Case 12-M-0501). In order to efficiently address future major storm events and prolonged outages (*see*, Order Establishing Policies, issued November 18, 2013 in Case 13-M-0061), the Company needs to develop an automated process, or processes to perform such tasks as: providing multiple credits of prorated basic service charges; the temporary waiver of LPCs; and the suspension of field collection activities and outbound collection phone calls. To date, the Company has performed these tasks manually, although they were done on a gross basis with little differentiation between customers and time periods. An automated process will allow the Company to perform these tasks more accurately, efficiently, and on a timelier basis. Automating these tasks will require code changes to CIMS.

<u>NY Retail Access</u> – This is a place holder to allow for the recovery of incremental costs, during 2015 and 2016, associated with the changes anticipated from the Commission's current Retail Access proceedings (*i.e.*, Cases 12-M-0476, 98-M-1343, and 06-M-0667)("Retail Access Proceedings"). The Company anticipates two significant changes to CIMS in order to provide Energy Services Companies ("ESCOS")/Marketers with the ability to send individual bill messages to individual customers. This is a major change from the current process by which ESCOS/Marketers provide mass bill messages. In addition, the Company will need to develop identifiable codes and tables to transfer additional customer information to ESCOS/Marketers via electronic data interchange (*e.g.*, low income status, Net Metering Identifiers, tax exempt status) that are ordered from the proceeding. This funding (*i.e.*, $200,000 in 2015 and $100,000 in 2016) is designed to cover the cost of these two changes that the Company anticipates the Commission will require in the Retail Access Proceedings. The Company also would note, as it has stated in the Retail Access Proceedings, modifications that require accelerated switching of ESCOS/Marketers or off cycle switching will require additional funding, not included in the requested normalizing adjustments, so that the Company can make the necessary changes to CIMS.

<u>CIMS Security Enhancements</u> – The CIMS team currently has an audit program that generates a report whenever an employee accesses his/her own O&R residential customer account. As a result of the KPMG Personal Identifiable Information ("PII") review in 2014, KMPG recommended that O&R should proactively program the billing system to recognize the relationship between the employee and his/her residential address in order to prevent the employee from accessing and editing his/her residential account. This change will require the development of secure tables to contain employee information, a portal within CIMS to identify employee accounts and logic to block individual users from accessing individual accounts. The tables and logic will allow for changing variables on an irregular basis.

<u>ROPES</u> – The Company is enhancing its existing Road Opening Permit System ("ROPES') so as to allow municipalities to electronically forward short-term and long-term Department of Public Works Roadwork and Paving schedules to the Company. This will allow for closer coordination between the Company and municipalities, thereby allowing for the more efficient implementation of underground electric and gas main extensions and replacements and enhanced communications between the Company and municipalities. It will also improve our customers' experience and reduce the impact of our work on local traffic by reducing the time during which road surfaces are open for the completion of this work.

Phantom Load Web Design - Design, develop, test and implement a customer self-service tool to assist customers in lowering their energy bill by reducing "Phantom Loads" in their homes. "Phantoms Loads" are defined as the hidden costs of maintaining standard household appliance and technologies such as DVRs, Cable Boxes, and video games. This will allow the customers to determine how many "phantom" appliances they have in their home, combine the estimated usage to their current electric rate, display how much these appliances are costing the customer, and provide recommendations to lower these costs. The goal is to assist customers in conserving energy that is unnecessarily consumed and help them reduce their energy bill. This project will require code changes to CIMS and changes to the ORU.COM website to provide this relevant information for customers.

Automate On Bill Financing ("OBF") Payments - The CIMS team needs to enhance the existing OBF functionality within CIMS relating to NYSERDA energy efficiency loans. The current process provides limited functionality and requires manual intervention in establishing loan accounts and tracking the associated loan data. Since the inception of the program loan activity has increased by a compound growth rate of 160% each year, and the automation of this process will benefit customers by streamlining the loan initiation process and providing real-time loan statistics. The enhancements also will eliminate manual processes required to maintain accurate loan data. This project requires core code changes within the CIMS billing functionality.

Q. Does that conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
COMPENSATION/BENEFITS PANEL

Q. Would the members of the Compensation and Benefits Panel ("Panel") please state their names and business addresses?

A. Hector J. Reyes, and my business address is 4 Irving Place, New York, New York 10003. John de la Bastide, and my business address is 4 Irving Place, New York, New York 10003. Roselyn Feinsod, and my business address is 199 Water Street, New York, New York 10038. Virginia Fischetti, and my business address is 45 Glover Avenue, Norwalk, Connecticut 06850.

Q. Mr. Reyes, by whom are you employed and in what capacity?

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison") as Director of Benefits.

Q. How long have you been employed by Con Edison?

A. I have been employed by Con Edison for 38 years.

Q. Please briefly outline your educational and business experience.

A. I graduated from Fordham University with a Bachelor of Science degree in Accounting in 1976. In 1982, I earned a Master of Science degree in Taxation from Pace University. I joined Con Edison in 1976 as a

Staff Accountant in Corporate Accounting. Between 1979 and 1981, I was promoted to different supervisory positions in Corporate Accounting. In 1983, I was promoted to Assistant Manager, Accounting Research and Procedures. In 1988, I was promoted to the position of Manager, Retirement and Insurance Benefits, and in 1989, I was promoted to the position of Manager of Employee Benefits. In September 1999, I was promoted to the position of Director of Benefits and Compensation. In July 2011, my title was changed to Director of Benefits.

Q. Please generally describe your current responsibilities.

A. My responsibilities as Director of Benefits include the development, implementation, communication, and administration of the Company's employee benefits programs.

Q. Do you belong to any professional societies or organizations?

A. Yes. I am a member of the Board of Directors of the Northeast Business Group on Health ("NEBGH"). NEBGH is a not-for-profit coalition of over 150 health plan sponsors and health-related organizations the mission of which is to find practical solutions to contemporary health care issues in the New York metropolitan area.

Q. Have you previously submitted testimony on behalf of the Company before the New York Public Service Commission ("Commission")?

A. Yes. I have submitted testimony or testified in the last electric rate case for Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R" or the "Company") and have submitted testimony or testified in a number of Con Edison electric, gas, and steam rate cases as well.

Q. Mr. de la Bastide, by whom are you employed and in what capacity?

A. I am employed by Con Edison as the Director of Compensation.

Q. Please describe your educational background.

A. I graduated from Hofstra University in 1985 with a Bachelor of Business Administration in Accounting.

Q. Please describe your work experience.

A. I have been employed by Con Edison for 28 years.

Between l986 and l996, I was promoted to various supervisory positions in Corporate Accounting. In l998, I was promoted to the position of Section Manager, Employee Benefits. In 2001, I was promoted to Department Manager, Financial Forecasting, in Corporate Accounting and have held various positions as Department Manager in Corporate Accounting and Electric Operations. I assumed the position of Department Manager, Benefits and Compensation, in March 2007. In June 2011, I was promoted to Director of Compensation.

Q. Please generally describe your current responsibilities.

A. My current responsibilities as Director of Compensation include administration of the compensation plans for non-officer management employees, officers of O&R, as well as members of the Con Edison’s Board of Directors.

Q. Have you previously submitted testimony on behalf of the Company before the Commission?

A. Yes. I have submitted testimony or testified in the last electric rate case for Orange and Rockland and have submitted testimony or testified in the most recent Con Edison electric, gas, and steam rate cases.

Q. Ms. Feinsod, by whom are you employed and in what capacity?

A. I am a Senior Partner and East Region Practice Leader for Retirement for Aon Hewitt. I have worked with utilities such as Ameren Corporation, GPU, Inc., and PPL Corporation, in addition to O&R and Con Edison.

Q. What is Aon Hewitt?

A. Aon Hewitt is a global market leader in human resources consulting and outsourcing with 29,000 employees serving more than 20,000 clients. More information on Aon Hewitt is available at aonhewitt.com.

Q. Please summarize your educational and professional background.

A. I am a graduate of the College of Insurance with a Bachelor of Science in Actuarial Science. Before joining Aon Hewitt, I was a Principal and a senior workforce strategy and retirement plan consultant to large global clients at Towers Watson, formerly Towers Perrin. At Aon Hewitt, I am the Retirement Regional

Leader for the East Region and a consultant to clients on compensation, benefits, and retirement issues. I specialize in workforce and total rewards strategy, mergers and acquisitions, and all aspects of retirement valuation and administration consulting. I have over 20 years of experience in consulting, having spent eight years with Towers Perrin and ten years with PricewaterhouseCoopers LLP prior to joining Aon Hewitt.

Q. Do you belong to any professional societies or organizations?

A. I am a Fellow of the Society of Actuaries, and I have spoken at numerous professional conferences including World at Work, The Conference Board, the American Gas Association, and The Harvard School of Continuing Public Health.

Q. Have you previously submitted testimony on behalf of the Company before the Commission?

A. Yes. I testified in the most recent Con Edison electric, gas, and steam rate cases.

Q. Ms. Fischetti, by whom are you employed and in what capacity?

A. I am a Partner and East Region Practice Leader for Executive Compensation for Aon Hewitt. I have worked with utilities such as Constellation Energy Group, Inc., Public Service Electric and Gas Company, NRG Energy Services, and Iberdrola USA, in addition to O&R and Con Edison.

Q. Please summarize your educational and professional background.

A. I am a graduate of Amherst College with a Bachelor of Arts degree in Economics. I also have a MBA, Finance and International Business, from New York University's Stern School of Business. Prior to joining Hewitt Associates (now Aon Hewitt) in 1997, I worked as a benefit and compensation consultant for Watson Wyatt (now Towers Watson) in New York. At Aon Hewitt, my work includes the benchmarking of total compensation, the design and implementation of compensation strategies and philosophies, pay structures, short-, mid-, and long-term variable pay programs, and severance and change-in-control benefits.

Q. Are you affiliated with any professional societies or organizations?

A. Yes. I am a member of The Conference Board, a global, independent business membership and research association working in the public interest. In addition, I have spoken to Society for Human Resource Management audiences on the topic of compensation and have had a cover article appear in the World of Work Journal (4th quarter, 2005).

Q. Have you previously submitted testimony on behalf of the Company before the Commission?

A. Yes. I testified in the most recent Con Edison electric, gas, and steam rate cases.

PURPOSE OF TESTIMONY

Q. What is the purpose of the Panel's testimony in this proceeding?

A. The Panel's testimony demonstrates that the Company provides market-competitive benefits and compensation packages designed to attract and retain those employees the Company requires to provide customers with safe and reliable service. The Company continues to proactively manage long-range costs like those related to pensions and health care. For example, the Company projects that the recently negotiated changes to retirement benefits for employees who are members of Local 503 of the International Brotherhood of Electrical (“Local 503”) are expected to reduce pension and Post-Employment Benefits other than Pensions (“OPEB”) costs starting in 2015 by over $2.1 million per year($1.5 million Electric and $0.6 million Gas). In addition, replacing the Cash Balance defined benefit pension plan with a defined contribution pension plan for new Local 503 hires helps to better manage future pension costs and liabilities by significantly reducing the financial risk and volatility associated with funding a defined benefit pension plan. This direct testimony examines the overall level of employee “Benefits” and “Compensation” reflected in the revenue requirements of this filing and demonstrates that the Company’s level of benefits and compensation in aggregate is market competitive and meets the Commission’s standards for assessing the overall competitiveness and reasonableness of such expenditures. The costs of the Company’s benefits and compensation plans constitute reasonable business expenses that should be recoverable in rates for the reasons discussed below. Benefits include retirement, active and retiree health, vacation, life insurance, and disability benefits. Compensation includes base salary, the variable component of management pay (also known as the “Annual Team Incentive Plan” or “ATIP”), and long-term equity grants. The Panel will address (1) a comprehensive review that the Company conducted, with the assistance of Aon Hewitt, of O&R’s total benefits and compensation package (“Review”) in 2014 for non-officer management employees; (2) officer and O&R Board of Directors (“O&R Board”) compensation; (3) the Company’s new three-year labor contract (“Labor Contract”) with Local 503; and (4) employee benefits costs.

Q. What was the purpose of the Review?

A. The purpose of the Review was to assess the market competitiveness of the Company’s total benefits and compensation package for non-officer management employees of O&R. The Panel describes below the Review process, methodology, and results.

Q. In conducting the Review, did the Company evaluate its benefits and compensation package as compared to those offered by other comparable companies?

A. Yes. Consistent with Commission policy and typical market practice, in assessing the overall competitiveness and reasonableness of O&R's benefits and compensation package, the Review compared the Company's package to those offered by a peer group of similarly situated companies.

Q. Were the peer companies limited to utility companies?

A. No, as recommended by the Commission, the Company evaluated total benefits and compensation relative to a blended peer group including both utility and non-utility, New York metropolitan general industry companies ("Blended Peer Group").

Q. What were the Review's overall findings with respect to the peer group analysis?

A. As explained below, the Review found that the Company's benefit programs and compensation for its non-officer management employees, as well as the combined benefits and compensation package value, are within a +/- ten percent range that is considered "competitive" with respect to the Blended Peer Group.

In fact, the Company's benefits and compensation programs are below the median of the Blended Peer Group.

Q. Did the Company make changes to its benefits and compensation plans in response to the Review?

A. No. The Company had previously implemented significant benefit and compensation changes for non-officer management employees effective January 1, 2013. The changes at that time were made to better align the benefit programs and compensation with competitive peer group company practices, while also continuing to attract and retain the type of employees who are critical to the Company's ability to provide safe and reliable service to customers.

Q. Please describe briefly the modifications to which you refer.

A. Effective January 1, 2013, the Company made several changes to pensions and other retirement benefits. For management employees under age 50 on January 1, 2013, who are covered by the Career Average Pay ("CAP") pension formula, two changes were made that affected pension benefits earned after January 1, 2013:

- The early retirement age when employees can receive an unreduced pension increased from 55 to 60; and
- The reduction in the retirement benefit for those employees who retire early (*i.e.*, between the ages of 55 and 60), increased from four percent to five percent for each full year of early retirement.

Q. Were there any changes to other retirement benefits?

A. Yes. The Company changed retiree health and retiree life insurance benefits for management employees retiring on or after January 1, 2013.

Q. Please describe these changes.

A. The Company changed the cost sharing for retiree health for employees covered under the Cash Balance pension formula so that these employees will pay the full cost of retiree health coverage if they elect coverage upon retiring. Effective January 1, 2014, the amount that O&R will provide toward the cost of future retiree health coverage in a given year for management employees covered under the CAP Formula is limited to the dollar amount contributed in the preceding year plus a specified increase for inflation based on the Consumer Price Index ("CPI"). Retiree Health Program costs for the year, above O&R's limited contribution are, fully borne by retirees.

Q. Please describe the changes made to retiree life insurance.

A. As of January 1, 2013, the current retiree life insurance benefit of $25,000 will continue for employees age 50 or older when they retire. Employees under age 50 on January 1, 2013 will not be eligible for retiree life insurance when they retire.

Q. Did the Company implement any other changes effective January 1, 2013?

A. Yes, the Company introduced three new health care options and has implemented changes to the management sick pay and vacation policies. Each of the three health care options is designed to make employees more aware of health care costs. The Company is also sponsoring wellness programs to help employees better understand their health status and to encourage employees to adopt healthy behaviors, such as not smoking. In addition, new sick and vacation pay policies, designed to be consistent with market practices and described in detail below, were implemented effective January 1, 2013.

Q. Were there any modifications made that offset these cost reduction changes?

A. Yes. As part of the Company's effort to align benefits with its peers, the Company also made the following changes:

- The Company match to the Thrift Savings 401(k) Plan increased for management employees covered by the Cash Balance pension formula to align the value of retirement benefits for new hires with market competitive practices;
- The vacation allowance schedule was revised to reduce the maximum vacation time employees can earn over their career. Current employees with less than six weeks of vacation and new hires can earn a maximum vacation allowance of five weeks instead of six. The vacation policy was also revised to allow new employees to reach the maximum number of vacation days earlier in their career;

- Employees are provided flexibility to designate four corporate holidays as floating holidays; and
- The Company modified slightly the ATIP target award opportunities for non-officer management employees in the Band 3L level from 10 percent of base salary to 12 percent of base salary, and for employees in levels EP, SH, SL and SE from 4 percent of base salary to 4.5 percent of base salary.

Q. What was the cost impact of the changes made to the management employee benefits and compensation package?

A. The aggregate cost impact of the changes made to the management benefits and compensation package is a reduction of $9.3 million per year ($6.6 million Electric and $2.7 million Gas) mainly attributed to the retirement benefit changes impacting accounting costs for OPEB.

Q. Since the implementation of the management benefit and compensation changes in January 1, 2013, has the Company conducted a subsequent review to determine whether its overall total benefits and compensation remains reasonable and competitive relative to similarly situated companies?

A. Yes. In 2014, the Company conducted a Review comparing its benefit and compensation programs to the Blended Peer Group.

Q. Did the 2014 Review include the Supplemental Retirement Income Plan ("SRIP") benefit provided to Orange and Rockland management employees?

A. Yes. The SRIP provides management employees with a supplemental pension upon retirement if their pension benefit earned under the tax qualified Retirement Plan is limited by federal tax law. The SRIP formulas for active employees are the same as the pension formulas of the Retirement Plan but makes up for pension benefits that have been earned but could not be paid under the Retirement Plan due to Internal Revenue Service ("IRS") limits imposed on the accrual and payment of pension benefits under tax qualified pension plans.

Q. Does the rate request include recovery for the cost of the SRIP as part of the retirement expense?

A. Yes.

Q. Why is the Company seeking rate recovery for the cost of the SRIP as part of the retirement expense?

A. The primary purpose of the SRIP is to provide those current employees participating in the Company's Retirement Plan with the benefits which would have been payable under the Retirement Plan but for the limitations imposed on qualified plans by Internal Revenue Code Sections 401(a)(17) and 415. The SRIP for current employees exists solely to pay the difference in pension benefits earned by employees under their respective pension formulas that cannot be paid under the qualified Retirement Plan due to these limits. The SRIP costs also include funding costs related to SRIP retirement benefits earned and still payable to former employees.

Q. Are the SRIP benefits consistent with the Blended Peer programs?

A. Yes. As part of the Review, the Company looked at the SRIP programs provided for current employees for the 50 companies in the Blended Peer Group. 44 of the 50 companies provide SRIP-type benefits. Providing SRIP benefits is consistent with the Blended Peer practices and serves to maintain the O&R retirement benefit at a competitive level with the Blended Peers. Please see the table below for a summary of the SRIP benefit prevalence for the Blended Peer Group. Like O&R, certain peers also include in their SRIP arrangement the various prior pension formulas that were used to determine the SRIP benefit earned by the peer company's former employees. We found that as a general rule, once SRIP benefits are earned, they are not modified. The focus of the Review and competitive features is for retirement benefits offered to new hires.

O&R: Summary of SRIP Type Benefits

50 Blended Peer companies – General Industry and Utility

Maintain a SRIP Type Benefit	*General Industry*	*Utility*	*Total*
Yes	21	23	44
No	4	2	6
Total	25	25	50

Q. What is the amount of SRIP expense included in the historic test year and forecast for the rate year?

A. The historic test year included $2.0 million per year ($1.4 million Electric and $0.6 million Gas) and the forecast of SRIP expense is $2.0 million per year ($1.4 million Electric and $0.6 million Gas).

Q. In conducting the Review did the Company evaluate its benefits and compensation package as compared to those offered by other comparable companies?

A. Yes. Consistent with Commission policy and typical market practice, in assessing the overall competitiveness and reasonableness of O&R's benefits and compensation package, the Review compared the Company's package to those offered by a peer group of similarly situated companies, *i.e.*, the Blended Peer Group.

Q. Does the rate request include compensation for members of the O&R Board?

A. Yes. One member of the three-person O&R Board, who is not an employee of either the Company or Con Edison, receives compensation. This non-Company/Con Edison O&R Board member receives an annual retainer of $25,000, with an additional $1,000 meeting fee for each Board meeting attended in excess of five meetings.

Q. Does the rate request include officers' compensation?

A. The rate request reflects only certain discrete elements of compensation for officers.

Q. Please explain.

A. The Panel will describe elements of the Company’s compensation program for the Company’s officers, including base salary, annual variable pay awards, and long-term equity grants. Such compensation constitutes a reasonable and necessary business expense the Company must incur to meet its obligation to attract and retain qualified leaders to direct and oversee the safe and reliable operations of the Company.

Q. Why is the Company not seeking recovery of all elements of officer management compensation?

A. To limit the contested issues in this filing, the Company is electing not to seek recovery of the long-term equity grants and variable pay awards provided to the Company’s officers. The Company may seek to recover all or parts of these elements of compensation in future proceedings.

Q. Please address the Labor Contract.

A. The Labor Contract constitutes a fair and equitable contract that includes benefits and compensation programs that will continue to attract and retain qualified employees and that will reflect the needs of all stakeholders — employees, customers, and regulators —and supports the long-term sustainability of the Company. As discussed in more detail below, the Labor Contract is cost-effective and competitive, and will result in long-term savings primarily associated with changes to retirement benefits for current and future employees who are members of Local 503.

Q. Does the Panel address employee benefit expenses?

A. Yes, this direct testimony explains the forecast of employee benefit expenses based on historic costs and escalation of existing programs. This direct testimony also addresses program changes that the Company has implemented for management employees, as well as the changes resulting from the Labor Contract. Health costs shown in the exhibits are net of participant out-of-pocket payments such as co-payments and deductibles that are paid to providers for medical services. This direct testimony also reflects the

Company's wellness efforts and plan design changes that are expected to mitigate future plan cost increases. The Company's employee benefit expenses net of capitalization are estimated to increase approximately 28 percent from the historic test year (*i.e.*, 12 months ended June 30, 2014)("Historic Year") to the rate year (*i.e.*, 12 months ending October 31, 2016)("Rate Year")or 11 percent per year compounded annually.

Q. What other cost mitigation actions with respect to Post-Employment Benefits other than Pensions ("OPEBs") has the Company taken?

A. Recent actions to mitigate OPEB expenses include taking advantage of the tax savings the Patient Protection and Affordable Care Act ("PPACA") generated related to Medicare-eligible retiree's prescription drug benefits. The plan known as an Employer Group Waiver Plan ("EGWP") replaced the Medicare Part D Retiree Drug Subsidy ("RDS") the Company had received. As described below, the EGWP program offers significantly more subsidies and reimbursements than available under the RDS program. In addition, effective January 1, 2013, those management employees who participate under the Cash Balance Pension Plan formula are responsible for paying for the full cost of retiree health coverage.

Q. Has the Commission articulated criteria to determine whether the costs associated with a utility's benefits and compensation plans should be recoverable in rates?

A. Yes. In the Commission's rate order dated February 21, 2014 in the most recent Con Edison rate cases (Case 13-E-0030, 13-G-0031, 13-S-0032)("Con Edison Rate Cases"), the Commission indicated that a utility should demonstrate the overall competitiveness and reasonableness of its total benefits and compensation package by including a comparison with a peer group comprised of similarly situated companies, including both utilities and general industry. In its rate order dated June 26, 2014 in the United Water New York, Inc. (Case 13-W-0295), the Commission reaffirmed that to obtain recovery of variable pay, a company must demonstrate that the overall compensation, including the variable pay component, is reasonable relative to similarly situated companies.

Q. Has the Commission addressed any other criteria with respect to evaluating recovery of costs associated with a utility's benefits and compensation package?

A. Yes. In its rate order in the Con Edison Rate Cases, the Commission noted with approval Con Edison's willingness to conduct its comparative compensation/benefits study to achieve at least a 50 percent matching of positions in a blended peer group of utilities and New York metropolitan employers.

Q. Has the Company compared its total benefits and compensation package with those of a peer group comprised of similarly situated companies?

A. Yes. O&R retained Aon Hewitt to conduct a comprehensive review of its total benefits and compensation package, *i.e.*, the Review. Aon Hewitt was selected because it is an industry leader in this type of review and has the experience, survey data, and tools needed to analyze the competitiveness of various benefit and compensation plans.

Q. Did Aon Hewitt conduct the Review addressed in this testimony?

A. Yes, Aon Hewitt conducted the Review.

REVIEW METHODOLOGY

Q. Please provide an overview of the general approach of the Review.

A. The Review compared O&R's non-officer management employee benefits and compensation package values to external benchmark data for the following components:

- Employee benefits (including pre- and post-retirement benefits and SRIP);
- Base salary;
- Variable pay; and
- Long-term equity grants.

Q What is included in the employee benefits value analysis?

A. The employee benefits value analysis compared the value of design features (*e.g.*, health plan co-payments, deductibles, and co-insurance) of the benefits programs at O&R to the value of design features of the benefits programs at the members of the Blended Peer Group.

Q. Please continue.

A. The benefit design value analysis also includes an assessment of the program features that are based on salary (*e.g.*, pension benefit accrual formulas, thrift saving plan company match percentages, and the definition of covered pay). Then the annual design value (on a salary equivalent basis) at O&R is measured against the annual value of the peer companies benefit designs to compare how compensation based benefit programs effect the total value of the benefits packages included in the comparison. If, for example, an employee at Company A earns more pay than an employee at Company B in the same position, then the value of the thrift savings plan company match (*i.e.*, five percent of pay) to the employee at Company A will be higher. The employee benefit analysis performed in this manner allows for a more accurate comparison of benefit packages.

Q. Please describe the process used to assess the benefit designs of the benefits programs of the Company and its peer companies.

A. The benchmarking of employee benefits design was done using Aon Hewitt's Benefit Index© ("Benefit Index"). The Benefit Index is a premier tool for comparing the relative worth of one company's benefits programs to those offered by a group of other companies. It has been used by companies since the 1970's to make such assessments.

Q. How were the benefit design competitiveness assessments made?

A. Benefit Index results are reached using a very specific process. Actuarial techniques measure the total value a representative population of employees would derive from O&R's benefits program and the benefits programs of each of the peer companies. All retirement income, death, disability, health care, and paid time-off benefits offered to employees are included, such as vacation and paid holidays. This actuarial analysis reflects the benefits that each program would be expected to pay during a year or the present value of the benefits employees would be expected to earn during a year but receive in the future. The same employee population and assumptions are used when measuring the values for each of the programs. This standardization verifies that the differences are attributable to plan designs, not pay levels. The impact of pay level differences is assessed in the benefit design value analysis of the Review. Finally, the benefit design features of O&R's benefits program were compared to the average for the peer companies' programs to arrive at a relative benefit design result reported by the Benefit Index.

Q. What is a Benefit Index benefit design result?

A. A Benefit Index benefit design result of 100.0 would be assigned if O&R's benefits exactly equaled the average of the benefits package value offered by the peer companies. Generally, differences in the overall benefit package value are not considered significant or material until they exceed 10 percent (*i.e.*, less than 90.0 or greater than 110.0 as compared to O&R). A Benefit Index benefit design result within this range would be viewed as "competitive."

Q. Which benefits programs are included?

A. The benefits analyzed included the following programs to which an annualized value was attributed:

- **All Post-retirement Benefits**: Post-retirement benefits reviewed included pension, thrift saving (401(k) plan), retiree health, hospital, medical, vision care, prescription drug, and life insurance.

- **All Pre-retirement Benefits:** Pre-retirement benefits reviewed included hospital, medical, dental, hearing, and vision, and sick, short- and long-term disability, and paid vacation and holidays.

Q. Please describe the peer companies that were used in the Review to analyze the competitiveness and reasonableness of the Company’s benefit plan designs and annual benefit and compensation package values.

A. A Blended Peer Group of 50 companies was used for comparison purposes, including 25 utility peers and 25 New York metropolitan general industries peers. The list of members of the peer group is provided in Exhibit ___ (AH C/BP – 1).

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AH C/BP – 1)

Q. Was the exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please describe the Blended Peer Group.

A. The Blended Peer Group is made up of 25 utility peer companies and 25 New York metropolitan general industry companies for a total of 50 companies. The utility peers have similar operations to O&R and have employees with similar experience and skills in the utility industry as O&R. The New York Metropolitan General Industry peers include general industry companies with headquarters locations in the New York metropolitan area (*i.e.*, New York, New Jersey, and Connecticut), and that have a significant number of both salaried and hourly employees in the New York metropolitan area. These companies have similar operations to O&R in its non-utility-specific areas such as finance, information technology, human resources, and legal. Together this group of 50 companies is representative of the labor market for non-officer, management employees at O&R. It also reflects a sample that has available data for both compensation and benefit benchmarking based on survey participation.

Q. Is the Panel sponsoring an exhibit in connection with the Benefit Index results used in this analysis?

A. Yes. Please see the exhibit entitled "BENEFIT INDEX RESULTS."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AH C/BP – 2)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT ___ (AH C/BP – 2).

A. This exhibit summarizes the details of the results of the Benefit Index analysis of the current O&R benefit plan designs, including a comparison to the Blended Peer Group.

In aggregate, the O&R benefit plan has a Benefit Index design score of 98.2 when compared to the Blended Peer Group.

Q. How was the compensation competitiveness assessment made?

A. The compensation competitiveness assessment included a comparison of base salary, annual variable pay (at target), and long-term equity grants for O&R positions and for the Blended Peer Group positions. The annualized value of each pay component is included in the analysis (*e.g.*, annual base salary).

Q. How did Aon Hewitt combine the Benefit Index results with the compensation benchmarking to develop the total benefits and compensation package value?

A. Aon Hewitt followed a standard methodology consistent with industry practice. First, Aon Hewitt determined which positions at O&R matched positions among the Blended Peer Group, based on a comparison of functional responsibilities, job duties, and organizational level for which data is available from the survey sources. Next, Aon Hewitt compared the benefit and compensation data for each of these positions at O&R to the benefit and compensation data for the same positions among the Blended Peer Group. Finally, Aon Hewitt aggregated these results to evaluate O&R's overall competitive position relative to the Blended Peer Group median.

Q. Why did Aon Hewitt compare O&R total benefits and compensation to the median, but compared the O&R benefit designs to the average for the Benefit Index?

A. Mean and average are both reasonable methods to make observations in a data analysis, and either may be used when doing a total benefits and compensation analysis. However, the use of median is an industry practice in total benefits and compensation studies because the median normalizes a data sample by placing equal emphasis on each observation, thereby mitigating the influence of extreme outlier values, if any. In benefit design reviews, the need to mitigate for extreme outliers is less important (program designs, not pay levels, are being examined). Therefore, it is a standard industry practice to use market average or market typical design when analyzing program design features.

Q. If the analysis were based on the average instead of the median in the total benefits and compensation study, would the result have been materially different?

A. No. The Blended Peer Group results are substantially similar using both market reference points. Using the median, O&R's total benefits and compensation was 6.6 percent below the Blended Peer Group median (or 93.4 percent of the median). Using the average, O&R total benefits and compensation was 7.5 percent below the Blended Peer Group average (or 92.5 percent of the average).

Q. What companies were used to assess the competitiveness of O&R's total benefits and compensation package value?

A. The Blended Peer Group was used in all of the analysis: the benefits design benchmarking and the total benefits and compensation positional analysis.

Q. What data sources were used for the Review?

A. Three data sources were used, all using the same Blended Peer Group: (1) the Aon Hewitt Benefit Index Database; (2) the Aon Hewitt Total Compensation Measurement Database; and (3) the Towers Watson Compensation Survey.

Q. Was the compensation survey data adjusted for geography?

A. Yes. It is a common industry practice to use national compensation data for analyzing management level roles. However, given O&R's metropolitan New York location, a location with a significantly higher than national cost of labor, a geographic adjustment was applied to the national data (*i.e.*, those utility members of the Blended Peer Group located outside the New York metropolitan area) to account for this cost of labor difference relative to the Blended Peer Group data used in the Review.

Q. How many non-officer management positions and employees were included in the total benefits and compensation analysis?

A. To provide a robust representation of the Company’s non-officer management employee base Aon Hewitt compared approximately fifty-five percent of the O&R non-officer management employees (*i.e.*, nearly 260 employees) across the Company’s pay structure to the Blended Peer Group companies.

Q. Is fifty-five percent coverage sufficient to draw valid conclusions from the Review?

A. Yes. The positions included in the analysis covered several functional areas: Electric Operations, Gas Operations, Gas Engineering, Public Affairs, and Environmental Health & Safety, among others, and all of the non-officer management salary bands at O&R with significant numbers of non-officer management employees: 1L/1H, 2L/2H, 3L/3H, and 4L. The results of the analysis, therefore, are representative of O&R’s pay positioning across the entire non-officer management employee population.

Q. Why were some O&R non-officer management positions excluded from the Review?

A. In performing the positional analysis, benchmark jobs were identified for approximately 88 percent of O&R's non-officer management employees. The remaining 12 percent are in positions at O&R that were not included in the compensation survey data sources. Of the 88 percent "benchmark" jobs, there was sufficient Blended Peer Group data to provide analysis for 55 percent of O&R's non-officer management employees.

Q. Why were some of the "benchmark" jobs not included in the Review?

A. For some benchmark jobs, there was not sufficient data reported by the Blended Peer Group companies to the compensation survey sources to include the position in the Review. The United States Department of Justice safe harbor guidelines indicate the need for a minimum of five data points with no more than twenty percent of the sample from any single peer company. If fewer data points were available for a benchmark position, it was excluded from the Review.

Q. Is the Panel sponsoring an exhibit in connection with the positions included in the Review?

A. Yes. Please see the exhibit entitled "CENSUS".

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AH C/BP – 3)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT ___ (AH C/BP – 3).

A. This exhibit lists all non-officer management positions at O&R, the survey benchmark job, if any, that "match" the O&R position, and whether the position was included in the Review. Positions were excluded for one of the following reasons:

- "Benchmark defined, but survey does not have sufficient data" indicates the O&R position is a benchmark position but there was not sufficient Blended Peer Group data to include the position; or
- "Non-Benchmark Job" indicates the O&R position is not similar to any survey benchmark positions in terms of functional responsibilities, job duties, and/or organizational level.

Q. Is the Panel sponsoring an exhibit in connection with the competitive positioning of Total Benefits and Compensation of O&R positions benchmarked as part of the Review?

A. Yes. Please see the exhibit entitled "Total Benefits and Compensation Results."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AH C/BP – 4)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT ___ (AH C/BP – 4).

A. This exhibit identifies the O&R employee positions included in the comprehensive review as compared to the Blended Peer Group. This exhibit includes the following information:

- Band;
- O&R title, section, and department;
- Benchmark title;
- O&R total benefits and compensation;
- Market total benefits and compensation at the 50th percentile (median) and average; and

- Variance for each O&R position to market using the average and the median.

Q. What did Aon Hewitt's analysis indicate when comparing O&R to the Blended Peer Group?

A. In the aggregate, Aon Hewitt found that O&R's non-officer management total benefits and compensation package value to be "market competitive." O&R's total benefits and compensation was 6.6 percent below the Blended Peer Group median (or 93.4 percent of the median). Using the average, O&R total benefits and compensation was 7.5 percent below the Blended Peer Group average (or 92.5 percent of the average). This is low but considered to be within a market competitive range of plus or minus ten percent in aggregate.

Q. Is the Panel sponsoring an exhibit in connection with the results of the Aon Hewitt analysis?

A. Yes. Please see the exhibit entitled "SUMMARY OF RESULTS."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AH C/B – 5)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT ___ (AH C/B – 5).

A. This exhibit identifies the aggregate results, relative to both the average and the median of the Review Aon Hewitt performed using the Blended Peer Group by each component of total benefits and compensation discussed above:

- Base Salary;
- Target Cash Compensation (sum of Base Salary and the variable component of management pay);
- Total Direct Compensation (sum of Target Cash Compensation and long-term equity grants);
- Total Benefit Value (estimated annual value of employee benefits); and
- Total Benefits and Compensation (sum of Total Direct Compensation and Total Benefit Value).

Q. Please provide a summary of the Blended Peer Group analysis findings with respect to the annual variable pay.

A. The O&R target annual ATIP award opportunities consistently lag the market at all Band levels.

Q. Is the Panel sponsoring an exhibit in connection with the findings regarding annual ATIP award opportunities?

A. Yes. Please see the exhibit entitled "ANNUAL VARIABLE PERFORMANCE-BASED PAY COMPARISONS."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AH C/B – 6)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT ___ (AH C/B – 6).

A. This exhibit identifies the O&R Band and the annual ATIP target award opportunity for employees in each Band compared to the median and average target annual variable pay award opportunities for employees at the Blended Peer Group companies at the same salary levels.

Q. Please provide a summary of the Blended Peer Group total benefits and compensation analysis.

A. In aggregate, as discussed above, the O&R total benefits and compensation value for non-officer management employees is approximately seven percent below the Blended Peer Group median and average.

Q. Based on the findings of the Review, what changes has the Company made?

A. The Company plans no significant changes to its compensation and benefits program at this time.

Q. Please summarize your findings.

A. In summary, the results of the Review demonstrate that the costs of the total benefits program and compensation, including the variable component of non-officer management base pay, and SRIP, are appropriate business expenses incurred so that the Company can meet its obligation to provide safe and reliable utility service to its customers. Accordingly, the Company has included the costs of these programs in the gas and electric revenue requirements.

NON-OFFICER COMPENSATION

Q. Does the base compensation for O&R's non-officer management employees include both base salary and a variable pay component?

A. Yes.

Q. Is O&R unusual in its inclusion of a variable pay component as part of base compensation?

A. No. Tying a portion of employees' base compensation to performance has become commonplace both in American business generally and for public utilities as well.

Q. Please continue.

A. The variable pay component of base compensation in the Company's plan is earned only if the Company reaches pre-set performance goals that are directly linked to specific measurable standards consistent with the Company's goal of providing safe and reliable service to customers. These performance goals encompass reliability, safety, customer-service performance indicators, and adjusted net income. The specific performance goals are tracked on a calendar year basis.

Q. Has the Commission addressed its standards for recovery of the variable component of management pay?

A. Yes, the Commission has addressed this topic in several recent O&R rate case related orders. In its *Order Denying Petitions for Rehearing and/or Clarification* issued on November 21, 2011, in Case 10-E-0362 (p. 6) the Commission stated:

The second point we wanted to emphasize is that it is not necessary to maintain an artificial distinction between compensation in the form of traditional pay and benefits and compensation that is incentive based. As we have stated previously, we recognize that variable compensation and incentive plans are common management tools aimed at encouraging performance improvements that can lead to more competitive operations. Consequently, if a utility can demonstrate that total compensation including incentive compensation for a class of employees is reasonable, with a comparable total compensation study of similarly situated companies being the preferred methodology, our concern about the relationship of incentive plan objectives to ratepayer interests is substantially diminished. As long as the plan does not promote employee behavior that would be contrary to ratepayer interests or Commission policies, the fact that it may contain financial, budgetary or other goals that benefit shareholders as well as ratepayers will not, by itself, be grounds for disallowing funding in rates, even if the relative benefits are unquantified.

Q. Please describe the Company's overall compensation philosophy.

A. The philosophy of the Company is to provide compensation that is competitive with the median levels of compensation provided by a peer group of similarly situated companies. This approach to setting compensation levels permits the Company to be reasonably competitive in the labor market and to be able to attract, and fairly compensate, employees important to the success of the Company. In targeting the median levels for compensation measured against a market competitive norm, the Company has taken a very conservative low-cost approach, an approach which benefits its customers.

Q. Please describe the O&R ATIP.

A. ATIP is the variable pay component of non-officer management compensation. The ATIP awards, which are reviewed and approved by the O&R Board, are based on the overall achievement of annual corporate and departmental goals. Awards under ATIP are based on actual performance relative to pre-specified goals. ATIP represents the portion of employees' annual base salary that is dependent upon the attainment of certain predetermined, measurable corporate and individual goals. ATIP must be earned each year. In linking a portion of annual salary to defined and measurable performance criteria, the Company's compensation philosophy strives to reward each employee's contribution to the overall operating, customer service performance, and financial strength of the Company. ATIP is available to all management employees and includes both team and individual components. The team portion of the award comprises 60 percent of the total available award and the individual portion of the award comprises 40 percent. Each employee's potential individual award is based on the individual's contribution toward the overall corporate initiatives and achievement of goals, and on his or her position within the non-officer management salary bands of O&R. ATIP goals are established annually and include both operating and customer service and financial targets. The O&R Board approves the corporate goals, employee award targets, and the corporate award in the first quarter following the completion of the plan year.

Q. Please continue.

A. The ATIP goals for 2014 include Customer Service (weighted at 50 percent), Operating Budget (weighted at 25 percent), and Net Income (weighted at 25 percent). The dominant factor for ATIP is now specific customer service goals. ATIP reflects the Company's focus on delivering to its customers safe and reliable utility service in a cost-effective manner. Fully 75 percent of ATIP goals are achieved through customer service and managing the Company's operating budget. This combination sends the proper signals so that employees focus on providing the highest levels of customer service while remaining focused on seeking cost savings and efficiencies. When Company employees are within or under budgets that are reflective of productivity and/or cost savings initiatives, customers receive the tangible benefit of lower costs for the provision of service in the long term.

Q. Please describe the Customer Service goals.

A. The Customer Service goal includes 12 distinct service targets, one of which is the completion of select major capital projects. Payout for the achievement of the Customer Service goal is based on the number of individual targets achieved, with no payout for the Customer Service Goals if less than seven of the 12 targets are attained.

Q. Is the Panel sponsoring an exhibit listing the Customer Service Goals?

A. Yes. Please see the exhibit entitled "2014 ATIP CUSTOMER SERVICE PERFORMANCE GOALS."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (C/B – 1)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT (C/B – 1).

A. This exhibit lists each of the twelve customer service goals, the unit of measure, and the 2014 targets.

Q. How do customers benefit from the attainment of Customer Service goals?

A. These goals are established to enhance particular areas of customer service, safety, and reliability, as well as employee development, environmental stewardship, and completion of system enhancements and capital projects. To the extent that such goals are achieved, customers benefit directly. The Company's concern for customer satisfaction and providing a high level of service and overall safety is demonstrated in linking ATIP compensation to particular goals. For example, service reliability is demonstrated in setting the Frequency of Outages goal and the Restoration Time goal. Managing calls answered, processing of customer service applications, and keeping appointments demonstrate concern for customer service and satisfaction. Other examples of direct customer benefits from the attainment of ATIP goals include: the Storm Scorecard goal which measures the Company's efficiency in managing storm situations and is aimed at quick restoration of customer utility service during storms; Employee Development, which will result in a capable, well-trained staff; the Safety Index, which not only is aimed at protecting the work force and the public but could lead to reduced insurance costs as accident incident rates are reduced; and the Environmental Index which is intended to motivate a rigorous focus on environmental compliance and continuous improvement of the Company's environmental stewardship.

Q. How do customers benefit from the attainment of the Operating Budget and Net Income goals?

A. Customers benefit both directly and indirectly when the Operating Budget and Net Income ATIP goals are achieved. Customers derive benefits from achieving the net income levels that attest to the Company's financial strength and stability. O&R competes for capital in a capital-intensive industry. A company that attains rigorous financial and operating budget goals will ultimately benefit its customers.

COMPENSATION PROGRAM FOR OFFICERS

Q. What are the elements of the Company's compensation program for its officers?

A. The Company's compensation program for its officers is comprised of three elements: base salary, a variable component, and long-term equity grants.

Q. Please describe the Company's officer compensation philosophy.

A. The Company's philosophy is the same for officers as it is for non-officer management employees -- to provide base salary, a variable component, and long-term equity grants that are competitive with the median levels of officer compensation provided by a peer group of comparable companies.

Q. Please describe how the Company establishes compensation levels for officers.

A. The O&R Board establishes, reviews, and approves the Company's officer compensation program for two of the three officers. The O&R Board makes recommendations for the President of O&R's compensation to the Management Development and Compensation Committee of Consolidated Edison Inc.'s Board for approval. The annual variable component for all three Company officers is linked to the ATIP goals for Customer Service, Operating Budget, and Net Income. Con Edison Inc.'s industry peer group is used for purposes of providing benchmark information on officer compensation levels. This peer group is also used to measure relative total shareholder returns for vesting one half of officer's equity grants.

Q. Is the Company seeking to recover all three elements of officer compensation, *i.e.*, base salary, the variable component, and long-term equity grants, in the contemporaneous rate filings?

A. No. The Company has elected not to seek recovery of the variable component and equity grants provided to the Company's officers, even though the costs of these two elements of officer compensation are reasonable and necessary business expenses the Company must incur to attract and retain officers to manage its operations and provide safe and reliable service to its customers. The Company specifically reserves the right to seek recovery of these costs in future rate filings.

LABOR CONTRACT

Q. What portion of the Company's work force is unionized?

A. Approximately 56 percent of the Company's 1,100 employees are members of Local 503. The total benefits and compensation for these workers are determined by collective bargaining.

Q. Has the Company recently concluded negotiation of the Labor Contract with Local 503?

A. Yes. The previous contract expired on June 1, 2014. On June 12, 2014, Local 503 ratified the Labor Contract.

Q. Please describe the principal changes negotiated in the Labor Contract.

A. The major changes negotiated in the Labor Contract relate to wages, health care coverage, and retirement benefits.

Q. Please describe the wage increases included in the Labor Contract.

A. The following wage increases will be granted to each eligible employee who is on the active weekly payroll on the effective date of such increase.

- Effective June 1, 2014, a 2.25 percent general wage increase for all regular employees;
- Effective January 1, 2015, a 0.5 percent general wage increase for all regular employees;
- Effective June 1, 2015, a 2.25 percent general wage increase for all regular employees;
- Effective January 1, 2016, a 0.5 percent general wage increase for all regular employees;
- Effective June 1, 2017, a 2.25 percent general wage increase for all regular employees; and
- Effective January 1, 2017, a 0.50 percent general wage increase for all regular employees.

Q. Please describe the changes to the Local 503 employees' health care coverage.

A. Beginning January 1, 2015, Local 503 employees will be offered new hospital, medical, and prescription drug coverage. These changes are designed to align health care benefits with market practices, moderate health care cost increases and to help employees become more conscious of health care costs. Employees will have a range of options, as discussed below, that are more consistent with other companies in the Blended Peer Group, to balance payroll contributions with out-of-pocket costs when employees use health care services. New wellness initiatives will be available to encourage employees and their families to live a healthy lifestyle and help manage health care costs. The new options are being offered in the fall 2014 enrollment for coverage effective January 1, 2015. The new medical options will be very similar to those described above being offered to management employees.

Q. Will the new medical plan options moderate future healthcare cost increases?

A. Yes. Over the past four years Local 503 health care costs have increased at a compounded annual average rate of 13.7 percent. Cigna, the Company's hospital and medical carrier, forecasts that the plan design changes negotiated as part of the Labor Contract are expected to decrease the forecasted future health care cost trend to approximately eight percent annually. With the plan-design changes included in the new choices (*i.e.*, increases in co-payments, deductibles, and out-of-pocket limits) and wellness initiatives, the Company is seeking to elevate employee awareness of health care costs and the importance of staying healthy, which should contribute to slowing the increasing health care cost trend and lower future costs for our customers.

Q. Please discuss the changes in the amounts that Local 503 employees contribute toward health care coverage.

A. Effective January 1, 2015, Local 503 employees' contributions toward hospital, medical, prescription drug, and dental coverage will increase from the current maximum of $43 per week for individual coverage, $83 for employee plus dependent coverage, and $108 per week for family coverage to $50 for individual coverage, $93 for employee plus dependent coverage, and $126 per week for family coverage. By the end of the Labor Contract (for calendar year 2017), the maximum employee contributions will be $58 for individual coverage, $105 for employee plus dependent coverage and $150 per week for family coverage.

Q. Are there situations in which employees can contribute less?

A. Yes, Local 503 employees may contribute less for health care coverage depending on the coverage level they choose. The maximum rates stated above are for the co-pay Plan. This plan most closely resembles the current hospital, medical, and prescription drug coverage, which generally provides employees with the lowest out-of-pocket cost at the point of service, *i.e.*, when they incur a claim. This level of health care coverage also requires the highest level of employee payroll contributions per paycheck. While the other two options (Co-insurance Plan and High-Deductible Health Plan) will have lower employee payroll contributions per paycheck, these plans will also require the employee to pay a higher out-of-pocket cost at the point of service. These two options are designed to help employees become more aware of actual health care costs and incent the employees to use the cost-efficient services and providers made available under each health care option. For example, in a co-insurance type plan, an employee who goes to his/her primary care physician for an office visit will be required to pay (after meeting the deductible) ten percent of the cost of the office visit. Therefore, if the cost of an in-network primary care physician office visit is $250 while the comparable out-of-network physician fee is $400, the employee has a choice to pay $23 for an in-network service or $100 (the out of network co-insurance percent is 25 percent) for selecting an out-of-network provider. The same ten percent co-pay applies if an employee visits an in network "specialist." The plan that allows employees the greatest flexibility in managing their health care costs is the High-Deductible Health Plan with a Health Savings Account ("HSA"). To continue to moderate cost increases, the Labor Contract provides for various future plan design changes which increase the co-payments, deductibles, co-insurance percent, and annual out-of-pocket limits in 2017.

Q. Are there other factors that may lower an employee's contributions?

A. Yes, as part of the Labor Contract, the Company included maximum rates for employee contributions under the above options which can be lower employee contributions depending on the plan an employee selects and the direction plan costs take in the future. To the extent that health care cost increase at a lower-than-expected rate, due to revised plan designs and employee utilization changes, employees will share in these savings by contributing amounts through payroll deductions that are less than the maximum rates set forth in the Labor Contract. Reducing the health care cost trend helps to mitigate future premium increases which lowers the Company's contribution toward health care coverage and results in lower costs for our customers.

Q. Please briefly describe the High-Deductible Health Plan with an HSA.

A. As was the case with the Open Access Plus – High-Deductible Health Plan with an HSA for management employees discussed earlier in this testimony, a High-

Deductible Health Plan with an HSA available to Local 503 will have the lowest employee payroll contributions per paycheck but higher out-of-pocket costs when employees receive medical care and services. Generally, healthy employees who actively manage their health care expenses will benefit from lower employee payroll contributions. In addition, a High-Deductible Health Plan provides employees with some tax savings with an HSA.

Q. What are the annual deductibles, out-of-pocket limits, and co-insurance levels for the High-Deductible Health Plan?

A. The High-Deductible Health Plan will cover hospital, medical, and prescription drug charges all subject to the following deductibles, out-of-pocket limits, and co-insurance. Employees who elect this coverage will be required to pay all hospital, medical, and prescription drug charges, except for in-network preventive care, up to $1,300 for individuals or $2,600 for family in network coverage. Once the deductible is met, the plan will pay 85 percent (decreasing to 80 percent in 2017) of additional healthcare costs, and the employees will be responsible for the remaining 15 percent (increasing to 20 in 2017) of the costs. The annual out-of-pocket limit for in network services, for an individual is $2,650 or $5,600 for family coverage. Once the employee reaches the out-of-pocket limit the plan covers additional health care costs at 100 percent. If an employee chooses to use out-of-network providers the deductible and out-of-pocket limits increase and the co-insurance (*i.e.*, the portion employees pay) increases to 45 percent. The out-of-network deductible is increased to $2,000 for individuals or $4,000 for family coverage, and the annual out-of-pocket limit for an individual is $4,850 or $9,750 for family coverage.

Q. What are the advantages of an HSA?

A. As noted previously, employees may elect to pay for increased out-of-pocket medical expenses under the High Deductible Health Plan by contributing pre-tax dollars to an HSA. One of the advantages of an HSA is that the unused balance rolls over from year to year. Therefore, employees will have a choice when they incur health care expenses: pay the expense out-of-pocket (to let the money in their HSA grow tax-free) or use their HSA to use pre-tax dollars to pay for some or all of their eligible expenses.

Q. Will the Company contribute to employees' HSAs?

A. Yes, to encourage employees to enroll in this new plan the Company will contribute $750 annually for individual coverage, or $1,500 for family coverage, to the employee's HSA. In addition, employees can contribute on a pre-tax basis in 2015 an additional $2,600 for individual coverage or $5,150 for family coverage. Total (Company and employee) pre-tax contributions will be subject to Internal Revenue Code limits each year.

Q. What retirement benefits were changed as part of the Labor Contract?

A. The Labor Contract provides for a several changes affecting both pension and retiree health care benefits.

Q. Please describe the changes to pension benefits.

A. Local 503 employees hired on or after June 1, 2014 will be covered under a new defined contribution pension formula instead of the cash balance pension formula. In addition, Local 503 employees who are currently covered under a cash balance pension formula will be offered an opportunity to change their pension benefit from the cash balance pension formula to the defined contribution pension formula.

Q. Please describe the new defined contribution pension formula.

A. The new defined contribution pension formula provides employees with a pension benefit based on compensation credits that are transferred to the employee's Thrift Savings 401(k) Plan account each quarter. The crediting rates for compensation credits are the same as the Cash Balance compensation crediting rates which are based on the employee's age and years of service and can range from a minimum of four percent to a maximum of seven percent as shown in the following table:

Points (Age Plus Service	Percent of Compensation	Plus	Percent of Compensation that exceeds Social Security Wage Base
Under 35	4.00%		4.00%
35 - 49	5.00%		4.00%
50 - 64	6.00%		4.00%
Over 64	7.00%		4.00%

For example, the quarterly compensation crediting rate for an employee who is age 25 with five years of service would be one percent (1/4 of the annual four percent rate).

Q. Does the change to the defined contribution pension formula reduce costs?

A. Yes. The new defined contribution pension formula is expected to cost less than the Cash Balance pension formula. Although the compensation crediting rates are the same under both plans, the Cash Balance pension formula provides for automatic interest credits each quarter ranging from a minimum of three percent to a maximum of nine percent depending on the 30-year U.S. Treasury’s rates in effect for the interest crediting period. Interest credits are not included in the new defined contribution formula. Instead, employees are responsible for directing the investments of the Company compensation credits transferred to their Thrift Savings 401(k) Plan account in the same manner they direct the investments in their Thrift Savings 401(k) Plan account balance. The return employees earn on their account balance will depend on the performance of the investment option(s) selected. As a result, employees assume the risks and costs associated with long-term investing instead of the Company. Initially, the Company will see modest short-term savings that increase over time as the Company hires new employees. Depending on the number of new hires, Buck Consultants, the Company’s actuary, estimates a steady increase in the annual reduction in pension expense attributed to Local 503 new hires from slightly under $0.1 million ($56,000 Electric and $23,000 Gas) in 2015 to about $1.2 million ($839,000 Electric and $347,000 Gas) by 2024.

Q. Does the Labor Contract provide for other changes to pension benefits?

A. Yes. Effective January 1, 2015, the Labor Contract provides changes to the early retirement pension provisions for employees who are covered by the CAP formula and imposes limits the pension service credit employees on a leave of absence and receiving long-term disability ("LTD") benefits may earn under the Retirement Plan. Effective January 1, 2015, the early retirement reduction factor increases from four percent to five percent per year for employees who retire after January 1, 2015, are between the ages of 55 and 60, have less than 85 points (service plus age), and begin their pension distribution before age 60. This change is applicable only to the pension benefits earned by an employee on or after January 1, 2015. In accordance with federal law, pension benefits earned before January 1, 2015 will be subject to the early retirement pension provisions in effect before the change is made. Currently, employees receiving LTD benefits continue to earn service credit for vesting or for credited service under the Retirement Plan for the duration of their LTD benefit. For union employees who become eligible for LTD after

January 1, 2015, the maximum pension credit they may earn while receiving LTD benefits is limited to 24 months. If the employee is approved for Social Security disability benefits, the pension service credit period is extended to a maximum of 36 months.

Q. Do the changes to the Retirement Plan provisions for early retirement benefits and pension service credit employees on a leave of absence and receiving LTD benefits may earn, reduce costs?

A. Yes. The changes to the provisions for early retirement and pension service credit for employees receiving LTD are expected to reduce future pension expense by $180,000 per year ($127,000 Electric and $53,000 Gas) starting in 2015.

Q. Does the Labor Contract change any other pension provisions of the Retirement Plan?

A. Yes. The Labor Contract provides for two more changes to employees covered under the CAP formula. The monthly pension supplement for employees who retire between the ages of 60 and 62 on or after January 1, 2017 increases from $900 to $1,050. The pension supplement is only available to employees who retire at age 60 but before age 62 and continues through the month in which the retiree attains age 62. In addition, the “pivot year” changes from January 1, 2009 to January 1, 2012 for employees who retire on or after January 1, 2016. Pivot year changes are a common practice under the CAP formula. The pivot year element of the CAP formula provides a snapshot in time that determines both the salary and qualifying years of service for calculating the various components of the pension plan. Specifically, the CAP formula is comprised of three parts: a prior service accrual equal to 1.5 percent of the salary rate as of January 1 of the pivot year multiplied by the years of service from the pension plan entry date to the respective pivot year, and a future service accrual which is equal to two percent of base earnings accumulated from the pivot year date to the date of retirement. The formula also provides for an additional future service accrual equal to two times the annual salary rate in effect upon retirement multiplied by two percent. The total pension level is simply the sum of these parts. Unlike final average salary formulas which automatically update earnings, usually based on an average of earnings in the last several years of employment, the CAP formula does not have an automatic method to update earnings. Instead, the pivot year updates serve as the method to update earnings similar to the way final average salary formula earnings are updated. The replacement income attributed to a pension benefit significantly diminishes if the underlying earnings component of the formula is not periodically updated.

Q. What is the pension cost impact of changing the pension supplement and pivot year?

A. The pension supplement change increases pension costs by $15,000 per year ($11,000 Electric and $4,000 Gas) and updating the pivot year results in additional pension costs of $184,000 ($130,000 Electric and $54,000 Gas).

Q. Will the Company make similar pension changes with respect to changes to the pivot year and pension supplement for management employees?

A. Yes. The Company traditionally has extended these types of negotiated pension changes after the Labor

Contract is ratified. As previously stated, the pivot year update serves as the method to update earnings similar to the way final average salary formula earnings are updated. The replacement income attributed to a pension benefit significantly diminishes if the underlying earnings component of the formula is not periodically updated. The Company expects that the additional annual pension costs attributed to the pivot year update and pension supplement change will be $512,000 ($362,000 Electric and $150,000 Gas). Once approved by the Board, the Company will alert Staff and the parties and will provide updated annual pension costs.

Q. Please describe the retiree health benefit changes for Local 503 employees under the new Labor Contract.

A. Currently, Local 503 employees retiring on or after age 55 with at least ten years of service may elect to be covered under the O&R retiree health program. Under the new Labor Contract, the eligibility requirement for election of coverage under the O&R retiree health program, for employees retiring on or after January 1, 2015, increases from ten years of service to 20 years. This increase in the eligibility requirement is expected to reduce OPEB expense by $1.0 million per year ($0.7 million Electric and $0.3 million Gas).

Q. Did the Labor Contract provide for any cost sharing changes for retiree health benefits?

A. Yes. The Labor Contract provides for changes to the amount retirees contribute toward their retiree health program costs. Currently, the amount contributed by Local 503 employees who retire before age 65 and elect to participate in the retiree health program is fixed at the same amount they were contributing as an active employee on the date they retire. That amount remains fixed until the retiree reaches age 65 when no further contributions are required from the retiree. Under the Labor Contract, all Local 503 employees retiring on or after January 1, 2015 who are under age 65 will be required to make a contribution toward the retiree health program costs based on the contribution rates set forth in the Labor Contract. The Labor Contract provides for different contribution rates based on the coverage category of the enrolled retiree which are scheduled to increase over the life of the contract. Upon reaching age 65, retirees who continue to participate in the retiree health program will be required to make a contribution toward the retiree health program costs. The Labor Contract also provides for different contribution rates based on the coverage category of the enrolled retiree which are scheduled to increase over the life of the Labor Contract. Employees retiring on or after January 1, 2015, who are age 65 or older, will be required to make a contribution toward retiree health premium costs. The contribution rates under the Labor Contract for retirees age 65 or older also apply to employees retiring on or after January 1, 2015 who are age 65 or older.

Q. Did the Labor Contract provide for any other cost sharing changes to retiree health benefits?

A. Yes. The Labor Contract also provides for reducing the Company subsidy for Retiree Health for union employees hired on or after January 1, 2015. Union employees hired on or after January 1, 2015 or their surviving spouse will be required to pay 50 percent of the premium cost if they decide to enroll in the Company's program upon retiring. In addition, the Labor Contract provides for plan design changes in deductibles, co-payments, and out-of-pocket limits commencing January 1, 2015 as well as additional changes to some of the plan designs during the term of the Labor Contract which are expected to mitigate future cost increases.

Q. What is the impact of the changes to the retiree health program cost sharing provisions?

A. The changes to the retiree health program contribution and cost sharing provisions are expected to reduce OPEB expense by over $1.1 million per year ($800,000 Electric and $300,000 Gas).

Q. Does the Labor Contract change any other provisions of the Retiree Health Program?

A. Yes. For union employees who retire on or after January 1, 2017 and enroll in Retiree Health, the Contract provides for an increase in the Company reimbursement for Medicare Part B from $45 to $50 per month. Similar to the pension improvements negotiated for union employees, the Company intends to increase the Medicare Part B reimbursement by $5 per month for management employees retiring on or after January 1, 2017. This change slightly increases the OPEB annual expense by $28,000 ($20,000 Electric and $8,000 Gas). Once approved by the Board, the Company will alert Staff and the parties and will provide updated annual OPEB annual costs.

EMPLOYEE EXPENSES

Q. Did the Accounting Panel prepare the exhibit entitled "ORANGE AND ROCKLAND UTILITIES, INC., Electric Operating Expenses, Employee & Other Insurance Costs"?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (AP-E4 SCHEDULE 4)Electric; (AP-G4 SCHEDULE 4)Gas

Q. What does this exhibit show?

A. The exhibit is a summary of the Company's forecast of employee benefit expenses for the Rate Year, based on costs incurred in the Historic Year. The exhibit shows costs for health insurance costs net of employee payroll contributions, life insurance, other employee benefits, property insurance, Workers Compensation, Injuries & Damages, and Capitalized & Recovered

Benefit Costs. The benefit expenses include the changes discussed above for the Rate Year.

Q. Please describe how employee benefit costs are escalated.

A. Historic Year costs are escalated using trend factors and premium rates provided by the various insurance carriers(*i.e.,* Cigna for hospital/medical costs, CVS/Caremark for prescription drug costs, MetLife for dental costs, and the various Health Management Organizations ("HMOs") for the Company's HMO offerings) to estimate the 2015 and 2016 health care costs.

Q. Does the employee benefit expenses projection include any program changes?

A. Yes. The health care costs reflect the new hospital/medical and prescription drug plan designs resulting from the Labor Contract for Local 503 employees, as discussed above.

HEALTH INSURANCE COSTS

Q. Please explain the increase for health insurance shown on this exhibit.

A. The exhibit shows the cost increases as follows: $2.1

million for health insurance less employee payroll contributions. Projections for 2015 and 2016 were developed using the Company's claim history and projections of premium cost changes provided by the Company's various health care vendors described above. The electric allocation factor of 55.9 percent, was applied to total projected health care costs and long-term disability costs to arrive at the Electric Rate Year forecast and the Gas allocation factor of 23.1 percent to arrive at the Gas Rate Year forecast.

Q. Please discuss the Company's proposed escalators for health care expenses.

A. O&R recommends using the plan-specific escalators developed by the health care plan providers, rather than the GDP deflator. For example, Cigna has analyzed the Company's hospital, medical, vision care experience, and participant demographics against its book of business and projects that expenses will increase by seven percent for the management plans and nine percent for the Local 503 plan. For prescription drug costs, the Company worked with CVS/Caremark and developed an estimated increase of 4.5 percent based on claims experience, and MetLife estimates that dental costs will increase by seven percent. These escalation factors provide a more accurate indicator of future increases to the Company's health care costs, that have been historically well in excess of the GDP but in line with health care inflation trends found in the Northeast section of the country.

Q. Is the Company proposing a change with respect to the proper escalation for health care costs?

A. Yes. Use of the GDP deflator is not the appropriate factor to measure the increase to health care costs. In reviewing and analyzing the disparity between increases in the GDP deflator and the Company's actual health care costs, it has become apparent that such disparity is being driven by fundamentally different forces. Increases in the GDP deflator are being driven largely by inflation-related increases in the unit costs of various products. In contrast, increases in health care costs are being driven by increased utilization of medical procedures and high cost specialty prescription drugs which are very expensive, as well as the availability of new high cost medical procedures, treatments, and devices. For example, a large portion of the increased spending for prescription drugs is attributed to an increase in utilization for high cost specialty drugs (such as XYREM which is used for the treatment of sleep disorders or GAMMAGARD LIQUID which is used for the treatment of neuromuscular disease). In 2013, specialty drugs accounted for eight percent of the drug costs and for the first seven months of 2014, the use of specialty drugs has grown by 67 percent which now account for 21 percent of total drug costs. The growth in use of specialty drugs is not isolated to the Company’s drug plan and is expected to increase in the future. In its ninth annual Health Research Institute (“HRI”) Medical Cost Trend report (June 2014), PricewaterhouseCooper’s estimates that U.S. specialty drug spending will quadruple by 2020. Increases of this nature and of this magnitude are definitely not captured by using GDP. Given this fundamental dichotomy, use of the GDP deflator alone fails to recognize the primary reason these costs are escalating and is therefore simply not the proper methodology to measure the increase in health care costs. Use of the GDP deflator will serve to arbitrarily and improperly understate the Company's health care costs for the Rate Year.

Therefore, to develop a more accurate estimate of the increase in health care costs, the Commission needs to adjust historic year expenses by recognizing other factors such as changes in utilization of services and procedures and employee demographics, as well as volume and mix of health care services which is a similar approach taken by actuaries who determine the premium rates for policies purchased from the Company's insurance providers. For example, based on the wellness, age, and past experience of employee and dependent population, Cigna estimates that the Company's health care costs will continue to increase significantly as the age of the covered population grows even though the Company has made significant plan changes to mitigate future cost increases. For example, Cigna reports that the average cost increase attributed to the male population over age 50 for the Local 503 group saw an increase in costs of about 15 percent in the current period or $550,000 and that the aging population has added more than one percent to plan costs. In addition, because of the small number of insured lives in the plan, Cigna believes that large catastrophic claims will result in plan cost increases greater than general inflation. The Company's claim history for the historical period has shown that catastrophic type claims accounted for approximately 20 percent of plan costs incurred by four claimants. To guard against absorbing cost of this risk, Cigna not only determines a premium rate that is based on the Company's claims history but also includes a risk charge in the premiums the Company pays. Furthermore, the Local 503 plan premiums paid to Cigna are subject to a State premium tax which is equal to two percent. Therefore, escalating costs by GDP do not even cover the premium tax cost.

Q. Has the Company experienced actual health care costs increases above general inflation?

A. Yes. The Company has experienced actual health care cost premium increases averaging 13 percent annually over the last three calendar years, which have been far greater than GDP increases of under two percent over the same period.

Q. Are there other factors that impact the future cost of providing health care?

A. Yes. Legislative and regulatory changes have impacted, and will continue to impact the cost of providing health care.

Q. Does the Company's projection for health care costs include changes to the health plans as a result of the PPACA?

A. Yes. The financial impact of the PPACA to the Company's health care costs assumes that there will be no changes to this legislation during the Rate Year. The Company has already absorbed additional costs in connection with this legislation, such as extending health care coverage to all dependent children up to age 26. Prior to the change in law, coverage for a dependent child ended when the child reached age 23. The additional costs of extending health care to dependent children to age 26 beyond the previous plan limits have grown to about $60,000 per year. In the area of preventive care, also due to the PPACA, the

Company is absorbing the premium costs for providing additional preventive health services at no cost to employees or dependents, which previously required some level of cost sharing by employees. For 2015, health care plans must place a limit on participants' annual out-of-pocket costs and include office visit and emergency room co-payments toward their annual out-of-pocket limit. This change will increase plan costs as office visit and emergency room co-payments are currently not credited to participants' out-of-pocket limits. As a result, employees will reach their out-of-pocket maximums more quickly and the plan is required to pay all eligible expenses above the annual out-of-pocket maximum, which serves to increase the costs paid by the Company. PPACA taxes and other fees that did not exist prior to 2013 have added an additional $400,000 annually to the cost of the health care plans.

Q. To summarize, what is the impact on health care expenses of using the GDP deflator for projecting health care expenses instead of using a health care projection rate which factors in the different health care cost drivers?

A. Using the GDP deflator to project health care costs instead of a projection rate that factors in the cost drivers described above results in a significant understatement of health care expenses that should be recovered as a reasonable business expense. For example, a comparison of the last four years actual growth in health care expenses to an increase solely based on GDP in each of those years results in an understatement of actual health care costs ranging from a low of $0.6 million in 2010 to a high of $3.5 million estimated for 2014.

OTHER MEASURES TAKEN TO MITIGATE COST INCREASES

Q. What actions has the Company taken to mitigate health and welfare costs?

A. The Company has taken numerous steps to contain and mitigate these costs. The Company is placing an increasing emphasis on promoting healthy behavior to mitigate health care costs in the future. For the open enrollment for the 2014 plan year, management employees were asked to participate in some wellness initiatives. Cigna, our hospital/medical insurance carrier, collected health information from employees to assess the general health of our employee population and recommend future wellness programs and incentives that encourage employees to participate in health improvement activities. Employees and their enrolled spouse were offered a monetary incentive to complete a health assessment, which is a tool Cigna uses to obtain baseline health information as well as to provide employees and their spouse with insight into their health status and an action plan to address any potential health risks. Management employees receive an incentive of $5.00 per pay period for completing their own health assessment and another $5.00 per pay period credit if their spouse completes the health assessment. Under the Labor Contract, Local 503 members will receive an incentive of $2.00 per pay period for completing the health assessment. In addition, management employees receive an incentive of $5.00 per pay period if they take a basic medical screening that includes blood pressure, cholesterol, blood sugar, and body mass index, all of which are essential for identifying potential health issues.

Management employees will receive another $5.00 per pay period incentive if their enrolled spouse takes a medical screening. Under the Labor Contract, Local 503 members will receive an incentive of $2.00 per pay period if they take a basic medical screening. The Company's 2015 wellness initiative will include a surcharge for tobacco usage (for management employees and Local 503 members), which has a direct correlation to increased health risks leading to higher medical costs. Employees who voluntarily identify themselves as tobacco users or who do not complete the tobacco usage question during open enrollment will be required to make an additional $240 payroll contribution toward health their care coverage each year. An employee who is a tobacco user can avoid the additional health care contribution by enrolling in a tobacco cessation program. Under the Labor Contract, Local 503 members will also be subject to a $3.00 per pay period tobacco surcharge.

Q. Do the Company's health care carriers offer any other programs to employees to assist them in adopting a healthy lifestyle?

A. Yes. Cigna offers a Health Advisor Program that is designed to facilitate healthy behavior and promote the achievement of health-related goals for at-risk individuals. Cigna also offers Well Aware Disease Management Programs to address various health conditions including heart disease, asthma, diabetes, and lower back pain. These programs are developed in accordance with recognized subject matter experts, the American Heart Association, the American Academy of Allergy, Asthma and Immunology, the American Diabetes Association, and others. Cigna has identified over 1,300 employees for weight loss, stress management, and other wellness activities. These programs are available to all employees and their dependents.

Q. Does Cigna offer programs to all employees and dependents to assist with their lifestyle choices that should help in controlling health care costs?

A. Yes. Cigna offers programs called Healthy Steps to Weight Loss and Stress Management Program. Both programs are designed to encourage lifestyle choices that will benefit the health of employees and dependents. Since January 2011, Cigna has engaged a total of 104 individuals in these programs. The cost of these programs is included in the Cigna administrative fees.

Q. What other actions has the Company taken to manage health care costs?

A. The Company works with Cigna to find ways to encourage employees and their dependents to take a greater role in managing their health care expenditures. For example, if an employee or dependent needs durable medical equipment and prosthetic devices, pre-notification to the insurance carrier is required in order to be covered under the plan. Treatment plans are required by the claims administrator for physical and occupational therapy, speech therapy, and services performed for diagnosis or treatment of dislocations, subluxations, or misalignment of the vertebrae before such programs may begin. The Company has introduced a co-payment for emergency room visits to discourage employees from using the emergency room for routine medical treatments.

Q. Does CVS Caremark, the administrator of the Company's prescription drug plans, offer any programs to assist employees to better manage their prescription drug costs?

A. Yes. For those employees or dependents with chronic and genetic disorders, there is a separate Specialty Pharmacy program, administered by the CVS Caremark, which manages the dispensing and use of high-cost specialty drugs. The Specialty Pharmacy program manages numerous health conditions including: Crohn’s disease, cystic fibrosis, macular degeneration, multiple sclerosis, pulmonary disease, Hepatitis-C, and other serious health conditions. The Specialty Pharmacy not only provides the patient with medications, but also provides proactive pharmacy care management services. When a patient is enrolled in the Specialty Pharmacy program, a pharmacist/nurse-led Care Team is assigned to each patient. A dedicated group of clinical experts helps to manage the patient’s condition effectively; provides early intervention; reviews dosing and medication schedules; trouble-shoots injection-related issues; discusses side effects with the patient; and supplies educational information. The pharmacists are available 24 hours a day, 365 days a year for emergency consultations. All medications are delivered promptly in temperature-controlled secure packing. With the medication, the patient receives any required ancillary supplies such as needles, syringes, alcohol swabs, and guidance on disposal of items. The Special Pharmacy Program also coordinates care with the doctor and health plan. In addition, CVS Caremark offers a Specialty Guideline Management Program in coordination with the Specialty Pharmacy Program. This program builds upon the Specialty Pharmacy Program by offering a more rigorous review of each specialty referral. The criteria for the program are developed using evidence-based medical standards that are continually updated based on the most recent medically accepted guidelines. The program works with communications between CVS Caremark and the patient's physician. If the physician decides to change therapy, Caremark telephones the patient to assist with better management of the new medication. For example, for patients who take Enbrel (TNF inhibitors), as a safety precaution, CVS Caremark assesses whether the patient has been tested for being a carrier of tuberculosis (with a skin test) because those medications contain a warning for patients with TB. CVS Caremark will also periodically assess the patient’s exposure to medication to verify its continued effectiveness and to determine whether there is a need to change to a different drug.

Q. Can you provide any other examples of how the program would work?

A. Yes. Votrient is prescribed for advanced renal cell carcinoma (kidney cancer) or for advanced soft tissue sarcoma (cancer that starts in soft tissue such as muscle). Though the FDA approved this medicine for the above uses, in clinical trials there have been instances of severe and fatal liver toxicity. As a safety measure, CVS Caremark coordinates with the employee’s physician to confirm that the liver function is being monitored.

Q. Are there any other programs available through CVS Caremark?

A. Yes. The Company works with CVS Caremark to help educate employees and their dependents to be better consumers. Employees are encouraged to use generic drugs where possible in order to mitigate plan costs as well as lower their own out-of-pocket costs by being a better consumer at the point of purchase. CVS Caremark prepares a report for each employee and dependent utilizing the program and highlights their expenditures and opportunities for savings. This report, sent at least once a year to the employee and dependents, contains information on how the employee could achieve savings on future prescriptions by using the more efficient and less expensive mail order program or switching from a more expensive brand name drug to a less expensive generic substitute, when available.

Q. Does the Company offer employees any programs to encourage healthy behaviors?

A. Yes. Nutrition education services are available to employees. Healthy food choices help employees better manage their weight and chronic health conditions such as diabetes and heart disease. In addition, Work Home Wellness counseling is available to all employees to help them manage stress and other mental and nervous conditions. For the last several years, the Company has been providing employees with free flu shots. In 2012, the number of employees who received a flu shot was 222. During calendar year 2013, 238 employees received flu shots.

Q. Are there any other steps that the Company is taking to mitigate health care costs?

A. Yes. The Company conducts periodic audits of the health and welfare plans to confirm the correct processing of claims and determine that the claims are processed in accordance with the plan design for each of the health care options. For example, the 2010 and 2011 Cigna claims were audited and the 2012 and 2013 claims are currently being audited for the Cigna hospital and medical plans, MetLife dental plan, and Caremark CVS prescription drug plan. Upon completion of the audit, if there were any overpayments to health care providers, the Company will recover those overpayments. In addition, the Company continues to annually review its cost-sharing arrangement with employees to maintain a reasonable and competitive cost sharing level with employees.

OTHER EMPLOYEE BENEFITS

Q. What changes did the Company make to its Thrift Savings 401(k) Plan for 2014?

A. The Company has not made, and is not planning to make, any further changes to the Thrift Savings 401(k) Plan based on the findings of the Review in 2014. The previous Review described above found that retirement benefits (*i.e.*, pension and Thrift Savings 401(k) Plan) for management employees covered under the Cash Balance pension formula are not competitive, and are below market compared with the Utility Peer Group of companies. As a result, effective January 1, 2013, for management employees under the Cash Balance pension formula who participate in the Thrift Savings 401(k) Plan, the Company match was increased from three percent to a maximum of six percent. In order to receive the maximum Company match, employees covered under the Cash Balance pension formula must contribute at least eight percent of their base salary and the Company matches 100 percent of the first four percent of the employee’s contributions plus an additional 50 percent of the next four percent of an employee’s contributions. This change was intended to increase an employee’s retirement income and bring retirement benefits closer to the Blended Peer Group average, as well as raise employees’ consciousness that they have a shared responsibility to plan for their retirement.

Q. How does this change impact employee benefit costs?

A. The Company estimates that the increased match to participants in the Cash Balance pension formula will be $0.4 million ($279,000 Electric and $116,000 Gas) in total for the Rate Year.

Q. Are any changes being made to the Group Life Insurance program for the Rate Year?

A. No. The Company-paid group life insurance benefit is one and one-half times annual base salary for management employees and a flat two times salary up to a maximum of $150,000 for union employees who are members of Local 503.

Q. What is the projected group life insurance benefit cost for Rate Year?

A. The projected group life insurance benefit cost is approximately $0.8 million ($579,000 Electric and

$240,000 Gas). The projection was made by multiplying the base salary for management employees by the premium rates.

POST EMPLOYMENT BENEFITS OTHER THAN PENSIONS

Q. Please describe the Company’s OPEB programs.

A. The Company’s OPEB programs are comprised of the Retiree Health Program, which includes major medical, hospitalization, vision, and pharmaceutical benefits. The Company also offers a limited retiree term life insurance program.

Q. What is the status of the Company’s OPEB plans?

A. Starting with the Retiree Health Program, O&R offers retirees who are age 55 with ten years of service at the time they retire from employment, and their eligible dependents, a voluntary Retiree Health Program. The Retiree Health Program offers enrolled retirees a prescription drug plan and comprehensive hospital, medical, and vision care plans with a network of participating providers. Once a retiree or covered dependent becomes eligible for Medicare, the Retiree Health Program coordinates his or her health care expenses with Medicare. For Medicare-eligible retirees, Medicare is the primary payer of hospital and medical claims, and the Retiree Health Program is the secondary payer. Under the prescription drug plan, once a retiree and covered dependent become eligible for Medicare Part D, retirees may continue their coverage under the Retiree Health Program or enroll in the Medicare program for their prescription drug coverage. The Company also provides retired management employees with retiree term life insurance benefits of $25,000 ($12,500 for Local 503 retirees) at no cost to the retiree.

Q. What steps has the Company taken to manage or mitigate OPEB costs related to the retiree life insurance program?

A. As described above, for the retiree life insurance program, the $25,000 Company-paid life insurance benefit has been eliminated for management employees who are under age 50 as of January 1, 2013.

Q. What savings did the Company realize as a result of the change to the retiree life insurance program?

A. The OPEB impact of the change to the Company provided retiree life insurance benefits (*i.e.*, eliminating the

$25,000 benefit for management employees under age 50 as of that date, who retire on or after January 1, 2013) reduces annual expense by $79,000 ($56,000 Electric and $23,000 Gas).

Q. What steps has the Company taken to manage or mitigate OPEB costs related to the Retiree Health Program?

A. For the Retiree Health Program discussed above, the Company implemented a cost-sharing formula in 2014 for management employees retiring under the CAP pension formula. Under the cost-sharing formula, the Company's contribution toward program costs is limited to its contribution in the preceding year plus inflation as measured by the change in the CPI. Contributions for retirees increase if Retiree Health Program cost increases are above CPI. Effective January 1, 2013, the Company's subsidy under the cost-sharing formula has been eliminated for management employees retiring under the Cash Balance pension formula. Employees under the Cash Balance pension formula who meet the eligibility requirements and enroll in the Retiree Health Program will be responsible for paying the full cost of Retiree Health coverage offered through the Company. Under the Labor Contract, Local 503 employees hired on or after January 1, 2015 will be required to pay 50 percent of the premium cost if they enroll for coverage when they retire. In addition, the Labor Contract provides for an increase in the eligibility requirements for Retiree Health coverage from age 55 with ten years of service to age 55 with 20 years of service. These changes will reduce future plan costs as new employees are hired. The reduction to annual OPEB costs attributed to changes to both management and union employees is $11.7 million ($8.3 million Electric and $3.4 million Gas).

Q. What other steps has the Company taken to manage or mitigate OPEB costs related to the Retiree Health Program?

A. The Company has implemented an Employer Group Waiver Plan ("EGWP") for Medicare-eligible retirees who are eligible for federal subsidies for prescription drugs that reduce Company and retiree costs and results in OPEB cost savings.

Q. What is an EGWP?

A. An EGWP is a Medicare Part D plan regulated by the Centers for Medicare and Medicaid Services that will supplement the retiree prescription drug benefits currently offered to retirees who are Medicare-eligible effective January 1, 2013. Under the EGWP, the Company foregoes receiving the RDS subsidy and instead our pharmacy benefits manager, CVS Caremark, contracts directly with the government prescription drug program. CVS Caremark will handle all administration and federal interactions and collect the RDS subsidy for our retiree drug plan. Employers with an EGWP retiree drug plan will experience savings under the Coverage Gap Discount Program, which was passed as part of health care reform. For employers providing prescription drug benefits through an EGWP, the Coverage Gap Discount, the direct subsidies, and the catastrophic reinsurance payments have a significant cost reduction impact.

Q. What savings does the Company expect to realize as a result of implementing the EGWP?

A. Since the inception of the program, the EGWP has reduced plan obligations by approximately $12 million and annual expense by $1.6 million ($1.1 million Electric and $0.5 million Gas).

Q. Were there any initiatives with respect to the Company’s OPEB programs that were considered and rejected?

A. No.

PENSION PROGRAM

Q. Please describe the Company’s pension program.

A. Originally, the O&R Retirement Plan was a defined benefit pension plan that provided vested employees with pension benefits under different formulas, depending on their date of hire. Over time, however, the O&R Retirement Plan has changed. Management employees hired on or before January 1, 2001; and members of Local 503 hired on or before January 1, 2010; are covered under a traditional CAP pension formula based on an employee’s earnings throughout an employee’s career. Employees may qualify for an unreduced early retirement benefit at age 55 if they have at least 30 years of service. Employees with less than 30 years of service may retire at age 55 with a reduction to their pension of 20 percent if they have at least ten years of service. Pension benefits for employees retiring before age 55 are not payable until at least age 55.

Q. What steps has the Company taken to manage or mitigate pension costs?

A. The Company has amended the O&R Retirement Plan to reduce future liabilities and annual costs by prospectively changing to a Cash Balance pension formula for newly hired employees. Management employees hired on or after January 1, 2001; union employees who are members of Local 503 hired on or after January 1, 2010; are now all covered under a Cash Balance pension formula instead of the CAP formula. Employees covered by the Cash Balance formula will earn a pension benefit over a 30-year career that is less costly than the benefit earned under a traditional CAP pension formula because of a lower benefit accrual rate.

Q. What other actions has the Company taken to manage or mitigate pension costs?

A. For management employees under the CAP pension formula who are under age 50 as of January 1, 2013, there was a change to the early retirement benefit provisions that will reduce future pension liabilities and annual pension costs. The change increases the age at which employees can elect to receive an unreduced early retirement benefit from age 55 to age 60 and the 85-point rule (*i.e.*, a combination of age and years of service equals 85) will no longer qualify employees for an unreduced benefit under age 60. Instead of receiving an unreduced or slightly reduced pension at age 55, employees will be subject to a five percent per year reduction from age 60 to age 55. For example, an employee would be subject to a 25 percent reduction of a portion of his/her pension if he/she elects to retire at age 55 (five percent multiplied by five years). The pension changes apply to prospective benefits earned from January 1, 2013, until retirement. As discussed above, under the Labor Contract, a similar change was made to early retirement provisions but it applies to all employees covered under the CAP formula instead of employees under age 50. In addition, the Labor Contract provides for a new defined contribution pension benefit instead of a Cash Balance formula for new Local 503 members hired on or after January 1, 2015.

Q. What savings does the Company expect to realize as a result of changing the pension benefits from the cash balance formula to the defined contribution pension formula under the Thrift Savings 401(k) Plan for Local 503 employees under the Labor Contract?

A. The Company expects that changing to a defined contribution pension formula for union employees will initially result in some savings as new employees are hired. Larger savings are expected in the distant future as the population of employees under the defined contribution pension formula grows. In addition, replacing the Cash Balance defined benefit pension plan with a defined contribution pension plan for new Local 503 hires helps to better manage future pension costs and liabilities by significantly reducing the Company's financial risk and volatility associated with funding a defined benefit pension plan

Q. Does that conclude your direct testimony?

A. Yes, it does.

Q. Would the members of the Demand Analysis and Cost of Service Panel (the "Panel" or "DAC") please state their names and business address?

A. Maureen Nihill and Kristin Graves, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. (**Nihill).** I will act as chairman of the Panel. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I am Department Manager of Load Research and Cost Analysis in the Rate Engineering Department. My background is as follows: I received a Bachelor of Arts Degree in Mathematics and Economics from the College of Mount Saint Vincent in 1979 and a Master of Business Administration Degree in Finance from Pace University in 1985. In 1981, I began my employment with Con Edison in the Demand Analysis Division of the Rate Engineering Department. Between 1983 and 1987, I worked in positions of increasing responsibility in the load research and electric class demand analysis areas. In 1989, I was promoted to Division Analyst and placed in charge of the Load Testing Division. I was promoted to Department Manager in 1996, taking on the additional responsibility for the Cost Analysis section. I currently serve on the Load Research Committee of the Association of Edison Illuminating Companies. I have previously testified before this Commission in numerous cases.

(Graves). I am the Section Manager of the Load Research section in the Rate Engineering Department. In that capacity, I am responsible for preparing demand analyses related to electric service. Additionally, I have a variety of duties related to load research sample design and data analysis. I began my employment with Con Edison in 2005 as a Senior Analyst in Load Research. In 2014, I was promoted to Section Manager. I received a Bachelor of Arts degree in Economics from the University of California at Davis in 1977 and a Master of Science degree in Consumer Economics from Cornell University in 1981. I am currently pursuing a GIS Certificate and a Master of Arts degree in Geography at Hunter College in New York. Since 2010, I have also been the instructor for the statistical sampling section of the Advanced Applications in Load Research Seminar for the Association of Edison Illuminating Companies.

Prior to working for Con Edison, I worked for the New York Power Authority for over 13 years in the areas of load research and customer billing. I have previously testified before this Commission.

Q. What is the purpose of the Panel's testimony?

A. Our testimony:

- Presents the Electric Class Demand Study for Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R", or the "Company");

- Presents the Company’s Electric Embedded Cost-of-Service (“ECOS”) study
- Describes the development of unbundled costs associated with competitive services; and
- Presents the Company’s Electric Marginal Transmission and Distribution Cost Analysis.

Q. Please summarize your testimony.

A. First, we address the Company’s Class Demand Study for calendar year 2013 which presents the demand cost responsibility measures that are used in the ECOS study for each customer service classification (“SC”). Second, we present the Company’s ECOS Study and the associated unbundled cost components for calendar year 2013 which:

- functionalize and classify various costs for the electric system;
- allocate these functionalized costs to the customer classes;
- demonstrate each customer class’s surplus or deficiency based on the application of a ± 10% tolerance band around the calculated total system rate of return;
- show a total system rate of return of 11.20% and rates of return for all SCs; and
- present the development of unbundled functional costs for competitive services pursuant to the Public Service Commission’s (“Commission”) Statement of Policy on Unbundling and Order Directing Tariff

Filings, issued August 25, 2004, in Case 00-M-0504 ("Unbundling Policy Statement").

Q. Is the Panel sponsoring any exhibits?

A. Yes, we are sponsoring the following three exhibits:

- Exhibit ___ (DAC-E1 – Class Demand Study);
- Exhibit ___ (DAC-E2 – ECOS Study and Unbundled Cost Components, Schedules 1-5); and
- Exhibit ___ (DAC-E3 – Electric Marginal Transmission and Distribution Cost Analysis).

Q. How is the Panel's testimony organized?

A. The testimony is divided into the following three sections: (1) Class Demand Study,(2) ECOS Study and Unbundled Cost Components, and (3) Marginal Cost Study.

CLASS DEMAND STUDY

Q. Please describe the purpose of the Class Demand Study.

A. The Class Demand Study presents demand cost responsibility measures for each Company SC. These cost responsibility measures, in turn, are used in the ECOS Study presented in this proceeding.

Q. Briefly describe the demand cost responsibility measures developed in the Class Demand Study.

A. There are three cost responsibility measures developed in the Class Demand Study. The first reflects class demands at the time of the Company system peak. The second is class non-coincident peak responsibility, which reflects customer demands at times of the individual class peaks.

The third is individual customer maximum demands (“ICMDs”), which reflect each customer’s individual peak.

Q. Have you prepared an exhibit showing the Class Demand Study?

A. Yes.

Q. Is this exhibit a document consisting of a title page entitled "ORANGE AND ROCKLAND UTILITIES, INC., CLASS DEMAND STUDY – ELECTRIC DEPARTMENT, YEAR 2013," three pages of descriptive text, an index, and over 100 tabular reports?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (DAC-E1)

Q. What period does the Class Demand Study cover?

A. It covers calendar year 2013, and includes specific analyses of the summer and winter peak periods for that year.

Q. Please explain the general organization of Exhibit ___ (DAC-E1).

A. The title page is followed by three pages of explanatory notes and an index for the study's tabular data. Tabular Reports 2 through 4 show step-by-step development of demand cost responsibility measures for each SC. These reports are followed by a summary of class demand allocators.

Q. Please explain the method you used in developing Exhibit ___ (DAC-E1).

A. The pages of explanatory notes briefly explain the procedures used to develop the class demand responsibility estimates shown in the exhibit. It includes a short discussion of Orange and Rockland's customer load testing program, which is the starting point for many of the calculations in the exhibit. Finally, it provides a brief description of each report in the exhibit.

Q. Please explain the analyses shown in Reports 2 through 4.

A. These reports show the step-by-step development of demand cost responsibilities for each SC. Data are first organized by energy or demand strata. The strata data are then aggregated to form subclass data, and the subclass data are further aggregated to form class data. Report 2 shows the starting data utilized in developing the class demand responsibilities, and shows either sample test customer load research data or time-of-use billing profile data by stratum. Report 3 shows a summary of class population data by stratum for each SC. Finally, Report 4 shows the resulting class demand responsibilities by stratum for each SC. Reports 2, 3, and 4 are provided by class for both the summer and winter peak periods. The Class Demand Summary Report provides a summary of the class demand responsibilities for each season, obtained from the individual Report 3's and Report 4's.

Q. As a typical example of the calculation procedure used for each class in this exhibit, please describe the method employed in developing the summer and winter class demand responsibility estimates for SC No. 1-301, the Residential class.

A. Referring first to Report 2 (summer page 1, winter page 1), the data in Columns 3 through 9 were developed from load tests that the Company performed on sample residential test customers. Column 2 lists the sample test strata. Columns 3 and 4 show the range of consumption or demand for the customers in each test stratum. Column 5 shows the number of customers in each stratum for which test results were obtained. Column 6 shows the calculated average consumption or demand per customer for each test stratum. Columns 7 and 8 show the load test results reduced to average kilowatts per customer for each test stratum. Column 7 lists the average of July and August maximum demands per customer for each test stratum (December and January averages are used for winter). Column 8 lists the maximum coincident demand per customer for each test stratum, based on averages for five selected system peak days for the summer or five selected system peak days for the winter during the test period. Column 9, derived from Columns 7 and 8, shows the calculated coincidence factor for each test stratum.

Q. Please describe the derivation of the coincidence factors.

A. The coincidence factors are derived from interval metered data collected during calendar year 2013. For each stratum of test customers, the recorded half-hourly demand data obtained from each test location were averaged for the five system peak days. For this study, the coincidence factor is defined as the ratio of the per-customer maximum coincident half-hour demand of a stratum of test customers, averaged for five days, to the per-customer individual maximum non-coincident half-hour demands of the test customers in that stratum.

Q. Please continue your explanation of the SC No. 1-301 reports.

A. Turning to Report 3, the stratum definitions are shown in columns 3 and 4. The stratum level customer count and kilowatthour sales for the residential class shown in Columns 5 and 6 are derived from billing records for the year 2013. Column 7 contains the average usage by stratum based on columns 5 and 6. The summer and winter coincident maximum half-hour demands for each stratum in the class population were then calculated using the respective sample test stratum load characteristics. These results appear in Column 11, and the computations are described in footnotes. Since each stratum's maximum half-hour demand (shown in Column 11) occurs at different times, complete daily profile curves were computed for each stratum in the class, again based on test results.

Summation of all 48 half-hour stratum load curves at the customers' meters produced composite summer and winter load curves for the entire class. The summer and winter coincident half-hour demands for each stratum, shown in

Column 5 of Report 4, were obtained by examining the stratum load curves at the time of the class peak. The summer and winter class load curves were further examined to determine the average class demands for the highest continuous four-hour period. Those results are shown in Column 6 of Report 4.

Q. Please continue.

A. The demands described so far have all been based on measurements and calculations at the customers' meters. To determine the system input level class responsibility shown in Column 8, the class demand at the customers' meters was divided by the annual distribution efficiency for the class. The class distribution efficiencies are shown in footnotes 8 and 9 of Report 4 of this exhibit. After applying class distribution efficiencies, the calculated grand total of all the class load curves, developed through the procedures described thus far, closely approximates but does not exactly match the known total system load curve at each half-hour. The total discrepancy during the high load periods of the day is generally found to be a few percent during any half-hour. Accordingly, for sampled classes, a percentage adjustment factor for every half-hour was applied to each of the class demands. Classes that are 100% profile-metered did not receive any adjustment. After adjusting the class data, the total of all class profiles exactly matched the total system load curve. The demand values in Columns 7, 9, and 10 of Report 4 are the adjusted class demands. These values are the average demands obtained from class load profiles for the four peak hours of the system peak load shape or the class peak load shape.

Q. Do the computations and analyses, which you have just described for SC No. 1-301, Residential, apply to the other classes shown in this exhibit?

A. Yes. With a few exceptions, which we will describe, the analyses for the remaining classes are similar to those for SC No. 1-301.

Q. Please describe the exceptions to which you referred.

A. For customers served under time-of-use rates, the data shown in Report 2 were obtained from the time-of-use billing profile recorders. For unmetered classes and traffic signals, a flat load shape was developed. For street lighting served under SC Nos. 4 and 16, load shapes were developed taking hours of daylight into account.

EMBEDDED COST OF SERVICE STUDY AND UNBUNDLED COST COMPONENTS

Q. Please describe the ECOS Study and its unbundled cost components.

A. The ECOS Study and unbundled cost components are shown in the Panel’s Exhibit __ (DAC-E2), entitled “ORANGE AND ROCKLAND UTILITIES, INC. – EMBEDDED COST-OF-SERVICE STUDY – ELECTRIC DEPARTMENT - YEAR 2013 RATES IN EFFECT JULY 1, 2014.” The exhibit consists of five schedules. Schedule 1 shows the results of the ECOS Study. Schedule 2 shows the Merchant Function Charge (“MFC”) calculations. Schedule 3 shows the unbundled metering costs, consisting of meter ownership, meter service provider (including meter installations) and meter data service provider functions. Schedule 4 shows metering costs associated with customers eligible for the Mandatory Hourly Pricing (“MHP”) program. They consist of the meter ownership, meter service provider (including meter installations) and meter data service provider costs the Company incurs to serve MHP-eligible customers. The development of MHP functions will be discussed later in this testimony. Schedule 5 shows the unbundled costs for printing and mailing a bill and receipts processing functions.

MARK FOR IDENTIFICATION AS EXHIBIT __ (DAC-E2)

Q. Please provide a general description of the ECOS Study.

A. The ECOS Study (Schedule 1) analyzes, on a class basis for calendar year 2013, revenues and book (accounting) costs for specific cost categories. The results of the study are expressed as class and total system rates-of-return.

Q. What cost categories are analyzed in the ECOS Study?

A. The ECOS study analyzes costs and revenues associated with the Company’s delivery system, i.e., transmission, distribution, and customer-related cost categories or functions. It also includes cost categories related to the electric merchant function, competitive metering functions, the receipts processing function and the printing and mailing a bill functions. Since the ECOS Study strictly focuses on transmission and distribution, the major supply function costs, e.g., purchased power and generation costs are not included in the ECOS Study. Also, revenues and expenses associated with the System Benefits Charge ("SBC"), Regulatory 18-A Assessment and Renewable Portfolio Standard Program ("RPS") charge, costs which are considered a pass through to customers, have been excluded from the study.

Q. What time period does the ECOS Study cover?

A. It covers calendar year 2013.

Q. What electric revenues are reflected in the ECOS Study?

A. Electric revenues reflect current delivery rates, which went into effect July 1, 2014.

Q. What customer classes are analyzed in the ECOS Study?

A. The study analyzes classes of customers corresponding to the SCs contained in Orange and Rockland's electric rate schedules, including retail access customers. A description of the type of customers served under each SC is shown beginning on page 12 of the ECOS study explanatory notes.

Q. How are the results of the ECOS Study expressed?

A. The results of the ECOS Study are expressed as total company ("total system") and class rates-of-return.

Q. What is the total system rate of return shown in the ECOS Study?

A. The total system rate-of-return is 11.20%, as shown on Table 1, Page 1, Column (1), Line 17 of the ECOS study. In addition, Table 1 sets forth rates-of-return for all classes included in the ECOS study. For example, the SC

No. 1-Total Residential return is 10.40%, the SC No. 2-Total C&I return is 11.56%, the SC No. 9-Total Commercial return is 14.50%,and the SC No. 22-Total Industrial return is 12.09%.

Q. Has the Commission historically employed “tolerance bands” around the system rate-of-return in developing class revenue responsibilities?

A. Yes. Based on past practice, class revenue responsibility has been measured with respect to a ±10% tolerance band around the total system rate-of-return. Classes would not be considered “surplus” or “deficient” if the class ECOS rate-of-return falls within this tolerance band. Classes that fall outside this range would be either surplus or deficient by the revenue amount, including appropriate state and federal income taxes, necessary to bring the realized return to the upper or lower level of the band. We propose to continue this practice in this case.

Q. Based on the application of the ±10% tolerance band around the calculated total system rate of return of 11.20%, what are the ECOS study class surpluses and deficiencies?

A. The revenue surpluses are shown on Table 1, Line 26 and the revenue deficiencies are shown on Line 27. For example, the SC No. 2 - C&I Primary class has a revenue surplus of $222,886, while the SC No. 19 - Residential Voluntary Time of Use class has a revenue deficiency of $121,437.

Q. What is the significance, for example, of the SC No. 19 – Residential Voluntary Time of Use class deficiency?

A. The deficiency is the amount of revenue increase, at current rates, required to bring the SC No. 19 – Residential Voluntary Time of Use class return to the lower level of the tolerance band around the system rate-of-return.

Q. Please describe what is shown on Table 1A, which is the last page of Exhibit___ (DAC E-2).

A. Due to the application of class tolerance bands, the total of the ECOS surpluses and deficiencies is a net surplus. In order that ECOS Study indications are revenue neutral to the Company, Table 1A adjusts average classes on an across-the-board percentage basis so that the sum of surpluses matches the sum of deficiencies.

Q. Let us now turn to the methodology used in developing the ECOS Study. Please describe the procedures followed in the preparation of this study.

A. There are two main steps in the preparation of the ECOS Study: (1) functionalization and classification of costs to operating functions, such as transmission, distribution, customer accounting and customer service with further division into sub-functions, such as distribution demand, distribution customer, services, overhead and underground; and (2) allocation of these functionalized costs to customer classes.

Q. Please describe the functionalization and classification step.

A. The functionalization and classification step assigns the broad accounting-based cost categories to the more detailed categories employed in the ECOS Study. This level of detail is required to differentiate, for example, demand-related costs from customer-related costs.

Q. Why is this necessary?

A. This provides for the proper allocation to the classes of the fixed and variable costs, i.e., operation and maintenance ("O&M") expense, based on cost causation.

Q. Please continue.

A. During the process of functionalization, all costs are classified as being demand-related, energy-related or customer-related. Demand-related costs are fixed costs created by the loads placed on the various components of the electric system. Energy-related costs are variable costs resulting from the total kilowatthours delivered during the year. Customer-related costs are fixed costs, which are caused by the presence of customers connected to the system, regardless of the amounts of their demand or energy usage.

Q. Please describe the allocation step in the study.

A. The allocation step allocates the functionalized and classified costs to the customer classes based on the appropriate demand, energy or customer allocation factors, which are shown on Table 7 of the ECOS Study.

Q. Does the ECOS Study present unbundled functional costs for competitive services as set forth in the Unbundling Policy Statement?

A. Yes. The ECOS Study separately identifies the following competitive functions: merchant function, meter ownership, meter service provider, meter installations, meter data service provider, receipts processing, and printing and mailing a bill.

Q. What costs are included in the merchant function?

A. The merchant function contains costs associated with procuring electric commodity, including an allocation of customer care-related activities, customer service-related activities, and information resources ("IR").

Q. What costs are included in the allocation of customer care and customer service-related activities?

A. The customer care allocation includes costs associated with the Company's call centers, service centers, and credit and collections/theft activities. The customer service allocation includes an assignment of education and outreach costs.

Q. How were these costs allocated to the merchant function?

A. Pursuant to the Unbundling Policy Statement, customer care and customer service-related costs were allocated to the merchant function on the basis of total revenues (including SBC, 18-A, ECA, MSC, transmission and distribution ("T&D"), MFC, Competitive Metering and Billing and Payment Processing revenues).

Q. How were IR costs allocated to the merchant function?

A. Pursuant to the Unbundling Policy Statement, IR costs were allocated on the basis of total revenues, with 50 percent of the resultant allocation included in the merchant function.

Q. Have you further unbundled the merchant function for use in developing rate components for competitive services?

A. Yes. Separate MFCs to recover the costs for two commodity-related competitive services as described below were developed for (1) SC No. 1 Total Residential and SC No. 19 Residential Voluntary Time of Use, (2) SC No. 2 Secondary, SC No. 20 Secondary Voluntary Time of Use, SC No. 4 Municipal Lighting, SC No. 5 Municipal and Private Lighting, and SC No. 16 Public and Private Lighting and SC No. 16 Energy Only and (3) SC No. 2 Primary, SC No. 3 Primary, SC No. 9 Commercial, SC No. 21 Primary Voluntary Time of Use and SC No. 22 Industrial.

Q. How have you defined these costs?

A. The MFC is made up of two components. The first consists of the costs associated with procuring commodity, IR, and education and outreach (hereafter referred to as the “competitive supply-related MFC component”). The second consists of costs associated with credit and collections/theft (hereafter referred to as the “competitive credit and collections-related MFC component”). Only full service customers pay both the competitive supply-related and competitive credit and collections-related MFC components.

Q. How are these components allocated to the SCs within the study?

A. 100 percent of electric procurement activity costs and 25 percent of credit and collections/theft, IR, and education and outreach costs were allocated on a per kilowatthour basis. The remaining 75 percent of credit and collections/theft, IR, and education and outreach costs were allocated on a per customer basis.

Q. Why were the customer care-type costs, such as credit and collections/theft, allocated predominantly on the basis of number of customers, while the electric procurement activity was allocated entirely on a volumetric (i.e., kWh consumption) basis?

A. The Company followed basic cost causation principles and determined that customer care-type activities are predominantly driven by the existence of customers on the system as opposed to their usage characteristics. On the other hand, the functional cost of purchasing commodity is aligned with sales volumes. This allocation is consistent with the Order Adopting Unbundled Rates and Backout Credits and Specifying Terms for the Recovery of Revenues Lost As a Result of Such Rates and Credits, issued April 15, 2005, in Case 04-E-0572, approving Con Edison’s unbundled rates.

Q. Is the allocation of the MFC components to various groups of customers shown in Exhibit __ (DAC-E2, Schedule 2)?

A. Yes. Schedule 2 of Exhibit __ (DAC-E2, Schedule 2, pages 1 and 2), shows the allocation of the competitive supply-related MFC cost components and the competitive credit and collections-related MFC cost components to the residential and commercial categories of customers. This exhibit presents these two components as percentages of the T&D and competitive revenues (i.e., MFC, Metering and BPP revenues)associated with service classifications under the Company’s electric tariff as used in the ECOS Study. Separate percentages are shown for the previously mentioned groups of customers for use in the development of the MFC, as detailed in the Electric Rate Panel’s testimony.

Q. Did the Company allocate costs associated with the separate metering functions to various groups of customers?

A. Yes. Schedule 3, pages 1, 2 and 3 of Exhibit __ (DAC-E2), shows the allocation of costs associated with the metering functions to the customer classes eligible to take metering services competitively. Schedule 3 presents the costs for the competitive metering functions as percentages of the T&D revenue requirement associated with service classifications under the Company’s electric tariff as used in the ECOS Study.

Q. Please describe each competitive metering function.

A. The Meter Ownership function includes the fixed costs for metering equipment on customers’ premises. Also included is a revenue based allocation of credit & collection/theft, uncollectibles and education & outreach costs.

The Meter Service Provider function represents the labor associated with meter O&M, such as meter testing and meter replacement and removal. The function includes a revenue-based allocation of credit and collection/theft, uncollectibles and education and outreach. This function is combined with the meter installation function described below.

Q. Please continue.

A. The Meter Installations function represents the book cost of meter installations. Also included is a revenue-based allocation of credit and collection/ theft, uncollectibles and education and outreach.

Q. Please describe the Meter Data Service Provider function.

A. The Meter Data Service Provider function consists of the customer accounting expense of reading meters, as well as allocations for Call Center and Service Center operations and information resources, all based on a detailed study of those activities. Also included is a revenue-based allocation of credit and collection/theft, uncollectibles and education and outreach.

Q. Were any costs functionalized differently in the ECOS study because of rate design requirements?

A. Yes. The study separately identifies metering costs associated with MHP-eligible customers for MHP meters that are now widely in use in several classes throughout Orange and Rockland, which were not in such use for the last ECOS study. These costs are shown in the ECOS as separate MHP functions. Meter ownership-MHP, meter installation-MHP, and meter service provider-MHP functions contain costs associated with installing and maintaining interval meters for the benefit of MHP-eligible customers within several classes. The classes that have these MHP meters included are SC No. 2 Secondary, SC No. 2 Primary, SC No. 3 Primary, SC 20 Secondary Voluntary Time of Use and SC 21 Primary Voluntary Time of Use.

The meter data service provider-MHP function consists of phone line installation costs, ongoing meter reading, and communication expenses and is applicable to all the MHP-eligible classes stated above. The meter data service provider–MHP function is also applicable to the SC No.9 Commercial and SC No. 22 Industrial classes which are now required to pay for the full communications costs. Schedule 4 of Exhibit ___ (DAC- E2) shows the above described components of the $70.69 MHP metering charge.

Q. Is the allocation of unbundled costs for the printing and mailing a bill and receipts processing functions shown on Exhibit __ (DAC-E2, Schedule 5)?

A. Yes. Schedule 5 of Exhibit ___ (DAC-E2, pages 1 and 2) shows the unbundled costs for printing and mailing a bill and receipts processing functions. The printing and mailing a bill function and the receipts processing function consist of the customer accounting expense of accepting customer payments and billing customers, including both direct costs and an allocation for Call Center and Service Center operations based on a detailed study of those activities. Credit and collection, education and outreach, and uncollectibles expenses were allocated to these functions on the basis of functional revenues. The unbundled average unit cost for receipts processing is 51 cents per bill. The average unit cost for printing and mailing a bill is 51 cents per bill. These two functions are combined to yield $1.02 per bill in unbundled costs associated with billing and payment processing. The costs associated with billing and payment processing do not vary by service classification and, thus, the system-wide $1.02 per bill in unbundled costs is applicable to all service classifications.

MARGINAL COST ANALYSIS

Q. Did you perform an analysis of the marginal cost to supply an additional kW of load on the transmission and distribution (T&D) delivery system?

A. Yes, the analysis is shown on Exhibit ___ (DAC-E3), "ELECTRIC MARGINAL TRANSMISSION AND DISTRIBUTION COST ANALYSIS."

Q. Was this exhibit prepared under your direction or supervision?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (DAC-E3)

Q. Before turning to the exhibit, please provide a general background and description of the marginal cost analysis that you are presenting.

A. The Commission's Order in Con Edison Case 09-E-0428 directed that a marginal cost study be performed to enable the evaluation of the costs and benefits of the energy efficiency programs operating in Con Edison's service area. The Company retained NERA Economic Consulting ("NERA") to direct this effort. As a result of this collaboration with NERA, the Marginal Cost of Service ("MCOS") Analysis was developed based on a planning/engineering approach, whereby marginal costs were determined based on transmission and distribution planning practices, and the cost quantification was derived to the maximum extent practicable from either engineering estimates or actual costs of specific projects. While the initial scope of the Commission's Order in Case 09-E-0428 was to evaluate energy efficiency programs using an avoided cost methodology, this methodology was later expanded in Con Edison Case 13-E-0030 into a full-scope marginal cost analysis that compares all marginal costs to current rates in order to establish a basis for discounts under the Excelsior Jobs Program. This expanded NERA methodology, established and employed in Con Edison, sets the foundation for the MCOS study presented by O&R in this proceeding.

Q. Please describe the planning/engineering approach in more detail.

A. This methodology develops marginal costs by identifying load growth that drives expansion of a system element and examining the engineering costs of constructing and operating that element. More specifically, the Company identified segments of the transmission and distribution system where expansions due to load growth were planned. For each segment, the unit cost of a planned project to serve incremental demand was developed. Total investment dollars were converted to annual marginal costs using carrying charges, O&M and other applicable loading factors, such as common plant and working capital. For the transmission and substation segments of the system, marginal costs were developed on a year-by-year basis to reflect the phased-in nature of the Company’s long term construction schedules for these portions of the system.

Q. Please continue.

A. Marginal costs for the primary segment of the system were also developed based on the unit cost of planned investment. Primary load relief is routinely undertaken to expand capacity as load grows. As such, similar projects are done year after year. Hence, the marginal cost at the primary level is stated in current dollars and is applicable to all future years.

Q. Please continue.

A. Marginal costs at the transformer and secondary segments of a non-network system are zero when viewed on a demand basis. To avoid changing these facilities, they are built anticipating five to ten years of load growth and at any point will by design have some short term excess capacity. Hence, the marginal cost of increasing load on these facilities or decreasing load in the short term is zero.

The MCOS Analysis also presents marginal customer costs incurred when accommodating new customer connections. These costs are not marginal for existing customers, but they are marginal when viewed on a per customer basis for new customers and include the minimum system component of secondary lines and transformers as well as service costs, metering costs, customer accounting, customer service and informational expenses.

Q. Turning to Exhibit ___ (DAC-E3), please describe this exhibit.

A. Schedule 1 presents total system transmission and distribution marginal costs. These costs are presented in nominal dollars and are stated on a per-kW of system peak basis. Schedule 2 presents a comparison of marginal costs developed in Schedule 1 to current T&D revenues. The functional marginal costs in column 2 of Schedule 2 represent 10-year averages in current dollars. This 10-year averaging was done to reflect the parameters of the Excelsior Jobs Program. The “by-class” comparisons of marginal costs to T&D revenues shown on Schedule 2 reflect an equal weighting of the marginal costs incurred for new and existing customers and are used by the Electric Rate Panel in setting rates under the Excelsior Jobs program.

Q. Does this conclude your direct testimony?

A. Yes, it does.

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Would each member of the Depreciation Panel please state your name and business address?

A. My name is Charles Lenns. My business address is 4 Irving Place, New York, New York 10003.

My name is Charles D. Hutcheson. My business address is 4 Irving Place, New York, New York 10003.

My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

My name is Matthew Kahn. My business address is 4 Irving Place, New York, New York 10003.

Q. Mr. Lenns, by whom are you employed and in what capacity?

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison"), the corporate affiliate of Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R" or the "Company"). I am the Vice President – Tax at Con Edison, and I am the Chief Tax Officer for Orange and Rockland.

Q. Mr. Lenns, please briefly outline your educational background and business experience.

A. I have a Bachelor's Degree (Magna Cum Laude) in Accounting from the University of Scranton, and a Juris Doctorate from Duquesne University Law School. I was a tax partner at Ernst & Young, LLP ("Ernst & Young"), for 23 years, mostly specializing in taxation of power and utility companies. While a partner at Ernst & Young, I was the firm's tax practice leader for the power and utilities mergers and acquisitions group. I am a frequent speaker at Power and Utility tax seminars and conferences and have testified as an expert witness in utility rate cases in California, West Virginia and Hawaii, and provided tax consulting services to utility companies in preparation for rate proceedings. I was employed by Ernst & Young in various tax positions for 11 years prior to my becoming a partner of the firm. I have been in my current position at Con Edison for approximately two years.

I am currently an adjunct instructor at the University of Scranton, where I teach various tax classes at both the undergraduate and graduate levels. While at Ernst & Young, I was an adjunct law professor at Duquesne Law School, and an adjunct instructor at Duquesne University's Masters in Taxation program. I also served as an instructor in the Ernst & Young National Tax Education program, called EY University. I am a member of the Edison Electric Institute Taxation Committee, and a member of the American Gas Association Taxation Committee. I am a licensed attorney and a certified public accountant in the Commonwealth of Pennsylvania. I am a member of the American Bar Association and a member of the American Association of Certified Public Accountants.

Q. Mr. Hutcheson, by whom are you employed and in what capacity?

A. I am employed by Con Edison and in that capacity am responsible for the tax and book depreciation functions for Con Edison and its affiliate Orange and Rockland Utilities. I also support the Company's property tax function and have submitted testimony in that capacity in this proceeding as a member of the Company's Property Tax Panel.

Q. Mr. Hutcheson, please briefly outline your educational background and business experience.

A. I graduated from Hofstra University in 1978 with the degree of Bachelor of Business Administration in Accounting. I have been employed by Con Edison since 1979 and have held various positions of increasing responsibility within the Finance area. My first assignment with the Company was in the Depreciation Section, where I spent my first 15 years of employment and attained the position of Senior Accountant. In 1993, I moved to the Rates and Budget Section. In 1996, I transferred to the Financial Restructuring Team, where my duties were to assist in the development of Con Edison's rate plan filed in the New York State Public Service Commission's ("Commission") Competitive Opportunities Proceeding. I moved to the Tax Department in 1997 as a Senior Tax Accountant in the Federal Tax Section. In September 1999, I was promoted to Manager, Property Taxes, responsible for the property tax compliance function and the Company's efforts to minimize its property taxes. In December 2001, I once again began working on depreciation matters when the Tax Department assumed responsibility for the book depreciation function. My current depreciation responsibilities include analyzing and interpreting the results of plant mortality and net salvage studies.

I am a member of the Society of Depreciation Professionals ("SDP"). The SDP serves as a forum to share information and insights related to the field of depreciation. Membership includes those in the utility industry, government, education, and other industries.

Q. Mr. Wiedmayer, by whom are you employed and in what capacity?

A. I am employed by the firm of Gannett Fleming Valuation and Rate Consultants, LLC, ("Gannett Fleming") where I am Project Manager of Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for their consideration and supporting such rates before regulatory bodies.

Q. Mr. Wiedmayer, please briefly outline your educational background and business experience.

A. I have a Bachelor of Arts degree in Engineering from Lafayette College and a Master of Business Administration from the Pennsylvania State University. I am a member of the National and Pennsylvania Societies of Professional Engineers and the SDP. I served as President of the SDP in 2005. In addition, I am certified as a depreciation expert by the SDP which has established national standards for certification via an examination which I passed in September 1997. I was recertified in August 2003, February 2008 and January 2013. I have also completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study." In 2000, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," and "Data Requirements for a Depreciation Study." I am currently an instructor for the SDP's "Introduction to Depreciation" and "Analyzing the Life of Real-World Property" courses.

In June 1986, I became employed by Gannett Fleming Valuation and Rate Consultants, Inc. (now Gannett Fleming Valuation and Rate Consultants, LLC) as a Depreciation Analyst. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation

Studies. In August 2004, I was promoted to my present position as Project Manager of Depreciation Studies of the Valuation and Rate Division of Gannett Fleming, Inc.

Q. Mr. Allis, by whom are you employed and in what capacity?

A. I am employed by the firm of Gannett Fleming Valuation and Rate Consultants, LLC, where I am Supervisor of Depreciation Studies. I am responsible for conducting depreciation studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I am also responsible for the development of Gannett Fleming's proprietary depreciation software.

Q. Mr. Allis, please briefly outline your educational background and business experience.

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in Easton, PA. I am a member of the SDP and currently serve on its Executive Board. I am certified as a depreciation expert by the SDP which has established national standards for certification via an examination that I passed in

September 2011. In addition, I have completed the following courses conducted by the SDP: "Depreciation Basics," "Life and Net Salvage Analysis" and "Preparing and Defending a Depreciation Study." I currently serve as an instructor for the SPD's "Introduction to Depreciation" and "Analyzing the Life of Real-World Property" courses.

I became employed by Gannett Fleming in October 2006 as an Analyst. My duties included assembling basic data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. In March 2013 I was promoted to my current position of Supervisor, Depreciation Studies.

Q. Mr. Kahn, by whom are you employed and in what capacity?

A. I am employed by Con Edison and, for all of the regulated affiliates of Consolidated Edison, Inc., I support the functions related to book depreciation and supervise the tax depreciation functions. I also support the income tax compliance and accounting functions.

Q. Mr. Kahn, please briefly outline your educational background and business experience.

A. I graduated from Bentley College (now Bentley University) in 2004 with an undergraduate degree in accounting, and completed a master's degree in taxation at Bentley University in 2010. I have been employed by Con Edison since 2010. Prior to my employment at Con Edison, I worked in various roles within the accounting industry and in the field of taxation with PricewaterhouseCoopers, LLC, and subsequently as an analyst with American Tower Corporation in Boston, Massachusetts. I too am a member of the SDP.

Q. Have any members of the Depreciation Panel previously testified before any utility commission on the subject of utility plant depreciation?

A. **(Hutcheson)** I have testified on the subject of depreciation and property taxes in numerous cases for Con Edison and O&R before this Commission; before the New Jersey Board of Public Utilities (on behalf of Rockland Electric Company); and before the Pennsylvania Public Utility Commission (on behalf of Pike County Light & Power Company).

(Wiedmayer) I have testified on the subject of depreciation before this Commission, the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission and the Pennsylvania Public Utility Commission.

(Allis) I have testified on the subject of depreciation before this Commission, the Nevada Public Utilities Commission and the District of Columbia Public Service Commission.

Q. What is the purpose of your testimony in these proceedings?

A. The Depreciation Panel's testimony:

- Presents depreciation studies performed by Gannett Fleming for the Company's electric, gas and common utility plant but recommends that the changes in depreciation rates supported by that study not be adopted at this time;

- Presents annual depreciation accruals based on the Company's existing rates as well as depreciation rates supported by Gannett Fleming's study;
- Identifies the Accumulated Provision for Depreciation recorded on the Company's books ("book reserve") at December 31, 2013, the computed reserve (also referred to as the theoretical reserve or calculated accrued depreciation) based on existing depreciation factors, and the computed reserve based on Gannett Fleming's recommended depreciation factors for electric, gas and common plant;
- Presents the variations between the book and computed reserves based on existing rates and on Gannett Fleming's recommended depreciation factors for electric, gas and common plant and a proposal that recommends no action be taken at this time to address those variations;
- Presents an explanation of an amortization accounting methodology for certain general plant accounts as an alternative to the current group depreciation approach for those accounts but recommends not to implement it at this time; and

- Proposes to continue use of the existing O&M expense rate allowance related to capping the negative net salvage amount chargeable to the depreciation reserve for the gas mains and gas services accounts.

Q. Are there any subjects addressed in the Depreciation Panel's direct testimony that are not, and should not be construed to be, sponsored by all members of the Depreciation Panel?

A. Yes, there are four. For purposes of the initial filing in these proceedings, the Company has considered these subjects to be within the sole purview of Company management as ratemaking approaches rather than depreciation study subjects. Mr. Wiedmayer, Mr. Allis and Gannett Fleming Valuation and Rate Consultants, LLC have no responsibility for the Company's decisions on the four subjects discussed below, whether in testimony, discovery responses or pleadings of any nature and express no view on them. Mr. Wiedmayer, Mr. Allis and Gannett Fleming Valuation and Rate Consultants, LLC may, however, present or join in testimony on any of these subjects at a later stage in these proceedings if proposals are made by

Staff and/or other parties that produce results materially different from the Company's filing.

Q. Please identify those subjects.

A. First, after a thorough review of the recommendations made by Gannett Fleming, which in some cases indicate the need to change depreciation parameters, the Company has elected to propose no changes to average service lives, life tables or net salvage factors in this proceeding.

Q. Why?

A. We discuss the dollar impacts later in this testimony, but the changes recommended by Gannett Fleming were not significant in either electric or gas. Additionally for electric we considered the impact that the Commission's Reforming the Energy Vision Proceeding, i.e., Case 14-M-0101 ("REV Proceeding") could potentially have on average service lives and therefore we don't think a change toward a decrease in expense due to longer lives is warranted at this time. Regarding gas, due to the relatively large overall rate request and the materiality of the proposed change, the Company elected not to make a change in depreciation rates at this time.

Q. Please continue with the other subjects addressed in this direct testimony that should not be construed to be sponsored by all members of the Depreciation Panel.

A. The second subject is the Company's proposal, discussed later in this direct testimony, to take no action at this time with respect to variations between the book and theoretical reserves at the levels reflected in the Company's filing. The third is the testimony on the subject of caps on negative net salvage. Those subjects, along with the discussion addressing the impacts of the REV Proceeding, are being testified to by Mr. Lenns, Mr. Hutcheson and Mr. Kahn only.

Q. Do you have a view on whether the Commission directives and orders resulting from the REV Proceeding will have an effect on the expected useful lives of existing utility plant?

A. It is our understanding that the REV Proceeding contemplates a fundamental change to how electric service is provided. As such, the usefulness of certain types of existing plant assets may well be affected. The reasonable expectation is that the useful lives of those assets will be shortened due to technological change and obsolescence, which are two significant factors bearing on the expected useful lives of plant assets. We are not in a position at the present time to provide specific estimates of potential effects but the expected result should give the Commission serious pause regarding lengthening expected average service lives in these rate proceedings.

Q. Is the Depreciation Panel sponsoring any exhibits in these proceedings?

A. Yes. The depreciation study which was prepared by Gannett Fleming and reviewed by Mr. Lenns, Mr. Hutcheson and Mr. Kahn, is presented in exhibits prepared under our supervision and direction along with other exhibits prepared under the supervision of Mr. Lenns, Mr. Hutcheson and Mr. Kahn only. The exhibits applicable to Electric Plant are:

- Exhibit ___ (DP-E1) entitled: "Orange and Rockland Utilities, Inc., 2013 Depreciation Study, Electric and Common Plant as of December 31, 2013;"
- Exhibit ___ (DP-E2) entitled: "Orange and Rockland Utilities, Inc., Electric and Common Plant, Summary of Annual Depreciation Rates at December 31, 2013;" and

- Exhibit ___ (DP-E3) entitled: "Orange and Rockland Utilities, Inc., Electric and Common Plant, Summary of the Computed Reserves for Depreciation at December 31, 2013."

The exhibits applicable to Gas Plant are:

- Exhibit ___ (DP-G1) entitled: "Orange and Rockland Utilities, Inc., 2013 Depreciation Study, Gas and Common Plant as of December 31, 2013;"
- Exhibit ___ (DP-G2) entitled: "Orange and Rockland Utilities, Inc., Gas and Common Plant, Summary of Annual Depreciation Rates at December 31, 2013;" and
- Exhibit ___ (DP-G3) entitled: "Orange and Rockland Utilities, Inc., Gas and Common Plant, Summary of the Computed Reserves for Depreciation at December 31, 2013."

Q. Please summarize any changes to depreciation expense levels due to Gannett Fleming's depreciation recommendations.

A. Although as noted above the Company is not recommending adoption of the results of the depreciation study for the reasons we stated, Gannett Fleming's recommended changes related to depreciation, based on existing plant in service balances as of December 31, 2013, would reduce annual electric depreciation expense by $0.8 million, increase gas depreciation expense by $0.6 million and increase common plant depreciation expense by $0.8 million including changes due to Gannett Fleming's recommendation to change to an amortization methodology for several general plant accounts. The above amounts do not reflect that the Company's common plant depreciation expenses are allocated to electric and gas. After that allocation, the Gannett Fleming recommendations would result in an overall decrease to electric expense of approximately $0.3 million and an overall increase to gas expense of approximately $0.8 million.

Q. Please discuss the Rate Year (i.e., the twelve months ending October 31, 2016) impact regarding depreciation.

A. The Rate Year impact regarding depreciation rate changes is zero, because the Company is not proposing any changes to depreciation rates. However, even without adopting the rates supported by the Gannett Fleming study, the level of depreciation changes because of forecasted plant balances. Therefore, for the Rate Year, the Company's Accounting Panel has computed electric depreciation expense of $44.6 million, an approximate increase to electric depreciation expense in the Rate Year totaling $7.3 million and gas depreciation of $18.7 million, an approximate increase in gas depreciation expense in the Rate Year totaling $5.7 million. The Rate Year amounts include allocated common depreciation expense but do not reflect Gannett's recommendation to change to an amortization methodology for several general plant accounts.

II. DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. In preparing the depreciation study, were generally accepted practices in the field of depreciation valuation followed?

A. Yes.

Q. Are the methods and procedures used in the depreciation study consistent with past practices?

A. Yes. The methods and procedures used in this study are the same as those utilized in past depreciation studies conducted by the Company as well as depreciation studies presented by other companies in rate proceedings before the Commission. The approach is to determine depreciation rates based on the broad group average service life procedure and the whole life method. For certain general plant accounts, adoption of amortization accounting would be a change in approach for O&R, but it is consistent with the practice of most utilities in the United States.

Q. Please describe the presentation of the depreciation study in your exhibits.

A. The electric and common plant study in Exhibit ___ (DP-E1) and the gas and common plant study in Exhibit ___ (DP-G1) are presented in nine parts. Part I, Introduction, presents the scope and basis for the depreciation study. Parts II through V include descriptions of the methods and procedures used for the estimation of survivor curves and net salvage and the calculation of annual depreciation and the theoretical reserve. Part VI, Results of Study, presents a description of the results and a summary of the depreciation calculations. Parts VII through IX present graphs and tables that relate to the service life analyses, the net salvage analyses and the detailed depreciation calculations.

The tables on pages VI-4 through VI-7 of Exhibit ___ (DP-E1) and pages VI-4 through VI-7 of Exhibit ___ (DP-G1) present the estimated survivor curve, the net salvage percent, the original cost of plant and the book depreciation reserve at December 31, 2013 and the calculated annual depreciation accrual and applicable depreciation rate for each plant account or subaccount. The sections beginning on page VII-1 of each of the exhibits present the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The sections beginning on page VIII-1 of each of the exhibits present the results of the salvage analysis. The sections beginning on page IX-1 of each of the exhibits present the depreciation calculations related to surviving original cost as of December 31, 2013. We note that the presentation and content of each of the exhibits related to common plant is the same, and that common plant is presented at 100% in both exhibits.

Q. Please explain how the depreciation study was performed.

A. The study used the straight line whole life method of depreciation, with the broad group average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the service value (original cost of plant assets plus estimated costs of removal less estimated salvage at the time of retirement) over the estimated useful life of each unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 391, 393, 394, 395, 397 and 398 (and associated subaccounts) for electric, gas and common plant we used an amortization methodology. The plant assets to which these accounts apply are items such as furniture, tools and communication equipment. A complete list of accounts for which amortization is recommended is shown on pages VI-5 and VI-6 of Exhibit ___ (DP-E1) and Exhibit ___ (DP-G1). The annual amortization amount distributes the cost of the plant assets over the amortization period selected for each account and vintage.

Q. How is net salvage treated for accounts you are proposing to be amortized?

A. There is no impact since all of the accounts we are recommending for amortization have a net salvage estimate of 0% under both the existing and recommended bases.

Q. How did you determine the recommended annual depreciation accrual rates?

A. This was done in two phases. In the first phase, estimates of the average service life and net salvage factors were developed for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, we calculated the annual depreciation accrual rates using the applicable average service lives and net salvage factors.

Q. What part does the average service life play in the determination of depreciation rates?

A. The estimated average service life is the period (number of years) over which the original cost of plant will be depreciated. For example, with an average service life of 25 years, annual depreciation is 1/25th, or 4%, of the original cost of the plant before taking into account the net salvage factor.

Q. What is the effect on annual depreciation expense of a change to an average service life?

A. The depreciation expense accrual varies inversely with its underlying average service life, all else being equal, the longer the average service life, the lower the annual depreciation rate, and therefore, the lower the annual depreciation expense. Conversely, the shorter the average service life, the higher the annual depreciation rate, and therefore, the higher the annual depreciation expense.

Q. What part does net salvage play in the determination of depreciation rates?

A. In addition to providing for recovery of the original cost of plant over its estimated average service life, the Company’s annual depreciation rates include an estimated net salvage factor. The purpose of this estimated net salvage factor is to reflect, over the life of the plant, the expected gross salvage value of plant less the expected cost of removal upon retirement. With very few exceptions, most of the Company’s plant experiences net negative salvage upon retirement, because removal cost exceeds salvage value. Those two values are netted and expressed as a percentage of original cost of plant and included in the annual depreciation rate. As a result, and in accordance with basic depreciation principles and the Commission's Uniform System of Accounts, the service value of an asset, which is the original cost of the asset along with the expected net salvage value, is recovered over the estimated useful life of the asset.

Q. Please describe the first phase of the depreciation study, in which you estimated the average service life and net salvage factors for each plant account or subaccount.

A. The average service life and net salvage study consisted of compiling historical data from records related to O&R's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; making visits to various sites to view the physical condition of facilities and interpreting these data and information along with the average service lives and net salvage factors used by other electric and gas utilities to form judgments of average service life and net salvage factors applicable to O&R's plant and equipment.

Q. You mentioned that the depreciation study included visits to O&R facilities, what is the significance of doing so?

A. A field review of O&R's property as part of the study was made during June 2014. Depreciation studies should not be limited only to statistical analysis or visual comparisons of smoothed survivor curves based on actual mortality experience and standardized survivor curves because other factors, as we have mentioned, should also be considered. Field reviews including discussions with operating and engineering personnel are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge as well as information from other discussions with management was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. What historical data was analyzed for the purpose of estimating average service lives?

A. The Company’s accounting entries that record plant asset transactions during the period 1952 through 2013 were analyzed. The transactions included additions, retirements, transfers and the related balances.

Q. What method was used to analyze these data?

A. The retirement rate method was used. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the depreciation study. It is also the method used in past depreciation studies by O&R and is the overwhelmingly predominate approach used in depreciation studies across the country when aged data is available.

Q. Please describe how the retirement rate method was used to analyze the Company's service life data.

A. The retirement rate analysis was applied to each different group of property, generally a particular plant account, in the study. For each property group, we used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating future average service life. Standard survivor curves, such as the Iowa-type survivor curves and the h-system of survivor curves are used to perform these interpretations.

Q. What is an "Iowa-type survivor curve" and how can such curves be used to estimate the average service life characteristics for each property group?

A. Iowa-type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves can be used to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 50-R1.5 indicates an average service life of fifty years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. What is the h-system of survivor curves?

A. The h-system of survivor curves was developed in 1947 by Bradford Kimball of the New York Public Service Commission. Similar to the Iowa curves, the h-curves are labeled in accordance with the relative height of the modes of the associated retirement frequency curves. Thus, for example a 50-h3.0 indicates a 50 year average service life and a mid-mode curve (modes for the h-system curves range from 0.0 to 5.0).

The average service lives and related modality presented in our depreciation study are based on the h-system of survivor curves as has been the common practice in past depreciation studies for O&R.

We more fully describe survivor curves in Part II of Exhibit ___ (DP-E1) and Exhibit ___ (DP-G1).

Q. Please provide an example of how the annual depreciation accrual rate for a particular plant account is presented in your depreciation study.

A. We will use electric Plant Account 362, Station Equipment, as an example because it is one of the largest depreciable accounts.

The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1952 through 2013 and analyzed in periods that best represent the overall service life of this property. The life table for the 1952-2013 experience band is presented on pages VII-46 through VII-48 of Exhibit ___ (DP-E1). The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-46 shows $357,761 retired at age 0.5 years with $191,813,909 having been exposed to retirement. Consequently, the retirement ratio is 0.0019 ($357,761 / $191,813,909) and the surviving ratio is 0.9981 (1 – 0.0019). These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 45-h1.75 on page VII-45.

The calculation of the annual depreciation accrual and the theoretical reserve related to the original cost of plant in Account 362 at December 31, 2013 is presented on pages IX-26 and IX-27. The calculations are based on the 45-h1.75 survivor curve and 10% negative net salvage factor, and the attained age for each vintage. The tabulation sets forth the installation year, the original cost, average service life, calculated annual depreciation rate and accrual, average remaining life, and calculated accrued depreciation factor and amount (that is, the theoretical reserve ratio and theoretical reserve).

The total annual accrual of $3,145,011 and theoretical reserve of $28,354,192 for the account are brought forward to the table on page VI-4. The reserve variation of $4,498,240 shown on page VI-4 is calculated by subtracting the $28,354,192 theoretical reserve from the book reserve for the account of $32,852,432.

Q. Please describe how the proposed net salvage factors were determined.

A. The net salvage factors were determined using informed judgment that considered all relevant factors such as the results of historical net salvage analyses, the existing net salvage rates in effect, the Company's current practices with regard to net salvage and the net salvage factors used by other electric and gas companies.

Q. Please describe the statistical net salvage analyses.

A. In the statistical net salvage analyses, net salvage is expressed as a percentage of the book cost of plant retired by calendar year. The analysis of historical net salvage as a percentage of the book cost of plant retired provides a statistical basis for the level of net salvage that can be expected to occur in the future. Thus, consistent with well-established industry practices we have made estimates of net salvage expressed as a percentage of original plant cost retired that are based on informed judgment that incorporates the net salvage analyses.

Q. Is the net salvage analyses and approach you used to reflect net salvage in depreciation rates consistent with authoritative depreciation texts?

A. Yes. The Uniform System of Accounts requires that the service value (original cost less net salvage) of the

Company's assets be allocated in a systematic and rational manner over the assets' service lives. The National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices ("NARUC Manual") and Wolf and Fitch's Depreciation Systems ("Wolf and Fitch") are well-regarded texts that are considered to be authoritative depreciation sources by depreciation professionals that describe the method of estimating net salvage, and explain that expected net salvage at the time of retirement of plant assets is expressed as a percentage of original cost of the plant that will be retired and is estimated using the same methods we have employed. While other alternative approaches to net salvage are mentioned in both texts, there is no substantial support for employing such approaches, nor has there been a widespread historical precedent set in previous rate proceedings with regulatory commissions.

Q. Are the methods used in the depreciation study presented by the Company in these proceedings for the net salvage analysis widely accepted in the industry?

A. Yes. The net salvage analysis method used in the depreciation study is explained in authoritative texts on depreciation and is used almost exclusively in the utility industry. In the vast majority of jurisdictions, a portion of depreciation expense includes a provision for the prospective recovery of future net salvage over the service life of the underlying assets, and the net salvage factors are estimated using the same methods used in the depreciation studies submitted for the Company in this proceeding. This is consistent with the Commission's Uniform System of Accounts, the NARUC Manual, Wolf and Fitch and other authoritative texts on depreciation and ratemaking practices used by most state and federal regulatory commissions.

There are three states, Pennsylvania, New Jersey and Delaware, in which net salvage is not recovered prospectively through depreciation rates, but is instead recovered after assets are retired. There are also two jurisdictions, Maryland and the District of Columbia, that do not use straight line depreciation for net salvage, but instead use a deferred method of recovery. However, in these two jurisdictions the method of estimating net salvage is the same as used in the depreciation study for O&R.

Although other approaches have been proposed in New York, the Commission has traditionally followed the predominate approach by including a net salvage factor in depreciation rates with the net salvage factor being based on the same methods as used in the depreciation study we have submitted in this proceeding. This methodology includes the objective of spreading the net salvage value at the time of retirement of plant assets over the estimated useful lives of the assets in a systematic and rational manner.

Q. Please describe the other approaches to net salvage to which you referred that have been proposed in New York.

A. These approaches do not attempt to allocate the estimated net salvage amount at the time of retirement of plant assets over the estimated useful lives of the assets, despite that the Commission's Uniform System of Accounts requires the allocation of the service value (original cost less net salvage) over the lives of the Company's assets, and despite that the method we have used is the predominate approach in use by regulatory commissions.

One such approach is to not provide for net salvage in depreciation rates at all but, rather, establish an O&M expense rate allowance for it with that rate allowance being based on recently incurred net salvage amounts (comprised largely of negative net salvage). The approach is one of pay-as-you-go and is known as PAYGO. The Commission has previously rejected the PAYGO approach in Case 08-E-0539, a Con Edison electric rate case, in which Staff as well as the Company opposed the approach.

In its April 24, 2009 order in Case 08-E-0539 ("2009 Rate Order"), the Commission found that adopting the PAYGO approach would not be a good policy because all negative net salvage costs associated with plant now serving existing customers would be shifted to those who are Company customers at or after the time such negative salvage costs are actually incurred and the Commission found (2009 Rate Order at 115) that such a shift in cost responsibility would not be equitable. The Commission also recognized a number of reasons cited by the Administrative Law Judges for rejecting the PAYGO approach (2009 Rate Order at 111). These include:

1. Current customers should contribute to the future cost of removal of plant used to serve such customers today. To the extent some or all of such costs of removal are

recovered in the future, they become an unwarranted burden on customers taking service at that time.

2. If customers pay less now to cover negative salvage costs, they will at a later date need to pay more toward such costs.
3. PAYGO decreases internally-generated cash flow available to fund a company's construction program.
4. The standard net salvage method offers the advantages of spreading out cost recovery over time and of allowing for periodic updates to reflect changes in estimates of negative salvage costs and to reflect those updated estimates in rates as feasible.

Another approach to net salvage that has been proposed is in practice only a variation of the PAYGO approach. In this approach, a net salvage factor is established for each account that produces depreciation accruals for net salvage that approximates recent net salvage expenditures as does PAYGO. Since this approach results in accruals for net salvage that are approximately equal to recent expenditures, it produces results that approximate the PAYGO approach.

Thus, while this approach may appear to incorporate an estimate for net salvage in depreciation rates, it is essentially PAYGO and suffers from the same deficiencies and inequities of PAYGO. Outside of settled cases, the Commission has accepted this approach in two cases under circumstances related to economic conditions experienced during the recent economic downturn. These two cases were Central Hudson Gas & Electric Corporation Case 08-E-0887 decided by the Commission in 2009 and Niagara Mohawk Case 10-E-0050 decided by the Commission in 2010.

III. GENERAL PLANT AMORTIZATION

Q. Please describe Gannett Fleming's recommendation for amortization accounting for certain general plant accounts.

A. Under that recommendation, the plant investment in certain of the Company's general plant accounts would be capitalized in the same manner and to the same plant accounts as they are currently but will be grouped by vintage year within each plant account for cost recovery and retirement purposes.

Under the amortization approach, an amortization period based on the expected average service life of the assets of the type in a particular plant account is established. Retirements are recorded when a vintage group is fully amortized rather than as individual units are removed from service. In other words, all units of a given vintage year are retired when the age of the vintage reaches the length of the established amortization period. For example, the cost of assets that have a 15-year amortization period will be fully recovered 15 years after being placed in service and will be retired from the Company's books 15 years after being placed in service even though some in the vintage group might still be in use while others may have ceased being used at an earlier time. This type of amortization is used for accounts with a large number of units, but small asset values and relatively short useful lives. Plant and depreciation accounting is difficult and not particularly suitable for these assets because of these characteristics.

Q. For which of the plant accounts has Gannett Fleming recommended amortization accounting be used?

A. Amortization accounting is appropriate for certain electric, gas and common plant general plant accounts. These accounts are 391, 393, 394, 395, 397, 398 (including the associated subaccounts), which represent only approximately 4 percent of the Company's total depreciable and amortizable plant. The plant assets to which these accounts apply are items such as furniture, tools and communication equipment. The amortization periods apply to the assets in these accounts that are currently in service for O&R. If the mix of investment for any of these accounts changes in the future, the amortization periods may be revised to reflect the assets in service at that time. A complete list is shown on pages VI-5 and VI-6 of Exhibit ___ (DP-E1) and pages VI-5 and VI-6 of Exhibit ___ (DP-G1).

Q. Is the amortization approach that Gannett Fleming has recommended used by any other major electric or gas utilities in the State?

A. Yes. The amortization approach for general plant has been in use at Con Edison since 1995. Amortization accounting is widely used by utilities in almost every jurisdiction in the country. In New York State it has also been in use at Niagara Mohawk Power Corporation, Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation. In addition, O&R's affiliates Rockland Electric Company (in New Jersey) and Pike

County Light and Power Company (in Pennsylvania) also started amortizing general plant in 2014.

Q. Would any adjustments be necessary upon a change to amortizing general plant costs?

A. Yes. Because under amortization accounting assets are recorded as retired once they reach an age equal to the amortization period applicable to them, any assets that have survived beyond that life at the implementation date of amortization accounting must be retired. Those amounts are listed as "Fully Accrued" on Table 1 of the depreciation studies, and are shown by vintage year beginning on page IX-67 of Exhibit ___ (DP-E1) and IX-31 of Exhibit ___ (DP-G1). Additionally, the cost of those assets may have been either over- or under-recovered as of the time of their retirement under the standard depreciation methods used in the past so we recommend a separate amortization of the unrecovered cost. These amounts are listed on Table 1 in Exhibits ___ (DP-E1) and ___ (DP-G1) as "Unrecovered Reserve Adjustment for Amortization," and are proposed to be amortized over a period equal to the remaining life of the surviving assets in each account.

Q. What would be the impact on expense of the recommendations regarding the general plant accounts to which amortization accounting would apply?

A. In total, the recommended change to amortization accounting, including the impacts of the retirements of assets, changes in recovery periods, and the amortization of the unrecovered costs of the general plant account assets to be retired that are older than the amortization periods recommended by Gannett Fleming, would result in a decrease in expense of approximately $406,000 for electric plant, an increase in expense of approximately $124,000 for gas plant, and an increase in expense of approximately $774,000 for common plant.

IV. TEST OF THE BOOK RESERVES

Q. What are the amounts of the variations between the book reserves and theoretical reserves that you mentioned earlier in you testimony?

A. For electric plant, the amounts we will address are summarized on Exhibit ___ (DP-E3). This exhibit indicates that for total electric plant at December 31, 2013, the Accumulated Provision for Depreciation per books, or book reserve, amounted to approximately

$340.4 million. The computed or theoretical reserve based on existing rates was calculated on the average service lives, net salvage percentages and life tables currently in use by the Company, and amounted to approximately $323.9 million. The computed reserve recommended by Gannett Fleming amounted to approximately $350.8 million.

This exhibit also indicates that the book reserve is approximately $16.6 million, or 5.11 percent more than the computed reserve based upon existing rates and, excluding the unrecovered reserve adjustment for amortization, is approximately $10.2 million, or 2.92 percent less than the computed reserve based upon the rates recommended by Gannett Fleming.

Q. Please continue with gas plant.

A. For gas plant, the amounts we will address are summarized on Exhibit ___ (DP-G3). This exhibit indicates that for total gas plant at December 31, 2013, the book reserve amounted to approximately $184.7 million. The computed reserve based on existing rates was calculated on the average service lives, net salvage percentages and life tables currently in use by the Company, and amounted to approximately $184.0 million. The computed reserve recommended by Gannett Fleming amounted to approximately $201.9 million.

This exhibit also indicates that the book reserve is approximately $0.7 million, or 0.39 percent more than the computed reserve based upon existing rates and, excluding the unrecovered reserve adjustment for amortization, is approximately $16.1 million, or 7.97 percent less than the computed reserve based upon the rates recommended by Gannett Fleming.

Q. Please continue with common plant.

A. For common plant, the amounts we will address are summarized on Exhibit ___ (DP-E3) and Exhibit ___ (DP-G3) as both exhibits show identical amounts for common plant. The exhibits indicate that for total common plant at December 31, 2013, the book reserve amounted to approximately $90.6 million. The computed reserve based on existing rates was calculated on the average service lives, net salvage percentages and life tables currently in use by the Company, and amounted to approximately $92.9 million. The computed reserve recommended by Gannett Fleming amounted to approximately $100.8 million.

This exhibit also indicates that the book reserve is approximately $2.3 million, or 2.53 percent less than the computed reserve based upon existing rates and, excluding the unrecovered reserve adjustment for amortization, is approximately $2.1 million, or 2.12 percent less than the computed reserve based upon the rates recommended by Gannett Fleming.

Q. Why have you excluded the amounts applicable to the unrecovered reserve adjustment for amortization when testing the reserve using the rates recommended by Gannett Fleming?

A. It would be improper to include those amounts in the test since Gannett Fleming has recommended a separate amortization for those amounts.

Q. Do Mr. Lenns, Mr. Hutcheson and Mr. Kahn have a recommendation regarding the book reserve variations?

A. Yes. We recommend no action be taken related to the reserve variations, at the levels indicated, at this time. The Commission's long-standing practice has been that no remedial action be taken when the book reserve varies from the theoretical reserve by up to 10% (plus or minus). The variations we have indicated are within that range.

V. NEGATIVE NET SALVAGE CAPS – GAS MAINS & SERVICES

Q. You referred earlier to capping the negative net salvage amounts chargeable to the depreciation reserve for the gas mains and services plant accounts. Would Mr. Lenns, Mr. Hutcheson and Mr. Kahn please explain further?

A. O&R has been required for many years, beginning with Case 92-G-0050, to limit the negative net salvage factor included in the depreciation rates for Account 376 (gas mains) and Account 380 (gas services) to negative 40% and negative 80%, respectively. Any negative net salvage incurred beyond these thresholds is included in O&M expense for accounting and ratemaking purposes. For purposes of this rate filing and without prejudice to the Company's right to propose discontinuing or modifying this approach for either or both of the accounts in a future rate case, the Company will not oppose continuation of the approach and proposes that both the existing negative net salvage cap percentages and the O&M expense rate allowance remain unchanged at this time to limit the gas rate request.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Q. Please state your name and business address.

A. My name is Deborah A. Patterson. My business address is One Blue Hill Plaza, Pearl River, New York 10965.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") as Project Director of Economic Development.

Q. Please summarize your educational background and business experience.

A. I hold a BS degree from Queens College. Prior to my position as Director of Economic Development at O&R, I was employed at Consolidated Edison Company of New York, Inc. ("Con Edison") for 40 years. I initially served as a Customer Accounting Representative and was promoted to management positions in electric operations, energy services and lastly, Manager of Economic Development, responsible for Con Edison's economic development programs, specifically the Business Incentive Rate program.

Q. Have you ever testified before the New York State Public Service Commission?

A. No, I have not.

Q. What is the purpose of your direct testimony in this proceeding?

A. I will testify to the Company's proposal to change its Economic Development Rate ("EDR"), Rider H. The changes we propose to this key economic development program will attract more business customers considering relocation into the O&R service territory and broaden the pool of existing business customers considering an expansion of their current facilities. Decreasing the current kilowatt load requirement will more effectively help stimulate job growth and enhance the local tax base within the O&R service territory. The proposed change will also allow the Company to be a more effective partner with county and state economic development agencies by working more effectively with businesses that apply for economic development attraction and expansion assistance. Additionally, the Company's proposal is consistent with and will help to further, the state's energy efficiency initiatives since business customers applying for the EDR (Rider H) is required to perform an energy efficiency audit, either by NYSERDA or by an independent third party such as a qualified energy audit firm under the Company's Small Business Direct Install and Commercial & Industrial programs.

Q. What is the Company proposing in this electric rate filing with respect to its economic development programs?

A. The Company is proposing to decrease the demand usage under the EDR program from 100 kW to 65 kW in order to increase customer participation. In 2012 and 2013 there were five business customers who applied for the Company's EDR program, but did not qualify because they did not meet the 100 kW requirement. Lowering the kilowatt load requirement would also eliminate a potential penalty some customers could experience as a result of energy efficiency measures lowering their demand usage below 100 kW. Lowering the minimum from 100 kW to 65 kW will remedy this situation and may result in more participation in the EDR program. As an added benefit, business customer will receive additional savings from energy efficient installations that could be used to reinvest in business growth such as capital improvements and job creation.

Q. **Are there any other changes needed with respect to the EDR program?**

Yes. Since the current tariff is due to expire on December 31, 2016, the Company is also seeking an extension of the program for an additional five-year term through December 31, 2020.

Q. What is the cost associated with this/these proposal(s)?

A. Under the EDR, businesses receive a savings from 4%-8% on their overall bill. There are currently nine customers enrolled in the EDR program, which have realized a total savings of $243,935.34 from January 1, 2012 through October 31, 2014.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Q. Would the members of the Electric Infrastructure and Operations Panel ("Panel") please state their names and business addresses.

A. **(Coffey)** John F. Coffey, 390 West Route 59, Spring Valley, New York, 10977.

(Prall) Stephen Prall, 500 Route 208, Monroe, New York 10950.

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

A. **(Coffey)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R," or "the Company") as Chief Engineer – Transmission and Substation Engineering.

(Prall) I am employed by Orange and Rockland as the Section Manager of the Transmission and Distribution Maintenance Section.

Q. Please briefly describe your educational and business experience.

A. **(Coffey)** I received a Bachelor of Science in Electrical Engineering from Manhattan College in 1988. I am a licensed New York State Professional Engineer. I have over 26 years of electrical engineering experience and have worked for Orange and Rockland for over 25 years. I have served in my current position since 2010. This position oversees the planning, engineering and design of capital improvement budget for projects in the Orange and Rockland transmission system. I worked for one year at Burns and Roe Co. in Oradell, New Jersey as an Electrical Engineer prior to my arrival at Orange and Rockland in 1989.

(Prall) I received a Bachelor of Science degree in Nuclear Engineering in 1995 from the State University of New York and a Masters of Business Administration degree in 1998, from Rensselaer Polytechnic Institute, in Troy, New York. I have worked for Consolidated Edison Company of New York, Inc. ("Con Edison") and Orange and Rockland since 1989, as a Nuclear Chemist, Supervisor, Quality Assurance Engineer, Project Auditor, Manager of Training and Section Manager of Compliance, prior to assuming my present position as Section Manager of Transmission and Distribution Maintenance in May 2012.

Q. Have you previously submitted testimony to the New York State Public Service Commission ("Commission")?

A. No, we have not.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to present and support O&R's electric transmission and distribution capital budget and major plant additions. The Panel also will discuss other programs and initiatives that the Company is implementing and proposing, including the following incremental initiatives:

- Tamar Drive Right-of-Way ("ROW") acquisition;
- Transmission Tower Leg Remediation Program;
- Vegetation and Asset Management;
- ROW Track Machine;
- Back Yard Machines; and
- Vegetation Management Program.

Finally, the Panel will briefly address the status of the Company's effort to remove double poles in its service territory.

PLANT ADDITIONS AND CAPITAL BUDGET

Q. Are you familiar with planned plant additions and the construction budget for O&R?

A. Yes.

Q. Was Exhibit ___ (AP-E5) prepared by you or under your direction?

A. Yes. Exhibit ___ (AP-E5), Schedule 1, reflects the capital expenditures, and Exhibit ___ (AP-E5), Schedule 2, reflects the capital plant additions forecasted for the period November 1, 2015 through October 31, 2018. Our testimony will focus on the plant additions by rate year, as set forth in Exhibit ___ (AP-E5). While, as discussed by the Company's Accounting Panel, the Company is not proposing a multi-year rate plan in this rate case, we do address certain capital plant additions and other programs and initiatives in the two years following the rate year in this proceeding (*i.e.*, November 1, 2015 through Oct. 31, 2016)("Rate Year" or "Rate Year 1"). For the sake of convenience, I refer to these two years as Rate Year 2 (*i.e.*, Nov. 1, 2016 through Oct. 31, 2017) and Rate Year 3 (*i.e.*, Nov. 1, 2017 through Oct. 31, 2018).

Q. Please continue.

A. Exhibit ___ (AP-E5), Schedule 2, shows the Company's major capital electric plant additions for the period July 1, 2014 through Oct. 31, 2018. This schedule includes spending totals for electric blankets and regular projects under $1 million that we will provide general details for below. This schedule also sets forth spending for regular projects over $1 million, along with their projected in-service dates. For purposes of this proceeding, the major capital plant additions that we will discuss in excess of $1 million fall into the following categories: (1) those projects that have been or will be completed and added to plant in-service during the period July 1, 2014 to Oct. 31, 2015 ("Linking Period"), (2) those projects that will be completed and added to plant in-service during Rate Year 1, (3) those projects that will be completed and added to plant in-service during Rate Year 2, and (4) those projects that will be completed and added to plant in-service during Rate Year 3. The forecasted in-service dates are based on projected approval time frames, in conjunction with the subsequent construction and installation schedules. The forecasted costs have been quantified based on an analysis of recent spending for material, equipment and labor experienced on similar transmission and substation projects that are in progress or have recently been completed by the Company.

The Company has defined three major milestone levels of progression for project cost estimates in excess of $5 million: (1) the Budgetary (Planning) Estimate, (2) the Appropriation Estimate, and (3) the Current Working Construction Estimate ("CWE").

Q. Please explain the differences among these three estimates.

A. These three estimates are more specifically described as follows:

1) The Budgetary (Planning) Estimate is used for initial representation in the Company's short- and longer-term budgeting process and for initial authorization by the Company's Board of Directors. It is a rough estimate based on a high-level scope of work for the project and preliminary engineering information at project initiation. Its purpose is to screen project

costs for feasibility and to assist in deciding whether to proceed with the design of a particular project or evaluate other alternatives. The Budgetary Estimate will typically contain higher amounts of contingency, approximately in the 20 percent to 30 percent range, due to the increased levels of risk factors and unknowns at this stage of a project.

2) The Appropriation Estimate is a more detailed estimate based on final engineering design data and construction requirements from external entities, including any required permits and approvals from local municipalities and environmental agencies. This estimate is used to allocate money and release funds for construction that have already been approved by the Company's Board of Directors for actual construction. It includes all direct and indirect costs of the project such as: labor, equipment, material, corporate overheads, escalation, contingency and the associated expenses and retirement costs. The Appropriation Estimate will typically contain contingencies and unknowns in the range of 10 percent to 20 percent. The project has advanced in design from the Budgetary Estimate, however, certain risk factors still exist that need to be accounted for in this stage, particularly with respect to final approvals, equipment and labor procurement.

3) The CWE is typically the final cost estimate leading into construction, which includes all of the information contained in the Appropriation Estimate, as well as bid-level pricing as the project proceeds into initial construction. This also may be the most current appropriation estimate. This estimate is likely to be updated monthly after the start of construction, or whenever

significant changes of scope occur to the project, as appropriate. The CWE applies to projects that are typically near or in construction and will apply to those projects described in the Linking Period portion of this testimony. Projects at the CWE Stage will typically have contingency in the 10 percent or less range as most of the unknowns have been removed at this stage of the project.

Q. What is the purpose of establishing these three estimates?

A. The purpose of establishing these three estimates is to align cost estimates with the actual information available and levels of risk at a given time. It is important that estimates are changed based only on the actual available project information and updates to that information. We will refer to these three cost estimate levels to describe the project cost estimate for each of the major capital project descriptions discussed later in our direct testimony.

It should be noted that Exhibit ___ (AP-E5), Schedule 2, is a plant additions schedule that sets forth the Company’s current best estimate of when the various plant assets listed are to be booked to plant in service.

The Plant Additions estimate, contained in Exhibit ___ (AP-E5), Schedule 2, is representative of the Company’s spending on a project to date and its budgetary spending projections. The Plant Additions estimate typically does not contain contingencies or unknown risks that are included in the different levels of estimates described above. For the purposes of this direct testimony, for each project described, the Company will include both the Plant Additions estimate, as well as the Budgetary/ Appropriation Estimate to provide the potential bandwidth that presently exists at this stage for each project.

Q. Does O&R have a robust electric delivery system planning process that effectively evaluates its system growth and capacity requirements?

A. Yes.

Q. Please describe the Company's electric planning process.

A. Each year, the Company performs detailed planning studies that determine electric load growth and assess the performance of the electric delivery system throughout a future forecast period with respect to its electric transmission and distribution design standards. The Company's electric planning design standards provide guidance to aid in prioritizing various electrical infrastructure projects for the Orange and Rockland electric delivery system. The design standards are designed to balance the costs of infrastructure investment vs. the benefit of mitigating the risk of significant outage events, as measured by both the amount of load/number of customers impacted and the anticipated duration of the outage. These standards are a key to the capital planning process, both short and longer term, as they provide a process by which future risk mitigation investments are identified and prioritized. The electric design standards primarily incorporate risk assessment methodology that provides criteria to assess if the electric facilities are, or will be, operating outside of acceptable tolerances with respect to equipment loading, operating parameters and customer exposure. The Company completes a future five-year assessment as part of its annual planning process, and every three years completes a 20-year long range assessment and outlook to assist in O&R's long-term corporate vision and strategy.

Q. Please describe in more detail O&R's forecasting and risk assessment processes.

A. The annual planning process commences with forecasting the overall system load, loads for all of the transmission lines and transmission transformer banks, each individual substation transformer bank, and all of the distribution circuit loads for the upcoming summer. The impact of photovoltaics ("PV") and distribution generation resources ("DG", or "DR"), as well as other demand side measures ("DSM"), such as energy efficiency programs and voluntary or program structured load reductions are all accounted for and factored into the forecasted growth rates to provide as accurate as possible growth projections for the forecast periods. Substation transformer banks and substations are grouped into specific load regions based on logical switching capabilities between adjacent stations and banks. The actual historical peak loads for each region are utilized within mathematical regression models, along with other relevant variables, to predict and determine the forecasted weather-normalized loads through a future forecast period for each region. The Company then utilizes a process to apportion the regional growth and expected demands through the forecast period to each substation transformer bank and distribution circuit within the region. Any known block loads or transfers in the region are then accounted for and applied to the affected infrastructure accordingly.

The Company utilizes all of the projected loads determined through its forecasting process to perform operating reviews on each of its major assets, from its transmission lines and banks down through its distribution circuits, for both normal operating conditions and for the failure or removal of those components through a detailed contingency analysis. As was mentioned above, the results of the contingency analysis are evaluated with respect to O&R's design standards, which contain the risk assessment methodology that provides the specific criteria to assess if the electric facilities are, or will be operating outside of acceptable tolerances with respect to equipment loading, operating parameters and customer exposure. If any of the assets do not meet their respective design standards at some point during the forecast period, a solution is determined, scheduled and prioritized as part of the Company capital budget development process.

Q. Once the high level solution is identified by the initial output of the planning process, is that the end of the process?

A. No. As part of the Company's annual planning processes, it periodically evaluates the need for, and appropriate timing to implement its identified capital projects. The Company initially investigates if alternative and less costly traditional infrastructure investments can substantially defer, reprioritize, or even eliminate more costly major capital infrastructure investments. Some of these traditional solutions include constructing lower cost distribution projects to defer upgrading or building new substations, utilizing technology and distribution automation for improved asset utilization to defer investment, reprioritizing and accelerating the construction of lower cost transmission and substation investments to defer more costly investments, or simply accepting risk for longer periods of time on projects with less exposure to accelerate the construction of higher risk projects. This is part of O&R's planning process and system review, and the Company has developed and implemented all of these alternative traditional solutions to defer higher cost major capital investments.

Q. Does the Company implement any other reviews to identify potential alternative solutions for its major capital infrastructure projects as part of its normal planning processes?

A. Yes. O&R implements an integrated planning process and methodology whereby it not only reviews alternative traditional infrastructure solutions, it also screens and reviews major capital investment projects with respect to targeted non-traditional alternative measures, such as DG, DR and DSM.

Q. Please describe the Company's integrated planning process that evaluates potential non-traditional alternatives.

A. O&R implements a screening and review for each major capital infrastructure project that exceeds $5 million to determine if it can be cost-effectively deferred through the implementation of non-traditional alternative measures, such as DG, DR, and DSM. This screening is typically done when the project need is initially identified, or soon thereafter.

Within this initial screening process, predominant project drivers are utilized to determine if deferral utilizing non-traditional alternative measures is even possible. Projects that are customer driven, needed to improve reliability, safety, or operational issues, or are required to replace aging or obsolete equipment cannot be deferred with non-traditional alternative measures, and are excluded from the initial screening process. Deferral will typically only be possible for those projects that have a high cost, have small capacity deficit need, have low demand growth, and that have a need date sufficiently far in the future to allow the non-traditional alternative measures to be installed with enough time and in sufficient quantity to allow deferral.

For those projects where deferral is possible, the screening test is continued through a process that determines a present worth value for deferring the project. This present value savings in revenue requirement is then divided by the load reduction required to defer the planned project in order to determine the value in dollars per KW ("$/kW"). The value of the deferral is the maximum incentive O&R could pay to in-area generators or customers to provide the necessary load relief for the area. The Company utilizes a hurdle rate of $150/kW as a hard stop in this part of the process. The cost of solutions through alternative measures will definitively not be cost-beneficial with respect to traditional investment projects that have deferral values less than the hurdle rate. For projects that pass the hurdle rate, more detailed studies are performed that review the type of customers, the number of customers, and the load profiles for the circuits in the geographic area of the project, as well as the specific measures, technologies and their costs, to determine if enough capacity reductions can be achieved, and if so, the costs and benefits in comparison to the traditional investment. This integrated planning process has been utilized by O&R since 2000.

Q. Please provide an example of the Non-Traditional Alternatives Screening Process.

A. An example of the Company's non-traditional alternatives screening process is provided in Exhibit ___ (EIOP-E1) for the Hartley Road Substation. The Company's experience in applying this screening process on all large capacity projects has resulted in the observation that high cost projects that require a small amount of MW reduction for deferral will provide the highest deferral value and therefore, are the best candidates for this method of deferral. It is also the Company's experience that these projects are few and far between. Even high cost projects that have large capacity deficit needs, and either have experienced, or are projected to experience substantial load growth will generally not be strong candidates for non-traditional alternative deferral measures because of the large amount of load reduction that needs to be attained for extended timeframes. The Company has identified a project that it believes has substantial deferral value and an adequate timeframe available to attempt to implement non-traditional alternative measures. This project is the Pomona Substation and is discussed below, and in the testimony of the Reforming the Energy Vision Panel ("REV Panel").

Q. Once an optimal solution is determined, does O&R have a formalized process to prioritize its projects?

A. Yes. The Company has a two-step process for prioritizing its major electric capital infrastructure projects. The first is completed within the system planning process, and then these projects are prioritized against other Company projects through a corporate-wide prioritization methodology.

Q. **Please explain both of these prioritization processes.**

A. After all methods of alternate solutions are exhausted, the final project solutions are initially prioritized by engineering. Multiple drivers determine the priority of a project and each driver has several possible components that contribute a weighted value. The key drivers include load, existing condition towards satisfying design standards, condition of equipment, relationship with respect to sequential project needs, reliability, customer driven, and construction window availability. Other drivers, such as operating conditions, safety, losses and voltage improvements that provide additional benefits are considered. The total weight sets the priority of the project relative to other projects.

Once the proposed portfolio of corporate projects is selected based on technical and economic screening, the portfolio is analyzed utilizing the Company's strategic alignment prioritization methodology and process. The projects are ranked relative to each other based on their impact on:

- Providing Reliable Service;
- Improving Public and Employee Safety;
- Reducing Costs to Customers;
- Reducing and Managing Risk;
- Satisfying Customer Needs;
- Enhancing External Relations;
- Being Responsible Stewards of the Environment; and
- Strengthening the Company's HR Activities and Corporate Processes.

The final project portfolio is then selected by the respective Department Managers and Directors, and ultimately approved by the Company's executive management.

Q. Please describe the process and procedures used to monitor and evaluate individual project milestones and cost objectives against actual and expected outcomes and benefits?

A. The Company's Project Controls Group tracks project performance on all large capital projects. The Project Controls Group is part of the Company's Project Management Department and is responsible for the development and tracking of project schedules, estimates and contract documentation for all large capital projects. This Group is comprised of schedulers, estimators and contract documentation specialists. The Project Controls Group and individual project teams utilize standardized project schedules to track schedule performance and milestone achievement. The Company's cost analysts and project managers utilize Oracle Business Intelligence to track actual costs and expenditure details. The majority of large capital projects are also tracked using earned value. Earned value compares the forecasted and actual expenditures over time against the value of the scope elements completed. Earned value is a construction industry standard for tracking project performance.

Q. Has the Company been keeping the Staff of the New York Department of Public Service ("Staff") and other interested partied informed of the status and progress of its electric transmission and distribution capital infrastructure spending?

A. Yes. Pursuant to the Company's current electric rate plan, O&R has been providing quarterly and annual reports to Staff and other interested parties regarding O&R's transmission and distribution capital expenditures. Also, the Company's Engineering, Operating and Financial departments meet with Staff on a regular basis to review projects and discuss other operating issues and details. The Company has kept Staff and the other parties abreast of any delays, project modifications, concerns and increased spending, particularly regarding projects identified in the current electric rate plan. The Company proposes to continue this project status review and update process as part of any new electric rate plan.

Electric Blankets

Q. What is included in the category of Electric Blankets set forth in Exhibit ___ (AP-E5), Schedule 2?

A. Blankets include a variety of work, including all materials and labor, which must be performed regularly so that the Company can continue to provide reliable service. Blankets are an accounting convention, long accepted by the Commission and Staff, whereby, for the sake of convenience, the costs of certain recurring labor and equipment are grouped together. Included in the overall blankets category on Exhibit ___ (AP-E5), Schedule 2, are the Electric Overhead and Underground Distribution Blankets. The Company uses these blankets to support its electric distribution business, and they break down into the following sub-categories:

- New Business;

- Streetlights;
- Road Widening;
- Telephone Interference Work;
- Voltage Complaints;
- System Integrity; and
- Customer Complaint Investigations.

These blankets cover routine expenditures on the Company's Electric Distribution Overhead and Underground systems to connect new customers, address municipal requirements, and provide necessary funds for daily requirements and upkeep of the distribution system. More details on these blanket categories are as follows:

- New Business - This blanket is for either overhead or underground system improvement electrical projects required for the connection of new customers to the O&R distribution system.
- Streetlights - This blanket is utilized to install new streetlights on the O&R system associated with new business projects and new customer requirements.
- Road Widening - This blanket is utilized for relocating existing Company facilities that interfere with municipal or state road widening projects.
- Telephone Interference Work - This blanket is utilized when required spacing for telecommunications facilities is not available on a pole and the electric facilities have to be relocated to order to accommodate other

utilities on the pole pursuant to the Company's joint use agreements with telecommunications companies (*e.g.*, Verizon).

- Voltage Complaints - This blanket is for installing or upgrading existing facilities to address individual customer voltage complaints. This type of work may include adding new transformers or upgrading existing transformer capacity and/or upgrading secondary systems to improve operating conditions.
- System Integrity - This blanket is for small system improvement projects on the distribution system to enhance service reliability.
- Customer Complaint Investigations - This blanket covers all types of projects that are the result of complaints and issues that are raised by customers. They may include relocation of guy wires, damage to customer property, and all other complaints that come through the Company's blue card system (*i.e.*, O&R's system for handling non-emergency customer trouble calls).

Also included in the overall blankets category on Exhibit ___ (AP-E5), Schedule 2, are the following: (1) the costs of transformers, tools, meters, test equipment, and automation devices; (2) the underground rebuild and rehabilitation programs that address aging underground cable infrastructure, so as to improve the reliability of underground residential subdivisions; and (3) electric transmission and substation system expenditures, which include costs associated with transmission relay upgrades, remote terminal unit ("RTU") upgrades, bank metering, substation communications protection, small substation equipment, substation paving and drainage, and the installation of substation battery banks.

Regular Projects Under $1 Million

Q. What is included in the category of Regular Projects under $1 Million set forth in Exhibit ___ (AP-E5), Schedule 2?

A. These expenditures predominantly reflect electric distribution system improvement projects that provide upgrades to the existing distribution plant or add new distribution circuitry. The majority of these projects are aligned with the substation system improvements that the Company has identified, to allow the increased substation capacity being installed to be efficiently and effectively utilized in order to provide improved reliability on the distribution system. These costs also reflect some smaller transmission and substation system projects and upgrades.

Regular Projects over $1 Million

July 1, 2014 to October 31, 2015 (Linking Period)

Q. Please describe the major electric capital projects that have been or are projected to be completed and booked to plant in-service during the Linking Period.

A. A description of these projects follows:

<u>Transmission Line 28 from Ramapo to Sugarloaf</u>

Project Description - This project involved the construction of a new transmission line within the O&R service territory from the Ramapo Substation to the Sugarloaf Substation, on the vacant side of the Southern Tier towers that presently support the existing 345 kV Line 77. This new line, named Line 28, was constructed to 345kV specifications, as originally designed, but is operated at 138 kV until such time that this line may be further extended to Rock Tavern and operated at 345 kV for additional capacity on the bulk power system. At the Sugarloaf end, Line 28 is connected into the 138 kV Sugarloaf Substation. At the Ramapo end, Line 28 is connected into a terminal bay formerly occupied by Transmission Line 26 in the 138 kV yard. The construction of Transmission Line 28 includes the installation of double bundle 1590 ACSR conductor in the open position of Con Edison's Transmission Line 77 towers between the Ramapo and Sugarloaf Substations. Since the applicable construction codes have changed considerably since Transmission Line 77 was originally constructed in the 1970's, the installation of the Transmission Line 28 conductors and optical ground wire required substantial structural modifications, but no total structure replacements.

Project Background - In 2006, the summer study indicated the Central Hudson SL Line will exceed its normal rating under normal conditions. In addition, the loss of a major system component (*i.e.*, N-1 condition) in the Northern Division will load the SL Line above its long term emergency ("LTE") ratings. Also, the summer system peak of 2006 confirmed this projected loading when the flow on the SL Line was 163MW exceeding its normal rating of 159MW. If N-1 contingencies occurred during at system peak, the power flow on the SL Line would have exceeded its LTE as well as its short term emergency ("STE") rating. Load shedding in the Orange County area would have been initiated to reduce the flow on this line. The worst case would have been the loss of the Middletown Tap substation that would load the SL Line significantly above its STE rating. Central Hudson would then have to initiate the outage sequence to de-energize their line when the power flow exceeded ten minutes above the line's STE rating. About 18,000 customers would be affected if load shedding were to occur.

Project History/Deferral - Originally scheduled for completion in December 2009, the project encountered several delays relating to securing necessary permits, the re-designing of existing towers, as well as environmental issues associated with the project. As a result, the project was not completed until June 2014.

Alternative Solution Screening - This project was primarily designed to improve transmission reliability by providing backup for the loss of the Middletown Tap. Likewise, being designed at 345kV, the Line 28 portion will become the southern part of Line 76 when the Ramapo to Rock Tavern line project is completed in the 2016 time frame. Therefore, no screening test was performed to defer the project.

Project Benefits - The Company has constructed a new transmission line from the Ramapo Substation to the Sugarloaf Substation. This project was required to improve the transmission source capacity and reliability to the Company's Central and Western Operating Divisions, which encompass approximately 110,000 customers. Construction of this new transmission line eliminates the need for the Orange and Rockland connection to Central Hudson's 115kV S/L

Transmission Line that previously tied Sugarloaf to Central Hudson's Rock Tavern Substation.

Although this transmission line has been energized, site clean-up continues and the overall work scope is scheduled to be completed in 2015. The current working estimate for this project is $24.8 million. The Company placed Transmission Line 28 in service on June 24, 2014.

<u>Rio Bank 53 and OCB 53-2 Replacement</u>

Project Description - This project includes the replacement of Bank 53 with an 18 MVA unit that was previously used at the Company's Silver lake Substation as Bank 3113. The replacement transformer fit on the existing foundation without modification, and was the largest capacity transformer bank that was capable of being transported to the site, due to travel and roadway/bridge restrictions near the site. This allowed for the fastest and most cost-effective restoration. Since the 18MVA bank was not capable of covering all contingencies on the 34kV load pocket at peak time, a 69/13.2kV mobile transformer was installed at a future station site (Deerpark) to relieve the load pocket. OCB 53-2 at the Rio Substation will also be replaced with a new Siemens SPS-2 gas insulated circuit breaker. OCB 53-2 is a Westinghouse oil insulated circuit breaker manufactured in 1950 and has been in continuous service since that time. The breaker is well past its normal operating life. The transformer differential relay system will also be upgraded to a new digital relay system. The existing system is over 60 years old and has exceeded its useful life.

Project Background - On December 18, 2013, Bank 53 at the Company's Rio Substation, tripped out of service. Testing revealed an internal failure of the transformer. Bank 53 is a 138-69kV/34.5 kV, 35 MVA transformer manufactured by Allis-Chalmers in 1974. The unit had been in continuous service since that time. Due to the significant weight of the 35MVA replacement bank and the present condition of the bridge and road system in Rio, a smaller lighter bank was the only timely consideration. From this, the Company adjusted to an alternate plan and replaced the 35MVA transformer with an 18MVA bank.

Project History/Deferral - A series of projects are scheduled to be completed: construction of the Deerpark Station in 2018, Port Jervis Upgrade in 2020, and the replacement of Rio Bank 53 with two 69/13kV Banks in 2026. The two Rio Banks and conversion of the 34kV circuit to two 13kV circuits will eliminate the single 69/34kV bank and provide bank backup for the single 34kV Rio circuit.

Alternative Solution Screening - Due to the fact that this was a transformer failure, and the transformer had to be replaced within the upcoming six month period to maintain adequate and reliable service to customers, non-traditional alternative measures were not a viable option.

Project Benefits – The overall solution allowed the 18MVA transformer and the Deerpark mobile installation to cover all contingencies at peak time. The mobile transformer also provides load relief for the Port Jervis Substation, which improves reliability for the area.

The final project costs are approximately $1.7 million. The Company placed Bank 53 and GCB 53-2 into service on May 28, 2014.

<u>Monroe UG Circuit Exit 61-2-13</u>

Monroe Circuit 61-5-13 is one of the heavily-loaded circuits that feed the Kiryas Joel area with a 2014 forecasted load of 479 Amps. Although the growth rates for peak demand in this area has reduced to 1.81% over the past year, the pre-recession growth rate was 5.6%. After the circuit exited the station, it split and crossed Route 17 in two locations to serve the Kiryas Joel load area.

Therefore, in the event of a single-circuit contingency at peak time, two of the Route 17 crossings were tripped and there was limited backup from another heavily-loaded Monroe circuit (61-4-13). Cascade switching to Harriman circuits provided minimal relief under these contingency conditions due to their load and length. A recently energized circuit (Circuit 61-9-13) relieved a portion of the heavily-loaded Circuit 61-5-13. This project resulted in the installation of a new UG exit (Circuit 61-2-13) to Forest Ave. Together, circuits 61-2-13 and 61-9-13, which are fed from different banks, will split the load of existing Circuit 61-5-13, and be capable of providing 100% backup for each other, as well as other adjacent circuits into the Kiryas Joel area.

The final project costs are approximately $2.0 million. This project was completed in September 2014.

<u>Montebello UG Circuit Exit 51-6-13</u>

This project provided for a section of circuit 51-6-13 along Montebello Road to be placed as underground construction. Prior to this project, this area was comprised of double circuit overhead construction that had a history of tree related outages.

Over the last ten years, this area has experienced numerous outages as a result of tree branch contact with the primary conductors. Close to the head-end of the Tallman Substation, the double circuits 51-2-13 and 51-6-13 run along Montebello Road through a heavily treed area commonly known within the Company as "Pine Tree Alley." Since both circuits share a common pole line, a single tree related outage or MVA can result in the loss of both circuits.

As part of the Company's Storm Hardening effort to increase reliability for customers on the 51-6-13 and 51-2-13 circuits, the 51-6-13 (bottom) double spacer circuit was placed underground as an express feeder along Montebello Road for approximately 5,400 feet. The 51-2-13 continues as a single spacer overhead circuit along Montebello Road and serves the entire overhead distribution load along this portion of the circuit route.

A smaller, separate overhead distribution project was completed to re-tap all spurs and transformers from circuit 51-6-13 to circuit 51-2-13, remove the retired spacer cable, and install new switching devices on circuit 51-2-13 in key locations to improve isolation/restoration.

Benefits for this underground project include the elimination of double circuit construction in an area that experiences significant tree related outages, particularly during storm conditions. Since both of these circuits currently share a common pole line, a single contingency during a storm can result in the loss of both of these circuits. In addition, this area has sustained significant storm damage in the past due to the large number of evergreens (soft wood pine trees). The tree damage has increased customer restoration time and tied up valuable resources during storm events. Undergrounding this section of Montebello Road will reduce the number of outages, improve customer restoration times, and re-purpose valuable line crew resources during major storm events.

The final project costs are approximately $2.0 million. The project was completed in September 2014.

<u>Blooming Grove - Electric Upgrade</u>

The Blooming Grove facility currently includes a data/file room which houses equipment in support of the alternate Energy Control Center ("ECC") and other systems. The existing room is at capacity for space. New equipment is required to be added to support the Distribution Engineering Workstation ("DEW") control system, the alternate ECC and other corporate business and mission critical systems. The room must be expanded to accommodate the installation of the new equipment. In addition, as part of storm hardening, the electrical facilities are in need of upgrade to provide better redundancy. The facility is currently fed from one primary feed to a single pad mount transformer. The upgrade will provide a second underground feed from a different circuit/bank. Each underground feed will serve a 1000 KVA padmount transformer. A recloser will be installed on the mainline to protect the underground feed to the facility from a downstream fault. The installation will require double ended switchgear and the installation of an emergency generator. An Uninterruptible Power Supply ("UPS") will be added to provide battery backup conditioned power to select critical loads prior to the start of the generator.

The current working estimate for this project is $4.5 million, with final work currently projected to be completed by year end 2014.

Hartley Road Substation and UG Distribution Circuit Exits

Project Description - The project scope comprises the installation of a new 138/69 – 13.2 kV station, consisting of two 50 MVA transformer banks and the capability for ten new distribution circuits. Six new distribution circuits will be installed initially. The new circuits will exit underground from metalclad switchgear in the station. The substation is currently heading into final wiring and checkout phases with foundations/conduit complete, transformer and switchgear delivered and steel erection complete.

Project Background - The Hartley Road area in Goshen, New York is centrally located between the Shoemaker, South Goshen, Silver Lake, and East Wallkill substations. Each of the three substations' distribution banks are heavily loaded and serve a combined 12,891 customers. There has been substantial demand load growth on the local electric delivery system in this area, which averaged approximately 4.3% in 2006, during the time period the project need was identified. The South Goshen substation is a single 20 MVA bank (Bank 189) substation located in Goshen, New York. In addition, Bank 189 is not equipped with a Load Tap Changer ("LTC") for voltage control. Due to the limited backup through distribution ties from adjacent stations, a contingency on South Goshen Bank 189 at peak time would have only 52% backup, which would result in 32,000 customer-hours of interruption until a mobile transformer is installed to assume the remaining load. Therefore, area reinforcement is necessary to allow this station to meet the Company's Distribution Design Standards.

The Shoemaker substation is also a single-bank station with a 35MVA transformer that peaks close to 32MVA. Although the bank meets the Distribution Design Standards with 87% backup in the event of a bank failure at peak time, approximately 22,590 customer-hours of interruption would occur until a mobile transformer is installed.

The East Wallkill Station is a two-bank station that serves load along the edge of the service territory and therefore has limited distribution ties to adjacent stations. Even after the 5MW of new Orange Regional Medical Center load was added in 2011, the East Wallkill banks are capable of providing 100% backup for each other in the event of a transformer contingency at peak time. As large companies continue to expand in the industrial / commercial load area served by the East Wallkill Substation and load continues to grow, these banks will exhaust their capacity, and the assistance from adjacent stations through distribution ties is limited.

The Silver Lake Station is also a two-bank station with one 35MVA bank and one 25MVA bank. The 25MVA transformer is a non-LTC bank with a peak load of 28.3MVA, which is below the normal rating of 32.0 MVA. Although the 35MVA bank is capable of providing 100% backup for a contingency on the 25MVA bank at peak time, distribution ties are required to assist the 25MVA bank when covering a contingency on the 35MVA transformer.

Project History/Deferral - The need for the Hartley Road Substation was identified in 2002. In 2006, the Company purchased land in the Hartley Road area of Goshen for the construction of a new substation for 2008. In 2008, the need to construct higher priority projects delayed the construction of the Hartley Road Station. At this time, the Company decided to minimize the risk of the area contingencies. In 2009, a distribution tie to Chester was constructed, which relieved the Goshen bank by 2MVA. In 2010, South Goshen Bank 189 peaked at 23.9 MVA. With the Goshen bank only exceeding its normal rating for a small percentage of the year (about 2%), operating plans were prepared to transfer a section of the bank to an adjacent station through a long and exposed distribution tie. This relieved the bank and minimized risk to the system. As load continued to grow, the percentage of the year that the bank would exceed its normal rating slightly increased, but the transfer still served its purpose. When the new hospital opened in 2011, circuits were reconfigured to provide a feed/backup until Hartley Road was constructed. This forced one of the Silver Lake banks to peak close to its normal ratings. The combination of the economic downturn over the past few years, new distribution ties to adjacent stations (Washington Heights), and the revised Distribution Design Standards in 2012 has allowed the Silver Lake and South Goshen banks to remain meeting design standards. Due to the economic downturn, the demand growth for this area has decreased and remained at 1.6% for the past three years (2011-2014).

Alternative Solution Screening - The Company has discussed above its alternative solution screening process for this project.

Project Benefits - The Hartley Road Substation will provide sufficient capacity for future load growth, as well as load relief and backup for the heavily-loaded South Goshen, Shoemaker, Silver Lake, and East Wallkill substations, which will allow South Goshen to meet the Distribution Design Standards for many years and defer the need to upgrade that station for years. The Hartley Road Substation will also enable the entire South Goshen substation to be unloaded to facilitate the upgrade of the South Goshen substation when it is needed in the future. This will significantly improve the opportunity for maintenance to be completed on the South Goshen Substation until its upgrade.

This project is currently projected to be completed by year end 2014. The current working estimate for this project is $16.2 million.

Please see Exhibit ___ (EIOP-E2) for Hartley Road Substation supporting maps and tables.

<u>New Hempstead Substation Upgrade and UG Distribution Circuit Exits</u>

Project Description - The Company identified the need for the New Hempstead Substation Upgrade in 2005. This project calls for the replacement of the two 35MVA non-LTC transformers with two 50 MVA banks with LTCs with two additional circuits (ten total). In addition, the underground circuit exits will be redistributed to alternate positions between the two banks. Two 16 MVAR capacitor banks will be added on the transmission bus to improve transmission voltages for contingencies.

Project Background - The existing New Hempstead Substation is located in the Town of Ramapo, New York. The New Hempstead Substation previously had eight distribution circuits, which all exited the substation underground in manhole and duct systems, from two 35 MVA transformer banks that did not have LTCs. During heavy load periods, the voltage at the New Hempstead 13.2kV bus and distribution circuits operated below the optimum operating range. Not only does this cause a problem under normal conditions, this also creates limitations on backup to adjacent stations during contingencies on those banks and/or circuits. In 2006, each bank was approaching its 42MVA normal rating and the area's peak demand growth rate was 3.5%. Therefore, in the event of a contingency on either bank at peak time, the remaining bank provided minimal backup. Due to high loading on distribution ties from adjacent stations (*i.e*., Burns, Tallman, Stony Point, and West Haverstraw), they were not capable of providing adequate contingency support to meet the distribution design standards in this area. This resulted in approximately 40% of the customers from the tripped bank out of service until a mobile transformer could be installed, which resulted to almost 50,000 customer-hours of interruption. In addition to station backup, the existing circuit layouts were less than optimal. New Hempstead Bank 145 primarily fed east of the station and New Hempstead Bank 245 primarily fed west of the station due to the existing routes of the underground distribution circuit exits. This caused concerns for backup during a bank contingency since there are limited distribution ties that could be used and the remaining bank would not have enough capacity to pick up the entire load. At this point, both New Hempstead banks and two New Hempstead circuits were operating outside the risk tolerances allowed by the Distribution Design Standards.

Project History/Deferral - Due to continued load growth in the New Hempstead, New City and New Square areas, the existing banks needed be upgraded to 50 MVA banks with LTCs. Original plans were to construct the Little Tor Station before the New Hempstead upgrade, which would provide a source to unload New Hempstead and allow the station to be upgraded with larger LTC transformers and reconfigure the underground exits. However, due to delay of the construction of the Little Tor Station from public opposition, a new approach has been taken. A mobile transformer was required at the Little Tor site to assist in unloading and prepare for contingency on circuits and one of the New Hempstead banks, particularly after removal of sections of distribution circuits along New Hempstead Road due to road widening project. Utilizing as much capacity from the recently constructed Snake Hill substation and the mobile transformer at the Little Tor site, the New Hempstead substation was unloaded and upgraded one bank at a time. In addition to the substation transformer upgrades at New Hempstead, the underground distribution circuit exits have been re-routed so that circuits from both banks extend in similar directions to provide better contingency capability and redundancy for the area, as well as better balance the load between the two banks within the station. Two additional circuits have also been installed to provide improved load relief and reliability for the circuits that feed towards the Pomona area, which allows deferral for the Pomona Substation for an additional two to three years. This resulted to a present worth savings of $5.6 million.

Alternative Solution Screening - A screening test was performed in 2005/6 and produced a deferral value that was not economically justifiable. This was due to the low project cost, the required capacity reduction needed for deferral (16MW), and the high area growth rate that was approximately 3.5%. The other issue was that DG would need to be installed in at multiple locations, thereby increased the installation and diversity/redundancy costs. There were also several operating issues that have led to reliability problems. With the New Hempstead Station having no LTCs, it was difficult to maintain adequate voltage at the station bus throughout the year. There was little opportunity to unload the equipment for maintenance without providing an additional source. For all of these reasons, non-traditional alternatives were deemed not to be a viable solution for this project.

Project Benefits - The two 50MVA New Hempstead transformer banks will increase station backup and decrease the dependency on distribution circuit tie backup during a bank contingency. Reliability will improve even more after the construction of the Little Tor Station, which is still required to provide load relief for the circuits east of the New Hempstead Station, as well as Congers circuits, as well as west towards the Pomona load area. The New Hempstead upgrade will improve backup for adjacent substations, such as Burns and Tallman. This will allow the Burns circuits to continue to satisfy the Distribution Design Standards.

The two new 50 MVA banks, new switchgear and new UG circuits are all complete. The completion of the second cap bank is scheduled for November 2014. The current working estimate for this project is $17.3 million.

Please see Exhibit ___ (EIOP-E2) for New Hempstead Road Substation supporting maps and tables.

Line 551/562/ 563 Structure Replacements

There are 11 existing single and double circuit structures being replaced with four double-circuit dead end poles, three double-circuit suspension poles and two single-circuit dead end poles. The majority of the poles to be replaced are along the CSX railway (on CSX property) in the Town of Clarkstown. In general, the structures to be replaced in Clarkstown are in Valley Cottage (in the vicinity of Kings Highway) and in West Nyack (in the vicinity of Snake Hill road and Old Mill Road). There are also two structures being replaced on either side of the New York State Thruway. These poles were selected for storm hardening based on age, condition and proximity to critical infrastructure, *e.g.*, crossings of the CSX railway and the New York State Thruway.

The current working estimate for the combined projects is $3.6 million, with final work currently projected to be completed by year end, 2014.

South Goshen - Route 17A - Conversion

A long and exposed South Goshen circuit (Circuit 89-3-13) currently serves almost 1,200 customers with limited backup at peak time from adjacent substations (Shoemaker/Hartley Road, Chester) due to the distance. Although this area only has a current peak demand growth rate of 0.2%, growth rates exceeded 5% in 2006 as existing residential homes were upgraded and new developments were constructed. This circuit, as well as two other circuits (89-1-13 and 89-3-13), is fed from South Goshen Bank 189 which has been peaking close to its normal rating of 23.5 MVA.

South Goshen Bank 289 is a 35 MVA 69/34kV bank that currently serves only two 34kV circuits (Circuit 89-10-34 and Circuit 89-11-34). Although these circuits only feed approximately 250 customers each, they are the primary/backup feed to the small Pine Island Substation, as well as the backup for the Chester 34kV Bank 363. Circuit 89-11-34 serves the customers along Route 17A towards Florida while Circuit 89-10-34 feeds along Route 17M towards Chester. The two circuits tie on Reservoir Road.

Energizing the Hartley Road Station at the end of 2014 will provide significant load relief for South Goshen Bank 189, but the station will provide no relief for Circuit 89-3-13 or Bank 289. The relief provided by the Hartley Road Station will reduce South Goshen Circuit 89-1-13 to approximately 30 Amps.

This project calls for the conversion of Circuit 89-11-34 along Route 17A from the South Goshen Station to Reservoir Road from 34kV to 13kV. By converting this portion of the circuit and transferring the load to Circuit 89-1-13, a distribution tie will be created with South Goshen Circuit 89-3-13. This will allow the installation of automation to significantly improve reliability for the circuit/area. Although these circuits are currently fed from the same bank, they will be served from different banks when the future South Goshen Station Upgrade is completed. At this point, the remaining 34kV South Goshen circuit (89-10-34) and 34kV Chester circuit (63-9-34) provide 100% backup for each other in the event of a circuit or bank failure. With other distribution projects simply removing the load off the Pine Island Station, a failure on Line 90, which is the radial 34kV portion off the South Goshen feed, has 100% backup through step transformers off Westtown circuits.

This project also prepares distribution ties to the future West Warwick Station.

The current budgetary estimate for this project is $1.05 million.

This project is currently scheduled to be completed in June 2015.

Regular Projects over $1 Million

November 1, 2015 to October 31, 2016 (Rate Year 1)

Q. Please describe the major electric capital projects that are forecasted to be completed and booked to plant in-service during Rate Year 1.

A. A description of these projects follows:

<u>Blue Lake Substation and UG Distribution Circuit Exits</u>

Project Description - The Watchtower Group purchased the former International Nickel/Kings College Facility on Long Meadow Road in the Town of Warwick, NY and plans to relocate their global headquarters from its current location in Brooklyn, NY. Construction of the new facility is underway. The customer contacted O&R and requested (1) the decommissioning and demolition of the existing Blue Lake Substation and (2) the undergrounding of a section of Lines 981 and 982. Also, due to reliability concerns, the customer requested the construction of a new single 5 MVA bank substation to supply the estimated 2 MW load of the new complex. Lines 981 and 982 will serve the new Blue Lake Substation, as well as provide 100% transmission reliability. At a preliminary meeting, the Watchtower Group inquired if O&R had any interest in a joint substation.

This project proposes the relocation and upgrade of the Blue Lake substation for joint Watchtower Group and O&R use. A new site in or near the existing Line 981 ROW has been provided by the Watchtower Group to construct a new jointly owned substation (approximately 1200' northeast of the existing Blue Lake substation). The new substation will consist of a single 35MVA, 69/13.2kV transformer with a five-circuit switch gear. Two of the five circuit positions will be used to supply the customer (for redundancy) and the remaining three circuits will be used by O&R to support its distribution system load during normal and contingency conditions.

Project Background - The former Blue Lake Substation was a single 5 MVA, 69/4.16 kV O&R owned/maintained substation. The substation was served along a 69kV loop by Lines 981 and 982 between Lake Road (IBM) Substation and Ringwood Substation, respectively. This substation previously supplied the Kings College campus through two 4.16 kV circuits. Since the closing of King's College in 1999, Blue Lake served no customers and Bank 177 remained de-energized. There are no transmission breakers at Blue Lake on Line 981 and Line 982. For a fault on either line, breakers at the remote end substations of Lake Road and Ringwood would operate, resulting in the loss of both lines and the Blue Lake substation. For a permanent fault, manual switching is necessary to restore the substation.

The Sterling Forest Substation (Station #67) is a single 20 MVA, 69/13.2 kV, non-LTC bank station. The station supplies two 13.2kV circuits that serve the Sterling Forest/Tuxedo load area. Circuit 67-1-13 feeds 1,131 customers and has one 13.2 kV field tie to Sloatsburg Circuit 42-3-13. Circuit 67-2-13 is a radial feed supplying 57 customers. For contingency on Bank 367 at Sterling Forest, the auto loop between Circuit 67-1-13 and Circuit 42-3-13 will operate restoring approximately 411 customers. The remaining customers on Circuit 67-1-13 can be restored through field switching. Following the restoration of Circuit 67-1-13, Circuit 67-2-13 can be picked up through Circuit 67-1-3 at the field tie outside the station. It is difficult to provide adequate voltage support during this contingency, particularly during peak load periods, due to the large distance from Sloatsburg to the tail end of Circuit 67-2-13 (approximately 11.5 miles). As a result, a project has recently been constructed along Long Meadow Road to provide a distribution tie between Sloatsburg/Ringwood (eventually Blue Lake) and Sterling Forest Circuit 67-2-13, which will improve reliability for this single-bank station.

The Sloatsburg substation is a single-bank station with a 25 MVA 69/13.2 kV transformer that has an LTC. The station supplies three 13.2 kV circuits that serve the Sloatsburg/Hillburn/Ringwood load areas. Circuit 42-1-13 feeds 670 customers and has one 13.2 kV field tie to Ringwood substation circuit 78-1-13. Circuit 42-2-13 feeds 651 customers and has field ties to Hillburn substation circuits 17-1-13 and 17-2-13. Circuit 42-3-13 feeds 1,063 customers and has a field tie to Ringwood substation circuit 78-1-13. All three circuits tie at a transfer bus in the station. There are no transmission breakers at Sloatsburg on Line 311 and Line 31. For a fault on either line, breakers at the remote station of Harriman and Hillburn will operate, resulting in the loss of both lines and the Sloatsburg Substation. For a temporary or permanent fault, customers will experience a momentary interruption until supervisory switching from the control center can be done to restore the substation. For a contingency on Bank 242 at Sloatsburg, the auto-loop between the 42-3-13 and the 67-1-13 will operate restoring approximately 156 customers. The remaining customers can be restored through field ties from Ringwood and Hillburn substations. For this contingency, the Sloatsburg load can be supported thermally with no issues even during peak times but voltage support is difficult to provide since Ringwood, Hillburn, and Sterling Forest all contain non-LTC transformers.

The Ringwood substation is a single-bank station with a 25 MVA 69/13.2 kV non-LTC transformer. The station supplies two 13.2 kV circuits that serve the Ringwood load area. Circuit 78-1-13 feeds 2,028 customers and has one field tie to Sloatsburg circuit 42-1-13. Circuit 78-2-13 feeds 1028 customers and has one field tie to West Milford circuit 79-8-13. For a contingency on Bank 278 at

Ringwood, both circuits can be restored through distribution switching using the West Milford and Sloatsburg ties.

Project History/Deferral - The project was first identified in 2011 and then originally scheduled for 2014. Due to an extension in the customer's timeframe, the new in-service date is 2016.

Alternative Solution Screening - Being a customer driven project with a required in-service date within two years and low overall cost, this is not a viable project that can be deferred by non-traditional alternatives.

Project Benefits - The proposed Blue Lake Substation will provide capacity and increased distribution circuit availability to substantially improve load relief and contingency redundancy for the Sterling Forest, Ringwood, and Sloatsburg Substations. The design of the Blue Lake Substation will include transmission breakers, which will increase reliability in the 69 kV transmission loop. The load relief for the Sloatsburg Station (Bank 242) will minimize the number of interruptions in the event of a contingency on either Line 311 or Line 31. The Blue Lake transformer and distribution circuits will provide improved operating conditions and voltage profiles in the area for both normal and contingency conditions. The Blue Lake Substation, along with the distribution project recently completed along Long Meadow Road, will improve 100% backup for Sterling Forest Bank 367 in the event of a bank contingency. This eliminates the present need to install a future second distribution bank at the Sterling Forest Substation and defers the need to replace the aging Bank 367, as well as eliminates the need to install a mobile transformer at Sterling Forest when constructing the new Sterling Forest 138/69kV Tap project needed for area transmission reliability. For a contingency on Ringwood Bank 278, the Blue Lake Bank will increase backup capability from a stronger source (closer than Sloatsburg). Along with underground projects being constructed around the Ringwood Substation, which will solve for circuit contingencies, the improved backup from the Blue Lake Substation will defer the need of a second Ringwood Bank for additional five years (*i.e.*, until 2027).

The Electric Plant Additions estimate for this project is $6.7 million.

The current budgetary estimate for this project is $8.8 million. This project currently is scheduled to be completed in May 2016.

Please see Exhibit ___ (EIOP-E2) for Blue Lake Substation supporting maps and tables.

Central Rockland Smart Grid Automation

Project Description - The scope includes all engineering, estimating, material procurement, construction and supervisory control and data acquisition (“SCADA”) commissioning for each device location. All reclosers, switches and controlled capacitor banks will have SCADA capability and shall be operator controlled with the reclosers providing auto-loops for automatic isolation and restoration.

Project Background - The Central Rockland Smart Grid Automation project involves the installation of reclosers, switches and capacitors to provide automatic restoration and circuit optimization on fourteen 13.2 kV distribution circuits in the Central Rockland County, NY area. Specifically, it includes the installation of approximately 14 reclosers, 18 controlled capacitor banks, 14 fixed capacitor banks and 34 motor operated air break switches, with final numbers to be determined based on detailed engineering design. The circuits involved originate from the Burns, New Hempstead, Monsey, Snake Hill, Nanuet and Grand Ave Substations. Approximately 25,200 customers are served from these circuits and will benefit from the installed improvements. These improvements not only will provide increased reliability but will defer the need to construct a $40 million substation for the Central Rockland area. This project has been awarded a $2 million grant from the New York State Energy Research and Development Authority ("NYSERDA").

Project History/Deferral - Currently, in the event of a bank failure, both Burns Substation distribution banks meet the Distribution Design Standards of 60,000 customer hours of interruption. The 60,000 hours will be exceeded in 2019 due to the current area load growth of 2.4%. The Smart Grid equipment will reduce the customer hours of interruption to 32,000 in 2019 by utilizing the automated equipment and eliminating manual switching. An alternative to Smart Grid would be the construction of a substation and underground transmission facilities, at a cost of $40 million. The Smart Grid equipment defers that need from 2019 to 2029, resulting in a 25 year present worth savings of $7.4 million.

Alternative Solution Screening - A screening test was performed on the Central Rockland Station. With high cost, this project has potential for DG/DSM deferral. However, the project will first be deferred by the installation of Smart

Grid, with the future potential for additional deferral with DG/DSM to be evaluated.

Project Benefits - In addition to deferring the cost of the new substation, the installed Smart Grid automation will benefit the service area in terms of reliability during storms and other contingencies through the implementation of auto-loops, fault isolation and voltage control.

The Electric Plant Additions estimate for this project is $2.6 million, which does not include anticipated spending in the linking period.

The current budgetary level estimate for this project is $6.6 million. NYSERDA has granted an award of approximately $2.0 million to offset the costs of this project.

The project is scheduled to be completed in June 2016.

<u>Sterling Forest L26 Transmission Tap</u>

Project Description - The new transformer bank in the Sterling Forest Substation will be supplied by existing 138 kV Line 26, which currently passes near the Sterling Forest Substation site. The installation of this new 138-69 kV source will tie into the middle of the existing Sugarloaf to Hillburn 69 kV loop, and provide an additional 69 kV source into the loop. The project includes the installation of two 138kV line terminals, one 138 - 69kV, 175MVA Autotransformer, two 138kV gas circuit breakers, one 69kV gas circuit breaker, seven disconnect switches and one 138kV circuit switcher.

Project Background - The Sterling Forest 69 kV loop begins in the Eastern Division at the Hillburn Substation 69 kV Bus, and ends at the Sugarloaf 69 kV bus, which spans a distance of approximately 26 miles. Along this route, this loop serves seven distribution substations. Most of the substations along this loop continue to experience significant load growth. Although the load along this loop was experiencing a demand growth close to 5% in the 2006 timeframe, the current average growth has decreased to 1.2%. In 2006, most of the growth was residential load around Warwick and Greenwood Lake. As the residential load growth has moderated over the past few years, individual customers, such as IBM and Watchtower, are contributing to the load increase.

Summer studies indicated that the power flow on the remote ends of the loop, namely Line 993 and Line 89, would exceed their long-term emergency ratings by summer of 2008. Widespread low voltages will occur on the station busses mentioned above. Due to relatively high load growth in the area, power flow will continue to increase and low bus voltage will only worsen with time.

Project History/Deferral - Although the project was first identified in 2006, the original in-service date was June 2009. However, due to reduced load growths during the recent recession period and project need prioritization in 2008, the in-service date was moved to June 2012. To address the voltage violations at system peak with the loss of either Line 89 or Line 993, 16 MVAR capacitor banks were installed at the Ringwood Substation in 2009 and at the Wisner Substation in 2010. Capital budget re-prioritization in 2012 deferred the in-service date further to June 2016. The project has received approval from the Town of Tuxedo Planning and Zoning Boards.

Alternative Solution Screening - Although this project is to improve transmission reliability, a screening test for this project has still been performed to determine the possible application of energy efficiency and/or installation of distributed generation to defer the project. The practical need to improve transmission source reliability did not make this a practical solution for non-traditional alternatives. The large capacity deficit need and relatively low overall cost of the project did not make this a viable solution from a cost-benefit perspective either utilizing non-traditional alternatives.

Project Benefit - This project effectively will split the 69kV long loop into two shorter loops, and provide substantially improved supply capacity and reliability to the seven substations. This will allow the reliable operation of the transmission circuit in the area, particularly during peak contingency conditions, for a minimum of 25+ years.

The Electric Plant Additions estimate for this project is $8,810.3K.The current appropriation level estimate is $11.8 million.

Please see Exhibit ___ (EIOP-E2) for Sterling Forest Substation supporting maps and tables.

<u>Underground Line 51 Upgrade</u>

Project Description - This project proposes to replace the existing overhead 795 MCM ACSR portion of Line 51 with an underground transmission system increasing its thermal ratings by approximately 20%. Placement of this portion of Line 51 underground will eliminate two crossings of Line 51 over transmission Lines 52 and 60 in this area, thereby reducing the exposure to a triple circuit transmission outage. The increase in thermal ratings will make its operation more reliable at system peak even during emergency conditions for the next 20 years.

The Electric Plant Additions estimate for this project is $2.1 million which matches the Budgetary Estimate for this project.

This project is currently scheduled to be completed in June 2016.

Project Background - Line 51 is a 138 kV line that emanates from the Ramapo Substation (New York) and terminates at the South Mahwah Substation (New Jersey). Although the majority of its five-mile stretch consists of 1033.5 MCM ACSR, the limiting element is about a 900 foot section of 795 MCM ACSR just outside of the Ramapo Substation. Recent summer studies indicated that a contingency on South Mahwah 345/138 kV Bank 258 will load Line 51 slightly above its LTE rating. This situation will worsen with time, as the load in the area continues to grow.

<u>West Warwick Part 8 - (Blooms Corner – Ryerson to Waterbury)</u>

Project Description - This project will provide a mainline tie between two of the West Warwick circuits which will allow the installation of a loop scheme, improving reliability significantly for both circuits. Until the West Warwick Station is constructed in 2020, this project will improve switching capability for contingency conditions, as well as the construction of future projects.

The Electric Plant Additions spending for this project totals $1.4 million, which matches the budgetary estimate for this project.

This project is currently scheduled to be completed in July 2016.

Project Background - The Warwick Area is presently served by the Wisner Substation. The station is located at the extreme eastern end of the load area it serves, which is approximately 59 square miles and contains almost 8,015 customers. The Wisner substation contains two 25MVA 69/13.2kV transformers that feed five distribution circuits. In 2006, this area was rapidly growing. New developments were being constructed and old homes were being remodeled, which made the peak demand growth hit almost 9%. The growth rate has slowly decreased since then and has declined to 1.3% over the past two years. The normal rating for Wisner Banks 280 and 380 are 31.4MVA and 30.1MVA. For a contingency on either bank at peak time, the remaining bank and limited long distribution ties can assume most (97.8% for loss of Bank 280 and 100% for loss of Bank 380) of the station load in 2014. The five 13.2kV distribution circuits are heavily-loaded and extremely long, averaging over 350 Amps and 8.25 miles in length on mainline. The circuit has high exposure with multiple spurs, which cause the circuits to average over 35 circuit-miles each. In order to satisfy the Distribution Design Standards and provide 100% backup in the event of a circuit contingency, multiple switching moves are necessary due to the circuit loads and in order to prevent voltage problems on these long circuits. Although only one circuit presently does not satisfy the design standards (80-3-13), by 2016 four of the five circuits will not meet design standards. The construction of the West Warwick Station will ultimately provide the necessary load relief and contingency backup for the Wisner circuits and banks. However, there are limited mainline paths in this area and the distribution circuit improvements must be constructed first.

Regular Projects over $1 Million

November 1, 2016 to October 31, 2017 (Rate Year 2)

Q. Please describe the major electric capital projects that are forecasted to be completed and booked to plant in-service during Rate Year 2.

A. A description of the projects follows:

Line 562 and 563 CAT-1 and OPGW

This project proposes to replace the existing Transmission Line 562 (West Nyack to Snake Hill Road) and Transmission Line 563 (Snake Hill Road to Congers) shield wires, with new Fiber Optic Ground Wire ("OPGW"). Having a continuous OPGW path between the Congers, Snake Hill Road and West Nyack Substations will allow for state of the art relay protection and communication between these substations.

The Electric Plant Additions estimate for this project is $1.4 million.

The current budgetary estimate for this project is $1.5 million.

Ramapo 138kV Yard Breaker Replacements

The Ramapo Substation presently has eight 138kV circuit breakers in service. Three of the circuit breakers are Siemens SPS2's, an SF_6 puffer design, one was a replacement for a failed oil circuit breaker in 2007 and the other two were installed as part of the upgrade project in 2009. Four of the remaining five oil circuit breakers are McGraw Edison AHJ's 1968 vintage and one ITE 138KM model 1968 vintage. These oil circuit breakers have been in service for 46 years and are no longer supported by their manufacturers.

The Electric Plant Additions estimate for this project is $1.8 million which matches the budgetary estimate.

This project is currently scheduled to be completed in December 2016.

Ramapo Fire Suppression System Replacement

This project is an integral part of the Line 28 Transmission Project described above. In order for Line 28 to be constructed, a new bay needed to be constructed at the Ramapo Substation. As a condition for issuing the building permit, the Town of Ramapo required that the existing fire suppression system for Banks 1300 and 2300 be placed back into service or upgraded. As the existing fire suppression was no longer supported by its manufacturer, the Company agreed to install a modern fire/heat detection system. An additional condition requires the Company to install a new fire hydrant at the entrance to the substation for Fire Department use in the event of an emergency. This hydrant will be accessible from outside the substation fence line. The infrared heat detection system will automatically communicate to Rockland County Fire Control and the O&R Electric Control Center notifying first responders of an emergency in the station. This project includes the design and installation of these facilities.

The Electric Plant Additions estimate for this project is $1.6 million which matches the budgetary estimate for the project.

This project is currently scheduled to be completed in December 2016.

<u>Little Tor Road Substation and UG Distribution Circuit Exits</u>

Project Description - This project proposes the construction of the new Little Tor Substation that includes two 50 MVA, 138kV to 13.2kV transformer banks with LTCs and one 25 MVA, 13.2kV to 34.5kV transformer bank. The new substation will have 13.2kV switchgear with provisions for eight distribution circuits. Five of these circuits will be commissioned with the substation and the remaining three will be available for future use. One of the five circuits will be used to supply the 13.2/34.5kV, 25MVA transformer bank. Once the substation is energized, the 34.5kV line will be intercepted where it crosses the Little Tor site and be re-supplied from the 25 MVA transformer bank.

The design of the 138kV portion of the station will be a ring bus scheme. The 138 kV transmission source would be provided from an existing overhead transmission line (L541) which connects the West Haverstraw and Burns Substations, and crosses directly over the proposed Little Tor Substation site.

Project Background - The New City area is located between the New Hempstead, Congers, and West Haverstraw Substations. The average growth rate of these stations in 2006 was 2.7% but this has significantly decreased to 0.85% over the past year. These three substations and the temporary mobile transformer at Little Tor site serve a combined total of approximately 35,807 customers and 187 MVA of load at peak time. Approximately 45% of this load is supplied from the New Hempstead Substation and the Little Tor mobile transformer. In 2014, the New Hempstead Substation was upgraded to two 50MVA, 138kV to 13.2kV transformer banks. In addition, the number of circuit positions was increased from eight to ten. The 2014 weather-normalized ("WN") forecasted loads for these banks are 41.4 MVA and 34.6 MVA, respectively. With the new larger banks in service, both New Hempstead banks satisfy the Distribution Design Standards with no customer hours of interruption. At this time, the mobile transformer at the Little Tor site is carrying approximately 8.7 MVA of load at peak time. Circuits 45-3-13 & 45-8-13 are at or above their relief rating (480 Amps) and require cascade switching to provide backup at peak time, which forces both circuits to no longer satisfy the Distribution Design Standards.

The Congers Substation has two 35MVA, 138kV to 13.2kV transformer banks. The 2014 WN forecasted loads for both of these banks are below the nameplate rating with loads of 21.6 MVA and 27.7 MVA. With the mobile transformer at the Little Tor site, all of the Congers circuits have 100 percent backup for an individual circuit contingency.

The West Haverstraw Substation has two 35MVA, 138kV to 13.2 kV transformer banks. The 2014 WN loads for West Haverstraw Banks 127 and 227 are 31.8 MVA and 21.4 MVA respectively. The substation supplies a total of eight circuits (four from each bank). Circuit 27-2-13 supplies 2,416 customers including a 13.2/34.5kV transformer that feeds a dedicated overhead line to a single customer. This overhead line travels south along the transmission ROW approximately 7,000 feet from West Haverstraw to the Little Tor substation site. At this point, the line continues east an additional 19,000 feet to the customer. Due to the length and route that this circuit takes, it has a high exposure to tree contacts and other reliability issues. These outages increase the number of momentary outages customers on the circuit experience. In the event of a contingency on Circuit 27-2-13, there is not enough available capacity to cover 100% of the circuit's load. Therefore, Circuit 27-2-13 does not satisfy the Distribution Design Standards.

Project History/Deferral - In 2002, the Company identified the need to upgrade/provide load relief to the New Hempstead Substation with both banks exceeding normal rating. Due to the inability to off-load New Hempstead for construction, a new substation was proposed at the site of a former O&R station at the intersection of Little Tor and South Mountain Road. This new substation will allow for the offload and rebuild of the New Hempstead Substation and provide load relief and improved reliability to New Hempstead, Congers, and West Haverstraw Substations. The original year needed was 2007. By 2007, higher priority projects and significant public opposition continued to delay the Little Tor Substation. At that time, Little Tor was budgeted to be in service by June of 2009 and the New Hempstead upgrade was scheduled to be in service by June of 2011. Strong public opposition continued to delay the Little Tor Substation during this timeframe.

In October 2011, a Rockland County road widening project along New Hempstead Road was scheduled to begin in 2012. This project eliminated one of the New Hempstead circuits on New Hempstead Road and forced an existing triple circuit to be rebuilt as a double circuit. This forced the need to install a mobile transformer at the Little Tor Site to replace the circuit removed from New

Hempstead. With the Company forced to change its path, a new plan was developed to utilize the capacity from the mobile transformer and rebuild New Hempstead one bank at a time. The revised plan allowed for the reconstruction of New Hempstead to new larger banks and two additional circuit positions. In June 2012, Mobile 3 was installed at the Little Tor Substation Site and carried approximately 11.4 MVA of former New Hempstead load. Work commenced at the New Hempstead Substation in 2013, and the upgraded New Hempstead banks were placed in-service in June 2014.

Alternative Solution Screening - Many screening tests have been performed for this project to determine the possible application of non-traditional alternatives to defer the project. Since this project was required to unload New Hempstead for construction in earlier years, it was not a candidate for deferral as initially determined. At its current state, as evidenced by the existence of the mobile still needed to provide core delivery service and the distribution circuit reliability needs that can only be satisfied through traditional infrastructure improvements, this project is not a viable candidate to be solved by the installation of non-traditional alternatives.

Project Benefits - The two 50MVA transformer banks at the Little Tor Station will provide 100% station backup in this area for over 30 years. The new 13.2kV distribution circuits that will be served by the Little Tor Substation will provide sufficient capacity for future load growth and provide load relief and backup for the heavily loaded New Hempstead, Congers, and West Haverstraw circuits.

Although the upgrade of the New Hempstead Substation allowed New Hempstead to satisfy the Distribution Design Criteria, the new Little Tor Substation will provide load relief and backup for New Hempstead Circuits 45-3-13 and 45-8-13, which will allow both circuits to meet the design standards. Providing distribution backup from another source will allow the installation of loop schemes, which will significantly improve reliability for the area. The construction of the Little Tor Station will allow for the removal of the 40MVA mobile transformer currently at the site to be repurposed for use as its intended function at other locations for either contingency conditions or construction assistance.

The Electric Plant Additions estimate for this project is $13.4 million.

The current budgetary estimate for this project is $18.5 million. This project is currently scheduled to be completed in June 2017.

Please see Exhibit ___ (EIOP-E2) for Little Tor Substation supporting maps and tables.

Transmission Line 702 Upgrade

Project Description - The upgrade of this line will require the replacement of approximately five miles of 556 ACSR conductor with 1272 ACSS conductor increasing the thermal ratings of Line 702 by approximately 170%. The Company is currently looking into the feasibility of replacing the conductor on this line utilizing many of the existing wood pole structures. Since the applicable construction codes have changed considerably since the line was constructed, this upgrade likely will require some structural modifications, and may require extensive structural modifications and/or total structure replacements. If full scale pole replacements are necessary, the cost of this project will increase considerably from the budgetary estimate provided below. There may also be significantly increased environmental protection requirements during project construction.

Line 702 currently has two conventional Alumoweld shield wires for lightning protection. This project proposes to re-conductor one of the existing shield wires with a new OPGW between the Burns and Harings Corner Substations. This new OPGW will tie to the tap of Line 702 (in Orangeburg) and extend underground to the new Corporate Drive Substation on the Verizon Wireless property in Orangeburg, New York.

Project Background - Line 702 is a 138kV transmission line running from the Burns Substation in Spring Valley to the Corporate Drive Substation in Orangeburg, NY. The Company’s planning process has identified that the loss of Line 561 (138 kV line between Bowline and Congers station) will load Line 702 above its LTE rating. Through the Company’s Datacenter Action Resource Team’s (“DART”) efforts, the Company has connected additional data center load to the Corporate Drive substation. Any new developments and load additions in this area will have the potential to add significant additional demand to Transmission Line 702. Very limited load transfers to adjacent stations are available, particularly under contingencies, to offload the transmission system. If the overloading persists, load shedding will commence to prevent further damage to the conductor. The limiting portion of Transmission Line 702, which is between the Burns Substation and West Nyack Substation, originally was constructed with wood poles in the 1960s and 556 ACSR conductor.

Project History/Deferral - The original plans were to construct a 138kV loop from Lovett to West Nyack. This would require the need to upgrade Lines 55 and 551, as well as any in-series stations, to 138kV. This would provide a 138kV loop to West Nyack which would provide transmission backup for Snake Hill Road Substation and Congers Substation. Another series of projects were planned to create a 138kV loop through Bergen County to the Harings Corner Substation. This would require the upgrade of several lines and in-series stations to 138kV. Although the loop would provide transmission backup for Harings Corner and Corporate Drive, there would still be a significant 69kV load pocket between these two isolated 138kV loops. By replacing the two originally proposed 138kV loops with four projects (Line 702 Upgrade, Harings Corner 138kV Yard, West Nyack 138kV Yard, and Line 701 Upgrade), a single 138kV loop would form between West Nyack and Harings Corner. The same stations (Corporate Drive, Congers, Snake Hill Road, West Nyack, and Harings Corner) would still benefit with 138kV transmission backup, the 69kV load pocket would be significantly reduced, and transmission losses would be improved. Therefore, numerous projects (Line 55/Line 551, several lines through Bergen County, and all the in-series stations) would either be eliminated or deferred for a long time. This results to a PW savings over $64.5 million. The original completion date was June 2014. Due to capital budget project prioritization, the in-service date has been rescheduled to June 2017.

Alternative Solution Screening - This project is part of a sequence of projects with the Harings Corner 138kV Yard, West Nyack 138kV Yard, and Line 701 upgrade projects. The combination of all these projects will improve transmission reliability. With these projects required for transmission reliability, they are not candidates be replaced or deferred through non-traditional alternatives. As additional large loads (*e.g.*, Data Centers) are connected within this load area, there are several contingencies that will result in either voltage problems or load shedding. This would require significant load reduction in multiple locations. Deferring these projects any longer will require additional projects in order to serve the load and handle contingency conditions while constructing.

Project Benefits - The increase in the thermal ratings will make the operation of Line 702 more reliable, especially during system peak for the next 30 years. Along with other future projects (Harings Corner 138kV Yard, West Nyack 138kV Yard, and Line 701 Upgrade), a 138kV loop will be completed. This will provide a 138kV backup for Corporate Drive, Harings Corner, West Nyack, Snake Hill, and Congers Substations, while significantly reducing the 69kV load pocket and improving transmission losses. A continuous OPGW in-service linking the Burns, Corporate Drive and Harings Corner Substations will allow for state of the art relay protection and communication among these stations. It also will allow the Company's Energy Control Center at its Spring Valley Operating Center ("SVOC") to communicate directly through the Company's own fiber optic path with these three substations via this new OPGW.

The Electric Plant Additions estimate for this project is $9.2 million.

The current budgetary estimate is $0.4 million and assumes that the existing structures will require some modifications and reinforcement, but no full scale structure replacements. This budgetary estimate also does not factor in any increased environmental protection requirements. More extensive and detailed engineering will determine the final project scope and any additional changes that will be required to the scope, estimate and schedule.

This project is currently scheduled to be completed in June 2017.

Please see Exhibit ___ (EIOP-E2) for Line 702 upgrade location map.

Regular Projects over $1 Million

November 1, 2017 to October 31, 2018 (Rate Year 3)

Q. Please describe the major electric capital projects that are forecasted to be completed and booked to plant in-service during Rate Year 3.

A. A description of these projects follows:

<u>West Warwick Part 9 - (Newport Bridge – Blooms Corner to Amity Road)</u>

Project Description - This project will continue off the West Warwick Part 8 project (Blooms Corner), described above, and provide a mainline tie between two of the West Warwick circuits which will allow the installation of a loop scheme and reliability will significantly be improved. Until the West Warwick Station is constructed in 2020, this project will improve switching capability for contingency conditions, as well as the construction of future projects.

The Electric Plant Additions estimate for this project is $1.2 million which matches the budgetary estimate for this project.

This project is currently scheduled to be completed in January 2018.

Project Background - The Warwick Area is presently served by the Wisner Substation. This substation is located at the extreme eastern end of the load area it serves, which is approximately 59 square miles and contains almost 8,015 customers. The Wisner substation contains two 25MVA 69/13.2kV transformers that feed five distribution circuits. In 2006, this area was rapidly growing. New developments were constructed and old homes were being remodeled, which made the peak demand growth hit almost 9%. The growth rate has slowly decreased since then and has declined to 1.3% over the past two years. The normal rating for Wisner Banks 280 and 380 are 31.4MVA and 30.1MVA. For a contingency on either bank at peak time, the remaining bank and limited long distribution ties can assume most (97.8% for loss of Bank 280 and 100% for loss of Bank 380) of the station load in 2014. The five 13.2kV distribution circuits are heavily-loaded and extremely long, averaging over 350 Amps on the high phase and 8.25 miles in length on mainline. The circuits are heavily exposed with multiple spurs, which cause the circuits to average over 35 circuit-miles each. To satisfy the Distribution Design Standards and provide 100% backup in the event of a circuit contingency, multiple switching moves are necessary due to the circuit loads and in order to prevent voltage problems on the long circuits. Although only one circuit presently does not satisfy the design standards (80-3-13), by 2016 four of the five circuits will not meet them as well. The construction of the West Warwick Station will provide load relief and backup for the Wisner circuits/banks. However, there are limited mainline paths in this part of the area and the circuits must be constructed first.

Wurtsboro Substation

Project Description - This project proposes to upgrade the existing Wurtsboro Substation to a two-bank station (2-35MVA) with six distribution circuits (eight positions) to provide additional circuit capability and improve reliability for the area. After the feed to the Station (Line 6 and Circuit 5-3-34) is upgraded to 69kV in the future, a third 69/34.5kV transformer will be added to maintain the 34.5kV feed to Summitville.

Project Background - The Wurtsboro Substation is a single-bank station that serves approximately 2,160 customers near the end of the Company's service territory. Normally fed by Circuit 5-3-34 out of Cuddebackville at 34.5kV, the Wurtsboro Substation contains a single 5MVA 34.5/4.8kV bank (Bank 29) that feeds two long distribution circuits. Line automation is used to provide a loop scheme for an automatic backup from a long exposed 34kV circuit out of Washington Heights (Circuit 109-4-34). Being one of the only two stations remaining at 4.8kV, any ties to adjacent 13kV stations are limited since they must go through step transformers. Although Bank 29 only peaks at 3.6MVA, all of the backup in the event of a bank failure is through two sets of step transformers from the tail-end of the primary/backup 34kV circuits that feed the station. These steps are only capable of providing 66.9% backup at peak time: a portion of the customers would be out of service until the transformer is either replaced or repaired, and the average customer-hours of interruption on a summer peak day would be approximately 12,175. With most of the Wurtsboro area using electric heat, the winter load is approximately the same as the summer peak. With no LTC on Bank 29, voltage operating conditions are challenged, particularly during contingency conditions. This requires voltage support along the 34kV lines and 4.8kV distribution circuits to cover both normal, as well as contingency, conditions. The 600 Amp bus switch, which limits the bank to 5MVA, prevents the capability of using the bank's emergency ratings. As one of the three remaining stations without supervisory control, this station also lacks communication. Therefore, breaker control and status of conditions requires sending a crew. The Wurtsboro Station also has M.A.D. issues which require the breakers for both circuits to be opened for clearance when performing work/maintenance. Since this is the same circumstances as a bank contingency, the window for maintenance is very limited. At the existing Wurtsboro Station, each circuit exits off the 4.8kV bus to their respective regulator with 250 MCM, which has a rating of 345 Amps. The 2014 forecasted load for Circuit 9-1-48 is 346 Amps (Circuit 9-2-48 is only 102 Amps) and due to bottleneck, there is no way to transfer a small section to Circuit 9-2-48. The two 4.8kV distribution circuits feed an isolated 4.8kV load pocket and along with the existing step-down transformers off the 34kV station feeds, have close to 100% backup in the event of a circuit contingency on the head-end of the circuit. However, Circuit 9-1-48 extends a significant distance along CR 172 to serve several large radial feeds (Yankee Lake, Masten Lake, and Wurtsboro Hills) where the only backup is from an adjacent station tie (Summitville) through a step transformer. With minimal backup for this portion of Circuit 9-1-48, this circuit does meet the design standards.

Project History/Deferral - Although the Wurtsboro Substation upgrade was identified in 2004 to improve the reliability of the 4.8 kV load pocket in the area, the original need date of the station upgrade was 2009. The original plan for this project in 2009 was to upgrade the existing 34 kV sub-transmission system to 69 kV. The station would have been fed from this converted 69 kV source with two 35 MVA 69-13.2 kV banks and six additional circuits, and a single 69-34.5 kV bank to feed Summitville station. In 2012, without progress in the conversion of the 34.5 kV system to 69 kV, the upgrade of the Wurtsboro station was delayed until 2018. The Company deferred the project by accepting increased risk based on the severity of the exposure in relation to other higher priority projects.

In 2013, the plan is for the station to be designed for 69 kV but operated at 34.5 kV, consisting of two 35 MVA 69/34.5-13.2 kV banks and a position for future 69-34.5 kV bank to feed Summitville Station. In 2014, distribution projects are being constructed in preparation for distribution circuit paths for the station upgrade. A current distribution project is being constructed along CR 172 to split this single feed into two circuits (remain on one feed until station is upgraded) and prepare another set of step transformers off the 34kV station feed (Line 3) for backup. This will provide load relief for Circuit 9-1-48 and improve backup for a circuit contingency, as well as a bank contingency, prepare paths for future circuits, and set the stage for future projects to provide backup for the large radial fed spurs. The distribution project will improve bank backup to

100% until the station is constructed in 2018. However, the limiting element(s) of the distribution circuit feed and reliability issues of the station will still be the driving force for the station upgrade. In the event of a contingency on the step transformers off Line 3 (or Line 3 itself), which just provided relief for the heavily-loaded Circuit 9-1-48, there would be no backup for the 4.8kV circuit, and the customers would be out of service until repairs are made. Along with the circuits, the construction of the station will be the other driving force to keeping this station on schedule. Although the distribution projects under construction appear to be able to defer the substation, it will already be extremely difficult to unload the station that has poor reliability without a mobile transformer to assist. Deferring this project will only require additional construction expenses.

Located at the end of the service territory, this area needs significant reliability improvement. The two Wurtsboro circuits are consistently in the top 40 worst performing circuits, while the 34.5kV primary/backup feeds have been in the top 20.

Alternative Solution Screening - After the construction of the distribution project along Sullivan Avenue (double circuit), a small amount of MW reduction is required to defer the project. However, due to reliability issues, this is not a viable project to defer any longer. The station has M.A.D. issues, a bus switch that limits the capability of the bank, no LTC on the bank, no supervisory control of the station, no telemetry readings, and no mobile transformer capable of serving the 34.5/4.8kV voltage. A combination of all these issues has made this area one of the worst performing portions of the system with respect to reliability, and this project is not a viable candidate for resolution by non-traditional alternatives.

Project Benefits - With the capability of expanding the existing Wurtsboro site, constructing a two-bank (2-35 MVA) station will improve bank backup to 100% for over 50 years. Designing the station for 69kV and installing dual banks will prepare the station for future operation at 69kV but still allow the station to operate at 34.5kV. This will prevent the need to rebuild the station when the time is needed to upgrade the transmission lines to 69kV (estimated time is 2026). At this time, only a 69/34.5kV bank will need to be added (position already designed) for the feed to Summitville. The two new distribution banks will have LTCs, which will maintain a station voltage under all conditions and reduce the need for voltage support along both the 34kV feeds and regulators on the distribution circuits.

The additional bank capacity and spare circuits will be available for future load growth. Located just off Route 17 (I86), this area has been investigated for several large customers such as warehouses, new developments, ski resorts, and many hotels with the possibility of a nearby casino. The station will be designed with transmission protection, which will eliminate the need of the 34kV loop scheme on the long circuits. The additional distribution circuits will significantly improve reliability for the area, especially Yankee Lake and Masten Lake. Operating at 13kV will allow ties to adjacent stations, such as Summitville, and even Bloomingburg and Cuddebackville which will greatly improve area reliability.

The new Wurtsboro Substation will have both communication and supervisory control. This will allow the ECC to see the status of the breakers and have control to operate breakers under contingency conditions, and be capable of monitoring the loads/voltages on all feeds/circuits at the station, which will eliminate the need of calling crews for this purpose. This will significantly improve restoration. The new station design will eliminate M.A.D. issues and the limiting 600 Amp bus limiting switch. Along with the second bank and additional capacity, this will improve the opportunity for maintenance, which will improve station reliability.

The Electric Plant Additions estimate for this project is $10.5 million.

The budgetary estimate for this project is $12.2 million.

This project is currently scheduled to be completed in June 2018.

Please see Exhibit ___ (EIOP-E2) for Wurtsboro Substation upgrade supporting maps and tables.

Deerpark Substation

Project Description - The Deerpark Substation project proposes the installation of two 50MVA, 69/34.5kV transformer banks with LTCs and a 34.5kV switchgear lineup with six circuit positions. These two 69/34.5kV transformers will feed Line 10 back to Cuddebackville, two feeds (a future third) to Pike County, and the temporary 34kV feeds to the Port Jervis Station along Line 10 and Line 111 until the upgrade of Port Jervis is completed. The project will also include a 35MVA 69/13.2kV bank with initial plans for a single circuit exit that will the circuit load presently be fed from Mobile #6.

Project Background - The 34kV Port Jervis load pocket is served by three sources: Rio Bank 53, Line 10 out of Cuddebackville, and Line 111/Bank 2103 out of Westtown. These three sources feed Port Jervis Bank 26, Rio Circuit 3-1-34, the Line 10 customers along Route 209, and the entire Pike County system (Matamoras Station and Line 7). This is a total of 13,815 customers. At the 2014 system forecasted peak load of 1630 MW, this load pocket is approximately 54 MW. For a contingency on Line 111/Bank 2103 at peak time, the remaining lines (Line 18 and Line 10) would reach their normal rating and circuits would reach their minimum allowable voltage operating limit. Within the next year or two, this contingency at peak time could require load shedding. The Deerpark property is 7.5 acres and was purchased in 2007.

Project History/Deferral - The Deerpark project was first identified in 2006 when it was required to provide 100% backup for the single 69/34 kV bank for the Port Jervis station upgrade due to the limited station footprint, since there was no room to install four banks (two 13 kV banks and two 34 kV banks) at the existing Port Jervis site. The current in-service date for the Port Jervis station upgrade at this time was 2009 while the Deerpark station was scheduled for 2012. With this arrangement, O&R was willing to accept the risk of a bank outage for three years since Line 18 and Line 10 can only provide 100% backup for 94% of the year. In 2009, the in-service date of Deerpark Substation was moved to 2017. With Port Jervis still meeting design standards but the distribution ties no longer capable of providing 100% backup throughout the year, the Company planned to install only one 69-34.5 kV bank at Port Jervis (three banks total) and live with the risk for a few years until Deerpark Station is constructed in 2017 for the needed backup allowing additional space at the Port Jervis site. In 2013, Port Jervis station upgrade was moved to 2020 while the Deerpark Station was moved to 2018. Space limitations at the Port Jervis property and the need to have two 69-34.5kV banks forced an engineering re-design of the projects.

The plan has been altered to install two 13 kV banks at Port Jervis and the two 34.5 kV banks to be installed at the Deerpark Station. Since additional sources will be required to unload Port Jervis for construction, a third 13 kV transformer bank will be installed at Deerpark. With the adjustments of the Distribution Design Standards in 2012 to accept 60,000 customer-hours of interruption for a bank contingency, Port Jervis continued meeting design standards. In December 2013, a failure on the 35 MVA 69-34.5 kV Rio Bank 53 occurred causing a major outage. By March 2014, a mobile transformer fed off the 69 kV line at Deerpark site was installed that allowed the largest available transformer bank (18 MVA 69-34.5 kV) to replace the failed Rio Bank 53 and also to cover all system contingencies in the area. A 35MVA replacement bank could not be used due to cost to transport and poor condition of the bridge leading to the substation.

Alternative Solution Screening - Deferring the Deerpark Substation would defer the Port Jervis Substation. Similar to Wurtsboro, the Port Jervis Substation has M.A.D. issues, a bus switch that limits the capability of the bank, no LTC on the bank, and no telemetry readings. A recently purchased mobile transformer can cover an outage on the 34/13.2kV Port Jervis bank. A combination of all these issues has made this area one of the worst performing portions of the system with respect to reliability, and the Port Jervis and Deerpark projects are not viable candidates for resolution by non-traditional alternatives. The Port Jervis station should not be deferred any longer, and thus, the Deerpark Station cannot be deferred.

Project Benefits - When the Port Jervis upgrade is completed, this will significantly reduce the load pocket. Along with the closed 69kV transmission loop, which will improve transmission reliability, the 35MVA 69/13kV bank at the Deerpark Substation will provide a strong source for the unloading of the Port Jervis Substation while the station is upgraded. The two 34kV Deerpark banks will unload the 34kV bus at Port Jervis and serve the Pike County area. As proven by Mobile #6 in the summer of 2014, the 69/13kV Deerpark bank will provide load relief and backup for Port Jervis Bank 26 and Circuit 6-8-13. The load relief provided for Bank 26 will allow the bank the capability to provide backup for Matamoras Bank 1104 in the event of a bank contingency at peak time, which will allow the bank to meet the design standards. Circuit 6-8-13, which is one of the worst performing circuits due to the number of interruptions on the heavily exposed circuit that serves over 3,100 customers, will receive needed relief and backup. The 69/34.5kV 50 MVA Deerpark banks will split the load/exposure on Circuit 5-10-34. This will reduce the exposure and load on the circuit, which will allow Deerpark to provide a stronger backup for Cuddebackville Bank 15 in the event of a bank failure at peak time. Once the Port Jervis Substation is upgraded and the 69kV loop is completed, the two

69/34.5kV Deerpark banks will simply provide a feed for the Pike County system, as well as backup for Bank 53, for Rio Circuit 3-1-34.

The Electric Plant Additions estimate for this project is $16.5 million.

The current budgetary estimate for this project is $19.7 million.

Please see Exhibit ___ (EIOP-E2) for Deerpark Substation upgrade supporting maps and tables.

North Rockland Substation

Project Description - The Company will install a 400-MVA 345/138 kV Autotransformer Bank to be electrically connected to the existing 345 KV Line Y88 owned by Con Edison. A ring bus configuration will be electrically connected to Con Edison’s 345 kV Line Y88 to accommodate the 400 MVA 345/138 kV transformer bank. A 138 kV line will be constructed from this station and will be connected to the 138 kV bus in the existing Lovett Substation.

Project Background - O&R planned several system improvements following the retirement of the Lovett Generating Station in 2008. The first phase of the system improvements was the re-conductor Line 60 (138 kV line from Ramapo to Tallman) referred to as “Rockland County Transmission Project” completed in May 2007. The second phase was the installation of capacitor banks inside the Company’s Eastern Load Pocket (“ELP”) to supply the needed reactive power for voltage support (32 MVARS at Closter Substation in 2007, 32 MVARS at Snake Hill Substation in 2012, and 32 MVARS at New Hempstead Substation in 2014). The Company plans to install additional capacitor banks on new and existing distribution station within the ELP in the next several years. The third phase is the installation of a 345-138 kV source connection from the bulk power system ("BPS") to the ELP. Following the New York Independent System Operator ("NYISO") 2010 Reliability Needs Assessment ("RNA") study, it was determined that there will be a security violation in the O&R system at system peak with the simultaneous loss of Lines 67 & 68 (single tower failure of the 345 kV lines from the Ladentown transmission station to Bowline generating station). For this N-1 contingency, Line 60 and Line 652 (a 69 kV feeder from the South Mahwah Substation to the Upper Saddle River Substation) will be loaded substantially above their long term and short term emergency ratings that will result in load shedding of about 50,000 customers in the ELP to prevent further conductor damage and eventually further outage.

Project History/Deferral - As mentioned earlier, Line 60 was upgraded in 2007, and several station capacitors have been added in the ELP to maintain system reliability since the retirement of the Lovett Generating Station. In 2007, just prior to the Lovett Plant retirement, the original in-service date for the North Rockland 345kV Station was identified for June 2013. In 2010, the NYISO's RNA determined a security violation in the O&R system with the simultaneous loss of Line 67 and Line 68 due to the common tower circumstance.

In 2012, due to lower load forecast and project re-prioritization, the in-service date of this project was deferred to June 2018. The 2013 NYISO Area Transmission Review ("ATR") study results revealed that, by tapping Con Edison's 345 kV Line Y94, various N-1-1 contingencies will overload North Rockland 345 kV Station. Con Edison did not allow the provision for a Special

Protection Scheme ("SPS") to disconnect the North Rockland Transformer Bank at this emergency condition. With this limitation, O&R was forced to change the Point of Interconnection ("POI") from Con Edison's Line Y94 to Line Y88. The revised System Impact Study ("SIS") is presently underway, as is the Company's internal scoping and feasibility study for the actual site construction.

Alternative Solution Screening – An extensive and detailed screening test for this project had been performed in 2000, and again in 2010. The extensive amount of capacity relief needed, as well as the need for transmission reliability from a BPS source makes this project not viable to be solved utilizing non-traditional alternatives.

Project Benefits - The proposed 345/138 kV substation will provide another interface into Orange and Rockland's eastern division, particularly the ELP and will relieve the loading on the remaining 400 MVA 345/138 kV transformer banks during normal operation. The North Rockland Bank solves overloading issues on Line 60 and Line 652 for 30+ years. The reactive power from the bulk power system flowing through the North Rockland Bank will mitigate voltage problems on the various 138 kV and 69 kV eastern division busses at various single contingency conditions during the summer peak.

The Electric Plant Additions estimate for this project is $30.4 million.

The current budgetary estimate for this project is $42.4 million. This project is currently scheduled to be completed in June 2018.

Please see Exhibit ___ (EIOP-E2) for North Rockland Substation location map.

Q. Please describe the major electric capital projects that are forecasted to have significant spending in the rate period but will be in service after October, 2018?

A. A description of these projects follows.

<u>Ramapo Bank 1300 Replacements</u>

Transformer Banks 1300 and 2300 at the Ramapo Substation are comprised of six single phase units rated at 345 - 138 kV, 120 MVA and have been in service for over 40 years and need to be replaced by six single phase replacement units The transformers were manufactured by Westinghouse. Each unit is equipped with UHT type LTC. Each LTC holds approximately 2600 gallons of dielectric fluid. Over their life the units have had a poor operating history requiring constant leak repair. Approximately six years ago all of the tap changer door gaskets were replaced to mitigate leaking. Earlier this year a leak on a low voltage (138 kV) bushing was repaired.

Over the years the dielectric fluid leaks have necessitated a major environmental cleanup. To date the current environmental remediation has cost $160,000 and the estimate to complete this effort is an additional $150,000 to $400,000 depending on the extent of the contamination.

Since 2002 approximately 1,200 man-hours have been spent on the maintenance and repair of these units.

The Capital Expenditures exhibit contains spending for $9.94 million.

The current budgetary estimate for this project is $10.5 million.

This project is currently scheduled to be completed in December 2018.

West Warwick Substation, Underground Distribution Circuit Exits

Project Description - This project proposes the construction of a new substation in the West Warwick area, in the Town of Warwick, New York. Due to significant load growth that has already developed on the local electric delivery system in this area, and continued projected load growth, the Company determined that a new substation in this area is required. This new substation will be a 138 – 13.2 kV station, consisting of two 50 MVA transformer banks and the capability for eight new distribution circuits. The new circuits will exit underground from metal-enclosed switchgear. The Company is also presently exploring different options for the required transmission feed to this new substation. The Company presently believes that an overhead transmission option may be available that can be extended from the Sugarloaf area into the Warwick area. More extensive and detailed engineering will determine the final project scope and any additional changes that will be required to the scope, estimate and schedule.

Project Background - The Warwick Area is presently served by the Wisner Substation. The station is located at the extreme eastern end of the load area it serves, which is approximately 59 square miles and contains almost 8,015 customers. In 2006, this area was rapidly growing. New developments were being constructed and old homes were being remodeled, which made the peak demand growth hit almost 9%. The growth rate has slowly decreased since then and has declined to 1.3% over the past two years. With the amount of open land and plans for development, forecasted growth rates are expected to reach 3%

within the next two years. The Wisner station is served by two 69kV transmission lines: one from Sugarloaf and one from Hunt. Without transmission breakers to protect the station in the event of a contingency on either line, the entire station would be out of service until System Operations sectionalizes the faulted line and restores the remaining feed to the station by supervisory control. The Wisner Substation contains two 25MVA 69/13.2kV transformers without LTCs that feed five distribution circuits. The normal rating for Wisner Banks 280 and 380 are 31.4MVA and 30.1MVA, respectively. However, the 1275Amp 13.2kV bus and 1200 Amp 13.2kV bus disconnect on Bank 280 limits the bank’s rating to only 27.4MVA. For a contingency on either bank at peak time, the remaining bank and limited long distribution ties can assume most (97.8% for loss of Bank 280 and 100% for loss of Bank 380) of the station load in 2014. By 2019, a contingency on Bank 280 would reduce to 91.7% backup. Although a contingency on Bank 380 would still have 100% backup in 2019, Bank 280 would only be capable of providing 5% backup and therefore require the distribution ties to assume the remaining load. Since there is no automatic transfer scheme, the load cannot be assumed by the remaining bank until field personnel arrive to switch. Due to switching time and growth, a contingency on Bank 280 at peak time in 2019 would cause approximately 18,000 customer-hours of interruption. With both banks being fed from the same 69kV bus, a single contingency on this bus would force both banks out of service. At peak time, it would be difficult to assume 30% of the entire station load through distribution ties. This would leave almost 5,800 customers out of service until repairs are made. The five 13.2kV distribution circuits are heavily-loaded and extremely long, averaging over 350 Amps on the high phase and 8.25 miles in length on mainline. The circuits are heavily exposed with multiple spurs, which cause the circuits to average over 35 circuit-miles each. To meet the Distribution Design Standards and provide 100% backup in the event of a circuit contingency, multiple switching moves are necessary due to the circuit loads and in order to prevent voltage problems on the long circuits. Although only one circuit presently does not meet the design standards (80-3-13), this will increase to four by 2016. The Pine Island Station is a small station that consists of a single 3MVA 34.5/4.8kV transformer and two 4.8kV distribution circuits. The station is fed from a 34.5kV "distribution circuit" out of South Goshen. A second 34.5kV circuit from South Goshen is also looped to this circuit in order to provide backup for the Pine Island feed. From the South Goshen Station to where they meet, the two 34.5kV circuits run along the road. From this point to the Pine Island Station, the feed is mostly along a R.O.W. off the road and difficult to access. For a contingency on this 34kV feed or the Pine Island bank, the entire station has backup through two sets of step transformers off a Westtown circuit.

Project History/Deferral - The project was first identified in 2004. At that time, the Warwick area was experiencing high growth rates (6%) and the original plan was to upgrade the two 25 MVA Wisner banks with larger transformers and more circuits. Unable to unload the station for clearance and the need to reduce the long exposed circuits, a new station was therefore needed. The original need date for the West Warwick Station is in 2011. The new 69 kV station will have two 50MVA banks and eight circuits would be constructed to split the Wisner load area. The station will be served by a 69kV underground transmission loop from the existing 69kV loop out of Wisner through the Town of Warwick since O&R had no other transmission in area. Other than the mainline of the current Wisner circuits, there are minimal 13kV distribution ties in the area and therefore several distribution projects should begin to prepare for circuit paths once property is located. In 2010, the project was pushed out to 2014 in the budget due to a reduction in the growth rate and higher priority projects, such as Hartley Road and Sugarloaf. In 2011, it was further moved to 2015. At that time, the property for the station was purchased and identified Central Hudson's overhead 115kV D&J Lines as a possible source to feed the station. Utilizing these Central Hudson lines to provide a 138kV feed from the Sugarloaf Station will eliminate the need for the expensive underground through Warwick while providing backup for the transmission system in the area from a different source, as well as significantly reducing losses. In 2014, due to Central Hudson's transition to new management, limited progress on the D&J lines negotiations has been made. Therefore this project has been pushed outside the five year budget (2020). Although the growth rate is beginning to increase, the Company can handle a contingency on a single bank or circuit. With the two banks not having LTCs, the voltage becomes a challenge at peak time and/or contingency conditions. However, the major risk is that both transformers are fed from the same 69kV bus.

Alternative Solution Screening - A screening test has been performed for this area on an annual basis for the installation of non-traditional alternatives. Originally (*i.e*., 2010), due to the expensive transmission cost, large amount of load reduction, and high growth rates, the Company viewed this project as having potential. However, constructing distribution ties, which also prepared paths for future circuits and was a cheaper solution than DG/DSM, maintained bank backup while improving circuit reliability. The only risk was a 69kV bus contingency. After transmission plans changed, cost reduced but the large MW reduction continued to grow even though the growth rate significantly decreased, but the need for DG/DSM also decreased as distribution projects continued to improve circuit backup while preparing paths for future circuits. Although the major risk was still the 69kV bus, a contingency on either bank was becoming a challenge, so that the Company developed contingency plans, as well as prepared a spot for a mobile transformer. With the more likely circuit contingency covered and accepting the risk of the 69kV bus/bank contingency with prepared plans until the West Warwick Station is constructed, it does not justify installing non-traditional alternatives. Due to the high growth rate and minimal overhead transmission cost, as well as the need to improve both transmission and distribution reliability, and replace obsolete station equipment, this is not a viable project to defer.

Project Benefit - As a result of this new station, the Company will be able to retire the existing older 4 kV Pine Island Substation, and the entire area will be converted to operate at 13.2 kV. This will allow for the connection of the new

West Warwick distribution circuits to make high capacity ties to the recently constructed Westtown Substation and the existing Wisner Substation, and thus significantly improve service reliability for this entire area. The proposed West Warwick Substation will provide load relief and backup for the Wisner Substation to a point that 100% bank backup will be attainable at both the West Warwick and Wisner Stations. This will allow both Wisner banks to meet the Distribution Design Standards for at least another 30 years. However, due to operating issues, the station would still require an upgrade within this timeframe. With the transmission lines lacking breakers, switches limiting the banks, and the 45 year old banks, and no space to expand the existing station, relocating the Wisner Substation to a 138kV source will benefit a weak part of the system (Florida). The load relief and backup provided by the West Warwick Substation will significantly reduce the exposure on the Wisner Circuits, which contain two of the longest circuits in the system. This will greatly reduce the low voltage problems that are also an issue in this area. This station is also the first step in a sequential plan for the Central Division. The West Warwick Substation will assume the load of the Pine Island Substation. This will allow for the retirement of the small and isolated 34.5/4.8kV station that has very limited backup, as well as the conversion of the two 34.5kV South Goshen Circuits that feed the Pine Island Substation. Converting these circuits to 13.2kV will reduce operating cost and provide ties to adjacent stations, such as Westtown, Hartley Road, and South Goshen. This will significantly improve reliability for the southern piece of Orange County. After assuming the Pine Island load, the West Warwick

Substation will provide backup for the tail-end of two Westtown Circuits, and the two recently converted South Goshen Circuits, which will allow all four distribution circuits to meet the Distribution Design Standards. The load relief and backup ties will allow the installation of automation, which will significantly improve reliability for the area. This will also improve backup for all of these adjacent stations towards meeting the Distribution Design Standards.

Utilizing Central Hudson's D&J Lines to provide a 138kV feed for the West Warwick Station, and future Wisner Station, will provide load relief for the 69kV loop that currently serves seven stations. This will also provide a significant reduction in losses.

The Capital Expenditures exhibit contains spending of $10.5 million for this project.

The current budgetary estimate for this project is $53.8 million. This project is currently scheduled to be completed in June 2019.

Please see Exhibit ___ (EIOP-E2) for West Warwick Substation upgrade supporting maps and tables.

POMONA SUBSTATION

Q. In its direct testimony, the REV Panel proposes to implement a DER pilot program in order to defer construction of a substation in Pomona, New York ("Pomona Substation"). Please discuss the need for the Pomona Substation.

A. *Project Description* - In order to meet the distribution planning criteria and significantly improve the electric delivery system reliability in this area, the

Company proposes to install two 50 MVA – 138/13.2kV transformer banks with LTCs at the Pomona Substation. The new Pomona Substation will be served by two 138 kV underground transmission lines from the West Haverstraw substation. This project will include new 13.2 kV switchgear, with ten distribution circuit positions. Six circuits are to be used initially and four circuits are provisioned for future use. With the present plan, the 138 kV transmission source would be provided underground from the West Haverstraw Substation. An alternate plan to break Line 53 near the West Haverstraw Substation and extend a shorter underground 138kV transmission source to the Pomona Substation is still being studied.

Project Background - Currently, the New Hempstead Substation, West Haverstraw Substation and mobile transformer at the Little Tor Substation site serve a combined 27,379 customers in the New Hempstead, West Haverstraw, and Pomona area. Part of the Pomona area is also served from tail end of Tallman Circuits 51-3-13 and 51-6-13, and Stony Point Circuit 23-4-13. These circuits are relatively long circuits from the station. The other circuits that supply the Pomona area are Circuits 27-6-13 and 27-7-13 from West Haverstraw, and Circuits 45-1-13 and 45-5-13 from New Hempstead. These circuits each average about five miles from the station.

Although the area’s current growth rate has decreased to 1.07% over the past few years, a 208 acre parcel of land (Patrick Farms) near to the proposed Pomona Substation site is planned to house 500 new multi-family units and other retail/commercial development. In addition to the Patrick Farms development, much of the surrounding area has been or will be purchased in conjunction with Patrick Farms for future development. Additional development is being proposed in the Mount Ivy area (RT 202 south of the PIP). This includes several retail stores, including a supermarket, and a large condominium complex. With this growth at the tail-end of the circuits, a contingency on any of these circuits in 2024/25 would make the circuit no longer meet the Distribution Design Standards with less than 100% backup.

Project History/Deferral - The Pomona Station was identified in 2003 and originally scheduled for 2016. At that time, plans were to construct a 138kV bus at the Hillburn Station and a 138kV underground feed between Hillburn and West Haverstraw to provide a feed/backup for the Pomona Station, as well as improve transmission reliability for the Eastern Load Pocket. Due to the North Rockland Tap project taking precedence, the need for transmission reliability from this solution was no longer needed, which eliminated the 138kV bus at Hillburn and the underground transmission between Hillburn and Pomona. A simple 138kV underground loop from West Haverstraw would provide the required sources for the Pomona Station. Although this put the system at extreme risk for a rare contingency, Manual Load Shed Reports were prepared, and the Pomona Station was deferred until 2019 which resulted in significant project deferral savings.

The New Hempstead Substation was upgraded in 2014 to two 50 MVA – 138/13.2kV transformer banks (Bank 345 & Bank 445) and ten circuit positions. With the new larger banks, either bank can carry the entire station load during a bank or bus contingency. The upgraded New Hempstead Substation also has LTCs to regulate voltage during normal and contingency conditions. Energizing two of the new circuits from New Hempstead assisted in serving the Pomona area and allowed the deferral of the Pomona Station until 2022, which resulted in additional PW savings of $5.6 million. A proposed non-traditional alternatives plan being developed in anticipated to provide additional load reduction to allow the planned deferral of the Pomona Station for three more years.

Alternative Solution Screening - Although a 138kV bus was going to be constructed and a 138kV underground line was going to be constructed from Hillburn to West Haverstraw to assist the ELP and improve transmission reliability with the closing of the Lovett Generating Station, a screening test was still performed in 2006. With a very expensive project cost, the capacity reduction required was still very significant, transmission reliability was the main driver, and this was not a viable candidate for deferral by non-traditional means. After the deferral of the Pomona Station to 2021/22 through the deferral means as mentioned above, and the revised project need driver was strictly for distribution, a new screening study was performed in 2013. Although the cost was still significant, a reduction of 3.2MW would provide a one year deferral (5.4MW would defer the station need for three years). A non-traditional alternative measures plan may provide enough load reduction to provide at least an additional three year deferral.

Project Benefits – When eventually constructed, the two 13.2 kV Pomona transformer banks will provide sufficient capacity for future load growth in the

Pomona area and provide relief and improved backup to the New Hempstead, Tallman, West Haverstraw, and Stony Point Substations.

The Pomona area is currently served at the tail end of circuits from New Hempstead, West Haverstraw, Tallman, and Stony Point. The addition of this new substation will significantly reduce exposure (circuit miles) on those circuits; allow the installation of loop schemes, thereby greatly improving customer reliability. If significant new business load growth occurs in this area, it will be difficult to serve the current and expanding load requirements from the existing circuits (including the additional two circuits from New Hempstead), even with the non-traditional alternative measures, and would negatively impact current circuit performance. Depending on the size and rate of new load growth, it will likely cause the existing circuits to not meet distribution design standard. The new substation will provide the ability to reliably serve the proposed new load along RT 306 and RT 202. The additional capacity and circuits from the new substation will permit advanced automation to be installed between the new station and existing distribution ties. This will further improve circuit performance during both storm and non-storm conditions. This type of automation is difficult to install at this time due to existing circuit length and loading. The LTCs at this new substation will provide for optimum voltage control under all load conditions/contingencies and provide better voltage regulation to the local customers.

Q. Has the Company included the cost of designing and constructing the Pomona Substation in the revenue requirement of this electric base rate case?

A. No. As discussed in the direct testimony of the REV Panel, the Company is proposing to proceed with the implementation of its proposed DER pilot program. Therefore, the Company is not seeking funding for the design and construction of the Pomona Substation in this rate case.

ADDITIONAL INITIATIVES AND RESOURCES

Q. Has the Company included the costs of any additional initiatives and resources in this rate case filing?

A. Yes. Consistent with its commitment to provide safe and reliable service in a cost-efficient manner, the Company is proposing a Spare Equipment Initiative.

Q. Please describe the Spare Equipment Initiative.

A. With the ever increasing threat of cyber and equipment attack, the Company has commenced an equipment initiative program to increase system resiliency and minimize the outage time if an event should occur. Orange and Rockland has 88 substations (34.5 through 345 kV) that contain the following equipment:

- Transformers;
- High Voltage Circuit Breakers;
- Circuit Switchers;
- Potential Transformers (“PT”);
- Capacitive Coupling Voltage Transformers (“CCVT”);
- Capacitor Banks;
- Surge Arresters;
- Disconnect Switches;
- Aluminum and Copper Bus, bus supports, stand-off insulators; and
- Switchgear that includes medium voltage circuit breakers, transmission and distribution relay protection.

The Company's plan to purchase spare equipment is motivated by the need to improve resiliency response in the event of intentional major power apparatus destruction. For the 345kV stations, the Company used the Middletown Tap substation as a model for replacement which has a single high side breaker and single low side breaker and associated equipment. It was assumed two 345kV facilities were affected. For the 138kV substation, it was assumed a typical two line breaker plus tie bus arrangement replacement. The spare list includes autotransformers, power transformers, breakers, PT's, switchgear, bushings, circuit switchers, disconnects and relaying equipment.

The Electric Plant Additions estimate is $14.3 million for this project.

The budgetary estimate for this program is approximately $16 million. This program is currently scheduled to be completed in 2019.

Please refer to the spare equipment list in Exhibit ___ (EIOP-E3).

Q. Please describe Orange and Rockland's Equipment Storage Facility initiative.

A. Orange and Rockland does not presently have adequate stores capacity or outside storage facilities for a significant portion of the spare material stock being procured as part of this resiliency initiative, particularly for large substation equipment. In the past, the major substation equipment was stored in existing substations or selected company facility locations like Middletown. Storing large items at substations has been discouraged due to the security risk.

With these existing conditions and the probability the Company will need to expand this initiative to buy more equipment, the company is reviewing storage options for large power equipment.

The Company is currently reviewing storage locations for both Company owned facilities and leased space.

<u>Tamar Drive ROW Acquisition</u>

Q. Why is the Company seeking to acquire additional ROW along Tamar Drive in Valley Cottage?

A. The Company requires additional ROW easements from 30 properties along Tamar Drive in Valley Cottage. Line 563, the O&R 138 kV transmission line closest to these properties has an insufficient ROW width. Presently at these properties the Company lacks the ROW necessary to trim to the minimum allowed clearance identified in the Company's transmission vegetation management plan. As a result, the Company is required to trim vegetation on these properties annually, instead of on a three-year cycle.

Q. Please describe the benefits of acquiring ROWs over these 30 properties.

A. The benefits include reduced operating costs (*i.e.*, approximately $20,000 to $40,000 annually) since crews will not have to perform annual hot spot work at this location due to O&R's inability to maintain adequate clearance between the 138kV conductor and existing adjacent vegetation. This will also improve system reliability for this line.

Q. How much will it cost the Company to acquire these ROWs?

A. The Company estimates the total cost of acquiring these ROWs at $1.2 million. The Company currently plans to acquire these ROWs in 2015-2016.

<u>Tower Leg Remediation Program</u>

Q. Please describe the Company's proposed Tower Leg Remediation Program.

A. Pursuant to its Transmission Maintenance Program, the Company has identified towers throughout the Orange and Rockland service territory that have a protective wrap installed on the tower legs. This protective wrap was originally installed to protect the tower legs from corrosion that would take place at the ground level, due to the soil/vegetation interface. The protective wrap on these towers has deteriorated over time and started to trap moisture against the steel tower leg, which has caused severe localized corrosion and pitting. This program consists of removal of the wrap, inspection of the steel tower legs and re-condition/repair of the steel where required. This three-year program will address the following transmission lines:

- Lines 24 & 25 – 69kV Sugarloaf Substation to Shoemaker Substation;
- Line 26 – 138kV Ramapo Substation to Sugarloaf Substation; and
- Lines 12 & 13/131 – 69kV Shoemaker Substation to Mongaup Substation.

Q. Please describe the benefits of the Tower Leg Remediation Program.

A. This program will remediate steel tower legs on transmission towers that are suffering from deterioration. Unless these structures are addressed they will continue to be exposed to a higher degree of degradation. Over time this exposure will reduce the service life of the structures and may result in a failure. The structures must be maintained in order to operate the system in a safe and reliable manner. Reconditioning the legs on these steel structures at this time will prevent possible future failures and extend the service life of the structures. Due to its scope and technical nature, this work will be performed by a contractor and a contract inspector also will be utilized.

Q. What is the projected cost of the proposed Tower Leg Remediation Program?

A. The projected cost of this program is as follows:

	Historical Year(2014)	**Forecast Rate Year 1**	**Forecast Rate Year 2**	**Forecast Rate Year 3**	**Forecast Total**
O&M Amount	**-**	**$100,000**	**$75,000**	**$125,000**	**$300,000**
Capital Amount		**$300,000**	**$200,000**	**$400,000**	**$900,000**

These estimates include the costs of the contact inspector, which are projected to be $60,000 annually.

Vegetation and Asset Management

Q. Please describe the vegetation and asset management tools that the Company is developing that utilize O&R's current Geographic Information System ("GIS") data capabilities.

A. The Company is seeking to leverage its damage assessment effort by incorporating current GIS data capabilities into its vegetation management (distribution system tree trimming), pole/structure management and other equipment and inspection programs.

Currently, the Company's assignment of tree trimming projects is done manually, utilizing hardcopy, maps, time sheets, daily reports, and estimates. In addition, the Company performs a significant amount of tracking utilizing manually maintained electronic spreadsheets. The tracking of hazard trees, mitigation, vegetation related outage investigations is data intensive and new tools will streamline and standardize the process and reporting.

In addition, the Company's own program for the inspection and replacement of utilities poles and other assets is becoming increasingly data intensive. O&R's service territory contains 1,180 steel pole/towers and 135,000 wood poles. The following are the identified areas for improved asset management practices within the Company's existing processes.

<u>Contract Construction</u> – The Company assigns overhead line construction projects manually, utilizing hardcopy, maps, times sheets, daily reports, and estimates. Also, a significant amount of tracking is performed utilizing manually maintained electronic spreadsheets. This is data intensive and new tools will streamline and standardize the process and reporting.

<u>Asset Management</u> – The Company's inspection and maintenance of its towers and poles is performed manually, utilizing hardcopy, maps, times sheets, daily reports, and estimates. These inspections are conducted annually on the high voltage electric delivery system and every 10-12 years on the distribution system by a vendor. Currently, the inspection results are maintained in the vendor's

database. Similar inspections performed by Company personnel are completed and maintained manually in electronic spreadsheets or manual updates to the vendor system. A capital project is under way to transfer this data into the Electric Inspection and Maintenance System ("EIMS"), which will facilitate tracking and allow for comprehensive reports.

Q. Please continue.

A. Providing GIS enabled handheld computers would significantly improve asset management capabilities for the Company's vegetation management and line construction personnel. Specifically, the Company proposes to distribute 20 handheld computers for use to:

- Identify planned vegetation work (high voltage ROW, distribution cycle, and hazard tree);
- Identify and plan line construction;
- Develop cost estimates based on contract units;
- Provide work electronically to personnel;
- Verify and document completion of work units;
- Perform investigations of tree related outages;
- Assign inspections and repairs of transmission assets to personnel; and
- Perform and document inspections and repair of transmission assets.

In addition, improved asset management would provide database interfaces with current and to be developed data management tools. These would include:

- Tracking and reporting of completed vegetation work;

- Tracking and reporting of unmitigated hazard trees;
- Work estimates for the requisition of work;
- Potential link to Oracle EBS I procurement system;
- Tracking and reporting of completed work;
- Tracking and reporting of tree related outages; and
- Tracking and reporting on Transmission Asset Condition.

Q. What is the cost of the Company adding these GIS enabled handheld computers and associated programs?

A. Adding these GIS enabled handheld computers and associated programs is estimated to cost $2.815 million, which includes (i) configuration and integration of the Vegetation Management and Asset Management modules at $565,000, (ii) the purchase of 20 - Panasonic Toughpads, at $2,500 each, for a total of $50,000 and (iii) configuration and integration of the contractor inspection data to O&R's work management system, EIMS and GIS system at $2.2 million.

<u>ROW Track Machine</u>

Q. Please discuss the Company's need to acquire a ROW Track Machine.

A. Orange and Rockland's electric transmission system traverses remote areas where access is often difficult, thereby hindering system maintenance and emergency restoration. In many cases, it takes more effort to construct an access to the work site than it does to perform the repairs. Immediate gains can be made to improving system resiliency and increasing productivity by purchasing track mounted line equipment for work in these areas.

When performing planned maintenance or restoration work due to a failure, a significant amount of time can be expended reconstructing/re-establishing access roads. A track mounted digger-derrick requires less ROW preparation *(i.e.*, brush clearing and trail maintenance), than a similar wheeled digger-derrick. Having a track mounted vehicle capable of setting a pole and for use as an aerial bucket will allow maintenance crews to immediately access the work site and begin repairs. Adding a vehicle with these capabilities to the fleet will greatly improve the ability to recover from a storm event and improve day-to-day productivity of the workforce. Improving productivity will increase O&R's ability to complete necessary repairs. A tracked digger-derrick would expedite maintenance and emergency repair work by minimizing the effort required to construct temporary access roads, expedite the effort to deliver the manpower and materials to the worksite, and minimize the amount of matting required.

Q. What is the cost of the proposed ROW Track Machine?

A. The estimated capital cost is $800,000. The Company does not expect any incremental O&M associated with this machine.

<u>Back Yard Machines</u>

Q. Please discuss the Company's proposal to purchase back yard machines.

A. The Orange and Rockland service territory contains many locations where the overhead distribution system is in rear yards and is not accessible by standard bucket truck or digger-derrick. Work on the system in these areas must be done by hand or requires a substantial amount of preparatory work to access the work. Track mounted line equipment (back yard capable tracked digger-derrick) is typically used for this application and allows the work to be completed in a more efficient manner. Specifically, the back yard capable tracked digger-derrick requires less room to operate, is more productive when replacing poles, and also eliminates the need for extensive matting and property restoration. The Company currently does not own this type of equipment and such equipment is subject to the availability through rental agreement with outside vendors. The Company currently rents this machine on six-month intervals at a cost of $26,190. The equipment has been successfully used for distribution work throughout the O&R system. Our experience has demonstrated the benefits of a tracked machine. Based on historical workload we have the need for two machines, one in Northern Division and one in the Eastern Division. Having this equipment available would greatly improve our ability to restore remote areas of the system after storm events as well as allow the Company to comply with the requirements of the defective pole replacement program.

Q. What is the cost of the proposed back yard machines?

A. The estimated capital cost is $200,000 per machine, for a total of $400,000. The Company does not expect any incremental O&M associated with this machine.

<u>Vegetation Management Program</u>

Q. Is the Company maintaining its Vegetation Management Program?

A. Yes. The Program is required to comply with vegetation management regulations, implement vegetation management work in accordance with the Company's vegetation management plans and specifications, oversee and manage O&R's contractor work force, and interact with stakeholders such as customers, landowners, community organizations, regulatory agencies, and elected officials.

Q. Please describe the benefits of the Vegetation Management Program.

A. The Company presently manages its program of over 3,900 miles of distribution and 300 miles of transmission on a three- to four-year cycle. The program provides for the maintenance of proper clearances and contributes significantly to the system reliability

Q. What is the cost of the Vegetation Management Program?

A. Based on new contracts that went into effect in 2013 and expire in 2016, with increases for labor and associated costs, the costs of the program are forecasted as follows:

	Historic Test Year	Rate Year 1	Rate Year 2	Rate Year 3	Forecast Total
O&M Amount	$8,147,000	$8,540,000	$8,800,000	$9,064,000	$26,404,000
Capital Amount	$0	$0	$0	$0	$0

<u>Operating Supervisor</u>

Q. Is the Company proposing to add a Chief Construction Inspector position?

A. Yes. A Chief Construction Inspector is required to provide field oversight of Electric Operations construction and maintenance contracts for contractor work that is performed in accordance with the Company's contracts and specifications, and to verify payments for the associated work completed. While current staff must devote time to attend to these functions, the work has increased, and is expected to continue to increase with storm hardening programs such that the hiring of additional personnel is advisable and warranted. It has become necessary to provide more comprehensive oversight of certain contracts, based on findings of the Liberty Management Audit of Con Edison and recognized good practice. Presently, the Company employs three contract inspectors. In 2013, they oversaw 48 full-time equivalents ("FTE") (1:16 ratio) who completed 13 projects valued at $8 million. In addition, the pole inspection/reinforcement, rock excavation and vacuum excavation account for five FTEs that complete approximately $1 million worth of work. The person hired for this position will be responsible for the safety and productivity of the workforce, work requisitioning, work verification, payment verification, and the development of reports for the following Electric Operations contracts.

Q. What is the cost to the Company of adding a Chief Construction Inspector?

A. The Company projects that the cost of this additional position, including salary ($100,000), overheads ($57,000 O&M), vehicle ($32,000) and computer ($4,000), is as follows:

	Historic Test Year	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**	**Forecast Total**
O&M Amount	**$0**	**$157,000**	**$162,000**	**$167,000**	**$486,000**
Capital	**$0**	**$36,000**	**$0**	**$0**	**$36,000**

Amount					

Double Poles

Q. What is meant by the term "double poles?"

A. "Double poles" occur 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.

Q. Does the Company file a report with the Commission regarding the double poles in the Company's service territory?

A. Yes. Pursuant to the Commission's Order Adopting Terms of Joint Proposal, with Modification, and Establishing Electric Rate Plan issued June 15, 2012 in the Company's last electric base rate case (*i.e.*, Case 11-E-0408), the Company is required to file with the Commission and other interested parties a semi-annual report on double poles within its service territory. These reports, which are due on February 15 and July 15 each year, identify the double poles outstanding by municipality.

Q. Please describe the Company's efforts to reduce the number of double poles in its service territory.

A. The Company is working cooperatively and coordinating work with Verizon, Cablevision and local municipalities to address the double pole situation, particularly in Rockland County. Through the operation of the National Joint Utilities Notification System ("NJUNS"), which became operational in

November 2012, the Company has been able to minimize the future growth of double pole conditions. NJUNS is a system that offers utility companies, such as the Company, a method of obtaining up-to-date information on pole transfers and removals. The availability of accurate up-to-date information allows the Company, Verizon, Alteva and Cablevision to coordinate their pole removal activities in an efficient manner. For example, during 2013 and 2014, the Company utilized NJUNS to coordinate the removal of 576 double poles throughout its NY service territory. In addition, the Company uses the Utility Management System ("UMS"), a vendor data management system, to track all double pole locations created before NJUNS became operational. The Company projects that all currently existing double poles on Town roads will be removed in Clarkstown by year end 2014 and County and State roads by mid-year 2015. The Company projects that all currently existing double poles on Town, County and State roads will be removed in Ramapo by year-end 2015.

<u>Map Conflation</u>

Q. Please describe what map conflation is and why it is needed?

A. Map conflation is the process by which new and more accurate geographic spatial data obtained through advanced technology and spatial data tools is utilized to re-align and substantially improve existing mapping data. O&R has developed and maintained its own base geographic maps since the early 1980's. Because these maps are based on aerial imagery technology from that era, they are not as accurate as maps produced using present day digitally-based technology. As the landscape and geography of the Company's service territory has changed over time (*e.g.*, new road construction, area growth), the Company's base maps have lost some of their accuracy because of this.

Q. What is O&R's solution to improving the accuracy of its base maps and what are the benefits?

A. O&R has obtained new high-resolution digital aerial imagery that will be incorporated into its base maps through a conflation process that will produce a new set of base maps containing survey grade resolution. This process will compare and re-align the current location of the Company's infrastructure, such as poles, towers, hand holes, underground transformers and gas valves. This new digital imagery will substantially improve the accuracy of these field assets on new base maps that O&R will utilize to improve its geospatial information system ("GIS"). This will make locating underground gas and electric facilities both more efficient and more accurate. It will also introduce the ability to more seamlessly integrate external data sets into the GIS (*e.g.*, town boundaries), as well as other state, municipal and environmental data (*e.g.*, wetland delineations). This is important when working with external entities, such as Emergency Management departments, the Army Corps of Engineers, the New York State Department of Environmental Conservation, and other local agencies, municipalities and utilities. Once the conflation process is complete, O&R will be able to use GPS information to more accurately place new and changing facilities on its base maps. This will improve the spatial accuracy of the maps to provide business and service improvements, as well as produce more accurate GIS reporting. The Company estimates that this conflation process will cost (incremental O&M) $204,000 for its electric maps, and $85,000 for its gas maps. These Transmission & Distribution expense cost elements are provided in Exhibit __ AP-E4, Schedule 9 and Exhibit __ AP-G4, Schedule 9.

Q. Does that conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ELECTRIC RATE PANEL

NYPSC CASE No. ______________

Table of Contents

I. INTRODUCTION

Q. Would the members of the Electric Rate Panel ("Panel") please state their names and business addresses?

A. William Atzl and Cheryl Ruggiero, 4 Irving Place, New York, New York 10003.

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

A. **(Atzl)** I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison") as the Director of the Rate Engineering Department.

(Ruggiero) I am employed by Con Edison as the Department Manager of the Orange & Rockland Rate Design section in the Rate Engineering Department.

Q. Please summarize your educational background and business experience.

A. **(Atzl)** In 1983, I graduated from the State University of New York at Stony Brook with a Bachelor of Engineering degree in Mechanical Engineering. In 1989, I graduated from Pace University, White Plains, New York with a Master of Business Administration degree in Management Information Systems. I am a Licensed Professional Engineer in the State of New York. My first employment was with Long Island Lighting Company in 1983 where I held the position of Assistant Engineer in the New Business Department. In 1984, I joined Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R," or the "Company") as a Commercial and Industrial Representative in the Commercial Operations Department. At Orange and Rockland, I also held the positions of Commercial and Industrial Engineer, Program Administrator - Demand-Side Management, Manager - Demand-Side Management Operations, Manager - Energy Services and Pricing, and Manager – Regulatory Affairs. In October 1999, I joined Con Edison and held the position of Department Manager – Electric and Gas Rate Design – O&R and Director prior to my present position.

(Ruggiero) In 2000, I graduated from Polytechnic University with a Bachelor of Science degree in Electrical Engineering. In 2009, I graduated from Baruch College with a Master in Business Administration degree in Finance and Investments. I joined Con Edison in 2000 as a Management Intern with rotational assignments in Electric Operations, Engineering Services, and Gas Operations. In July 2001, I accepted a position as Associate Engineer - A in Distribution Engineering. In November 2005, I accepted a position as Senior Analyst in Rate Engineering and since then, I have held positions with increasing responsibility. I was promoted to my current position in March 2013.

Q. Have you ever testified before the New York Public Service Commission ("NYPSC") or any other state utility commission?

A. **(Atzl)** Yes. I testified in numerous regulatory proceedings before the NYPSC, the New Jersey Board of Public Utilities ("BPU"), and the Pennsylvania Public Utility Commission ("PAPUC").

(Ruggiero) Yes. I testified before the NYPSC in Case 10-E-0362 and I also have submitted testimony before the BPU and PAPUC.

II. PURPOSE OF TESTIMONY

Q. What is the scope of the Panel's direct testimony in this proceeding?

A. We testify to Orange and Rockland's proposed electric revenue allocation and rate design, including the impact of the proposed rate changes on customers' bills; the Company's proposed electric standby rate design; changes to the Company's Revenue Decoupling Mechanism ("RDM") provision; a change to a service fee to reflect updated costs; the Company's proposed REV Surcharge; and other miscellaneous proposed tariff changes.

III. REVENUE ALLOCATION AND RATE DESIGN

Q. What is the basis for the revenue increase for the rate year, *i.e.*, the 12 months ending October 31, 2016 (“Rate Year”), used in the proposed rate design?

A. The proposed revenue increase of $33,359,000, including applicable revenue taxes, was provided to us by the Company’s Accounting Panel.

Q. Please describe the first step in allocating the increased base rate revenue among the Company’s service classifications (“SC”).

A. First, we removed from the total incremental revenue requirement for the Rate Year, the 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. These tax-related revenues total $597,000.

Q. Please describe the next step in the revenue allocation process.

A. Next, Rate Year delivery revenues at the current rate level for each SC were realigned to reflect the deficiency and surplus indications identified in the embedded cost of service (“ECOS”) study presented by the Demand Analysis and Cost of Service Panel (“DAC Panel”).

Q. Did you attempt to eliminate fully the deficiencies and surpluses indicated by the ECOS study?

A. Before making final decisions on the elimination of the deficiency and surplus indications, we realigned the Rate Year delivery revenues to reflect the ECOS deficiency and surplus indications and then allocated the net delivery revenue increase among the SCs in proportion to the relative contribution made by each class to the realigned total Rate Year delivery revenues. We then reviewed, by class, the combined impact of eliminating a deficiency or surplus and the impact of the delivery revenue increase. We found that fully eliminating the deficiencies and surpluses, coupled with the delivery revenue increase, would result in relatively large revenue impacts for several classes, including SC No. 1, Residential; SC No. 2, Secondary; SC No. 3, and SC No. 22, General Industrial Time-of-Use. Therefore, to address the need to eliminate the surpluses and deficiencies while considering the impacts on customers, we applied one third of the class-specific deficiency and surplus indications from the ECOS study in a revenue neutral manner prior to applying the revenue increases. This approach allows us to address revenue and cost imbalances while considering customer bill impacts. In the event this case results in a multi-year settlement, we intend to reduce further any deficiencies and surpluses in the additional rate years.

Q. Please continue.

A. We next allocated the net delivery revenue increase among the SCs in proportion to the relative contribution made by each class to the realigned total Rate Year delivery revenues.

Q. Please continue.

A. We next determined what portions of the delivery rate increase would be attributable to changes in both the competitive delivery rate components and the customer charges. The competitive delivery rate components include the billing and payment processing (“BPP”) charge; 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. As discussed by the DAC Panel, Exhibit __ (DAC-E2, Schedule 2) presents the MFC fixed components and the POR credit and collections component as percentages of delivery revenue. Exhibit __ (DAC-E2, Schedule 3) presents the metering charges as percentages of delivery revenue. Based on the increased level of proposed delivery revenue, we computed a revised level of revenue for the MFC fixed components, POR credit and collections component, and metering charges.

Q. Were there any exceptions to the manner of developing the competitive revenues?

A. Yes. In updating the metering charges for the applicable SCs, we also updated the metering charges for those customers subject to Mandatory Day Ahead Hourly Pricing ("MDAHP"). MDAHP is currently applicable to non-residential customers in SC Nos. 2, 3, 20, and 21, whose billing demand exceeds 300 kW twice within a 12-month period, and to all customers in SC Nos. 9 and 22. We updated the metering charges for customers subject to MDAHP in SC Nos. 2, 3, 20 and 21 to be equal to the metering charges established by the DAC Panel in Exhibit __ (DAC-E2, Schedule 4). For SC Nos. 9 and 22, where the entire classes are MDAHP eligible, the meter ownership charge and meter service provider charge were increased based on percentages provided by the DAC Panel in Exhibit ____(DAC-E2, Schedule 3) and the combined SC Nos. 9 and 22 proposed delivery revenue to develop common charges for these two classes since metering installations for customers in these subclasses are similar. The meter data service provider charge for SC Nos. 9 and 22 was set equal to that of the MDAHP meter data service provider charge for MDAHP customers in SC Nos. 2, 3, 20, and 21 as presented in Exhibit __ (DAC-E2, Schedule 4) since these costs are common among all MDAHP classes.

Q. Have you changed the BPP charge?

A. No. The DAC Panel noted that the unbundled cost for BPP is $1.02 per bill. This is equal to the current BPP charge that was established in Case 07-E-0949, thus no changes are proposed.

Q. Do you have an exhibit which shows the proposed customer charges?

A. Yes. These customer charges are shown in Exhibit __ (ERP-E1, Schedule 1).

Q. Please explain how you designed the proposed customer charges shown in Exhibit __ (ERP-E1, Schedule 1).

A. In general, customer charges were increased to be more reflective of customer costs, consistent with the ECOS study, while limiting bill impacts. For example, even though the ECOS study presented by the DAC Panel shows an embedded customer cost of $28.36 per month for SC No. 1, we increased the customer charge from $20.00 to $25.00 considering the bill impact of the increased customer charge on low usage residential customers. We increased customer charges in the other SCs in a similar manner to better reflect customer costs with the exception of SC Nos. 2 – Primary, 9, 21, and 22, where customer charges are already reflective of customer costs. The customer charge for unmetered service under SC No. 16, Energy Only, continues to be set at the same level as the SC No. 2 unmetered service customer charge due to their similar service characteristics.

Q. How did you determine the non-competitive delivery revenue increase excluding the revenue changes associated with changes in competitive delivery rate components and changes in customer charges?

A. The incremental revenue derived from the MFC fixed components, the POR credit and collections component, metering charges, and customer charges were subtracted from the class-specific bundled delivery revenue increases to determine the non-competitive delivery revenue increase excluding customer charges, for each class.

Q. Did you restate the Rate Year non-competitive delivery revenue increases excluding customer charges, as determined above, on a historical period basis?

A. Yes. We restated the Rate Year non-competitive delivery revenue increases excluding customer charges by SC based on the twelve months ended June 30, 2014, *i.e.*, the historical period for which detailed billing data are available.

Q. Please describe how you developed the non-competitive delivery revenue increases excluding customer charges for the historical period.

A. Revenue ratios were developed for each class by dividing the historical period non-competitive delivery revenues excluding customer charges for each class by the Rate Year non-competitive delivery revenues excluding customer charges for each class at current rate levels. These revenue ratios for each class were applied to the Rate Year 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.

Q. Please explain how you designed the proposed usage delivery rates shown in Exhibit __ (ERP-E1, Schedule 1) for SC No. 1.

A. Prior to applying the non-competitive delivery revenue increase excluding customer charges for the historical period for SC No. 1, we made revenue neutral changes to this class as explained below.

Consistent with the NYPSC's goal to promote energy efficiency and to continue with the changes made in Case Nos. 10-E-0362 and 11-E-0408, we further reduced SC No. 1 discounts for optional electric space and water heating service. In Case 10-E-0362, the optional electric space and water heating discounts were closed to new customers after July 1, 2011, and we began a gradual process to eliminate the discounts, first reducing the discount at that time. In Case 11-E-0408, the Company further reduced the space and water heating discounts by eliminating an additional 20 percent of the differential among usage rates in Rate Year 1 and an additional 10 percent of the differential among usage rates in each of Rate Years 2 and 3. There still remains a discount of approximately 17.2% for the summer water heating special provision and a discount of 33.5% for the winter water heating, heat pump, and space heating special provisions. In this case, we propose to reduce the remaining differential among usage rates by one-third, which will continue the process that was introduced in the prior cases of gradually eliminating the discounts. We made these changes on a revenue-neutral basis before applying the SC No. 1 revenue increase. If a multi-year rate plan results from this proceeding, the differentials would be reduced by one-third in the first rate year, one-half in the second rate year, and eliminated entirely in the third rate year.

Once these revenue neutral changes were made, we then applied the SC No. 1 non-competitive delivery revenue increase excluding customer charges for the historical period to the usage rates on an equal percentage basis.

Q. Please explain how you designed the proposed usage and demand delivery rates for the SC No. 2 – Secondary Demand Billed class as shown in Exhibit __ (ERP-E1, Schedule 1).

A. Prior to applying the non-competitive delivery revenue increase excluding customer charges for the historical period for SC No. 2 – Secondary Demand Billed, we made revenue neutral changes to continue the phase out of declining block rates for this class. As directed in the Commission's Order Establishing Rates for Electric Service, issued June 17, 2011 in Case 10-E-0362, the Company was required to file a plan to phase out the declining block rates in SC Nos. 2 and 3. In Case 11-E-0408, the Company eliminated the declining block rates in SC No. 2 Secondary Non-Demand Billed, SC No. 2 Primary, and SC No. 3. For SC No. 2 Secondary Demand Billed service, we eliminated ten percent of the usage rate differentials and eliminated a corresponding portion of the demand rate differentials in each of Rates Years 1, 2, and 3 of the rate plan established in Case 11-E-0408. In this case, we propose to eliminate a further ten percent of the usage rate differentials and eliminate a corresponding portion of demand rate differentials for SC No. 2 Secondary Demand billed service on a revenue neutral basis.

If a multi-year rate plan results from this proceeding, the differentials would be reduced by a further ten percent in each of Rate Years 2 and 3.

Once these revenue neutral changes were made, we then applied the SC No. 2 – Secondary Demand Billed non-competitive delivery revenue increase excluding customer charges for the historical period to the usage and demand rates.

Q. Please explain how you designed the proposed usage and demand delivery rates for the SC No. 2 – Primary class as shown in Exhibit __ (ERP-E1, Schedule 1).

A. As previously mentioned, in Case 11-E-0408, the Company eliminated the declining block demand and usage rates in SC No. 2 – Primary. In this case, we have proposed to shift 20% of the usage revenue into demand revenue on a revenue neutral basis, prior to applying the revenue increase. Since the majority of transmission and distribution costs are of a fixed nature, moving revenue for this class into fixed charges more closely aligns how costs are incurred and collected from customers. Once this revenue neutral change was made, we then applied the SC No. 2 – Primary non-competitive delivery revenue increase excluding customer charges for the historical period to the usage and demand rates.

Q. Please explain how you designed the proposed usage and demand delivery rates for SC Nos. 3, 9, and 22 as shown in Exhibit __ (ERP-E1, Schedule 1).

A. Since the majority of transmission and distribution costs are of a fixed nature, moving revenue into fixed charges more closely aligns how costs are incurred and collected from customers. Based on the current percentage of revenue recovered through fixed charges for SC Nos. 3, 9, and 22, we have proposed to apply the entire increase in the non-competitive delivery revenue excluding customer charges for these classes to increase the demand charges. The usage charges for these classes will remain at their current level. This results in a higher percentage of revenue for these classes being recovered through fixed charges.

Q. How did you design the proposed usage and demand delivery rates for the remainder of the SCs as shown in Exhibit __ (ERP-E1, Schedule 1)?

A. For all other SCs, the usage and demand charges, where applicable, were increased by the class-specific percentage increase in non-competitive delivery revenue excluding customer charges.

Q. Are there are other rate design issues you would like to discuss?

A. Yes. We would like to discuss the discounts applicable to customers served under Rider C – Excelsior Jobs Program (“EJP”).

Q. Have you revised the discounts applicable to customers who take service under EJP?

A. Yes. Discounts under the EJP are provided if marginal costs are less than average electric delivery rates. As explained in Rider C, if marginal costs change over time, the Company may file amended discounts. Based on the results of the marginal cost of service study prepared in this filing, the Company has amended the discounts contained in Rider C since marginal costs are less than average electric delivery rates.

Q. How did you determine the discounts for Rider C customers?

A. As discussed by the DAC Panel, Exhibit __ (DAC-E3, Schedule 1) shows the ratio by which marginal costs are currently less than what is being recovered in delivery rates. In order to determine the EJP discounts, these ratios were subtracted from 1 to arrive at the percentage discounts by class. For new customers served under Rider C effective November 1, 2015, the following percentage reductions will be applied to their customer and delivery charges:

- SC Nos. 3, 21, and 22 – 61%;
- SC No. 9 – 62%;
- SC No. 2 Secondary – 63%;
- SC No. 20 – 64%; and
- SC No. 2 Primary – 66%.

The EJP discount applicable to a Service Classification No. 25 customer will be the discount of the customer's otherwise applicable service classification.

Q. Would you please describe Exhibit __ (ERP-E1, Schedule 2)?

A. Exhibit __ (ERP-E1, Schedule 2) shows the impacts that the proposed rates will have on bills to full service customers at various levels of consumption.

IV. STANDBY RATE DESIGN

Q. Please describe the Company's Standby Service rates.

A. The Company's standby service rates are included in SC No. 25 and are applicable to sales and delivery of electric power supply provided by the Company, or delivery of electric power supply provided by an Energy Service Company ("ESCO") under the Company's Retail Access Program, for standby service purposes. Standby service is used to replace or supplement power and energy ordinarily generated by an on-site generator and also for "station use" by a wholesale generator. A number of provisions currently exist exempting certain customers from standby service. The rate applicable to non-exempt customers billed under SC No. 25 is determined based on the service classification under which the customer would otherwise receive service. The delivery portion of the bill for a standby customer consists of the following components: a contract demand charge, as-used daily demand charges, and a customer charge.

Q. Please describe the general principles you applied in the rate design process for standby service.

A. Consistent with the currently effective SC No. 25 rate design, we prepared our proposed standby rate design 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 October 26, 2001 ("Standby Rates Order") in Case 99-M-1470. The Commission stated that "the standby rates for each service classification should produce the same revenues as the standard rates, using the class billing determinants." (Standby Rates Order, Appendix A, Page 2). Therefore, the billing determinants used to design standby rates are based on those used in the formulation of the proposed rates for the otherwise applicable non-standby service classifications.

We also used 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 Cases 02-E-0780 and 02-E-0781. This matrix shows the percentage allocation of costs between the as-used demand charge and the contract demand charge, at various service levels.

Q. Please describe the rate design process for the contract demand charges.

A. 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.

Q. Please describe the rate design process for the as-used daily demand charges.

A. 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.

Q. Please describe how you determined the customer charges for standby service.

A. The customer charges were based on the customer costs as indicated in the ECOS study provided by the DAC Panel. In general, we subtracted applicable metering and billing and payment processing charges from the customer cost to develop the customer charge for standby service.

V. <u>REVENUE DECOUPLING MECHANISM</u>

Q. Are you proposing any changes to the RDM?

A. Yes.

Q. Please summarize the changes you are making to the RDM.

A. We are proposing three changes: (1) adding SC Nos. 4 and 6 into the applicable RDM classes; (2) changing the definition of the timeframe of the rate year in two instances; and (3) changing the definition of "Actual Delivery Revenue" in the tariff to include revenue received from the reactive power demand charge.

Q. Please describe your first change.

A. We have added the Company's municipal street lighting service classifications, SC Nos. 4 and 6, to the list of applicable classes for the RDM. These two classes have been combined as Group F in the RDM section of the tariff (*i.e.,* General Information Section No. 30). The description of the RDM was also added to SC Nos. 4 and 6 in the list of monthly rates applicable to these classes.

Q. Why have you proposed this change?

A. Currently, customers served under SC No. 4 have the option to purchase street lights from the Company and be served under SC No. 6. Any such street lighting sale can lead to significantly reduced delivery revenue to the Company. Therefore, we have proposed the introduction of Group F.

Q. If a customer served under SC No. 4 were to purchase street lights from the Company and take service under SC No. 6, would there be any offset to the revenue reduction the Company would be permitted to recover through the RDM?

A. Yes. There would be an offset to the revenue reduction to account for estimates of the lower carrying cost on the net value of the assets, property taxes, and depreciation the Company would realize as a result of the sale. This provision would apply only to street light purchases that are not reflected in the RDM delivery revenue targets. This provision has also been noted in General Information Section No. 30.

Q. Please describe your next change.

A. The Company's current rate years resulting from Case 11-E-0408 are defined as the 12-month periods ending June 30 of each year. The Rate Year in this filing is defined as the 12-month period ending October 31, 2016. Therefore, due to the change in the definition of the beginning and ending month of the rate year, language was modified to change the definition of the annual RDM period from the 12-month period ending June 30 each year to the 12-month period ending October 31 of each year. The annual reconciliation of the RDM surcharge will be required to be filed no less than ten calendar days before December 1, the effective date of new RDM adjustments.

Q. Please describe your next change.

A. As a result of the change of the starting month of the rate year from July 1, 2015 to November 1, 2015, there will be a partial rate year for the period July 1, 2015 through October 31, 2015. The electric tariff currently has a provision in the RDM section stating that, in the case of a partial rate year, the RDM would operate as per the terms of the Joint Proposal adopted by the Commission in Case 11-E-0408. In this filing, we have amended that provision to refer specifically to the partial rate year described above.

Q. Please describe your final change.

A. Since the Forecasting Panel is proposing to include reactive power demand charge revenue in the RDM delivery revenue targets, we have included reactive power demand charge revenue in the definition of "Actual Delivery Revenue" contained in General Information Section No. 30.

Q. Have you amended General Information Section No. 30 to reflect revised RDM delivery revenue targets?

A. Not at this time. General Information Section No. 30 will be further revised at the end of this proceeding to (a) set forth the RDM delivery revenue targets based on the final revenue requirement level approved by the Commission and (b) update the threshold for implementing interim RDM adjustments to reflect 1.5% of the delivery revenue subject to the RDM.

VI. SERVICE FEES

Q. Are you proposing any changes to the Company's service fees?

A. Yes. We are proposing to increase the re-inspection fee contained in General Information Section No. 6, "Wiring, Apparatus, and Inspection."

Q. Please describe the re-inspection fee.

A. The re-inspection fee was established and approved by the Commission in Case 07-E-0949. Upon receipt of a Cut-In Card from the applicant's underwriter or municipality having jurisdiction over the construction project confirming that the Applicant's electrical service project is ready to be energized and has met all applicable electrical code requirements, the

Company sends a New Business Services representative to inspect the installation for compliance with the Company's specifications for electric installations. This inspection is performed at no cost to the Applicant. If the installation does not comply with the Company's specifications, the Company's representative cannot approve the electric service and must return at a later date after the Applicant has taken corrective actions. At such time, a re-inspection fee is assessed to the Applicant. The purpose of the re-inspection fee is to appropriately allocate the costs associated with the re-inspection and return visit exclusively to the Applicant who did not comply with the Company's requirements and as a consequence necessitated a second visit, as opposed to allocating those costs to the Company's other customers. Payment of the re-inspection fee must be made prior to the Company's re-inspection of the Applicant's electrical service. Currently, the Company assesses a re-inspection fee of $51.00 for any subsequent re-inspections of the installation.

Q. Please describe the Company's proposed update to the re-inspection fee.

A. The re-inspection fee includes a labor and a mileage component. Both of these components have been updated. The labor component was determined by applying the applicable man-hour rate to the administrative and field time associated with completing a re-inspection. Specifically, as shown below, the total time of 52 minutes required to complete all activities associated with a re-inspection has been multiplied by the current average hourly rate of $77.51 for a New Business Services representative to arrive at the labor component of the re-inspection fee of $67.18.

Activity	Time (min)
Phone call/letter to customer indicating failed inspection	5
Update work management system	3
Contacts with customer/contractor to arrange re-inspection	3
Visual re-inspection of service installation	5
Travel time	36
Total	**52**

The mileage component of the re-inspection fee is $12.07 and is based on an average of 21.36 miles per re-inspection times a rate of 56.5 cents per mile, which is the Internal Revenue Service's 2014 mileage reimbursement rate for the use of personal vehicles. The resulting re-inspection fee is the total of the labor and mileage components, or $79.25 per re-inspection. We have rounded this fee to $80.00.

VII. REV SURCHARGE

Q. Are you proposing any other changes to the Company's electric tariff?

A. Yes. We have proposed tariff provisions designed to implement a surcharge mechanism to recover the costs proposed by the Reforming the Energy Vision Panel (the "REV Panel") for the Pomona demonstration program and future REV-related projects

Q. Where has the surcharge mechanism been included in the electric tariff?

A. We have added the REV Surcharge as a component in the Company's existing Energy Cost Adjustment ("ECA") mechanism, which is applicable to full-service and retail access customers.

Q. How will the initial REV Surcharge component of the ECA be set?

A. The initial REV Surcharge will be calculated to recover any expenditure made prior to the filing of the surcharge and the forecasted revenue requirement for the succeeding period. Subsequent filings will be made every six months and will include a true-up of any prior period over- or under-collections and the forecasted revenue requirement for the subsequent six-month period. The sum of the forecasted revenue requirement and the prior period over- or under-collection will be divided by the forecasted kWh deliveries for customers during the period in which the resulting revised REV Surcharge component of the ECA will be in effect.

Q. When will the Company make its filings to reset the REV Surcharge component of the ECA?

A. The Company will file workpapers with the Commission 15 days prior to the effective date of a change in the REV Surcharge component of the ECA. The resulting REV Surcharge rate shown on these workpapers will be included in the monthly ECA statement filed with the Commission three business days prior to the effective date of the new ECA rate.

Q. Does the Company plan to limit the REV surcharge component of the ECA?

A. Yes. Since the workpapers for the REV Surcharge component of the ECA will be filed 15 days prior to any change in the surcharge, the Company has proposed that the maximum rate for the REV surcharge in any six-month period be 0.2 cents per kWh. However; if the Company anticipates that a higher surcharge is required, then the Company will make a filing with the Commission detailing the requested change in the REV Surcharge.

Q. Does the Company plan to transfer amounts to be recovered through the REV Surcharge into base rates?

A. Yes. In the Company's next base rate proceeding, any remaining unrecovered costs associated with projects to be recovered through the REV Surcharge component of the ECA will be transferred to base rates.

Q. Has the Company calculated the initial REV Surcharge component of the ECA?

A. At this time, the REV proceeding is in its initial stages and many fundamental decisions have not yet been made. As a result, the Company has not calculated an initial surcharge. In addition, as described in the REV Panel's testimony, the costs for the demonstration program in Pomona are still being developed and finalized. During the pendency of this rate case, the Company will further refine its estimates for the Pomona demonstration project and should be able to file its initial REV Surcharge component of the ECA upon Commission approval of the REV Surcharge cost recovery mechanism.

VIII. <u>OTHER TARIFF CHANGES</u>

Q. Are you proposing any other changes to the Company's electric tariff?

A. Yes. We are proposing the following: (1) changes to certain mechanisms with rate years ending June 30 to account for a partial rate year and to change the definition of the starting month of the rate year; (2) changes to add provisions for an AMI Opt out fee; (3) changes to Rider H, the Company's Economic Development Rider; (4) changes to Special Provision A of SC No. 4, the Company's municipal street lighting SC; and (5) housekeeping changes.

Q. Please describe your first change.

A. As previously discussed, the rate year in the current electric rate plan is based on twelve-month periods ending June 30, whereas the proposal in this filing is for a rate year to be based on a 12-month period ending October 31. There are a number of mechanisms with reconciliations and/or targets currently tied to rate years ending June 30 that must be amended to account for a partial rate year (*i.e.,* the period July 1, 2015 through October 31, 2015) and to change the definition of the starting month of the rate year.

Q. Which mechanisms besides the RDM required a change to align with a rate year ending October 31 and/or to account for a partial rate year?

A. There are three mechanisms -- the credit and collections component of the POR discount percentage, the transition adjustment for competitive services ("TACS"), and the reconnection fee waiver.

Q. Please describe your changes to the credit and collections component of the POR discount percentage related to the change of the definition of the start and end date of the rate year.

A. The credit and collections component of the POR discount percentage contained in General Information Section No. 7.5 has been revised to state that it will be set effective each November 1 instead of the July 1 date currently in the tariff.

Q. Please describe your changes to the TACS related to the change of the Rate Year.

A. The description of the effective period for the TACS contained in General Information Section No. 29 has been changed from the 12-month periods commencing July 1 to the 12-month periods commencing November 1 with the TACS being reset effective November 1 of every year beginning in November 2016. In addition, a section has been added to the TACS to describe the reconciliation of the partial rate year July 1, 2015 through October 31, 2015. The TACS will be reset effective November 1, 2015 to true-up the period July 1, 2015 through October 31, 2015 based on a target of $4,344,689 for the MFC fixed component lost revenue and a target of $372,258 for the credit and collections lost revenue associated with retail access. These targets are based on the sum of the monthly targets for July through October for Rate Year 3 contained in Appendix B, Schedule 5, of the Joint Proposal adopted by the Commission in Case 11-E-0408. Any over- or under-collection for this partial period will be collected through a revised TACS that will be in effect for the 12-month period ending October 31, 2016.

Q. Please describe your changes to the reconnection fee waiver related to the change of the definition of the start and end date of the rate year.

A. As described in General Information Section No. 11.14, the Company will waive the reconnection fee one time for any customer enrolled in the Company's low income program up to a total of $40,000 of waivers granted in any 12 month period from July 1 through June 30. The Company has added revised language to state that, for the 12 month period beginning November 1, 2015, and every 12 month period thereafter, the Company will waive the fee until a total of $40,000 of reconnect fees has been waived.

Q. Please describe the AMI Opt-Out fees.

A. As described in the AMI Panel's testimony, the Company proposes to install advanced meter infrastructure ("AMI") meters in Rockland County. General Information Section No. 7 has been amended to include the provisions for the fees associated with customers who choose to opt out of AMI metering as discussed in the AMI Panel's testimony.

Q. Have you modified the Company's electric tariff to reflect changes to the Company's Economic Development Rider – Rider H as proposed by Company witness Patterson?

A. Yes. Based on the changes proposed in the testimony of Company witness Patterson, the following changes have been made to Rider H applicable to customers with a letter of intent dated on or after November 1, 2015: (1) customers will be required to maintain a metered demand of 65 kW or more in six months of any twelve-month period to remain on Rider H; (2) customers can only commence service once their metered demand is 65 kW or more for two consecutive months; and (3) customers will be required to submit an energy audit / survey that has been organized through the Company's Customer Energy Services group for customers who purchase, lease, or expand an existing building.

Q. Have you made any changes to the Company's lighting service classifications?

A. Yes. In Case 11-E-0408, the Company amended Special Provision A of SC No. 4 to allow municipalities to replace more than 2% of their street lights at no cost to the customer in any given year as long as the sum of all municipality requests did not exceed 2% of the total number of SC No. 4 street lights. This amendment was to be in effect through June 30, 2015. The Company has chosen to extend this amended Special Provision for the new Rate Year and has updated Special Provision A of SC No. 4 in the electric tariff accordingly.

Q. Are you proposing any housekeeping changes to the electric tariff?

A. Yes. We are proposing the following housekeeping changes to the tariff:

- The Village of South Blooming Grove has been added in General Information Section No. 1 to the list of communities to which the electric tariff applies;
- SC No. 25, Standby Service has been revised to remove the provisions related to the phase-in of Standby Service rates since the phase-in period concluded in February 2011;
- Rider C - Excelsior Jobs Program has been modified to clarify that this Rider is only applicable to demand-billed customers; and
- Rider J – NYPA Power for Jobs ("PFJ") has been removed from the electric tariff since this Rider was closed effective July 1, 2012. In

addition, Rider G – NYPA EDP Delivery Service has been removed from the electric tariff because there are no customers currently served under Rider G and, to our knowledge, NYPA no longer provides this service. References to Riders G and J were also removed in the following sections in the electric tariff: Table of Contents, General Information Section Nos. 13, 14, 15, and 30, and Service Classification Nos. 2, 3, 9, 20, 21, and 22;

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF

ELECTRIC FORECASTING PANEL

Q. Would the members of the Electric Forecasting Panel please state their names and business address?

A. Patrick F. Hourihane and Berna Falay-Ok. Our business address is 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity and what are your professional backgrounds and qualifications?

A. **(Hourihane)** We are employed by Consolidated Edison Company of New York, Inc. (“Con Edison”) a corporate affiliate of Orange and Rockland Utilities, Inc. (“Orange and Rockland”, “O&R” or the “Company”). I am Section Manager of Electric Revenue and Volume Forecasting in Business Finance. My background is as follows: I received a Bachelor of Arts Degree in History from Saint Meinrad in 1974 and a Masters Degree in Energy Management from New York Institute of Technology in 2000. In 1975, I began my employment with Con Edison in the Customer Service Department. Between 1978 and 2005, I worked in positions of increasing responsibility in Customer Service and Energy Management Departments working on such projects as the electric governmental forecast and gas sales forecast. In 2005, I transferred to the Rate

Engineering Department. In December 2006, I was promoted to my present position.

(Falay-Ok) I am a Senior Planning Analyst in the Revenue and Volume Forecasting Department in Business Finance. My background is as follows: I received a Bachelor's degree in Mathematics from Yildiz Technical University, in Turkey, in 2003. I also received a Master of Science in Economics degree from Bilgi University, in Turkey, in 2007 and a Masters of Arts in Economics degree from Rutgers University, in 2008. Prior to joining Con Edison, I taught economics at Rutgers University. In 2008, I joined Con Edison in the capacity of Senior Analyst as an experienced economic modeler and forecaster. I have developed econometric time series models and forecasts for Orange and Rockland and Con Edison.

Q. Please generally describe your current responsibilities.

A. **(Hourihane)** My responsibilities include the preparation of electric delivery volume forecasts, as well as electric non-competitive and competitive transmission and distribution ("T&D") delivery revenue forecasts.

(Falay-Ok) My current responsibilities include the development, maintenance and updating of the Company's electric energy forecasting models used to produce the electric delivery volume and revenue forecast.

Q. Have you previously testified in regulatory proceedings?

A. **(Hourihane)** Yes, I have submitted testimony in Case 07-E-0949, 09-E-0428, 11-E-0408 and testified in Case 07-E-0523, 08-E-0539, 10-E-0362, 13-E-0030.

(Falay-Ok) No.

Q. What is the purpose of the Forecasting Panel's testimony?

A. We present the forecast of O&R electric system sendout, delivery volumes and revenues for the four month period ended October 31, 2014, the 12 months ending October 31, 2016 ("Rate Year" or "RY1"), and the 12 month periods ending October 31, 2017 and 2018, respectively. We also discuss the methodologies used to develop these forecasts. While, as discussed by the Company's Accounting Panel, the Company is not proposing a multi-year rate plan in this electric rate case, the Electric Forecasting Panel does present the Company’s forecasts for the two years following the Rate Year in this proceeding. For the sake of convenience, we refer to these two years as RY2 (*i.e.*, November 1, 2016 through October 31, 2017) and RY3 (*i.e.*, November 1, 2017 through October 31, 2018).

Q. What are the actual and normalized total delivery volumes for the 12 months ended June 2014?

A. The actual total delivery volume for the 12 months ended June 2014 is 4,008,201 MWHs. The normalized total delivery volume for this period is 3,986,331 MWHs.

Q. Please summarize, in aggregate form, your delivery volume forecasts for the four months ended October 31, 2014, the 12 months ending October 31, 2015, and RY1 through RY3, respectively.

A. As set forth in Exhibit __ (EFP-E1), Schedule 4, Page 1 of 5, for the four months ended October 31, 2014 total delivery volume forecast is 1,501,300 MWHs. For the 12 months ending October 31, 2015 the Company’s total delivery volume forecast is 3,949,644 MWHs. For RY1, the Company’s total delivery volume forecast is

3,941,333 MWHs, a decrease of 8,311 MWHs which amounts to a 0.2% decrease from the 12 months ending October 31, 2015. The decrease includes the effect of the gain of one day for the 2016 leap year (*i.e.*, approximately 10,770 MWHs). The forecasted volume growth is not enough to offset the anticipated decreased energy usage associated with the energy efficiency ("EE") programs and customer installation of solar panels in the Company's service territory. For RY2, total delivery volume forecast is 3,920,410 MWHs, a decrease of 20,923 MWHs which amounts to a 0.5% decrease from the forecast for the 12 months ending October 31, 2016. The decrease includes the effect of the loss of one day for the 2016 leap year (*i.e.*, approximately 10,770 MWHs). The forecasted volume growth is not enough to offset the anticipated decreased energy usage associated with the EE programs and customer installation of solar panels in the Company's service territory. For RY3, the Company's total delivery volume forecast is 3,897,093, a decrease of 23,317 MWHs which amounts to a 0.6% decrease from the forecast for the 12 months ending

October 31, 2017. The forecasted volume growth is not enough to offset the anticipated decreased energy usage associated with the EE programs and customer installation of solar panels in the Company's service territory.

DELIVERY AND SENDOUT VOLUMES

Q. What forecasting methodologies did you use to project the Company's electric delivery volumes described above?

A. The billed delivery volume forecasts are based on various econometric and time series models. Models used for forecasting billed delivery volumes are done on a major classification basis, with the major classifications defined as residential, secondary including small primary (SC 2P), primary excluding small primary (SC 2P), lighting, and other public authority. These major classifications are comprised of various O&R service classes.

Econometric Time Series Models

Q. Please describe the econometric time series models you used including their modeling periods, the independent variables included in them, and the model structures.

A. We used econometric time series models to forecast the billed delivery volumes for residential, secondary including small primary, primary excluding small primary, lighting and public authority. The modeling period, the independent variables, and the model structure for these econometric models are described below.

Modeling Period

The econometric time series models are developed on a quarterly basis. The modeling period starts with the first quarter of 1990 and ends with the second quarter of 2014. For the lighting and public authority models, the modeling period starts in the first quarter of 1993.

Independent Variables

The O&R models are developed employing basically two types of independent variables – weather and economic. Weather variables, in terms of heating and cooling degree days and billing days, are included in the models to account for delivery volume variations due to differences in weather conditions and billing days. Weather variables are included for all service classes except for lighting. Also included are key economic variables. The key economic variables in the various models are real average electric price, private non-manufacturing employment, and the number of customers. The residential and secondary models include real average electric price, private non-manufacturing employment, and the number of customers variables. The primary model includes real average electric price and the number of customers variables for their respective major classifications. The lighting model includes real average electric price, the number of customers, and burn hour variables. The public authority model does not include any economic variables and is therefore based solely on weather and billing day variables.

Model Structure

Each of the econometric time series models consists of two components: the first component is similar to a regression model, which correlates the delivery volume with a set of independent variables included in the model; the second component is an autoregressive integrated moving average (“ARIMA”) component. The combined model is often referred to as an ARIMAX model in the econometric modeling literature, where the letter “X” stands for the set of independent variables included in the model. The ARIMA component can take different forms, and each model has its own ARIMA structure statistically determined according to the data pattern of each major classification.

Q. What is the purpose of including an ARIMA component in the models?

A. An empirical forecasting model can include only a few key economic variables, such as real electric price, number of customers and employment. All other economic variables, which may have an effect on electric delivery but either are not quantifiable or have no data available, are excluded from the model. The ARIMA mechanism captures some of the collective effect of those excluded variables. Furthermore, the ARIMA mechanism also smoothes out autocorrelations in the residuals, thereby reducing forecast error.

Q. What criteria are used to measure the accuracy of the econometric models?

A. Generally accepted criteria to measure the accuracy of each model are used. These criteria include a high R^2, low standard error and a Durbin-Watson value near two.

Q. Have you prepared an exhibit showing the measures of accuracy you have just described?

A. Yes. In the one-page document entitled “ELECTRIC FORECASTING MODEL STATISTICS”, Exhibit ___ (EFP-E1), Schedule 1, we present measures of model performance for the residential, primary excluding small primary, and secondary including small primary classifications. These three major classification models are featured because they account for over 95 percent of total Orange and Rockland billed delivery volume. This Exhibit lists the adjusted R^2, standard error, and Durbin-Watson statistic of the model for residential, primary excluding small primary, and secondary including small primary. All three statistics indicate that the models fit the historical data well.

Assumptions for Model Variables

Q. You listed the key economic variables used in forecasting models as real average electric price, private non-manufacturing employment, and number of customers in each major classification. What assumption do the models use for the real average electric price variable for forecasting purposes?

A. For forecasting purposes, we assumed that the real average electric price remains at the same level as for the 12 months ended June 2014.

Q. Please explain how the forecast of private non-manufacturing employment is developed.

A. The private non-manufacturing employment forecast is developed using the economic consulting firm, Moody's Analytics' forecast. The Moody's Analytics' forecast is developed for New York State as a whole as well as for individual regions and counties within the State. For the historical period, the Company uses the Bureau of Labor Statistics Current Employment Survey ("CES") data for Rockland and Newburgh Counties (through 2004). The Bureau of Labor Statistics CES discontinued the Rockland and Newburgh Counties series at the end of 2004. As such, starting from 2005, employment figures for Rockland and Newburgh Counties are estimated by applying the most up-to-date year over year growth rates (obtained from Moody's

Analytics' database) to the actual CES historical figures. For the Company's service territory, private non-manufacturing employment is projected to increase by 2.2% in 2014. It then will increase by 2.0% in 2015, 2.3% in 2016, 1.5% in 2017, and 0.6% in 2018, respectively.

Q. Please explain the development of the number of customers for the various major service classifications.

A. The forecasts of the number of customers for residential, secondary, and primary classes are based on ARIMAX models, *i.e.*, based on employment and ARIMA components, using quarterly data from the first quarter of 1990 through the second quarter of 2014. The forecast of the number of customers for lighting class is based on an ARIMA model using quarterly data from first quarter of 1993 through the second quarter of 2014.

Q. Are the foregoing projections of employment, real electric price and the numbers of customers used as inputs in the forecasting models to generate the O&R delivery volume forecasts?

A. Yes.

Q. Are there any adjustments to the volume forecasts generated by these models?

A. Yes. The primary model was adjusted because of a change in one of our largest primary customers (“Large Primary Customer”). This Large Primary Customer, who had taken all of its energy requirements from the Company, began taking only supplemental power from the Company under Service Classification (“SC”) 25 in February 2006. Therefore, this Large Primary Customer’s full load was subtracted from the billed Primary volumes as of December 2001 and its volume currently under SC 25 is forecasted separately on the basis of its recent supplemental requirements.

Q. Do your forecasts of the delivery volumes to O&R customers reflect the impact of EE programs?

A. Yes. The forecasts are net of the impact of the EE programs that were supplied to us by the Orange and Rockland Energy Services Department.

Q. Have you treated EE savings in a similar fashion as in the last rate case?

A. Yes. Our forecast is adjusted for the projected EE savings in the same manner as in Case No. 11-E-0408. The delivery forecast generated from the forecasting models was manually adjusted to reflect the incremental EE savings that these programs are forecasted to provide once the EE measures have been installed.

Q. Are there any other adjustments to the delivery forecast?

A. Yes. The forecast includes the impact of customers' installation of solar panels. This is to capture the losses of delivery volumes as customers are now generating a portion of their energy requirements.

Q. Have you prepared an exhibit showing the adjustments you have made to the delivery volume forecast?

A. Yes, we have prepared a two-page document entitled "DELIVERY VOLUME ADJUSTMENTS", Exhibit ___ (EFP-E1), Schedule 2. In this exhibit we provide the EE impacts and loss of volumes related to the installation of solar panels, by service class for each rate year.

Q. How was the quarterly volume forecast disaggregated into monthly delivery volumes?

A. Quarterly forecasted delivery volumes were divided into monthly delivery volumes by reflecting the patterns of weather-normalized historical monthly delivery volumes of the past three years. Monthly delivery volumes also were adjusted for the appropriate billing-days.

Q. How was the major classification monthly delivery volume disaggregated into service class volumes?

A. The major classification monthly delivery volumes were allocated to service class volumes based on the 12 months ended June 2014 monthly service class delivery volumes.

Q. How is the Company's sendout forecast developed?

A. Because of the changes of a Large Primary Customer, as mentioned above in the discussion regarding the Primary volume model and volume forecast, the forecasted billed delivery volumes were used to develop a sendout forecast. We convert the billed delivery volumes, which is based on the number of days in the billing cycle, and the respective cycle degree days, to the calendar delivery volumes using the number of calendar days within a month, and the respective calendar degree days. Lastly, the final sendout is developed by taking the calendar delivery volumes and adding Company use, as well as line losses.

Q. How do you account for unbilled delivery volumes in calculating the Company’s total delivery volumes?

A. The total delivery volumes are derived by estimating the unbilled delivery volumes and adding those volumes to the billed volume forecast.

Q. Please explain unbilled delivery volumes.

A. Billed delivery volumes are recorded on a billing cycle basis, which varies from the calendar month. The unbilled delivery volumes translate the billed delivery volumes from a billing cycle basis to delivery volumes on a calendar month basis.

Q. How are the unbilled delivery volumes estimated?

A. The unbilled delivery volumes are derived by subtracting the monthly billed volume forecast from the calculated calendar month delivery volumes forecast.

REVENUE FORECAST

Q. Please explain the method of estimating the Company’s delivery revenues for the forecast period.

A. The delivery revenue forecast consists of both the non-competitive delivery revenues and the competitive delivery revenues. The non-competitive delivery revenues represent revenues from customer charges, and the energy and demand delivery rates while the competitive delivery revenues are comprised of the Merchant Function Charge ("MFC"), Billing and Payment Processing Charge ("BPP"), and Metering Charge Revenues.

Q. Please explain the method of estimating Orange and Rockland's non-competitive delivery revenues for the forecast period.

A. The non-competitive delivery revenues from the forecasted billed delivery volumes to Orange and Rockland's customers were estimated by month and by service classification. The individual service classes have a customer charge that is multiplied by the number of eligible customers for each class. For the energy delivery volumes, a pricing equation was developed by correlating historical average billed T&D revenue to historical billed volumes and summer/winter rate differentials, if applicable. For the demand classes that have a flat rate (*i.e.*, SC 3, 9, 9s, 9t, 20, 21, 22, 22s, 22t), the demand T&D revenue was calculated by multiplying the service class demands forecasted for the class by the tariff rate for the service class. For the demand classes that have block rates (*i.e.*, SC 2 secondary and SC 2 primary), a demand pricing equation was also developed by correlating the historical billed average. The T&D energy revenue for commercial and industrial classes is based upon pricing equations similar to those developed above for the energy only classes with the inclusion of MWs as an independent variable, if applicable. The majority of the pricing models are based upon the historical data for the period August 2007 through July 2008. An update of these equations using more recent data is not possible at this time because 12 full months of revenues at the same rates are required. With rate changes occurring in August 2008, July 2009, July 2010, July 2011, July 2012, July 2013, and July 2014, revenues at unchanged rates are available only for August 2008 through June 2009, which does not equate to 12 months. In addition, revenues from August 2008 cannot be used as they do not reflect the full extent of the August 2008 rate increase. The revenue from the pricing models was then adjusted to reflect the rate increases that are effective as of August 1, 2008, July 1, 2009, July 1, 2010, July 1, 2011, July 2012, July 2013 and July 2014. For purposes of this filing, revenues are priced at the rates that became effective on July 1, 2014. The non-competitive delivery revenue for other public authorities, which in this forecast represents one customer, was priced at their current contract rate. Lighting customers under SC 5 were priced at the tariff rate, lighting customers under SC 6 were priced with a rate provided by Rate Engineering, and the Large Primary Customer was priced at the SC 25 tariff rate. For the unbilled delivery revenues, we calculated average non-competitive rates for the forecasted billed volumes for each SC by month. We then multiplied those rates to the forecasted unbilled volumes in each SC by month.

Q. Please explain the method of estimating Orange and Rockland’s competitive delivery revenues for the forecast periods.

A. The MFC revenues represent the supply and credit and collection related charges. The billed volumes for full service customers were multiplied by the current MFC rate as determined in Case 11-E-0408. The BPP revenues were determined by applying the BPP charge per bill to the forecasted number of bills. This charge is at the level set in Case 07-E-0949 and depends on the customer’s choice of billing option and choice of service. The Metering Charge is also on a per bill basis and applies to demand classes only (*i.e.*, SC 2S, 2P, 3, 9, 20, 21, 22, and 25). We similarly forecasted this charge by using the rates established in Case 11-E-0408.

Q. Please explain the projection of billable demand for Orange and Rockland’s commercial and industrial customers.

A. Billable demand is the ratio of the forecasts for billed energy volumes and the average hours use. Hours use is simply the ratio between billed delivery volumes and billable demand.

Q. How is the average hours use forecasted?

A. An analysis of the relationship between historical billed delivery volumes and billable demand was used to project the average hours use.

Q. The revenue forecast also includes Market Supply Charge (“MSC”), System Benefit Charge (“SBC”), Revenue Tax, PSA Fixed Charges, and Intercompany Fuel & PSA Bill Revenues. Please explain how these components are forecasted.

A. All of these components were supplied to us by the Orange and Rockland Financial Services Department.

Q. Please describe what is shown on Exhibit __ (EFP-E1), Schedule 3.

A. This page is a summary of the forecast and shows the Company’s electric system sendout, delivery volumes, and revenues derived from delivery volumes for the four months ended October 31, 2014, the 12 month period ending October 31, 2015, and RY1 through RY3, respectively. Line 1 shows the estimated sendout. Lines 2 through 4 show the estimated electric delivery volumes, and lines 5 through 18 show estimated revenues for each of the periods. For the Rate Year, as shown in column 3, lines 19 to 21 show the proposed revenue increases from delivery volumes to Orange and Rockland customers, as well as the associated revenue taxes. Line 22 shows total revenue at the proposed rates.

Q. Please describe what is shown on the five pages of Exhibit __ (EFP-E1), Schedule 4.

A. Page one of this Exhibit __ (EFP-E1) Schedule 4, shows electric delivery volumes and revenues by service classification for the four months ended October 31, 2014. Delivery volumes are shown in Column 1, the annual sum of the monthly billable demand is shown in Column 2, non-competitive T&D delivery revenues at the currently effective rates in Column 3, competitive service revenues at the currently effective rates in Column 4, Reactive Power revenue in Column 5, MSC revenues in Columns 6, Temporary ECA in Column 7, SBC revenues in Column 8, revenue taxes in Column 9, and total revenues in Column 10. Pages two through five are similar in format to page one; page two covers the forecast for the 12 months ending October 31, 2015, page three covers the forecast for RY1, page four covers the forecast for RY2 and page five covers the forecast for RY3. For RY1, as shown on page 3, the effect of the proposed changes in non-competitive revenues are shown in Column 11, the effect of the proposed changes in competitive revenues are shown in Column 12, the effect of the proposed changes in reactive power revenues are shown in Column 13, and the associated increase in revenue taxes shown in Column 14. Column 15 shows the total revenue at proposed rates. The total proposed revenue increase to Orange and Rockland's customers of $34,367,000, exclusive of gross receipts taxes, consists of the non-competitive related delivery revenue increase of $39,042,000and the competitive service revenue requirement portion of the delivery revenue decrease of $4,675,000. The resulting proposed overall increase for RY1, inclusive of the increase in rates and charges of $667,000, for revenue taxes, amounts to $35,034,000.

Q. Should this revenue forecast be used as the basis for setting the target revenues in the revenue decoupling mechanism ("RDM")?

A. Yes, the non-competitive delivery revenue forecast shown in Columns 3, 5, 11 and 13 on page 3 of Exhibit ___ (EFP-E1), Schedule 4.

Q. Is the Company proposing any changes to the RDM?

A. Yes, as discussed in the direct testimony of the Electric Rate Panel, the Company is proposing to include a new group and establish a single RDM target for SC 4 and 6. Group F will be the RDM target for SC 4 and 6. The Company also proposes to include Reactive Power revenues in the RDM.

Q. Please explain your proposal for Reactive Power revenues.

A. The Company has been deferring the Reactive Power revenues. We propose that, beginning November 1, 2015, the Reactive Power revenues be included as part of the RDM targets of the applicable service classes. Reactive Power revenues are not subject to reasonable estimation at the moment because it is difficult to predict a power factor for a customer or group of customers.

Q. Will you be revising this forecast as part of the Company’s update?

A. Yes, we will be revising this forecast to reflect more current data during the update phase of this proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Q. Please state your name, title, employer and business address.

A. My name is Joseph Briscese. I am Section Manager – Electricity and Gas Hedging for Consolidated Edison Company of New York, Inc. (“Con Edison”). My office is located at 111 Broadway, New York, New York 10006.

Q. Please describe your responsibilities in that position.

A. I am responsible for developing and implementing electric and gas hedging programs for Con Edison and its affiliate, Orange and Rockland Utilities, Inc. (“O&R” or the “Company”); strategically evaluating and participating in capacity, Regional Greenhouse Gas Initiative (“RGGI”) and transmission congestion contract (“TCC”) auctions; and evaluating and procuring renewable energy certificates (“RECs”).

Q. Please describe your professional background.

A. I have been in my current position since March 2009. From 1998 to 2009, I was involved in Risk Management for various companies, including Deloitte and Touche, Constellation Energy, and Public Service Company of New Mexico. From 1986 to 1997, I was employed by

Jersey Central Power and Light in various engineering positions of increasing responsibility. I received a Bachelor of Science in Electrical Engineering and Bachelor of Arts in Economics from Rutgers University in May 1986 and a Master of Science in Electrical Engineering from Rutgers University in May 1991. I also have a Professional Engineering License.

Q. Is this your first testimony before the New York Public Service Commission (“Commission” or “NYPSC”)?

A. No, I have previously testified in the 2011 O&R electric rate case (*i.e.*, Case 11-E-0408).

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe O&R’s historical and projected wholesale electricity supply purchases for the Company’s full service customers. Historical supply purchases cover calendar years 2011 through 2013 and projected supply purchases cover calendar years 2014 through 2018, which includes the rate year (*i.e.*, the twelve months ending October 31, 2016).

HISTORICAL SUPPLY COSTS

Q. What are the Company's objectives when purchasing energy for its full service customers?

A. The Company seeks the lowest reasonable electricity purchase costs for its customers, subject to reliability and contractual constraints. As part of this objective, the Company also seeks to mitigate price volatility.

Q. In what ways does the Company accomplish these objectives?

A. The Company pursues structural and tariff changes in the NYISO's wholesale electricity markets that are beneficial to the Company's customers through active participation in the NYISO governance process and through filings with FERC. Where appropriate, the Company pursues certain matters before FERC through the use of litigation, settlement, and mediation.

Q. Please describe, in general terms, how O&R procures electricity supply for its full service customers.

A. Electric energy and capacity are procured from the NYISO’s energy, capacity, and ancillary services markets. The Company also uses financial hedges to mitigate price volatility for its customers.

Q. I show you a one-page document entitled, “ORANGE AND ROCKLAND UTILITIES, INC. - WHOLESALE ELECTRICITY SUPPLY COSTS – CALENDAR YEARS 2011 THROUGH 2013,” and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (JB-E1)

Q. What does Exhibit ___ (JB-E1) show?

A. Exhibit ___ (JB-E1) illustrates the allocated and invoiced costs, from January 1, 2011 through December 31, 2013, for energy, capacity, and other services acquired on behalf of the Company’s full service customers. I note that this exhibit shows a decline in the volume of the Company’s spot market purchases, which is primarily due to customers migrating from full service to retail access.

Exhibit ___ (JB-E1) also identifies the net impact of the Company’s financial hedging in each of the last three years, including the cost of those hedges. The exhibit shows that the Company's hedging costs decreased significantly, especially when energy prices rose between 2012 and 2013, stabilizing wholesale supply prices for customers. The hedge premiums were approximately 12% of the overall supply costs for customers during the three-year period.

Q. Please describe the Company's spot purchases for O&R's electric commodity customers.

A. Spot energy purchases are made from the NYISO, primarily in its day-ahead market, but also from its real-time market. The NYISO prices energy in each of those markets at eleven different load zones. O&R customers' consumption is in NYISO's Zone G, the Hudson Valley load zone. Such energy is typically purchased at the NYISO spot price.

Spot capacity purchases are also made from the NYISO's capacity markets. The NYISO administers four capacity market areas: one for NYC, one for Long Island, one for Lower Hudson Valley and one for rest-of-state ("ROS"). O&R's capacity obligation is primarily in NYISO's Lower Hudson Valley market;

however, prior to May, 2014, O&R’s entire capacity obligation was in NYISO’s ROS market. The NYISO conducts auctions that allow load serving entities (“LSEs”), like O&R, to purchase capacity for a one-month period or for periods of up to six months. In general, any LSE with capacity obligations not met by the sum of non-NYISO purchases and NYISO purchases made in “strip” or monthly auctions are sold capacity by the NYISO from spot auctions it conducts monthly. Prices in each spot auction are set at the intersection of a demand curve and the supply offer curve. The demand curve is administratively established through the NYISO’s governance processes and approved by FERC. One aspect of the spot auction is that all supply offers in NYISO’s spot auction that are below the intersection of the administrative demand curve and the supply offer curve receive the spot market clearing price. That is, it is a single clearing price auction. It is typical for more capacity to be available for sale than is required to be purchased. Such excess capacity is purchased by NYISO on behalf of the LSEs, which are obligated by the NYISO tariff to purchase such “excess capacity.” LSEs buy the excess by default in the spot auction because there are more offers to sell than bids to purchase

Q. Please describe the Company’s financial hedging practices.

A. The Company uses financial hedge products to mitigate the volatility of its spot purchases. Products include fixed-for-floating price swaps, also known as contracts for differences (“CFDs”) and options. CFDs are typically traded on a peak or “5x16” basis, meaning their value is computed over the 16 peak hours (7 AM to 11 PM, prevailing time) on non-NERC-holiday weekdays. For example, a buyer of a CFD will negotiate a fixed price per unit to give the seller of a commodity at settlement in exchange for the seller giving the buyer the market price per unit of the commodity at settlement. CFDs may also be traded on an “around the clock” basis, priced at the arithmetic average of all 24 hours in a day, or on an “off-peak” basis, meaning their value is computed over eight off-peak hours (11 PM to 7 AM) during weekdays, and all weekend and NERC holiday hours.

Options typically provide a financial benefit to the option holder when the contracted parameters exceed prior agreed-upon thresholds. For example, if a commodity settles above a negotiated (strike) price, the option holder will receive the difference between the settlement price and the strike price. The costs of such options are related to the volatility of the underlying product, the length of time prior to delivery and the agreed-upon strike price.

I anticipate that capacity hedges for the Lower Hudson Valley will be used to mitigate capacity price volatility once a product is defined and available.

PROJECTED SUPPLY COSTS

Q. Have you prepared a projection of wholesale energy costs?

A. Yes.

Q. I show you a one-page document entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - PROJECTION OF WHOLESALE ELECTRICITY SUPPLY COSTS – 2014 through

2018" and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (JB-E2)

Q. What does Exhibit ___ (JB-E2) show?

A. Exhibit ___ (JB-E2) sets forth my projections of electricity supply costs through 2018, based upon the forecast of full service sendout provided to me by the Company's Forecasting Panel.

Q. Please describe the methodology used to develop these projections.

A. As noted earlier, capacity and energy are supplied from spot purchases. Spot capacity purchase costs are based on a projection of capacity supply margins in the Lower Hudson Valley region as provided by the NYISO, the application of these margins to expected demand curve parameters to project prices, and then the application of these prices to the Company's expected spot capacity requirements in the Lower Hudson Valley region. Excess capacity costs, as described earlier, and ROS capacity purchases are also included in these cost projections.

Spot energy costs are based on market values as of September 30, 2014. These price projections were then applied to the forecast of full service volumetric requirements as provided to me by the Company’s Forecasting Panel.

Q. Has the net impact of financial hedges been included in these projections?

A. Hedges have been assumed to be “at the money,” which means that it is assumed hedges will settle without a gain or a loss, thereby not affecting customers’ prices for the purposes of these cost projections. However, financial hedges may command premiums for reducing buyers’ price volatility risks and so may be expected to increase costs marginally over the long-term.

It should be noted that the Company currently hedges only for those customers with demands less than 300 kW. I would further note that in its February 26, 2008 Order in Case 06-M-1017, the Commission reiterated that utilities are responsible for taking steps to mitigate wholesale price volatility for their residential and small commercial customers. As a result of that Order, O&R and the other New York utilities publish on their Internet websites quarterly volatility reports that compare actual supply rates charged to full service customers to a hypothetical unhedged market index based on load-shaped spot market prices.

Q. Please describe the system used to support the hedging program?

A. The Company uses Allegro, which is an energy trading and risk management software system provided by a third party vendor.

Q. What benefits does Allegro offer over other alternative approaches to managing hedging activities?

A. Unlike other alternatives, Allegro is a Sarbanes-Oxley compliant system. For example, the use of a spreadsheet for hedging does not meet Sarbanes-Oxley requirements. More specifically, Sarbanes-Oxley requires enhanced controls, such as separate permission or security rights for data entry and data approval, or enhanced audit trails. Spreadsheets do not support such enhanced controls.

Q. Is Allegro used exclusively for O&R hedging?

A. No. Allegro is used to capture hedge transactions for both O&R and Con Edison.

Q. What percentage of Allegro use is attributed to hedging for O&R customers?

A. 7.33%, based on a combination of ratio between CECONY and O&R of total assets, payroll and gross margin.

Q. What are Allegro's recurring costs?

A. Allegro has an annual maintenance cost of approximately $164,000, of which $12,000 is allocated to O&R based on the above percentage.

Q. How are the costs recovered?

A. Currently, costs are expensed in O&M. The hedging program and its support systems directly affect the O&R portfolio. Therefore, we recommend that the ongoing costs for these systems be recovered through the market supply charge.

Q. Does this conclude your testimony?

A. Yes. It does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
MARIBETH MCCORMICK

INTRODUCTION

Q. Please state your name and business address.

A. Maribeth McCormick, 3 Old Chester Road, Goshen, NY 10924.

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

A. I am employed by Orange and Rockland Utilities, Inc. (“Orange and Rockland”, “O&R” or the “Company”). I hold the position of Technical Manager in the Environmental Health and Safety (“EH&S”) Department.

Q. Please summarize your professional and educational background.

A. I received a Bachelor of Science degree in Environmental Studies from Ramapo College in 1986. I have been employed by the Company since 1975. In 1983, I began working in the Environmental Services Department as a staff specialist with responsibilities related to environmental compliance and permitting with my primary responsibilities being related to polychlorinated biphenyls (“PCBs”), hazardous wastes, spill prevention and emergency spill response. In 1985, I was assigned responsibility for overseeing the investigation and remediation of the Company’s former manufactured gas plant (“MGP”) sites and Comprehensive

Environmental Response, Compensation, and Liability Act (“Superfund”) sites. I was promoted to the Position of Section Manager – Environmental Services in 2002. In that position, I managed the Environmental Services Department staff and was responsible for all of the Company’s environmental programs. In 2008, I assumed my current position as Technical Manager in the EH&S organization. In 2011, I received a Project Management Certificate from the State University of New York at Stony Brook.

Q. What are your responsibilities as Technical Manager in the EH&S Department at the Company?

A. As Technical Manager, I manage the implementation of site investigation and remediation programs for former MGP sites and non-MGP sites. This includes oversight and direction of the construction activities at O&R’s MGP and non-MGP remediation projects. I work with the Company’s Public Affairs Department to develop and implement community participation programs necessary to support Site Investigation and Remediation (“SIR”) programs and act as the Company liaison with regulatory agencies, principally the New York State

Department of Environmental Conservation (“DEC”), property owners and community, environmental and industry groups with respect to SIR matters.

Q. Have you previously submitted testimony before the New York State Public Service Commission (“Commission”)?

A. Yes.

SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony focuses on the Company’s SIR program activities, most importantly with respect to MGP sites.

This includes SIR program expenditures that are mandated by agreements, regulations, administrative consent orders (“ACOs”), or permit requirements. My testimony will describe O&R’s SIR program for MGP sites. In addition, I will discuss briefly the Company’s West Nyack Operating Center site (“West Nyack Site”) and an underground storage tank (“UST”) site at the Company’s Spring Valley Operating Center, which the Company must address under Federal and DEC regulations. These two sites comprise a very small portion of the Company’s SIR obligations. I will also provide brief descriptions of the Third-Party Superfund Sites where O&R is a Potentially Responsible Party (“PRP”) and the estimated liability for each site.

Furthermore, I will explain the steps the Company takes to control and mitigate its SIR program costs. As discussed below, I also support Exhibit __ (MM-E1).

SIR PROGRAM

Q. Please provide an overview of the Company’s SIR program.

A. Orange and Rockland has a comprehensive on-going program for managing its SIR sites and verifying that required remedial response measures (investigations followed by any necessary remedial action) are properly performed for sites that have been contaminated by past releases of petroleum products, hazardous wastes, and hazardous substances from the Company’s and its predecessor companies’ facilities and/or operations. The predominant focus of this program is MGP sites. To a lesser extent, the Company’s SIR program also addresses the West Nyack

Site, the single UST site, and the Third-Party Superfund sites.

MGP SITES

Q. Please provide a brief background on the Company's and its predecessor companies' former MGPs and manufactured gas storage holder facilities.

A. MGPs provided energy in the form of combustible gases of varying composition to municipal street lighting systems and to homes and businesses in cities and towns across the more densely populated regions of the United States. In the case of the areas served by O&R and its predecessor companies, MGPs operated from the late 1850s through the early 1960s. The MGPs converted coal (oven gas) or a combination of coke or coal, oil and water in the form of steam (carbureted water gas) into a gas product that could be used for lighting, cooking, and/or heating beginning at time before electricity and natural gas came to be used for those same purposes. There were more than 200 MGPs in New York State and an estimated 3,000 to 5,000 in the United States, mostly in the Northeast and Midwest, prior to these plants becoming obsolete due to the construction of natural gas pipelines and large electric generating stations.

Q. What are the current environmental concerns related to MGP sites?

A. Manufactured gas production was a complex process that entailed the production, handling and storage of significant quantities of feedstock materials, by-products, and residuals that contained organic and inorganic chemical constituents that are now, but not at the time of the operation of the MGPs, considered to be hazardous substances under Federal and New York State laws and regulations and that, when released to soil, groundwater, or waterways, may pose a threat to human health and/or the environment. The materials of primary concern at MGP sites include carbureting oils, scrubber oils, coal tar, coal tar-related emulsions and sludges, and gas purification wastes.

Q. What are the DEC requirements regarding SIR for MGP sites?

A. The DEC has required New York State’s investor-owned utilities, such as the Company, to investigate and, when necessary to protect human health and the environment, to undertake remedial response actions for the sites of their MGPs. Most New York State utilities have entered into ACOs or cleanup agreements with the DEC pursuant to which the utility will undertake remediation of an MGP site in accordance with DEC requirements and under DEC monitoring. In some cases, such as for O&R, these ACOs or cleanup agreements might cover multiple sites. The New York State Department of Health ("DOH"), which works with the DEC in evaluating the results of MGP site investigations and determining the need for remedial response actions for them, views the primary goal of these investigations as assessing potential human exposure to MGP-related contaminants.

Q. Turning to the Company's MGP sites, please provide some additional background information.

A. Orange and Rockland's and its predecessor companies manufactured gas at MGP sites located in Rockland and Orange Counties. Some of these sites are now owned by parties other than O&R and have been redeveloped by their new owners for other uses, including residential and commercial development. Pursuant to two ACOs that

O&R entered into with the DEC, the DEC requires the Company to investigate and, if necessary, develop and implement DEC and DOH-approved remedial action plans for all of its and its predecessor companies' seven confirmed MGP sites. Of these seven MGP sites, four are still owned in whole or in part by the Company. In addition, since the execution of these ACOs, O&R has identified, investigated and remediated another site – the McVeigh Road site. The McVeigh Road site was not an MGP site but it is a site where MGP tar was disposed.

Q. Please identify and describe O&R's seven MGP sites and the McVeigh Road site and the current SIR status of each.

A. Nyack Gas Plant

This site is currently a privately-owned vacant property located along Gedney Street and the Hudson River in Nyack. Significant subsurface contamination of soils, groundwater and bedrock were found on the site. In addition, MGP impacts were identified in nearby Hudson River sediments. The DEC issued a Record of Decision ("ROD") for the land portion, Operable Unit 1 (“OU-1”), of the site in March 2004 requiring remediation of impacted media. Remediation activities for OU-1 were completed in November 2007 and included a combination of excavation and in situ treatment technologies including chemical oxidation and solidification. The DEC issued an ROD for the shore line soils and river sediments (OU-2) in March 2011. The ROD requires shallow soil excavation, in situ solidification (“ISS”) of deeper soils and removal of impacted sediments. The remedial design for this remedy was completed in 2013. Remedial construction began in March 2014 and will continue through December 2014. Final site restoration activities are scheduled to be completed in Spring 2015.

Suffern Gas Plant

In December 2008, O&R purchased the former MGP site property that had been operated by Econo Truck/US Bus since the 1950s. This purchase will enable O&R to implement the necessary remediation to address the MGP impacts in subsurface structures, soils and groundwater at and around the site. To comply with the Village of Suffern Building Department requirements, the US Bus building was demolished in February 2010. Supplemental investigation activities were completed in October 2009 and May 2010. Sentinel wells, installed between the site and the Village of Suffern water well field are monitored on a quarterly basis to verify that the Village water supply wells are not being impacted adversely by site contaminants. The Feasibility Study (“FS”) for this site was finalized in 2013 and a ROD was issued by the DEC in March 2014. The remedy that must be implemented according to the ROD includes excavation of subsurface soils to the water table (approximately 10 ft.) and in situ solidification of impacted soil to a maximum depth of 35 ft. The ROD also requires institutional controls such as a deed restriction, a Site Management Plan (“SMP”) and development of a Water Supply Protection Plan that will outline steps to protect the Village water supply wells if impacts are identified in the sentinel wells. The Remedial Design has been initiated and is currently scheduled to be completed in late 2015. O&R conducted an Interim Remedial

Measure ("IRM") at this site in 2010 to remove the septic system that was contributing to groundwater impacts. An IRM is a discrete set of remedial actions that can be conducted without completion of the extensive FS process. An IRM is part of the overall remedy that is implemented earlier in the SIR process to address an imminent threat or to obtain additional information for the FS.

Haverstraw Gas Plant (93 B Maple Avenue)

This site is privately owned and located in a residential area, with several residences immediately adjacent to the site. Remediation of the site and off site properties was completed in 2004. The DEC issued two RODs (one in 2005 and one in 2006) for the various remediation phases. No further action is required regarding this site at this time. The Company developed a SMP that maintains the existing building on the site in place as an engineering control. The SMP has been approved by the DEC and O&R will be entering into discussion with the property owner to negotiate a formal agreement relative to the requirements in the SMP. The institutional controls in the SMP restrict any intrusive activities under and around the building and allow for the removal of the remaining contamination should the building be demolished in the future. Annual inspection and certification to confirm that the institutional control is in place will be required.

Haverstraw Gas Plant (Clove & Maple)

This site is owned by O&R and was operated as a gas regulator station. The regulator station was retired in 2007. A comprehensive remedial investigation ("RI") and numerous supplemental investigations have been completed on the site and on several adjacent properties. MGP residuals and contamination have been found in subsurface soils and groundwater both on and off site including an apartment complex and several residential properties. MGP impacts that are associated with this site also have been detected in nearby Hudson River sediments. The FS to evaluate remedial alternatives was completed in 2010. Due to the complexity of the remediation aspects of the site and the numerous third party property owners, the DEC separated the site into three operable units. The ROD for the onsite property (OU1) owned by O&R was issued in March 2011. The ROD for the offsite properties (OU2) was issued in March 2012. The ROD for OU3 has not been issued. O&R prepared a Pre Design Investigation Work Plan for OU2 in 2013. However, due to sale of the apartment complex in 2014 and potential development plans for that parcel, the commencement of the PDI has been deferred. Remedial design activities will be initiated for OU1 instead.

Fulton Street – Middletown

This site is a privately owned commercial property. A comprehensive RI and numerous supplemental investigations have been conducted on the site and on several adjacent properties including property operated by the U.S. Postal Service. These investigations have determined that significant MGP impacts are present in subsurface structures, soils and groundwater on site; on some of the offsite properties; and beneath the road between them. Some pre-design investigation work will be conducted in late 2014 – early 2015 prior to finalizing the FS.

Genung Street – Middletown

This property is owned by O&R and is comprised of four individual parcels. Three of the parcels are vacant, and one is operated by O&R as a gas regulator station. O&R has completed a comprehensive remedial investigation (“RI”) and FS on the site. Significant contamination in subsurface soils and groundwater is present on one of the parcels. Minor impacts have been noted in the other three parcels. An ROD was issued by the DEC in March 2005. The ROD stipulates that impacted soils will be excavated from the site; soil or pavement cover will be provided in areas exceeding certain regulatory guidance values and institutional controls will be imposed to control the future use and development of the site. Given the greater priority for the remediation of the Company’s other MGP sites, O&R and the DEC have agreed that the remedial work at this site likely will not occur until close to the end of the Company’s remediation program. However, the DEC has requested that O&R complete the remedial design for this site. The remedial design and pre-design investigation activities are ongoing.

Port Jervis Gas Plant

This site is owned by O&R and previously served as a customer service center and as a satellite operating center for field crews. A comprehensive RI and numerous supplemental investigations have been completed at the site, on several adjacent properties and in and along the Delaware River. Significant MGP impacts and contamination have been identified in subsurface structures, soils and groundwater both on and off-site. No significant impacts to the Delaware River have been identified. The FS was completed in 2006 and the DEC issued a ROD in December 2007. In order to implement the ROD, the Company purchased several adjoining properties. The Company completed one property purchase in May 2011 and the other property purchase in December 2011. Remedial design was completed in 2012. The remedial construction associated with the soil excavation component of the remedy was completed in June 2013. Tar collection wells to address contamination that was not removed during the excavation phase of the remedy were installed in August 2014. The Company will monitor these wells on a monthly basis and any tar that is found in the wells will be recovered. A deed restriction will be placed on the O&R property and a Site Management Plan will be developed for both on and off site impacted areas.

McVeigh Road

This site was identified in 2001 during the construction activities for the installation of a fire hydrant for O&R’s Middletown Tap Substation. The source of the contamination is unknown, but was confirmed to be MGP-related. The impacts were limited to sediments located within a small section of Monhagen Brook. Remediation of the site required excavation of impacted sediments and was completed in December 2009 with DEC oversight. The Company completed site restoration during the Spring of 2010.

Q. What specific MGP SIR activities are expected to be conducted during the twelve months ending October 31, 2016 (“Rate Year”)?

A. During the Rate Year, the Company plans to: (1) complete remedial design activities and initiate remedial construction at the Suffern MGP site, (2) proceed with remediation design and planning activities at OU1 of the Clove and Maple Ave. Haverstraw and at the Fulton St., Middletown site (3) prepare SMPs and conduct periodic site inspections at sites where remedial construction is complete such as Port Jervis and Nyack.

Q. Do you expect the Company to continue to conduct similar MGP site investigation and remediation activities over the next five years?

A. Yes, but since O&R has completed remedial investigation of all of its sites, the investigation activities will be focused on data collection for remedial design. Remedial planning/design activities and/or remedial construction will be performed during this time period.

NON-MGP SITES

Q. Other than MGP sites, what other types of sites are covered by O&R’s SIR efforts?

A. As noted above, the Company must address the West Nyack Site and a single UST site. The Company also is responsible for the investigation and remediation of environmental conditions at third-party Superfund sites. These are sites to which O&R shipped hazardous substances or waste for treatment, storage, or disposal and has been designated as a PRP for the investigation and remediation of site contamination by the EPA, the DEC or other government environmental agency pursuant to the Comprehensive Environmental Response, Compensation and liability Act ("CERCLA") or comparable state statutes, including statutes imposing liability for the costs of investigating and cleaning up oil spills.

<u>West Nyack</u>

The West Nyack Site is currently listed on the New York State Inactive Hazardous Waste Site Registry as a Class 4 Site. This means that the site has been properly closed but requires continued management and monitoring. The remediation of impacted soils at the facility was completed in 1999. Quarterly groundwater monitoring was conducted at the site as directed by the DEC. In addition, indoor air and soil vapor sampling was conducted annually. Based on O&R's successful efforts to identify the offsite source of groundwater contamination, effective fourth quarter

2012, the DEC has removed the requirements for the quarterly groundwater monitoring and indoor air and soil vapor sampling. A SMP was developed by the Company and approved by DEC in 2012. The SMP restricts intrusive work on the site and requires annual inspection of the impervious asphalt cap on the site.

UST Site

Q. How many UST sites are currently being addressed under the Company's SIR Program?

A. As noted above, the Company currently has one UST site that is located at the Company's Spring Valley Operating Center. Soil and groundwater contamination were identified following investigation of a line leak in 2008. In 2013, the Company conducted soil remediation and tank removal in conjunction with installation of a replacement tank system. During the Rate Year, the Company currently anticipates that it may have to perform a limited amount of groundwater monitoring and reporting.

Q. Do you expect the Company to continue to conduct similar UST site investigation and remediation activities over the next five years?

A. At this time, O&R has not identified any other UST systems that require investigation and/or remediation.

Third-party Superfund Sites

Borne Chemical

The Borne Chemical site is a PRP site. The site was a 14-acre former petrochemical packaging/waste oil recycling facility located along the Arthur Kill waterway in Elizabeth, New Jersey. The site was abandoned in 1985 when its owner filed for bankruptcy. The site is being investigated and remediated by a PRP steering committee in compliance with administrative directives issued by the New Jersey Department of Environmental Protection ("NJDEP") pursuant to the New Jersey Spill Compensation and Control Act ("Spill Act"). Orange and Rockland joined the PRP steering committee as part of the settlement it entered into with the members of the steering committee. As directed by the NJDEP, the PRP steering committee has investigated the site and completed a $10 million

NJDEP-approved program to clean out the site's oil and chemical storage tanks and piping systems. The PRP Group is now implementing an NJDEP-approved remediation plan to collect the free-phase oil present beneath portions of the site and to excavate and cap contaminated soils on the site. The NJDEP is evaluating, but has not yet approved, a remediation plan for the site's contaminated groundwater.

Orange and Rockland's share of estimated total liability for the Borne Chemical site is 2.27%.

Ellis Rd.

The Ellis Road/American Electric Corporation site is a PRP site. The site is a former PCB waste consolidation, storage and treatment facility that was operated by the now defunct American Electric Corporation ("AEC") from 1979 until 1984. In 1984, the warehouse building that AEC used at the site for the processing and storage of regulated PCB equipment and materials was destroyed by a fire that resulted in PCBs being released to the environment. EPA performed an emergency response action and a series of initial removal actions to secure the site and to prevent further releases of PCBs. EPA subsequently identified AEC's former customers and demanded that they fund an additional removal action for the site. Orange and Rockland was designated a PRP for the site because it shipped 440 gallons of PCB-contaminated waste water to the site for treatment. Approximately 200 of AEC's former customers, including Orange and Rockland, joined together in 1988 to form a PRP Group. In 1989, the members of the PRP Group entered into an EPA administrative order on consent (“Consent Order”) that obligated the group to perform EPA’s required site removal action. Between 1990 and 1991, the PRP Group performed the required removal action and excavated PCB-contaminated surface soil, disposed of about 20,000 gallons of PCB-contaminated liquid waste, and emptied and decontaminated the above ground storage tanks that EPA installed at the site as part of its initial emergency response and removal actions. However, because the site is located near residential properties and more recent soil and groundwater sampling detected PCBs at concentrations that exceeded

EPA's residential PCB cleanup standards, at the end of 2011 EPA notified all presently existing site PRPs of the need for a new removal action and demanded that they enter into another Consent Order under which the group would reimburse EPA for site oversight costs, and either implement or fund the implementation of the required removal action. In March 2012 Orange and Rockland entered into an agreement with the other PRP Group members regarding allocation of costs to be incurred pursuant to the proposed Consent Order. Orange and Rockland signed the Consent Order with EPA in July 2012. The total cost of cleanup for the site is currently estimated to be $5.4 million.

O&R's share of estimated total liability for this site is 0.24%.

<u>Metal Bank</u>

The Metal Bank Superfund Site is a PRP site. The site is a ten-acre former scrap metal reclamation facility located along the Delaware River in northeastern Philadelphia. It was added to the Superfund National Priorities List in 1983 after EPA and the U.S. Coast

Guard documented releases of PCB-contaminated oil from the site to the Delaware River. Orange and Rockland is a member of a PRP steering committee comprised of electric utilities that shipped scrap transformers to the site during the late 1960s and 1970s. In 1998, EPA issued Unilateral Administrative Orders compelling Orange and Rockland, most of the other steering committee members, and the current and former owners and operators of the site to design and implement the remedy EPA selected in December 1997 for the site and the PCB-contaminated sediment in the area of the Delaware River along the site’s waterfront. EPA’s selected remedy was challenged by the current and former site owners and operators in the U.S. District Court for the Northern District of Pennsylvania. The members of the steering committee also sought contribution from the current and former site owners and operators. After years of negotiations, settlements resolving all claims and consent decrees embodying the requirements of the settlements were approved and entered by the District Court in 2006. Under their consent decree with the government, the steering committee members were required to design and implement the required remediation work for the site and Delaware River sediment affected by the site’s contamination. They were entitled to receive contribution of approximately $4.1 million from the principals of the metal reclamation company that contaminated the site with PCBs while salvaging scrap transformers. The steering committee members were also entitled to seek reimbursement of their remediation work-related costs from the $13.2 million trust fund established as part of the settlement of their claims against the bankruptcy estate of the corporate parent of the current site owners and operators. The implementation of the remedy was started in early 2008 and completed in 2010. As required under their consent decree with the government, the members of the steering committee are currently implementing monitoring activities as part of the site’s completed remedy.

During 2013, state and federal natural resource trustees provided the PRP steering committee and other site PRPs with a copy of their Natural Resource Damage

Assessment and Restoration Options Report ("DAROR") that assessed natural resource damages ("NRD") allegedly caused by releases of hazardous substances at the site. The natural resource trustees for the Metal Bank site include the National Oceanic and Atmospheric Administration, the United States Department of the Interior, the National Fish and Wildlife Service, and various Pennsylvania agencies. The DAROR focuses on losses to soil, sediment, and fish resulting from releases of PCBs from the site and habitat losses caused by the EPA's required site remedial construction activities. Such losses are estimated by comparing PCB concentrations in site soils, Delaware River sediment, and fish tissue to literature-based adverse effects thresholds. The PRP steering committee has assessed the DAROR and submitted comments to the trustees questioning the extent, if any, of NRD by the site. Negotiations with the trustees regarding NRD issues are expected to continue during the upcoming reporting period.

Orange and Rockland's share of estimated total liability for this site is 4.58%.

COST PROJECTIONS

Q. Have you prepared an estimate of projected SIR costs in connection with this rate case?

A. Yes. That estimate is shown in Exhibit__ (MM-E1) bearing the caption "Orange and Rockland Utilities, Inc., Site Investigation and Remediation Expenditures."

Q. Was Exhibit__ (MM-E1) prepared by you or under your supervision?

A. Yes.

Q. Please describe what is shown in Exhibit__ (MM-E1).

A. Schedule 1 of Exhibit__ (MM-E1) details the projected SIR expenditures for the MGP sites. Schedule 2 of Exhibit__ (MM-E1) provides details regarding the projected costs for the West Nyack, Spring Valley UST and the Third-party Superfund Sites.

Q. How much does the Company expect to spend in total during the linking period, the rate year, and the two subsequent 12 month periods following the rate year for its SIR Program?

A. The expenditures shown for those periods on Schedules 1 and 2 of Exhibit __ (MM-E1) aggregate to $33,334,000. I would note that while, as discussed by the Company's Accounting Panel, the Company is not proposing a multi-year rate plan in this electric rate case, I do address certain capital plant additions and other programs and initiatives in the two years following the Rate Year in this proceeding. For the sake of convenience, I refer to these two years as Rate Year 2 (*i.e*., November 1, 2016 through October 31, 2017) and Rate Year 3 (*i.e*., November 1, 2017 through October 31, 2018).

Q. Please discuss the major reasons for the projected SIR Program expenditures of $33,334,000.

A. The major drivers for the projected SIR Program expenditures are construction and remedial action activities at the MGP sites that are not yet remediated. The sites include the Suffern MGP and the Clove and Maple Ave., Haverstraw MGP. Remedial design at several of the MGPs is also planned.

Q. How did you determine the projected expenditures in Exhibit __ (MM-E1)?

A. The projections for the MGP projects are calculated by cost loading the projected schedule for each of the MGP sites to generate project/program cost forecasts. The costs for the West Nyack and Spring Valley UST are estimated annual monitoring costs. The costs for the Third-party Superfund sites are based on estimates of O&R’s share of the PRP group costs. The Accounting Panel’s direct testimony explains the allocation of these expenditures and the amount included in the Company’s revenue requirement.

Q. Could actual expenditures differ from these estimates?

A. Yes. The projected expenditures represent what the Company expects to spend on these programs during the linking period and the Rate Year and Rate Years 2 and 3 based on information that is currently available. The projected schedules and estimated costs presented in my testimony are subject to change based on design and construction related contingencies, which may include regulatory review and approval schedules, regulatory agency decisions,, access and cooperation issues with property owners, property owner development plans, community concerns, permitting and new information. Delays in a project may result in acceleration or substitution of other projects. It is important to note that each site is different due to various factors (*e.g.*, nature of the site, level of contamination, and site usage). Remediation costs will vary accordingly. I also would note that the MGP spending projections for known 2014 actuals, along with the West Nyack Site and the Spring Valley UST site will be updated as part of the Company's rebuttal and update testimony.

SIR COST CONTROL EFFORTS

Q. What steps has O&R taken to control its SIR costs and liabilities?

A. Orange and Rockland follows the management/mitigation practices set forth in the Inventory of Best Practices for Utility SIR Programs adopted by the State's electric and gas utilities pursuant to the Commission's Order issued November 28, 2012 in Case 11-M-0034. Specific details regarding O&R's SIR cost control efforts are detailed below.

Development of Remedies - When permissible under applicable laws and regulations, Orange and Rockland attempts to pursue remediation requirements with regulatory agencies based on the present and contemplated future use of sites, so that the remedies selected by the agencies are not more stringent than necessary for such uses. For example, if the present and contemplated future use of a site is for industrial or commercial purposes, the Company attempts to negotiate remediation requirements that are consistent with such uses, rather than the more stringent remediation requirements that would apply at sites with residential uses. When desirable and permissible under applicable laws and regulations, Orange and Rockland attempts to negotiate with regulatory agencies and third party property owners, remediation work plans that rely in whole, or in part, on post-remediation engineering and/or institutional controls in order to avoid more costly remediation to “unrestricted use” standards. In addition, when investigation results show that remediation may not be necessary to protect human health and/or the environment, the Company advocates its position to the regulatory agencies so that remediation requirements are not imposed unnecessarily. For example, at the Port Jervis MGP site, the Company was able to convince DEC that excavation at this MGP site should be limited to accessible source areas and that it was not necessary to disrupt and relocate existing infrastructure such as a gas regulator station and large municipal storm drain. In addition, the DEC concurred with Orange and Rockland that excavation substantially below the water table would not be necessary and that a non-aqueous phase liquid (“NAPL”) recovery system would provide an effective remedy in conjunction with a requirement that the site remain commercial/industrial. O&R also conducted a pilot study to determine the most effective well construction and installation methods for the NAPL recovery system. Based on the results of the pilot study, DEC modified the requirements for the NAPL recovery system. The various efforts detailed above saved millions of dollars on the remediation for the Port Jervis site.

Experienced Staff - Orange and Rockland staffs the Remediation Section of its EH&S Department with an experienced and dedicated full time project manager. The project manager works closely with qualified consultants and contractors to develop and implement the best possible work plans and specifications, consistent with applicable government agency requirements. Orange and Rockland also uses qualified consultants who are specially trained to perform constructability reviews of remedial design plans and specification, to manage these types of contracts and contractors, and to oversee field work so that the contractors comply with the terms of their contracts. To further enhance project management of remedial construction, O&R’s Project Management Department supports the Remediation Project Manager in the implementation of the required remedial action. Project Management reviews and approves the bid specifications, coordinates the remedial construction bidding with Purchasing and manages the remedial action contracts.

Reuse of Excavated Material - Whenever feasible and acceptable to the DEC and DOH, excavated soil and stone are reused as backfill at remediation sites. During remediation at the Port Jervis MGP site, non-impacted soil was excavated and reused as subsurface backfill.

Cost Effective Investigations - When appropriate and acceptable to the DEC, Orange and Rockland incorporates "step-out" procedures in its RI and pre-design investigation ("PDI") work plans. These procedures allow Orange and Rockland's project manager and DEC's project manager to expand the scope of an investigation while field work is being performed. Broadening the scope of investigation while field work is in progress helps minimize the need to prepare work plans for and conduct subsequent rounds of investigation.

<u>Participation in External Organizations</u> - Orange and Rockland actively participates in national and state industry forums and research organizations, such as the MGP Consortium, the Utility Solid Waste Act Group (“USWAG”) Remediation & Response Committee, the Environmental Energy Alliance of New York (“EEANY”), and the Electric Power Research Institute (“EPRI”), so that it obtains the benefit of others’ experience and knowledge and its in-house staff keeps abreast of regulatory requirements, technical developments in the remediation industry and innovative technologies. In addition, some of these organizations (*e.g.*, USWAG, EEANY) comment on regulatory proposals in an attempt to obtain more reasonable, more flexible, and less costly requirements.

<u>Competitive Procurement</u> - The Company competitively bids all remediation projects, retains qualified contractors, and follows its comprehensive procedures, including remediation contractor management protocols, so that project work is performed properly and cost effectively.

<u>Pre-Remedial Design Investigation and Treatability Studies</u> - When appropriate, the Company performs PDIs to fill data gaps in order to develop the best possible remediation work plans and specifications for regulatory agency approval and for competitive bidding.

<u>Insurance Cost Recovery</u> – Orange and Rockland has put its excess liability insurance carriers on notice of demands by the EPA and DEC that the Company pay for or implement site investigation and remediation work. It also has pursued indemnification of the costs of such work with its excess liability insurance carriers and, when necessary and appropriate, pursued litigation against insurance carriers that deny or reserve coverage for such costs.

With respect to insurance recoveries, in September 2002, O&R resolved its MGP claims with an insurance company that sold O&R excess liability insurance policies during the periods 1978 – 1983 and 1986 – 2001. The terms of the settlement agreement between

O&R and the insurance company are confidential. Another insurance company, Travelers Insurance, O&R's liability insurer until 1978, sued O&R in 2002 for a declaratory judgment that Travelers has no duty to indemnify O&R for costs incurred for remediation at MGP sites. That litigation remains pending. It should be noted that beyond the Travelers matter, the Company has no further opportunity to seek MGP cost recovery from an insurance carrier.

Claims for Indemnification- Orange and Rockland attempts, where possible, to transfer environmental liability for future remediation costs in agreements with third-parties in connection with the purchase or sale of real property or other assets and seeks indemnities for such future liabilities.

Identification of Other PRPs – Orange and Rockland attempts to identify other PRPs and, when appropriate, attempts to recover investigation or remediation costs from such entities. For example, Orange and Rockland undertook an investigation program in 2009 to demonstrate to the DEC that chlorinated solvent impacts on the West Nyack Site were attributable to an offsite source. Orange and Rockland was able to convince DEC/DOH Project Managers for both sites to view the information on an area wide basis. Orange and Rockland arranged for the submission of comments on the offsite property's Proposed Remedial Action Plan that resulted in acknowledgement of these impacts to Orange and Rockland's property in the ROD for this site. Based on these efforts, Orange and Rockland is no longer required to conduct quarterly groundwater monitoring at the West Nyack site. This has resulted in a savings of $80,000 per year.

Participation in PRP Groups - O&R participates in Superfund site PRP Groups to encourage them to negotiate with the government consent decrees and orders that equitably allocate liability among all financially viable PRPs and, when warranted, institute Superfund cost contribution actions against recalcitrant PRPs.

TSDF Audits - To minimize the potential that it will become a PRP at newly listed Superfund sites, O&R in conjunction with Con Edison has established a list of acceptable waste treatment, storage and disposal facilities ("TSDFs") and periodically reevaluates that list. The Company's procedures require that new TSDFs be approved before they are used.

Due Diligence in Property Transfer - To minimize the potential that property transfers might result in significant SIR costs, properties for prospective sale and purchase are extensively evaluated to identify potential environmental risks using environmental site assessment procedures.

Q. Does this conclude your direct testimony?
A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
INCOME TAX PANEL – ELECTRIC & GAS

I. INTRODUCTION AND PURPOSE

Q. Would the members of the Income Tax Panel ("Panel") please state their names and business addresses?

A. My name is Charles Lenns and my business address is 4 Irving Place, New York, New York 10003.

My name is Matthew Kahn and my business address is 4 Irving Place, New York, New York 10003.

Q. By who are you employed, in what capacity and what are your professional backgrounds and qualifications?

(Lenns) We are both employed by Consolidated Edison Company of New York, Inc. ("Con Edison"), the corporate affiliate of Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company"). I am the Vice President – Tax at Con Edison, and I am the chief tax officer for Orange and Rockland.

I have a Bachelor's Degree (Magna Cum Laude) in Accounting from the University of Scranton, and a Juris Doctorate from Duquesne University Law School. I was a tax partner at Ernst & Young, LLP ("Ernst & Young"), for 23 years, mostly specializing in taxation of power and utility companies. While a partner at Ernst & Young, I was the firm's tax practice leader for the power and utilities mergers and acquisitions group. I am a frequent speaker at Power and Utility tax seminars and conferences I have also testified as an expert witness in utility rate cases in California, West Virginia and Hawaii, and I have provided tax consulting services to utility companies in preparation for rate proceedings. I was employed by Ernst & Young in various tax positions for 11 years prior to my becoming a partner of the firm. I have been in my current position at Con Edison for approximately two years.

I am currently an adjunct instructor at the University of Scranton, where I teach various tax classes at both the undergraduate and graduate levels. While at Ernst & Young, I was an adjunct law professor at Duquesne Law School, and an adjunct instructor at Duquesne University's Masters in Taxation program. I also served as an instructor in the Ernst & Young National Tax Education program, called EY University. I am a member of the Edison Electric Institute Taxation Committee, and a member of the American Gas Association Taxation Committee. I am a licensed attorney and a certified public accountant in the Commonwealth of Pennsylvania. I am a member of the American Bar Association and a member of the American Association of Certified Public Accountants.

(Kahn) I am a Senior Tax Accountant at Con Edison. I support the income tax compliance and accounting functions, as well as the functions related to book depreciation and supervise the tax depreciation functions.

I graduated from Bentley College (now Bentley University) in 2004 with an undergraduate degree in accounting, and completed a master's degree in taxation at Bentley University in 2010. I have been employed by Con Edison since 2010. Prior to my employment at Con Edison, I worked in various roles within the accounting industry and in the field of taxation with PricewaterhouseCoopers, LLC, and subsequently as an analyst with American Tower Corporation.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to propose and provide the basis for a change in the way Orange and Rockland calculates and reports federal income tax expense for financial accounting (*i.e.*, "book") purposes and treats federal income tax expense for ratemaking purposes. Currently, for both financial accounting and ratemaking purposes, the Company uses flow through accounting for temporary differences between financial accounting income and taxable income related to certain plant-related costs and property tax expense. The Company proposes that the full normalization method of accounting be adopted for both of those purposes for those plant-related costs and property taxes with respect to federal income taxes.

We would note that our proposals do not affect State income taxes because a full normalization approach currently is applied to all plant-related costs in the Company's accounting and ratemaking for State income taxes.

Q. Please identify the plant-related costs to which your proposal applies.

A. Our proposal is to normalize, rather than flow through, the tax benefits related to cost of removal, book-tax basis differences related to capitalized costs, such as capitalized overhead costs, contributions in aid of construction ("CIAC"), and repair costs related to in service plant assets.

Q. Please explain what you mean by temporary differences between financial accounting income and taxable income.

A. Temporary differences are differences between book and tax treatment as to the period in which an item of income or expense is recognized. An example of such a temporary difference would be the difference between depreciation expense for financial accounting purposes and depreciation expense for tax purposes. Depreciation expense for financial accounting purposes is based on spreading the plant asset cost over its expected useful life, *e.g.*, 40 years, while for tax purposes that plant asset may be depreciated over a much shorter period, *e.g.*, 20 years. The difference, assuming all else being equal *(e.g.*, the asset cost being the same for financial accounting and income tax purposes), is one of timing of recognition of the expense between financial accounting and income tax, rather than one of amount.

Q. Please discuss how flow through accounting addresses temporary differences.

A. Flow through accounting does not take into account temporary differences. Rather, for both financial accounting and for ratemaking purposes, income tax expense is based on the income tax treatment rather than the financial accounting treatment of temporary differences. For example, with accelerated depreciation, under a flow through approach, the tax benefits of depreciation expense would be realized over a much shorter period than the book life of the plant asset. The tax benefit of depreciation expense would be reflected in income over that shorter period. In other words, the tax benefit would be "flowed through" to customers as realized and there would be no tax benefits to recognize over the remaining longer book life of the plant asset. Thus, under flow through accounting, income tax expense for temporary differences does not correlate with when the income or expense is recognized for financial accounting purposes.

With flow through accounting with respect to costs related to plant assets, rates are lower in the early years of the useful life of the plant assets that produced the tax benefits and higher in the later years. Customers in earlier years receive the benefit of accelerated tax deductions, while customers in later years receive none. Normalization of temporary differences avoids that inequity.

Q. Please discuss how normalization accounting addresses temporary differences.

A. Normalization accounting matches the income tax benefit of temporary differences with the related book expense. The difference between tax expense per a company's tax return and the expense per books is recorded in a deferred income tax account.

For example and referring again to accelerated depreciation for tax purposes, assume that depreciation expense for financial accounting and ratemaking purposes is $100 per year based on an estimated 30-year useful life of a plant asset. For income tax purposes, however, an accelerated method of depreciation results in a depreciation deduction of $1,000 in an early year, say the first year of the asset's life. The Company would take the $1,000 tax deduction but the income tax benefit recognized for accounting and ratemaking purposes would be as if the tax deduction was equal to the $100 of book depreciation. The tax benefit of the additional $900 deduction would be recorded in a deferred income tax account and recognized in tax expense for financial accounting and ratemaking purposes ratably over the remaining years of the asset's useful life.

Consequently, with normalization accounting, the tax benefit of an asset's cost is spread over the same time period that the cost of the asset is reflected in rates. As a result, both current and future customers equitably pay for their "consumption" of the asset and receive a commensurate share the related tax benefits.

At the time there are no further tax deductions for depreciation and the deferred tax benefits begin to be recognized for accounting and ratemaking purposes, the tax benefits are said to have begun to "reverse."

Q. Is normalization accounting used by the Company for financial accounting and ratemaking purposes with respect to accelerated depreciation for tax purposes?

A. Yes. The Internal Revenue Code ("IRC") requires normalization with respect to accelerated depreciation and shorter tax lives. IRC Section 168 requires that a utility's tax expense for ratemaking purposes be computed using the same depreciation method used in determining depreciation expense for ratemaking purposes (*e.g.*, straight line) and a recovery period that is no shorter than the useful lives of plant assets employed for ratemaking purposes. The temporary difference between the actual tax expense computed using accelerated tax depreciation methods and tax expense for ratemaking purposes must be carried on the utility's balance sheet in a deferred tax reserve and reflected as a rate base reduction for ratemaking purposes.

Q. Are all plant related temporary differences normalized for financial accounting and for ratemaking purposes?

A. No. The Company currently normalizes only temporary differences related to accelerated depreciation and related shorter tax lives. Other plant-related temporary differences such as capitalized overhead costs, allowance for funds used during construction ("AFUDC"), capitalized repairs, removal costs, and CIAC, are accounted for as flow through items. For income tax purposes, these costs are deducted when incurred. For financial accounting purposes, these costs are capitalized into plant accounts and recovered through book depreciation expense.

Q. Is it the Company's position that these temporary differences should be normalized as well?

A. Yes. The full normalization of all temporary differences allows for a fair matching of the tax benefit of temporary differences with the regulatory treatment of the underlying temporary difference. As a result, customers who are charged in rates with the cost of a temporary difference will also realize the tax benefit attributable to that expense. Full normalization should apply whether the temporary difference is related to accelerated depreciation and related shorter tax lives, or whether the temporary difference is related to costs that are capitalized for ratemaking purposes but currently deducted for income tax purposes.

Q. Is normalization of temporary differences sound public and ratemaking policy?

A. Yes. Normalization fosters intergenerational equity between current and future utility customers by spreading the tax consequences associated with the utility's assets over the in-service lives of the utility's assets. The effect levels customers' rates over time. Most states apply normalization concepts to all long-term differences between financial accounting and the associated income tax treatment.

Q. Are there any similar plant-related costs currently subject to flow through accounting and ratemaking that you propose remain treated on that basis?

A. Yes. Continuing the flow through approach for the equity component of the AFUDC included in the cost of plant assets is appropriate.

Q. Please explain.

A. The equity component of AFUDC may be considered a permanent difference because this item is never recognized as income for income tax purposes. No tax expense is ever incurred with respect to this item. Accordingly, income tax should follow the book treatment of equity AFUDC.

Q. What impact will switching to full normalization have on utility rates?

A. The Company will experience an increase in cost of service as the regulatory asset that is recorded on the books related to prior years' flow through taxes reverses. We estimate that the revenue requirement related to the reversal of this regulatory asset will be $ 266,000 per year for electric and $ 81,000 per year for gas. In addition, full normalization will result in the recording of additional deferred income tax credits on the Company's books in future years. Deferred income tax credits reduce rate base. The Company estimates that full normalization will result in the recording of an annual increase in the amount of $2.7 million of additional deferred income tax credits for electric and $53,000 for gas.

Q. Is the Panel sponsoring an exhibit related to its proposals?

A. Yes. The Panel is sponsoring Exhibit ITP-1, Schedule 1 ORU Tax Accounting Method Comparison, which was prepared under our supervision and direction.

Q. Please describe Schedule 1 of Exhibit ITP-1.

A. Schedule 1 of Exhibit ITP-1 provides a summary of the effects of changing from flow through accounting to full normalization accounting for the plant-related cost items that we propose are subject to the change. This Exhibit also shows the detailed calculations for both current and deferred income tax expense under both the flow through and full normalization methods forecasted for calendar years 2015 through 2019, as well as the Rate Year (*i.e.*, 12 months ending October 31, 2016) and the twelve months ending October 31, 2017 and October 31, 2018. Each scenario of flow through and normalized tax accounting methods details the plant related temporary differences between financial accounting and income tax treatment in order to provide the results of the proposed method.

The fourth page of Exhibit ITP-1, Schedule 1 sets forth the 2015 calculation of current, deferred and total tax expense for plant related differences between financial accounting and income tax accounting under the current flow through method. The specific items included in the annual calculation are tax depreciation, taxable gain or loss on disposition, book depreciation, cost or removal, mixed service cost ("MSC"), and repair tax expense. The summary includes both current federal income tax expense related to the noted differences and current State tax expense. The calculation of deferred income taxes (both the accumulation as well as the expense), is summarized for reference on page 1 of Exhibit ITP-1, Schedule 1. The fifth page of Exhibit ITP-1, Schedule 1 contains the same set of plant related differences between financial accounting and income tax treatment as would be recorded under the proposed full normalization method. The specific items are consistent between pages 4 and 5 in order to facilitate the analysis and comparison in the file for the 2015 year, and subsequent years. The years are broken down in the following manner, with flow through accounting as the first example followed by the same criteria under full normalization; 2014 on pages 2-3, 2015 on pages 4-5, 2016 on pages 6-7, 2017 on pages 8-9, and 2018 on pages 9-10, and 2019 on pages 12-13.

Q. Please summarize the effects of your proposals on federal income tax expense.

A. Our proposals have no effect on current period federal income tax liabilities. Annual income tax expense for book purposes will, however, be higher under our proposals due to tax benefits that are currently treated under the flow through approach being deferred with the adoption of normalization accounting. Our forecast indicates the amount of the increase to be approximately $2.8 million in 2015, which consists of an effective tax rate increase of 1.3% for electric service, and 6.5% for gas service. The net impact on the Company is an increase in the ETR of approximately 3% (from 26% to 29%). Along with the change in income tax expense there will be a rate base decrease due to the deferral of tax benefits increasing the balance of deferred income tax credits. That decrease is forecasted to be approximately $251,000 in the first Rate Year and that reduction is forecasted to grow by approximately $200,000 in each succeeding year. The net rate impact of the increase in tax expense and the reduction in rate base return would be an increase in the revenue requirement of approximately $2.5million in the Rate Year. For more details see page 1 of the Exhibit ITP-1, Schedule 1.

Q. Please discuss your proposed change in the treatment of property tax expense.

A. The Company pays property taxes at various times during the year. For financial accounting and regulatory purposes, the Company defers property tax expense and amortizes the expense over a twelve month period, beginning with the month after the date of payment. For income tax purposes, the Company deducts the full amount of the payment in the year of payment.

Q. How does the Company account for property taxes in calculating its income tax expense for regulatory purposes?

A. The Company computes income tax expense by accounting for property taxes in the year of payment. Income taxes on the unamortized deferred property tax balance are reflected on the balance sheet in a regulatory asset account. The Company proposes to change its method of accounting for income tax expense to record income tax expense based on the book amortization of property taxes. This treatment matches the income tax benefit of property taxes with the property tax expense recorded on the Company's regulatory books and records.

Q. What is the anticipated balance in the regulatory asset account and how does the Company propose to treat this regulatory asset?

A. At December 31, 2015, we anticipate the regulatory asset to be $12,806,599, and we propose to recover this asset in rates over the remaining service lives of the assets to which the property taxes relate. As set forth in Exhibit ITP-1, Schedule 2, service lives range from 34-46 years, and the recovery is approximately $348,000 per year.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
CHARMAINE CIGLIANO – ELECTRIC & GAS

Q. Please state your name and business address.

A. Charmaine Cigliano, 390 W. Route 59, Spring Valley, New York 10977.

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

A. I am Section Manager – Customer Energy Services for Orange and Rockland Utilities, Inc., ("O&R" or the "Company").

Q. Please briefly outline your educational and business experience.

A. I received a Bachelor of Science degree from the Binghamton University in 1988 with a double major in Mathematics and Computer Science. My first employment thereafter was with O&R as an Analyst with the Economic Research Department where I held positions of increasing responsibility. In 1998, as a result of the merger between Consolidated Edison Company of New York, Inc. ("Con Edison") and O&R, I was offered and accepted the position as a Senior Planning Analyst in Con Edison's Electric Forecasting Department. In 1999, I accepted a Senior Planning Analyst position in Con Edison's Rate Engineering Department. In 2000, I returned to O&R as the Customer Information Management

System Billing Team Lead and in 2004 I was promoted to the Manager of Retail Access. In 2008, I was promoted to my current position as Section Manager - Customer Energy Services. I have testified before the Public Service Commission in Case 11-E-0408.

Q. Please describe your responsibilities as Section Manager - Customer Energy Services.

A. I am currently responsible for the design, implementation and evaluation of O&R's portfolio of Energy Efficiency Portfolio Standard ("EEPS"), demand response, targeted demand-side management ("DSM"), renewable and low-income programs. I am also a member of the E2 Advisory Group which supports EEPS efforts.

Q. What is the scope of your direct testimony in this proceeding?

A. In my direct testimony, I will address the Company's low-income program for electric and gas customers.

Q. Does the Company propose to continue its gas low-income program?

A. Yes. The Company proposes to continue its gas low-income program whereby any gas customer who receives a grant under the Home Energy Assistance Program

(“HEAP”), will receive a monthly bill credit. Currently that credit is $11.63 per month and for the last two rate years expenditures under the gas low income program have exceeded $1.2 million. This current rate year (*i.e*., 12-month period ending October 31, 2014) expenditures are expected to exceed $1.3 million. The reason for the significant increase in expenditures is due to the steady growth of gas customers receiving monthly bill credits, *i.e*., from an average of 6,750 customers in the 2010 rate year to an average of 9,474 during the current rate year. As a result of this customer growth, expenditures have exceeded the Company’s current annual rate allowance of $878,000 for the last four rate years (*i.e*. rate years ending October 2011, 2012, 2013 and 2014).

Q. Does the Company propose to continue its electric low-income program?

A. Yes. The Company proposes to continue its electric low-income program whereby any electric customer who receives a grant under HEAP, will receive a monthly bill credit. Currently that credit is $9.00 per month for electric customers and $17.40 per month for electric heating customers. For the rate year ended June 2013, low-income program expenditures were $890,721 and consistent with the annual rate allowance of $1.0 million. However, for the rate year ended June 30, 2014 expenditures were $1,068,487 with the corresponding annual rate allowance $1.4 million. For the current rate year ending June 2015 the rate allowance is $1.8 million. The Company does not expect expenditures to exceed $1.2 million for the current rate year ending June 2015, which will also be well under the rate allowance of $1.8 million.

Q. Is the Company proposing to increase the annual rate allowance for the gas low-income program and decrease the annual rate allowance for the electric low-income program?

A. Yes. The Company proposes to increase the gas low-income annual rate allowance to $1.4 million, based on the current rate year expenditures, the upward trend of the last several rate years, and the expected increase in gas customers who receive HEAP assistance over the next rate year. In contrast, the Company proposes to decrease the electric low-income program annual rate allowance to $1.3 million, based on the trend of the last few rate years and the slight increase in customers expected to receive HEAP assistance during the next rate year.

Q. Does the net effect of the increase and decrease produce a higher collections target for electric and gas customers?

A. No. The increase of $0.5 million in the gas collections target is offset by the decrease of $0.5 million in the electric collections target and should be viewed simply as a reallocation of the funding levels.

Q. Under both its current electric and gas rate plans, under certain circumstances the Company waives reconnection fees for low income customers. Is the Company proposing any changes to its current reconnection fee waiver policy?

A. No. The Company proposes to continue its current reconnection fee waiver policy.

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
DAVID V. WORK

Q. Please state your name and business address.

A. David V. Work, 390 West Route 59, Spring Valley, New York, 10977.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R," or "the Company") as Department Manager of Project Management.

Q. Please briefly describe your educational and business experience.

A. I received a Bachelor of Science degree in Civil Engineering in 1996 from Lehigh University and a Masters of Science degree in Civil Engineering in 1999 from University of Massachusetts. I am a registered professional engineer (PE) in the States of New York and Connecticut as well as Project Management Institute ("PMI") certified Project Management Professional ("PMP"). Prior to joining Orange and Rockland in 2010 I have held various positions in the engineering, construction and utility industry ranging from Project Engineer to Vice President. At Orange and Rockland I have held the positions of Project Manager and Section Manager, prior to assuming my present position as Department Manager of Project Management.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the Company's project management efforts and how they are consistent with certain recommendations contained in the Liberty Management Audit of Consolidated Edison Company of New York, Inc. ("Con Edison"), released in June 2009 ("Liberty Audit"). I also present and support O&R's proposed position additions related to its project management program.

Q. Are the recommendations contained in the Liberty Audit applicable to the Company?

A. Yes, in its Order Establishing Rates for Electric Service issued June 17, 2011 in Case 10-E-0362, the Public Service Commission ("Commission") directed the Company to produce a report detailing its implementation of those recommendations contained in the Liberty Audit that were applicable to the Company. Several of those recommendations (*i.e.*, Recommendations 42, 44, 68, 69, 70 and 72) relate to project management. Orange and Rockland submitted a report dated June 24, 2014 to the Commission describing its efforts to implement those Liberty Audit recommendations applicable to the Company. A copy of this report is included in this rate case filing as Exhibit ___ (AP-E7).

Q. Please describe the Project Management initiatives implemented by Orange and Rockland that are consistent with the Liberty Audit recommendations.

A. A description of the Company's Project Management initiatives is set forth below.

Project Management Efforts at O&R and New Resources

Consistent with recommendations from the Liberty Audit, the Company has a stated goal of continuing to increase its focus on project management and cost consciousness throughout the organization. O&R has instituted initiatives to transform the project delivery and management model for its capital projects. The Company's effort to carry out these initiatives has been a multi-year process that includes the consolidation and fundamental reconfiguration of O&R's financial and supply chain systems ("Project One"), development of a Project

Management Department and organizational structure, and a significant increase in the Company's focus on project management for all of its projects and programs, both large and small.

Historically, project management at O&R was conducted through a decentralized model among different engineering groups. This process was effective when there were fewer projects to manage and project scopes were relatively smaller and less complex. As the Company's projects have become larger, more complex, and more expensive, the decentralized model has proved less effective. The amount of work required to manage projects under the decentralized approach resulted in Company engineering resources being spread too thin to effectively manage all aspects of a major project. It became evident that the Company's Engineering resources were overtaxed and were not being utilized to their full potential on their primary job function, *i.e.*, system engineering and design.

Q. Please continue.

A. The Company recognized that there were substantial resource limitations in implementing an effective and well-functioning capital delivery model. The need to focus new and additional resources, specifically on project management, project approvals, scheduling, cost control, construction and overall O&R process improvement was identified as a critical gap. With the Company experiencing more involved and protracted approval processes, in combination with the expansion in number and scope of its major capital projects, in 2009 O&R identified the need to implement a significantly more formalized, focused and centralized project management model.

Q. Please describe the current status of this effort.

A. O&R has established a Project Management Department with responsibility for managing and implementing the Company's large capital projects (generally defined as projects with estimated construction costs in excess of $5 million). Currently, the Project Management Department is composed of 20 staff members with expertise in project management, scheduling, estimating, cost control, engineering, permitting and construction. The Department manages all aspects of projects from inception through commissioning. O&R is firmly committed to a centralized project management model based on PMI standards and continues to make investments in expanding the model across the organization.

Q. Has the Project Management Department made a significant impact on the project performance of the overall O&R organization?

A. Yes. O&R has made extensive progress implementing its project management program. By employing this model, the Company has been able to achieve significant and comprehensive improvements, including those described below. Achievement of large project completion key performance indicator ("KPI") in 2014, 2013 and 2012. Prior to the realignment of the Company's project delivery model, this KPI was regularly missed. The KPI consists of delivery of four to five key projects on schedule and budget within the specified year. The projects are generally the largest of the Company's projects and/or key strategic projects.

- Over the previous three year rate term O&R has seen a significant improvement in the completion of capital projects. In the rate year ending June 2013 net plant additions were $21 million under the minimum PSC targets for that agreement. In the rate year ending June 2014 net plant additions were $7 million above PSC targets. For the rate year ending June 2015 the net plant additions as of September 2014 are $19 million above target. This trend is a result of the Company's comprehensive focus on project management fundaments and capital project delivery.

- Increase in the stability of project financials. For example the quarterly reports filed with the Commission regarding our large capital projects have become significantly more consistent. Reduction in approval timeframes for projects and more accurate forecasting of project in-service dates.
- Comprehensive and detailed monthly project status and reviews of schedule and budget with senior management. Project status meetings have dramatically increased the project teams' and Company's focus on the schedule and budgets of large capital projects, consistent with O&R's increased focus on cost consciousness.
- Development of a Project Controls Group within the Project Management Department. This Group is responsible for estimating, scheduling and documentation of contract information for all large projects implemented by the Project Management Department. O&R's estimating and scheduling processes have undergone a major overhaul in the past four years. The Company has developed and implemented formal estimating guidelines. The details of which are discussed in the Electric Infrastructure and Operations Panel's direct testimony regarding the capital budget. The Company's scheduling processes have undergone a similar transformation from decentralized ,inconsistent scheduling to

central scheduling and tracking of large projects. The Company's project teams are now able to forecast the schedule impacts several years in the future of decisions made today.

- For several years, the Company's Engineering and Public Affairs departments have been expanding advance communications and outreach with Mayors, Town Supervisors and other municipal officials and customers in the boroughs and municipalities that will be affected by the Company's project construction activities. Over the past few years, the Company held corporate outreach meetings in Orange and Rockland counties with municipal officials, politicians, and business leaders to discuss the benefits that the Company's projects have for local communities and to encourage municipalities to streamline approval processes. These efforts have been successful in some cases, but the level of community opposition to a project typically dictates how much time and effort is required to obtain necessary approvals. While the Company will continue to implement these efforts, we have expanded our focus and improved our approach on addressing permitting and approvals in the early stages of a project by deploying a cross functional team that concentrates on just these aspects of our projects. The team is composed of members from a variety of Company departments, including Project Management, Engineering, Environmental, and Public Affairs. This team has begun the approvals process for the next generation of projects both in the permitting phase, as well as projects beyond the permitting phase. For those projects that are not in the permitting phase, the Project Management

Department is working closely with O&R's Property Acquisition Team to identify and screen potential properties. Once the property has been acquired, the permitting team works with the appropriate stakeholders to set the stage for future project approvals. The resulting focus on project approvals and permitting has significantly expedited the permitting process for many of our existing projects.

- There has been and continues to be increased coordination with the Company's Purchasing Department to manage contract risk and obtain competitive pricing. The Project Management Department has dedicated a Project Manager to managing the supply chain for large capital projects. The result has been a significant increase in the efficiency of the project procurement efforts.
- The Company has expanded the oversight of its large capital construction projects over the past four years. The Construction Management Group within the Project Management Department has made significant improvements in the safe management of construction projects. Improvements include re-organizing contractor safety processes, expansion of the number of construction management staff, increased technical training of field staff and implementation of electronic contract documentation processes. Improvements to the Construction Management Group have allowed for substantially improved continuity and functionality within the Group.
- The Company has made a significant commitment to formal project management training for staff both within the Project Management

Department as well as other O&R Departments involved in the execution of capital projects. Many of the Company's staff have received advanced degrees in Project and/or Construction Management and professional project management certifications.

Q. What additional steps are needed to increase the effectiveness of the Project Management Group?

A. Resource constraints in estimating, scheduling and permitting have become limiting factors in the Project Management Group's ability to provide services to the Company. The Company's projects are characterized by increasing complexity and a greater number of capital projects exceed the $5 million threshold which triggers the Project Management Department's involvement. O&R has used contracted resources to augment internal resources in the areas of estimating, scheduling and permitting. However, the Company's ability to use contractors in these positions is limited due to the sensitive nature of this work. These areas have limitations on the use of contract employees, as in many public forums company employees are either required or recommend to be the representatives of the company. On the financial side, sensitive financial data, project estimates, approval of payments, etc. require the use of company employees.

The key to continuing the positive initiatives discussed above, and realizing additional benefits, is the addition of project management resources which will allow the Company to maintain and increase the current level of performance on an increasing number of large capital projects.

As such, the Company is proposing to add one Estimator/Scheduler Specialist and one Permitting Specialist in the Rate Year (*i.e.*, 12 months ending October 31, 2016). These new resources are critical if O&R is to continue to expand the project management model resulting in timely and cost-effective completion of capital projects. The proposed positions are described in detail as follows:

- The Estimating/Scheduling Specialist will be focused on the estimating and scheduling of the Company's large capital projects. This position will augment the Company's two large project estimating and scheduling staff. While the Company has experienced significant success in improving project estimating and scheduling, the number of projects needing detailed estimates and schedules continues to increase. In 2010 the Department was managing 20+ estimates and schedules, in 2014 it is managing 110+ estimates and/or schedules, an increase of over five times the previous workload. As noted above, while contractors can provide some support, concerns regarding the sharing of sensitive financial information (i.e. project financials, estimates, payment approvals, etc.), as well as the multiyear nature of many of these projects (with the corresponding need to maintain institutional knowledge), limit the Company's ability to employ such contractors.
- The Permitting Specialist will be focused on securing the permits and approvals of the Company's large capital projects. This position will augment the Company's sole Permitting Principal Engineer. While the Company has improved significantly its project approval and permitting processes, a greater number of projects require an increasing array of

approvals and permits. Moreover, the processes for obtaining such approvals and permits continue to become more complex and involved.

The costs associated with these new positions are addressed in the direct testimony of Company's Accounting Panel.

Q. Please summarize your testimony.

A. In summary, O&R has made significant improvements to its capital project delivery and project management processes. The benefits from this approach have resulted in greater cost certainty, better planning, schedule accuracy, project documentation, organization and risk management. O&R is proposing to add two positions in order to address the current/future workload and continue to expand the influence of the Project Management model.

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.

PROPERTY TAX PANEL – ELECTRIC & GAS

Q. Would each member of the Property Tax Panel please state your name and business address?

A. **(Lenns)** My name is Charles Lenns. My business address is 4 Irving Place, New York, New York.

(Talbot) My name is William Talbot. My business address is 4 Irving Place, New York, New York.

(Hutcheson) My name is Charles D. Hutcheson. My business address is 4 Irving Place, New York, New York.

Q. By whom are you employed?

A. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison") and in that capacity are responsible for the property tax functions for Con Edison and its affiliate Orange and Rockland Utilities, Inc. ("O&R" or "the Company").

Q. Mr. Lenns, please explain your educational background, work experience and current general responsibilities.

A. I have a Bachelor's Degree (Magna Cum Laude) in Accounting from the University of Scranton, and a Juris Doctorate from Duquesne University Law School. I was a tax partner at Ernst & Young, LLP ("Ernst & Young") for 23 years, mostly specializing in taxation of power and utility companies. While a partner at Ernst & Young, I was the firm's tax practice leader for the power and utilities mergers and acquisitions group. I am a frequent speaker at Power and Utility tax seminars and conferences. I was employed by Ernst & Young in various tax positions for 11 years prior to my becoming a partner of the firm. I am the Vice President – Tax at Con Edison, and I am the chief tax officer for Orange and Rockland and have been in my current position for approximately two years.

I am currently an adjunct instructor at the University of Scranton, where I teach various tax classes at both the undergraduate and graduate levels. While at Ernst & Young, I was an adjunct law professor at Duquesne Law School, and an adjunct instructor at Duquesne University's Masters in Taxation program. I also served as an instructor in the Ernst & Young National Tax Education program, called EY University. I am a member of the Edison Electric Institute Taxation Committee, and a member of the American Gas Association Taxation Committee. I am a licensed attorney and a certified public accountant in the Commonwealth of Pennsylvania. I am a member of the American Bar Association and a member of the American Association of Certified Public Accountants.

Q. Mr. Talbot, please explain your educational background, work experience and current general responsibilities.

A. I graduated from Pace University in 1978 with the degree of Bachelor of Business Administration (Cum Laude). I received a Master of Business Administration degree from Iona College in 1985. I have been employed by Con Edison since 1978 and have held various positions of increasing responsibility within the Finance area. My first assignment with the Company was in the Corporate Accounting Department, where I spent 16 years and attained the position of Department Manager. I was Department Manager of the Accounting Research and Procedures Section from 1987 until May 1994. In 1994, I moved to the Tax Department as Director. In 2003, I returned to Corporate Accounting as a Director, ultimately responsible for Property Records, Payroll and Tax. Since March 2007, I have been a Department Manager in the Tax Department. My responsibilities include oversight of the sections and personnel responsible for taxes other than income taxes, including property taxes, book and tax depreciation, and tax audits.

Q. Mr. Hutcheson, please explain your educational background, work experience and current general responsibilities.

A. I graduated from Hofstra University in 1978 with the degree of Bachelor of Business Administration in Accounting. I have been employed by Con Edison since 1979 and have held various positions of increasing responsibility within the Finance area. My first assignment with the Company was in the Depreciation Section, where I spent 15 years and attained the position of Senior Accountant. In 1993, I moved to the Rates and Budget Section. In 1996, I transferred to the Financial Restructuring Team, where my duties were to assist in the development of Con Edison's rate plan filed in the New York State Public Service Commission's ("Commission") Competitive Opportunities Proceeding. I moved to the Tax Department in 1997 as a Senior Tax Accountant in the Federal Tax Section. In September 1999, I was promoted to Manager, Property Taxes, responsible for the property tax compliance function and the Company's efforts to hold down property taxes. In December 2001, I once again began working on depreciation matters when the Tax Department assumed responsibility for the book depreciation function. My current responsibilities include book and tax depreciation and supporting the

Company's property tax function.

Q. Have any members of the Property Tax Panel previously testified before any regulatory commission?

A. **(Lenns)** I have testified as an expert witness in utility rate cases in California, West Virginia and Hawaii, and I have provided tax consulting services to utility companies in preparation for rate proceedings.

(Talbot) I have testified before the Commission on the subject of income taxes in Cases 03-M-1148 and 04-M-0026 and on the subject of property taxes in Case 09-E-0428.

(Hutcheson) I have testified before the Commission on the subject of depreciation and/or property taxes in numerous cases for O&R and Con Edison; before the New Jersey Board of Public Utilities (on behalf of O&R's New Jersey utility subsidiary, Rockland Electric Company); and before the Pennsylvania Public Utility Commission (on behalf of O&R's Pennsylvania utility subsidiary, Pike County Light & Power Company).

Q. What is the purpose of the Property Tax Panel's direct testimony in this proceeding?

A. Our testimony:

- Presents general background information on property taxes;

- Describes the level of the Company's recent electric and gas property taxes;
- Presents our electric and gas property tax forecasts and explains the methodology and certain assumptions used in those forecasts;
- Explains the limitations on the Company's ability to control, and as a consequence, estimate, the level of its property tax obligations; and
- Discusses the Company's efforts to pay no more than its fair share of property taxes.

Q. Please explain the general basis upon which property taxes levied upon the Company have historically been determined.

A. Property taxes are based on the "value" of property and include taxes on land and the structures and/or equipment erected or affixed to the land, known as real estate taxes. In New York State, utilities also pay special franchise taxes, *i.e.*, property taxes on utility equipment located on or under the public streets and highways.

In New York State, public utility property is valued under a method known as the "cost approach." The New York State Office of Real Property Tax Services ("ORPTS") and most of the local assessors in the

Company's service territory where the Company has a significant amount of property, determine value by using a Reproduction Cost New Less Depreciation ("RCNLD") methodology for utility property. RCNLD calculates what it would cost to reproduce property at current construction costs based on a trending index, subtracts an allowance for depreciation and obsolescence, if any, and adds the value of land to arrive at a "value" for the entire property. RCNLD is used only to value certain of the Company's structures and all of its taxable equipment. The value of land and office buildings is determined by comparable sales data.

Q. What was the amount of the Company's property taxes for the Historic Test Year?

A. For the Historic Test Year in these proceedings (*i.e.*, the twelve months ended June 30, 2014) the tax payments allocated to electric operations amounted to \$34.1 million and for gas the amount was \$19.9 million, for a total of \$54.0 million.

Q. What is your forecast of property taxes for the Rate Year (*i.e.*, the twelve months ending October 31, 2016)?

A. For the Rate Year (which we may also refer to as "(RY1)" for ease of reference), we have forecasted $40.7 million and $23.9 million of expense for electric and gas property taxes, respectively, for a total of $64.6 million.

Q. What are the main drivers of the Company's property tax increases?

A. Property taxes change because either the tax rate changes or the assessed value of the property changes. However, both of those items are influenced by many factors, which we have found makes it difficult to estimate future property taxes. For example, it is not possible for us to determine the needs of each individual town government and school district each year. It is also far from certain as to whether they will be able to restrict tax levy increases to comply with the so-called "2% levy cap" under real property tax law. In all cases, the Company's property taxes are subject to the vagaries of municipal management, economic circumstances and political influences. In addition, the Company has no control over tax rates, leaving assessment challenges, when warranted, as the only recourse.

Regarding assessments, the Company's growth, or infrastructure investment is the primary driver of assessment increases. Although there have been unusual spikes in the past regarding how RCNLD is computed which can greatly influence the Company's property tax liability, as a *rule of thumb*, property tax increases are driven by the infrastructure investment needed to support the Company's efforts to provide safe and reliable electric service to our customers. However, even with an accurate plant forecast, estimating the tax level in each county, town, school district and village is problematic because of various moving parts including general economic conditions, equalization rates, levies, inflation, market values of other taxpayers, and of course how all of that information impacts each tax rate, and tax bills often contain many different tax rates.

Q. Can you estimate how much infrastructure investment growth and tax rate changes influence the Company's property tax liability?

A. It is difficult to make such an estimate as there are many assumptions to be made, but we estimate that from fiscal year 2009/10 through 2013/14, changes in tax rates are responsible for about one-third of the Company's property tax increase while the growth of infrastructure investment accounts for about two-thirds of the increase.

Q. Please explain how you arrived at the forecasted property taxes for the Rate Year?

A. We first established a base level of electric and gas property taxes to use in our forecast. The base levels, except for school taxes for the City of Middletown for which we included an estimated amount in the base levels, were the Company's actual electric property taxes paid for calendar year 2014 and the Company's actual gas property taxes paid for calendar year 2014. We included estimated amounts for school taxes for the City of Middletown because those taxes are not paid until October 31 making the actual amounts not available in time to reflect in the base amounts. We will update for that later in this proceeding. For Rate Year purposes, we escalated the base amounts by applying an overall, or Company-wide, escalation factor. We used an overall escalation factor because it is not practicable to specifically forecast property taxes for each of the many different municipalities and school districts to which the Company pays property taxes.

Q. How did you develop the overall escalation factor?

A. We first determined the five-year annual average rate of escalation based on historical tax payment information for calendar years 2009 through 2014.

Q. What was the five-year annual average escalation rate you determined?

A. The five-year annual average escalation rate was 12.9%.

Q. Did you use that 12.9% annual escalation rate to develop your forecast of property taxes for the Rate Year?

A. No, we used an 8% escalation rate.

Q. How does the annual average escalation rate of 8% reflected in your forecast compare to the actual annual rates of escalation in property taxes in recent years?

A. On a combined basis (*i.e.*, County & Town, School and Village taxes) the year-over-year percentage increases have been 14.67% in 2010, 11.93% in 2011, 11.90% in 2012, 16.75% in 2013 and 9.47% in 2014.

Q. Why did you use an annual escalation rate that is lower than the actual historic five-year annual average rate of escalation?

A. Forecasting property taxes encompasses many factors, including general economic conditions, property values, the Company's efforts to control property taxes, and the Company's construction activities compared to other construction in the area and should not be just a rote mathematical exercise. Informed judgment should also be applied. In our judgment, the annual rates of increase in property taxes in the coming few years will be somewhat less than they have been on average over the last five years due to economic improvement and New York State's pressure on municipalities and school districts to control their costs.

Q. On what do you base that judgment?

A. There are a few important factors. One is that the five-year annual average rate of escalation pertains to property taxes paid during a period that coincided with a sudden and significant downturn in the economy. That downturn was met with a loss of tax revenue from sales and other taxes. However, and in general terms, the property tax levies collected by municipalities and school districts did not decrease, resulting in higher property tax rates since the property tax is sometimes the only source of revenue or the "last" source of revenue used to balance budgets. A second factor is that we think that local taxing authorities, especially school districts, remain under enormous pressure from their communities to hold their tax levy increases within the limits of the "cap" law. Third, while during the last five years our assessments were increasing due to the Company's construction program and general inflation, the other assessments in the municipalities were likely decreasing or remaining the same as they are more closely aligned with the general economy. Although difficult to predict, our forecast is that an improving economy and cost controls by the school districts and municipalities will result in near-term property tax rates of escalation that will be below what was experienced in the previous five years. Therefore, we have concluded that a combination of some reliance on the five-year annual average computation as well as the judgments we made concerning the improving economy and pressure on taxing authorities by taxpayers will influence what will happen in the near future.

Q. Has the 2% “cap” limited the Company’s property taxes?

A. It is not possible to quantify the effect on the Company. Having said that, the cap seems to be limiting tax levy increases for municipalities and school districts have generally been compliant with the law, although compliance does not mean the levy was limited to a maximum 2% increase because of various exceptions allowed in the law. However, as indicated, it limits tax levies but not assessments so if the Company’s assessments are increasing for infrastructure investments while other properties have not or even decreased, the Company’s taxes will increase at rates well more than 2%.

Q. Will the Company provide any updates related to property taxes during this proceeding?

A. As indicated earlier, the Company anticipates it will be able to update for the Middletown school tax payments during the update stage of this proceeding.

Q. Does the Company have a proposal regarding reconciliation of property taxes to reasonably address the uncertainty of the Company’s level of property taxes for the Rate Year?

A. Yes. As we have already pointed out, we have found that it is very difficult to estimate future property taxes. As explained by the Company's Accounting Panel, and given the variability and uncertainty we have explained, the Company believes that an accounting and ratemaking mechanism that symmetrically and fully protects the interests of customers and the Company from forecast variations is reasonable and appropriate.

Q. Do you believe full and symmetrical property tax reconciliation lessens the Company's incentive to mitigate its property tax liability?

A. Not at all. As we will explain in greater detail later in our testimony, and as the Company has explained in numerous rate proceedings and annual reports to the Commission of its activities regarding property taxes, the Company has a long history of fighting to reduce the Company's property tax burden. Challenges to unfair assessments; lobbying efforts to seek favorable legislation; obtaining expert consultation; and aggressively pursuing available and potential tax benefits are a normal course of business for the Company.

Q. Has the Commission previously approved the full reconciliation of property taxes for a single-year rate plan?

A. Yes, in Case 08-E-0539, a rate case in which the Commission established electric rates for Con Edison on a litigated rather than settled basis and for a single rate year (i.e., outside of the context of a multi-year rate plan on settled terms).

Q. In Case 08-E-0539, did the Commission address concerns that a full reconciliation would lessen the Company's incentive to minimize property taxes?

A. Yes. The Commission concluded that would not be the case. On pages 106-107 of the Commission's *Order Setting Electric Rates*, issued April 24, 2009 in Case 08-E-0539, the Commission said:

> We share DPS Staff's concern about removing an incentive for the Company to minimize its property tax expenses. However, the record in these cases shows that the Company has aggressively sought to minimize its property tax assessments. Indeed, there is no assertion to the contrary. Moreover, our long standing policy is that a utility will be allowed to retain a share of property tax refunds, frequently in the 10-15% range, to the extent it can be established conclusively that the utility's efforts contributed to that outcome. Taking these two factors into account, we conclude that the Company already has and will retain an incentive to minimize its property tax assessments.

Given the variability and uncertainty we have explained, the Company believes that a full and symmetrical property tax reconciliation mechanism that serves to protect both customers and the Company from forecast variations is reasonable and appropriate.

Q. Please summarize the Company's efforts to minimize property taxes.

A. The Company has aggressively challenged its property tax assessments so that it pays no more than its fair share of property taxes. The Company has been and remains very concerned with the impact of property taxes on customer bills.

Q. Please discuss the Company's efforts to keep property taxes to a minimum.

A. Property tax amounts are a function of a tax rate multiplied by an assessed value. The Company has no influence on the tax rates that municipalities set; therefore, our basic effort is to focus on the fairness of assessments in a particular municipality.

Q. How do you determine which properties are over-valued?

A. Annually, we review our property assessments to determine if they fall within a range of reasonableness when calculated under RCNLD. If the actual assessments vary substantially from our RCNLD calculations, we institute complaints with the applicable taxing authorities. We attempt to settle these complaints when we believe that a settlement is a more cost-effective way of reducing our tax burden than prolonged litigation, the outcome of which is uncertain. We do, however, pursue litigation when our efforts to reach what we believe to be a fair compromise fail.

Q. Please describe the Company's efforts to avoid property tax increases.

A. O&R has reached settlements with the City of Middletown; the Towns of Blooming Grove, Chester, Clarkstown, Forestburgh, Haverstraw, Lumberland, Monroe, Orangetown, Ramapo and Wawayanda; and the Village of Hillburn. Those settlements cover a significant amount of the Company's property and assessments continue to be monitored in all of these areas to see if additional challenges are warranted. In fact, the Company continues to have active settlement discussions in jurisdictions where prior settlements had been reached and concluded (*e.g.*, Blooming Grove, Ramapo, Clarkstown and Orangetown).

Q. Please describe the Company's most recent efforts to minimize property taxes?

A. During 2013 O&R reached a settlement with the Town of Tuxedo reducing assessments on Transmission Line 311. The settlement covers years 2010 through 2013 and results in assessment reductions for those years from $767,600 to $300,000, or 61%, producing a refund from the Town and two school districts totaling $202,000, although approximately $23,000 of that was received in the form of an assessment reduction. Lower future assessments will provide annual tax savings of $85,000 for each of the years 2014 through 2016, bringing the total value of the agreement to $457,000.

In Middletown, litigation continues for years 2010 through 2014 regarding assessments on certain propane gas tanks that were not included in a settlement reached by the parties in 2012 on various other properties in Middletown. The matter that remains active concerns property taxes related to the propane tanks that were dismantled and removed yet were still being taxed as if they were in service. This case is currently on the court’s trial calendar.

In the Town of Goshen, in anticipation of a town-wide revaluation in 2012, the assessor sought an advisory appraisal from the ORPTS for a new substation under contemplation by O&R. Even though there were no physical improvements at the site, the assessor assessed the non-existent substation at the ORPTS theoretical value. O&R was recently successful in getting the current assessment reduced to zero, resulting in a refund.

During 2013 and 2014, the Company challenged the assessment on its office building in the Town of Blooming Grove. The matter has been the subject of preliminary discussions between O&R and the Town and we have hired an appraiser to prepare for trial. As a result of those discussions to date, the Town has reduced the assessment from $3,629,200 to $3,004,200 for the 2014-15 tax year. However, we do not believe that reduction is sufficient and our challenges for both years remain active.

More recently, we had, and are continuing to have, discussions with officials from the Towns of Ramapo, Clarkstown and Orangetown, all three of which we have previously settled with, in order to again lower our taxes in these municipalities. Those three towns comprise a significant portion of the Company’s tax liability, representing approximately 45% of taxes Company-wide.

As explained earlier, the ORPTS assesses special franchise property (*i.e.*, the Company's facilities in the public right-of-way) and we generally support the assessing policies of ORPTS. Therefore, we do not challenge the ORPTS assessments computed under RCNLD. However, we have applied for a Company-wide economic obsolescence ("EO") reduction for the Company's electric and gas facilities in an effort to lower our tax liability.

Q. What is an EO reduction?

A. The ORPTS defines EO as the loss in service value of property caused by an impairment in desirability or useful life resulting from factors external to the property and ORPTS has developed a model for determining EO. EO is approved when ORPTS concludes there is insufficient usage (*i.e.*, sales) to produce a reasonable return on investment at rates that permit the system to remain competitive with alternative sources of energy. If an EO reduction is approved, ORPTS lowers the assessed value of the special franchise property to provide a tax benefit.

Q. What is the status of the Company's applications for an EO reduction?

A. The Company applied for an EO reduction in 2013 and in

2014 but ORPTS denied the requests because they computed that the Company's achieved return on rate base exceeded the allowed return.

Q. Despite these efforts, do the Company's property taxes continue to increase?

A. Yes. Property taxes are used to finance local governments and public schools. The funds raised via the property tax levy are often the major revenue source for the taxing entity. The Company bears the levied tax obligations determined by the taxing authorities seeking to raise the funds they determine are necessary. Those needs, in concert with the Company's need to add critical capital infrastructure to serve the needs of its customers have combined to result in higher tax bills for the Company despite successful Company challenges to assessed valuations of its property.

Q. Does that conclude your direct testimony?

A. Yes, it does.

Direct Testimony and Schedules
Mr. Robert B. Hevert

Before the New York Public Service Commission

In the Matter of the Application of Orange and Rockland Utilities, Inc. to Increase Rates for Electric Service in New York

Return on Equity

November 14, 2014

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, AFFILIATION, AND BUSINESS ADDRESS.

A. My name is Robert B. Hevert. I am Managing Partner of Sussex Economic Advisors, LLC ("Sussex"). My business address is 161 Worcester Road, Suite 503, Framingham, MA 01701.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of Orange and Rockland Utilities., a New York corporation ("O&R" or the "Company") and a wholly owned subsidiary of Consolidated Edison, Inc. ("CEI").

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I received my Bachelors of Science degree in Finance from the University of Delaware, and a Master's degree in Business Administration from the University of Massachusetts. In addition, I hold the Chartered Financial Analyst designation. I have worked in regulated industries for over 25 years, having served as an executive and manager with consulting firms, a financial officer of a publicly-traded natural gas utility (at the time, Bay State Gas Company), and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in over 100 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies and the Federal

Energy Regulatory Commission (“FERC”). A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included as Attachment A.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony in this proceeding (“Direct Testimony”) is to present evidence and provide a recommendation regarding the Company’s Return on Equity (“ROE”)[1] for its electric and natural gas utility operations, and to provide an assessment of the capital structure to be used for ratemaking purposes, as proposed in the direct testimony of Company witness Saegusa. My analysis and recommendations are supported by the data presented in Exhibit Nos.___ (RBH-1) through (RBH-14).

Finally, I note that the Cost of Equity, which is the return required by equity investors to assume the risks of ownership, is a market-based concept. As discussed further in my Direct Testimony, as opposed to the earned return on common equity, which is an accounting construct that can be observed in historical data, the Cost of Equity is unobservable and must be estimated based on observable capital market data. As a consequence, there may be differences of opinion among analysts as to the data, assumptions and models used in the estimation process. I further am aware that in a recent rate proceeding for the Company, the New York Public Service Commission

[1] Throughout my Direct Testimony, I interchangeably use the terms “ROE” and “Cost of Equity” when referring to the market required Return on Equity. When referring to the accounting based concept of book return on equity, the distinction is noted.

("Commission") discussed its preferences with respect to certain methodologies.[2] As such, my Direct Testimony has been developed to note and explain any areas in which my approach may differ from the Commission's current practices.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY FOR THE COMPANY?

A. Based on the range of results produced by the quantitative and qualitative analyses discussed throughout my Direct Testimony, I conclude that an ROE of 9.75 percent to 10.50 percent is reasonable and appropriate. That range, in particular the 9.75 percent low end, reflects the unusual situation in which utility company Price/Earnings ratios traded well in excess of their historical average.[3] Those valuation levels, together with the methods discussed later in my Direct Testimony, produce ROE estimates somewhat lower than otherwise would be expected; under more typical market conditions, the analyses likely would indicate an ROE at or above 10.00 percent. Nonetheless, the Company's proposed ROE, 9.75 percent, lies at the low end of the unadjusted range. As such, I conclude that the Company's proposal is reasonable, if not conservative. If the Company, Staff and other parties are able to negotiate a three-year rate plan in settlement of this case, I conclude that up to a 50 basis point adjustment to the ROE would be appropriate.[4] With respect to the Company's capital structure, I conclude that the proposed capital structure, consisting of 48.00 percent common equity, 51.10 percent

2 Case 10-E-0362, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service*, Order Establishing Rates For Electric Service, (Issued June 17, 2011), at 64 ("2011 O&R Rate Order").

3 I note 9.75% is one basis point removed from the 9.74% mean low Two-Stage DCF result.

4 As discussed below in Section XI of my Direct Testimony, although the Company has not proposed a specific multi-year rate plan in this rate filing, I recognize that parties frequently have agreed to, and the Commission has adopted multi-year rate plans (often with a three-year term). I have assumed a three-year stay-out period in my calculations, but note my recommendation may change if a different stay-out period were used.

long-term debt, and 0.90 percent customer deposits, as testified to by Company witness Saegusa, is reasonable.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSIS THAT LED TO YOUR ROE RECOMMENDATION.

A. As discussed in more detail in Section VI (below), it is extremely important to consider the results of several analytical approaches in determining the Company's ROE. In order to develop my ROE recommendation, I therefore applied two forms of the Discounted Cash Flow ("DCF") model, and two forms of the Capital Asset Pricing Model ("CAPM"). Because the Commission has applied specific weighting factors to the DCF and CAPM models in prior proceedings, I have produced a set of analyses reflecting those weighting factors, *i.e.,* two-thirds weight applied to DCF results, and one-third weight applied to CAPM results.

In addition to the DCF and CAPM analyses, I considered the effect of flotation costs on the Company's Cost of Equity, and made a specific adjustment to my analytical results to reflect those costs. Finally, I considered the effect of certain business risks, most notably the Company's substantial capital expenditure plans, in arriving at my ROE recommendation.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized as follows:

Section III – Provides a summary of my conclusions and recommendations;

Section IV –	Discusses the regulatory guidelines and financial considerations pertinent to the development of the Cost of Capital;
Section V –	Explains my selection of the proxy group of electric utilities used to develop my analytical results;
Section VI –	Explains my analyses and the analytical bases for my ROE recommendation;
Section VII –	Summarizes the specific regulatory and business risks that have a direct bearing on the Company's Cost of Equity;
Section VIII –	Briefly discusses the current capital market conditions and the effect of those conditions on the Company's Cost of Equity;
Section IX –	Provides an assessment of the Company's proposed capital structure;
Section X –	Summarizes my conclusions and recommendations; and
Section XI –	Discusses the appropriate stay-out premium if the parties negotiate a multi-year rate plan in settlement of this case.

III. SUMMARY OF CONCLUSIONS

Q. WHAT ARE THE KEY FACTORS CONSIDERED IN YOUR ANALYSES AND UPON WHICH YOU BASE YOUR RECOMMENDED ROE?

A. My analyses and recommendations considered the following:

- The *Bluefield* and *Hope* decisions[5] that established the standards for determining a fair and reasonable allowed return on equity including: consistency of the allowed return with other businesses having similar risk; adequacy of the return to provide access to capital and support credit quality; and that the end result must lead to just and reasonable rates.

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5 *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

- The Company's business risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.
- The effect of the current capital market conditions on investors' return requirements.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSES?

A. The results of my analyses are summarized in Table 1.

Table 1: Summary of Analytical Results

	Mean Low	**Mean**	**Mean High**
Two-Stage DCF	9.74%	9.88%	10.03%
Three-Stage DCF	9.62%	9.84%	10.08%
	Bloomberg Beta Coefficient	**Value Line Beta Coefficient**	**Twelve-Month Beta Coefficient**
Market-Based CAPM			
Bloomberg Market-DCF Derived MRP	11.35%	10.74%	10.79%
Value Line Market-DCF Derived MRP	10.90%	10.32%	10.36%
Zero-Beta CAPM			
Bloomberg Market-DCF Derived MRP	11.83%	11.37%	11.41%
Value Line Market-DCF Derived MRP	11.35%	10.91%	10.95%
Average CAPM	11.02%		
CEI Flotation Cost	0.02%		
Proxy Group Flotation Cost	0.13%		
Weighted Average Cost of Equity (2/3 * Two-Stage DCF) +(1/3 * CAPM)			
Three-Month Average (including CEI Flotation Cost)		10.29%	

Based on the analytical results presented in Table 1, and in light of the considerations discussed throughout the balance of my Direct Testimony regarding the Company's business and regulatory risks relative to the proxy group, it is my view that an ROE in the range of 9.75 percent to 10.50 percent is reasonable and appropriate.

IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with the returns on equity investments in other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the means of arriving at a fair return are not controlling, only that the end result leads to just and reasonable rates.[6]

Based on those standards, the consequence of the Commission's order in this case should be to provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms, thereby enabling it to continue to provide safe, reliable service; (2) sufficient to support the financial soundness of the Company's operations; and (3) commensurate with returns on equity investments in enterprises having comparable risks. The authorized ROE should enable the Company to finance capital expenditures at reasonable rates and maintain its financial flexibility over the period during which rates are expected to remain in effect.

[6] *Ibid.*

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT EQUITY CAPITAL AT REASONABLE TERMS?

A. A return that is adequate to attract capital at reasonable terms enables the Company to provide safe, reliable electric and gas service while maintaining its financial integrity. While the "capital attraction" and "financial integrity" standards are important principles in normal economic conditions, the practical implications of those standards are even more pronounced when, as with O&R, the utility has substantial capital investment plans. That is particularly the case when, as discussed in more detail in Section XI, consensus projections for long-term Treasury yields suggest rates may rise.

V. PROXY GROUP SELECTION

Q. PLEASE EXPLAIN WHY YOU HAVE USED A GROUP OF PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR O&R.

A. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. In this proceeding, we are focused on estimating the Cost of Equity for O&R, a wholly owned subsidiary of CEI. Since the Cost of Equity is a market-based concept, and given that O&R is not publicly traded, it is necessary to establish a group of companies that are both publicly traded and comparable to O&R in certain fundamental business and financial respects to serve as its "proxy" in the Cost of Equity estimation process. As discussed later in my Direct Testimony, the proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to O&R, and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

It is my understanding that since the Recommended Decision in the Generic Finance Case approximately 20 years ago, the Commission has endorsed the use of proxy groups for the purposes of determining the ROE in utility rate proceedings.[7] Because proxy companies are used as the basis for estimating O&R's Cost of Equity, the primary objective of the screening process is to render a group of companies that are highly comparable to the Company with respect to fundamental financial and business risks. As a practical matter, while the determination of an appropriate ROE necessarily requires a degree of informed judgment, the careful selection of a risk-appropriate comparison group serves to mitigate the extent to which subjective assessments must be applied.

Q. DOES THE RIGOROUS SELECTION OF A PROXY GROUP SUGGEST THAT ANALYTICAL RESULTS WILL BE TIGHTLY CLUSTERED AROUND AVERAGE (*I.E.*, MEAN) RESULTS?

A. Not necessarily. As discussed in greater detail in Section VI, the DCF approach is based on the theory that a stock's current price represents the present value of its future expected cash flows.[8] Notwithstanding the care taken to establish risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. At issue, then, is how to select an ROE estimate in the context of that range. As discussed throughout my

[7] Case 91-M-0509, *Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York State Utilities*, Recommended Decision, (issued July 19, 1994) ("Generic Finance RD"), at 57.

[8] As noted later in my Direct Testimony, cash flows include both dividend payments and the stock's terminal value at the end of the analysis' projection period.

Direct Testimony, that determination necessarily must reflect the informed judgment and experience of the analyst.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF O&R.

A. O&R provides electric distribution service to approximately 225,000 customers, and natural gas service to approximately 130,000 customers, all located in southeastern New York.[9] O&R's long-term issuer ratings are A- (S&P), A3 (Moody's), and BBB+ (Fitch Ratings). The Company's senior unsecured bond ratings are A- (S&P), A3 (Moody's), and A- (Fitch Ratings).[10]

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the companies that Value Line classifies as "Electric Utilities", which comprise a group of 47 domestic U.S. utilities, and simultaneously applied the following screening criteria:

- I eliminated the companies that are not covered by at least two utility industry equity analysts;
- I eliminated companies whose corporate credit ratings and/or senior unsecured bond ratings are below investment grade according to Standard & Poor's Financial Services LLC ("S&P") or Moody's Investor Service ("Moody's");
- I eliminated companies that have not paid regular dividends or do not have positive earnings growth projections because such characteristics are incompatible with the DCF model;

[9] Orange and Rockland Utilities, Inc. FERC Form-1, April 16, 2014 at 301. Annual Report of Electric and/or Gas Corporations to State of New York Public Service Commission, April 30, 2014 at 64.

[10] Source: SNL Financial.

- To develop a proxy group of companies that are primarily regulated utilities, I excluded companies with less than 70.00 percent of total net operating income derived from regulated utility operations over the three most recently reported fiscal years; and
- I eliminated companies known to be party to a merger, acquisition, or other transformational transaction.

Q. BASED ON YOUR CRITERIA WHAT COMPANIES MET THE SCREENING CRITERIA FOR YOUR INITIAL PROXY GROUP?

A. The criteria discussed above resulted in an initial group of 34 comparable companies as set forth in Table 2 (below).

Table 2: Initial Screening Results

Company	Ticker
Allete	ALE
Alliant Energy Corp.	LNT
Ameren Corp.	AEE
American Electric Power	AEP
Avista Corp.	AVA
Black Hills Corp.	BKH
CenterPoint Energy, Inc.	CNP
Cleco Corp.	CNL
CMS Energy Corp.	CMS
Consolidated Edison	ED
DTE Energy Co.	DTE
Duke Energy Corp.	DUK
Edison International	EIX
Empire District Electric	EDE
Entergy Corporation	ETR
FirstEnergy Corp.	FE
Great Plains Energy Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA

ITC Holdings Corp.	ITC
NextEra Energy, Inc.	NEE
Northeast Utilities	NU
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
PG&E Corp.	PCG
Pinnacle West Capital	PNW
PNM Resources, Inc.	PNM
Portland General Electric Co.	POR
SCANA Corp.	SCG
Sempra Energy	SRE
Southern Co.	SO
Vectren Corp.	VVC
Westar Energy	WR
Xcel Energy, Inc.	XEL

Q. DOES THIS CONSTITUTE YOUR FINAL PROXY GROUP?

A. No, it does not. My initial set of screening criteria produced a group of 34 potential proxy companies. I then examined the operating profile of each of those 34 companies to be certain that none displayed characteristics that were inconsistent with my intent to produce a proxy group that is fundamentally similar to the Company. As a result of that examination, I have modified the initial screening results.

Edison International ("EIX") recorded a loss of $1.7 billion in 2012 as a result of placing Edison Mission Energy, the subsidiary that owns and operates unregulated electric generating assets (including Homer City), into Chapter 11 bankruptcy, and the divestiture of its Homer City assets.[11] As part of the Chapter 11 bankruptcy proceeding, EIX entered into a purchase agreement on October 18, 2013 with NRG Energy for Edison

[11] *See*, Edison International, SEC Form 10-K for the fiscal year ended December 31, 2012, at 35.

Mission Energy's assets including the assumption of certain related liabilities.[12] In addition, EIX recorded a $1.05 billion loss resulting from an after-tax earnings charge (recorded in the fourth quarter of 2011) relating to the impairment of its Homer City, Fisk, Crawford, and Waukegan power plants, wind-related charges, and other expenses.[13] Given the significant nature of those results, it is difficult to assess the degree to which EIX's recent financial metrics and earnings growth projections reflect investor expectations for the regulated electric utility operations going forward. Consequently, I have excluded EIX from my final proxy group. Second, I also excluded ITC Holding Corp. ("ITC") because it is a FERC-regulated transmission-only company, and as such is not fundamentally comparable to O&R.

Q. DID YOU INCLUDE CONSOLIDATED EDISON, INC. IN YOUR FINAL PROXY GROUP?

A. No, I did not. While the screening criteria indicate that CEI is fundamentally comparable to the proxy companies, in order to avoid the circular logic that otherwise would arise, it has been my consistent practice to exclude the subject company from the final proxy group. Consequently, my final proxy group includes the 31 companies set forth in Table 3 (below).

Table 3: Final Proxy Group

Company	**Ticker**
Allete	ALE
Alliant Energy Corp.	LNT
Ameren Corp.	AEE
American Electric Power	AEP
Avista Corp.	AVA
Black Hills Corp.	BKH

[12] *See*, NRG Energy, Inc., SEC Form 8-K, October 18, 2013, at 2.
[13] *See*, Edison International, SEC Form 10-K for the fiscal year ended December 31, 2012, at 35-36.

CenterPoint Energy, Inc.	CNP
Cleco Corp.	CNL
CMS Energy Corp.	CMS
DTE Energy Co.	DTE
Duke Energy Corp.	DUK
Empire District Electric	EDE
Entergy Corporation	ETR
FirstEnergy Corp.	FE
Great Plains Energy Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
Northeast Utilities	NU
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
PG&E Corp.	PCG
Pinnacle West Capital	PNW
PNM Resources, Inc.	PNM
Portland General Electric Co.	POR
SCANA Corp.	SCG
Sempra Energy	SRE
Southern Co.	SO
Vectren Corp.	VVC
Westar Energy	WR
Xcel Energy, Inc.	XEL

Q. IS YOUR CREDIT RATING SCREEN CONSISTENT WITH THE COMMISSION'S APPROACH?

A. Yes. The screening criterion described above reflects the Commission's findings in the 2011 O&R Rate Order:

> …there appears, at least recently, to be a difference between bondholders' perception of risk and that of equity investors. Therefore, we will not use credit ratings as the basis for a credit quality adjustment in this case, nor will we use credit ratings to narrow the proxy group beyond our normal requirement that all group members be at least investment grade [14]

[14] 2011 O&R Rate Order, at 67.

My current approach, which requires only that proxy companies be investment grade, is consistent with the Commission's investment grade requirement and does not further narrow the group on the basis of credit ratings.

Q. IN PRIOR CASES STAFF HAS USED REVENUE INSTEAD OF NET INCOME WHEN SCREENING FOR REGULATED COMPANIES.[15] PLEASE EXPLAIN WHY YOU HAVE RELIED ON NET INCOME AS A SCREENING CRITERION.

A. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is directly derivative of earnings, as opposed to revenue. As part of its rating methodology, Moody's assigns a 40.00 percent weight to measures of financial strength and liquidity, of which 25.00 percent specifically relates to the ability to cover debt obligations with cash from operations.[16]

Just as rating agencies focus on measures of cash from operations, equity analysts likewise prefer measures of income in assessing equity valuation levels. Common measures of valuation, for example, include the Price/Earnings ratio, the Price/Earnings to Growth ("PEG") ratio and the ratio of Enterprise Value/EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortization). The reason, of course, is that measures of revenue can obscure the assessment of the underlying value of the subject company. Energy marketing businesses, for example, typically are characterized by high volumes

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15 *See*, for example, Case 13-E-0030, Direct Testimony of Craig E. Henry, at 14-15.

16 *Rating Methodology, Regulated Electric and Gas Utilities,* Moody's Global Infrastructure Finance, August 2009, at 13.

and comparatively low margins. Consequently, focusing on revenue may mislead the analyst into assuming that such segments are the primary driver of long-term growth, when, as a practical matter, the majority of earnings and cash flows are derived from other business segments. In this instance, in which we are considering whether the underlying utility is the predominant source of long-term growth, it could be misleading to focus on revenue rather than earnings.

Q. IS THERE A NEED TO DEVELOP SEPARATE PROXY GROUPS TO REFLECT THE RISK PROFILES OF O&R'S ELECTRIC UTILITY RATE BASE AND GAS UTILITY RATE BASE?

A. No. Following the issuance of the Generic Finance RD in 1994, the Commission has consistently relied upon electric utility proxy groups to establish the Cost of Equity for both the gas and electric operations of all of the combination utilities in the state. In practice, O&R operates its electric and gas utility assets as a single entity, regulated within a single jurisdiction, and therefore investors view the Company in a similar manner. Since the Company is a combined electric and gas company, the proxy group should be comprised of electric and gas utility companies that are commensurate with the Company's risk profile, rather than the risk profile of its individual operating segments.[17] While the risks of the Company's electric and gas business operations may vary slightly, I have selected a group of companies whose aggregate operating risks are substantially comparable to those of O&R, and thus provide a reasonable basis to establish an ROE for the Company.

[17] *See*, also, Case No. 13-W-0295, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of United Water New York Inc. for Water Service,* Order Establishing Rates, (issued June 26, 2014), at 58.

VI. COST OF EQUITY ESTIMATION

Q. PLEASE BRIEFLY DISCUSS THE ROE IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant and equipment. The rate of return ("ROR") for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the Cost of Equity is market-based and, therefore, must be inferred from market-based information.

Q. HOW IS THE REQUIRED ROE DETERMINED?

A. In New York, the required ROE is estimated by using several analytical techniques that rely on market-based data to quantify investor expectations regarding required stock returns, adjusted for certain incremental costs and risks. The resulting Cost of Equity, adjusted for the cost of issuing equity securities, serves as the recommended ROE for ratemaking purposes. The key consideration in determining the Cost of Equity is whether the methodologies employed reasonably reflect investors' view of the financial markets in general, and the subject company's common stock in particular. As discussed throughout my Direct Testimony, I have structured my analyses with that consideration in mind. Lastly, while I do not necessarily agree with the Commission's practice of applying two-thirds and one-third weights to the respective DCF and CAPM results, I have produced and presented analytical results based on that convention.

Q. WHAT METHODS DID YOU USE TO DETERMINE THE COMPANY'S COST OF EQUITY?

A. Consistent with the Commission's past practice, I have used the DCF model and the CAPM approach to develop my Cost of Equity recommendation. With respect to the DCF approach, my analyses include the two-stage model on which the Commission has relied in prior rate proceedings. As a check on the two-stage method, I also have included a three-stage model that allows for a transition period between the near- and long-term growth estimates. Also consistent with the Commission's stated preference, I used both the traditional form of the CAPM, as well as the "Zero-Beta" form of that model. In both forms of the CAPM, I incorporated *ex-ante* measures of the Market Risk Premium.

Q. WHY DO YOU BELIEVE IT IS IMPORTANT TO USE MORE THAN ONE ANALYTICAL APPROACH?

A. Because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. As a result, a number of models have been developed to estimate the Cost of Equity. As a practical matter, however, all of the models available for estimating the Cost of Equity are subject to limiting assumptions or other methodological constraints. Consequently, many finance texts recommend using multiple approaches when estimating the Cost of Equity. For example, Copeland, Koller and Murrin[18], suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham

[18] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd ed. (New York: McKinsey & Company, Inc., 2000), at 214.

and Ehrhardt[19] recommend the CAPM, DCF and "Bond Yield Plus Risk Premium" approaches.

In essence, practitioners and academics recognize that financial models simply are tools to be used in the ROE estimation process, and that strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* finding that it is the analytical result, as opposed to the methodology, that is controlling in arriving at ROE determinations. Thus, a reasonable ROE estimate appropriately considers alternate methodologies and the reasonableness of their individual and collective results.

Consequently, I believe it is both prudent and appropriate to use multiple methodologies as a means of mitigating the effects of assumptions and inputs associated with any single approach. Such use, however, must be tempered with due caution as to the results generated by each individual approach.

Q. DO YOU HAVE ANY CONCERNS WITH THE COMMISSION'S PAST PRACTICE OF APPLYING TWO-THIRDS AND ONE-THIRD WEIGHTS TO THE RESPECTIVE DCF MODEL AND CAPM RESULTS?

A. Yes, I do. First, all models rely on specific assumptions that may become less relevant depending on market conditions. Consequently, the weight given to specific results may change over time but always would reflect the informed judgment of the analyst. Second,

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19 Eugene Brigham and Michael Ehrhardt, Financial Management: Theory and Practice, 12th Ed. (Mason, OH: South-Western Cengage Learning, 2008), at 367.

while academic texts support the use of multiple ROE models, there is no academic support of which I am aware for a strict, formulaic weighting of model results. Lastly, there is no evidence that the weighting reflects investors' actual practice when they determine the price they are willing to pay for a company's stock (and, therefore, may not reflect the market's actual required Return on Equity).

Discounted Cash Flow Model

Q. ARE DCF MODELS WIDELY USED TO DETERMINE THE ROE FOR REGULATED UTILITIES?

A. Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. In its simplest form, the DCF model expresses the market Cost of Equity as the sum of the expected dividend yield and long-term growth rate.

Q. PLEASE DESCRIBE THE DCF APPROACH.

A. The DCF approach to estimating a market Cost of Equity is based on the theory that a stock's current market price represents the present value of all expected future cash flows (*i.e.*, dividends and the terminal price at which the stock is sold). In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current market stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required return, that sets the observed price equal to the present value of expected cash flows. As discussed in more detail below, I have not included the Constant Growth form of the DCF model, but instead have focused on two multi-stage forms.

Stock Prices used in the DCF Model

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE CURRENT STOCK PRICE IN YOUR DCF MODELS?

A. The stock prices in my DCF models are based on the average market closing prices for the proxy companies' shares over three months ended September 30, 2014.

Q. WHY DID YOU USE A THREE-MONTH AVERAGING PERIOD?

A. I believe it is important to use an average of recent trading days to calculate the term P_0 in the DCF model so that the calculated market Cost of Equity is not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long-term. In my view, the use of the three-month averaging period reasonably balances those concerns. That averaging period is also consistent with the period considered by the Commission in recent proceedings.[20]

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[20] For example, in Case 10-E-0362 the Commission relied upon the Staff DCF analysis, which used three months of stock price data (2011 O&R Rate Order, at 72). Therefore, I have relied on a three-month averaging period for the purpose of my DCF analyses.

Multi-Stage DCF Models

Q. PLEASE NOW DESCRIBE THE MULTI-STAGE DCF MODELS INCLUDED IN YOUR ANALYSES.

A. Consistent with the Commission's stated preference, I have prepared a two-stage DCF analysis based on the structure discussed in the Commission's Order in Case 10-E-0362.[21] For the reasons discussed in more detail below, I also have included a three-stage form of the model as a check on the reasonableness of the two-stage DCF results.

Q. WHAT ARE THE SPECIFIC BENEFITS OF THE MULTI-STAGE DCF MODELS THAT YOU HAVE PRESENTED IN THIS PROCEEDING?

A. Both forms of the multi-stage DCF model define the Cost of Equity as the discount rate that sets the current stock price equal to the discounted value of future cash flows (*i.e.*, projected dividends). Consistent with the Commission's past preference, my two-stage DCF model relies on Value Line projected dividends through the Value Line projection period.[22] Dividends in the three-stage DCF model, as well as in the second stage of the two-stage DCF model, are projected as the product of the dividend payout ratio and earnings. Because both models project future dividends as the product of the dividend payout ratio and earnings, they include the important ability to recognize that dividend payout ratios may decrease during periods of increasing capital expenditures. That capability is enhanced by the three-stage DCF model, which, as described below, allows for a transition between near- and long-term growth stages.

It also is important to note that while the three-stage DCF model calculates the Cost of Equity based on projected dividends, it does not rely solely on Value Line for near-term

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21 2011 O&R Rate Order, at 68 – 69.

22 2011 O&R Rate Order, at 64.

dividend growth rate projections. Rather, the three-stage DCF model combines expected Earnings Per Share ("EPS"), which are projected based on consensus earnings growth estimates, with Value Line's projected dividend payout ratio. In my experience, a common and legitimate criticism of DCF models that rely solely on projected dividend growth is that Value Line is the sole source of such projections.[23] Moreover, there is no reason to believe Value Line consistently provides more accurate projections than other forecast providers.[24] While the form of the model I have used relies on Value Line for projected dividend payout ratios, the potential bias resulting from reliance on a single analyst is mitigated by the use of consensus earnings forecasts.

The model also enables the analyst to check for the reasonableness of the inputs and results by reference to certain market-based metrics. The terminal price, for example, can be divided by the expected EPS in the final year to calculate a projected Price/Earnings ("P/E") ratio. To the extent that the projected P/E ratio is inconsistent with either historical or expected levels, it may be an indicator of incorrect or inconsistent assumptions within the balance of the model. Importantly, as noted earlier, there are no common market-based valuation metrics that solely rely on dividend projections.

Q. PLEASE GENERALLY DESCRIBE THE STRUCTURE OF THE TWO-STAGE DCF MODEL.

A. As shown in Table 4 (below), the two-stage DCF model calculates the proxy companies' individual required ROEs by projecting annual dividends over two stages - a near-term growth stage (years one through five) and a long-term growth stage (from year six to

[23] *See*, for example, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 65.

[24] *See*, Ramnath, Rock, Shane, *Value Line and I/B/E/S Earnings Forecasts*, International Journal of Forecasting, Vol. 21, No. 1, Jan-Mar 2005, at 1.

perpetuity). The model relies on Value Line dividend projections in the near-term. As noted above, the near-term growth stage ends in year five, after which the model immediately moves to the long-term growth stage, which calculates dividends as the product of earnings and the dividend payout ratio. As noted in Table 6 (further below), near-term earnings growth projections are provided by Value Line, Zacks and Thomson First Call. During the long-term growth stage, earnings are projected to grow at a rate equal to projected nominal Gross Domestic Product ("GDP"), and the dividend payout ratio is assumed to have reverted to the industry's long-term norm.

In the first stage, "cash flows" are defined as projected dividends. In the second stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period. The expected stock price is based on the "Gordon" model, which defines the price as the expected dividend divided by the difference between the Cost of Equity (*i.e.*, the discount rate) and the long-term expected growth rate. The price calculated using the Gordon model in the terminal stage is approximately equal to the price calculated using terminal stage cash flows that extend indefinitely, or for an extended time period (*e.g.*, 200 years).

Table 4: Two-Stage DCF Model Structure

Stage	**0**	**1**	**2**
Cash Flow Component	Initial Stock Price	Expected Dividends	Expected Dividends + Terminal Value
Inputs	Stock Price Earnings Per Share (EPS) Dividends Per Share (DPS)	Expected EPS Value Line Projected DPS	Expected EPS Expected DPS Terminal Value
Assumptions	Three-month stock price averaging period	Analyst EPS growth rates	Long-term dividend payout ratio Long-term growth rate

Q. THE COMMISSION HAS PREVIOUSLY NOTED ITS PREFERENCE FOR RELYING ON STAFF'S DCF APPROACH, WHICH USES VALUE LINE'S DIVIDEND GROWTH PROJECTIONS AS THE NEAR-TERM GROWTH RATE.[25] DOES YOUR TWO-STAGE DCF MODEL ADDRESS THAT PREFERENCE?

A. Yes, it does. My two-stage DCF model relies on Value Line's projected Dividend Per Share for the 2014-2018 period. For years beyond Value Line's projection period, I have assumed earnings grow at the estimated long-term growth rate and that dividends will equal the product of expected earnings and the industry average long-term payout ratio.

Q. WHY HAVE YOU USED YOUR ALTERNATIVE THREE-STAGE DCF MODEL AS A CHECK ON THE REASONABLENESS OF THE COMMISSION'S PREFERRED TWO-STAGE DCF MODEL?

A. I believe the three-stage DCF model is a more refined method of estimating the Company's ROE. Because the three-stage DCF model allows for a transition from the first-stage growth rate to the long-term growth rate, it avoids the often unrealistic

25 *Ibid.* 2011 O&R Rate Order, at 64.

assumption, implicit in the two-stage DCF model, *i.e.,* that growth will change immediately between the first and final stages. In my view, that additional flexibility is very important when, as is the case with electric and gas utilities, there is an expected period of high capital expenditures in the near and intermediate terms.

Q. PLEASE GENERALLY DESCRIBE THE STRUCTURE OF YOUR THREE-STAGE DCF MODEL.

A. As noted above, the model sets the subject company's stock price equal to the present value of cash flows received over three stages. Similar to the application of the two-stage DCF model, in the first two stages cash flows are defined as projected dividends. In the third stage, cash flows equal both dividends and the expected price at which the stock will be sold at the end of the period. Again reflecting the two-stage DCF model, the expected stock price is based on the Gordon model. In essence, the terminal price is defined as the present value of the remaining cash flows in perpetuity, and has the same practical effect on the ROE calculation as continuing the long-term growth stage indefinitely.[26] In each of the three stages, the dividend is projected as the product of the projected earnings per share, and the expected dividend payout ratio. A summary description of the model is provided in Table 5 (below).

[26] I understand that in prior cases, Staff has assumed a long-term period of 195 years. Given the nature of present value calculations, 195 years is essentially equal to perpetuity, which is assumed in the Gordon Model.

Table 5: Three-Stage DCF Structure

Stage	0	1	2	3
Cash Flow Component	Initial Stock Price	Expected Dividend	Expected Dividend	Expected Dividend + Terminal Value
Inputs	Stock Price Earnings Per Share (EPS) Dividends Per Share (DPS)	Expected EPS Expected DPS	Expected EPS Expected DPS	Expected EPS Expected DPS Terminal Value
Assumptions	Three-month stock price averaging period	Near-term dividend payout ratio Analyst growth rates		Long-term dividend payout ratio Long-term growth rate

Q. DO YOU BELIEVE THAT THE DCF MODELS DESCRIBED ABOVE ARE CONSISTENT WITH THE INTENT OF THE TWO-STAGE MODEL RELIED UPON BY THE COMMISSION?

A. Yes, I do. In my view, both the construction of the model and the underlying inputs and assumptions are consistent with, and enhance, the application of the two-stage model. As noted above, the general form of the two-stage model relied upon by the Commission involves a near-term growth stage based on estimated dividend growth and a long-term growth stage based on estimated long-term growth.[27] Consequently, my two-stage DCF model relies on Value Line's Dividend Per Share projections in the first stage, and assumes earning grow at the estimated long-term growth rate in the second stage while payout ratios revert to long-term norms.

In the three-stage DCF model, the calculation of dividend growth does not solely rely on the Value Line Dividend Per Share growth estimate; rather, it includes both Value Line's estimated dividend payout ratios and consensus analyst growth projections. The use of

[27] *See* the Commission's decisions in Case 06-E-1433, Case 08-E-0539 and Case 10-E-0362.

consensus projections mitigates the potential bias associated with relying on a single source of projections (*i.e.*, Value Line). Moreover, the ability to consider industry trends and company-specific circumstances enables the analyst to provide more refined projections by recognizing that payout ratios are likely to change over time. Conversely, as with the Constant Growth form of the model (which has been rejected by the Commission), the two-stage DCF model relied upon by Staff assumes a constant payout ratio, in perpetuity. Finally, the long-run growth estimate, the timing of which extends beyond the horizon of the Value Line and analyst projections, is based on highly visible, market-derived projections of long-term macroeconomic (*i.e.*, GDP) growth.

Q. PLEASE SUMMARIZE YOUR INPUTS TO THE DCF MODELS.

A. I applied both DCF models using the proxy group described earlier in my testimony. My assumptions with respect to the various model inputs are described in Tables 6 and 7 (below).

Table 6: Two-Stage DCF Model Assumptions

Stage	**0**	**1**	**2**
Stock Price	Three-month average daily stock price		
Growth Rates	Initial EPS as reported by Value Line	Analyst growth as average of (1) Value Line, (2) Thomson First Call, and (3) Zacks projected growth rates	Long-term GDP growth
Dividends		Value Line company-specific DPS projections	Long-term industry average payout ratios (Calculated based on median long-term payout ratios for Value Line universe of electric utilities)
Terminal Value			Expected dividend in final year divided by solved Cost of Equity less long-term growth rate

Table 7: Three-Stage DCF Model Assumptions

Stage	**0**	**1**	**2**	**3**
Stock Price	Three-month average daily stock price			
Growth Rates	Initial EPS as reported by Value Line	Analyst growth as average of (1) Value Line, (2) Thomson First Call, and (3) Zacks projected growth rates	Transition to Long-term GDP growth	Long-term GDP growth
Dividend Payout Ratio		Value Line company-specific	Transition to long-term industry average payout ratio	Long-term industry average (Calculated based on median long-term payout ratios for Value Line universe of electric utilities)
Terminal Value				Expected dividend in final year divided by solved Cost of Equity less long-term growth rate

Q. HOW DID YOU CALCULATE THE LONG-TERM GDP GROWTH RATE?

A. The long-term growth rate of 5.60 percent used in my multi-stage DCF models is based on the real GDP growth rate of 3.27 percent from 1929 through 2013, and an expected inflation rate of approximately 2.26 percent. The real GDP growth rate is calculated as the compound growth rate in the chain-weighted GDP for the period from 1929 through 2013.[28] The rate of inflation of 2.26 percent is a compound annual forward rate starting at year ten (*i.e.,* 2024) and is based on the 30-day average of projected inflation based on the spread between yields on long-term nominal Treasury Securities and long-term Treasury Inflation Protected Securities ("TIPS"), known as the "TIPS spread".

28 Bureau of Economic Analysis, September 26, 2014 update.

Q. WHY IS THE LONG-TERM GDP GROWTH RATE A REASONABLE ESTIMATE OF LONG-TERM GROWTH IN YOUR MULTI-STAGE DCF MODELS?

A. In regulatory proceedings, long-term estimates of GDP growth are commonly used as a proxy for the long-term growth in proxy group company dividends in multi-stage DCF analyses. That application is based on the common theoretical assumption that, over the long-run, all the companies in the economy will tend to grow at the same constant rate. That assumption is designed to address the uncertainty associated with estimating individual company growth rates over very long time horizons and is not meant to act as a prediction that company growth rates in the economy will indeed converge in practice over any given period.

As noted by Eugene F. Brigham and Michael C. Ehrhardt in Financial Management: Theory and Practice:

> Expected growth rates vary somewhat among companies, but dividend growth for most mature firms is generally expected to continue in the future at about the same rate as nominal gross domestic product (real GDP plus inflation). On that basis, one might expect the dividends of an average, or "normal," company to growth at a rate of 5% to 8% a year.[29]

Q. PLEASE DESCRIBE THE LONG-TERM GROWTH ESTIMATE DEVELOPED BY STAFF IN THE COMPANY'S LAST RATE PROCEEDING.

A. In the Company's last rate proceeding, Staff relied on an estimate of long-term growth derived from the Sustainable Growth model, which was calculated using Value Line projections over a three- to five-year period. That is, Staff's second stage growth estimate

[29] Eugene Brigham and Michael Ehrhardt, Financial Management: Theory and Practice, 12th Ed. (Mason, OH: South-Western Cengage Learning, 2008), at 291.

was based on projections that ended in the first stage. Staff then compared the average Sustainable Growth rate to the ten-year projected nominal GDP growth rate published by Blue Chip Economic Indicators ("Blue Chip") ending in 2020, approximately six years beyond the horizon of the Value Line projections.[30] Based on that comparison, Staff concluded that the short-term "Sustainable Growth" projection was a reasonable estimate of long-term growth.

Q. HOW DOES YOUR ESTIMATE OF LONG-TERM GROWTH DIFFER FROM THE ESTIMATE DEVELOPED BY STAFF?

A. Rather than relying on a short-term estimate of Sustainable Growth (three to five years per Value Line's published data), the long-term growth rate included in my DCF analyses reflects market-derived projections of inflation beginning in 2024 and extending over the longest available time period (*i.e.,* 20 years). That estimate of expected long-term inflation is combined with the long-term average historical real GDP growth rate to calculate the expected nominal GDP growth rate. Importantly, the final stage of both DCF models, as well as the two-stage DCF model relied upon by Staff in the Company's last rate proceeding, extend indefinitely. Consequently, the long-term growth estimate used in my multi-stage DCF models is a more accurate representation of investor and economist views of nominal long-term GDP growth than either the three- to five-year Value Line Sustainable Growth estimate or the ten-year Blue Chip GDP growth estimate.

30 *See,* Prepared Testimony of Staff Finance Panel, Case 11-E-0408, at 53-56.

Q. PLEASE DESCRIBE THE SUSTAINABLE GROWTH ESTIMATE AS APPLIED IN STAFF'S TESTIMONY IN THE COMPANY'S LAST RATE PROCEEDING.

A. The Sustainable Growth model is an alternative approach to the use of analysts' earnings growth estimates. In essence, the model is premised on the proposition that a firm's growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the enterprise. In its simplest form, the model represents long-term growth as the product of the retention ratio (*i.e.*, the percentage of earnings not paid out as dividends, referred to below as "b") and the expected return on book equity (referred to below as "r"). Thus the simple "b x r" form of the model projects growth as a function of internally generated funds. That form of the model is limiting, however, in that it does not provide for growth funded from external equity.

The "br + sv" form of the Sustainable Growth estimate is meant to reflect growth from both internally generated funds (*i.e.*, the "br" term) and from issuances of equity (*i.e.*, the "sv" term), as shown in Equation [2] below. The first term, which is the product of the retention ratio (*i.e.*, "b", or the portion of net income not paid in dividends) and the expected return on equity (*i.e.*, "r") represents the portion of net income that is "plowed back" into the company as a means of funding growth. The "sv" term can be represented as:

$$(\frac{m}{b}-1) \text{ x Common Shares growth rate [2]}$$

where:

$$\frac{m}{b} = \text{the market to book ratio.}$$

In this form, the "sv" term reflects an element of growth as the product of (1) the growth in shares outstanding and (2) that portion of the market-to-book ratio that exceeds unity.

It is important to note the calculation of the Sustainable Growth estimate requires the analyst to rely upon forecasts of the subject companies' return on equity, retention ratio and growth in common shares outstanding (when including the "sv" component). Staff has consistently derived all of the inputs for the Sustainable Growth estimate from Value Line.[31] Consequently, by relying on a single source of data (Value Line) whose estimates are produced by a single analyst, there is an increased risk of idiosyncratic error that may bias the end results.

Q. ASIDE FROM STAFF'S USE OF A SHORT-TERM FORECAST AS THE BASIS OF ITS LONG-TERM GROWTH ESTIMATE, DO YOU HAVE CONCERNS WITH THE USE OF THE SUSTAINABLE GROWTH ESTIMATE AS THE LONG-TERM GROWTH RATE IN THE MULTI-STAGE DCF MODEL?

A. Yes, I do. First, the underlying premise of the Sustainable Growth calculation is that future earnings will increase as the retention ratio increases. That is, if future growth is modeled as "b x r", growth will increase as "b" increases. There are, however, several reasons why that may not be the case. Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can and do influence dividend payout (and therefore earnings retention) decisions in the near-term. Consequently, it is appropriate to determine whether the data relied upon in the Sustainable Growth

[31] *See,* Prepared Exhibits of Staff Finance Panel, Case 11-E-0408, Exhibit__(FB-8).

estimate supports the assumption that higher earnings retention ratios necessarily are associated with higher future earnings growth rates.

Q. DID YOU PERFORM ANY ANALYSES TO TEST THAT ASSUMPTION?

A. Yes, I did. Based on Value Line data as of September 30, 2014 (which include historical information regarding both earnings and dividends per share) for the companies in the proxy group, I calculated (in each year of the historical period) the dividend payout ratio, the retention ratio, and the subsequent five-year earnings growth rate. I then performed a regression analysis in which the dependent variable was the five-year earnings growth rate, and the explanatory variable was the earnings retention ratio. The purpose of that analysis was to determine whether the data source typically relied upon by Staff for the sustainable growth estimate empirically supports the assumption that higher retention ratios necessarily produce higher earnings growth rates.

Q. WHAT DID THAT ANALYSIS REVEAL?

A. As shown in Table 8 (below),[32] there was a statistically significant negative relationship between the five-year earnings growth rate and the earnings retention ratio. That is, based on Value Line (*i.e.*, the source of the data typically relied upon in Staff's analysis), using historical data, earnings growth actually decreased as the retention ratio increased.

[32] *See* also Exhibit No.___ (RBH-11)

Table 8: Regression Results

	Coefficient	Standard Error	t-Statistic
Intercept	0.211	0.022	9.582
Retention Ratio	-0.294	0.036	-8.249

Q. IS THERE INDEPENDENT RESEARCH THAT SUPPORTS YOUR FINDINGS?

A. Yes, there is. In 2006, for example, Financial Analysts Journal published two articles that addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[33] Both of those articles cite a 2003 study by Arnott and Asness[34] who found that, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[35] In essence, the findings of all three studies are consistent with my findings regarding the relationship between retention ratios and future earnings growth for the proxy group companies: there is a negative, not a positive relationship between the two. In light of those articles, it appears that my findings are not anomalous. Given the strong statistical results of my analyses, and the corroborating research discussed above, I continue to believe that substantial reliance on an estimate of long-term growth derived from a Sustainable Growth rate calculated using Value Line projections over a three to five-year period is inappropriate.

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33 Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See* also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

34 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

35 Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

Q. ARE THERE OTHER CONCERNS WITH THE SUSTAINABLE GROWTH ESTIMATE?

A. Yes. It is important to note that the Sustainable Growth model itself requires an estimate of the earned return on common equity and is therefore circular. By adopting Value Line's earned ROE estimates, the analyst has effectively pre-supposed the Return on Common Equity projected by Value Line for the proxy group companies.

In addition, I note that the fundamental premise of the Sustainable Growth Model assumes that the retention ratio (and therefore, the dividend payout ratio) will remain constant in perpetuity. In that important respect, the Sustainable Growth model is fundamentally related to the Constant Growth DCF model that has been rejected by Staff and the Commission. In my view, it would be inconsistent to reject the Constant Growth DCF model, yet assume a long-term growth rate based on the Constant Growth assumptions.

Q. ARE VALUE LINE'S PROJECTIONS FOR THE PROXY GROUP COMPANIES' GROWTH IN EARNINGS PER SHARE CONSISTENT WITH THE SUSTAINABLE GROWTH ESTIMATE?

A. No, they are not. As shown in Exhibit No.___ (RBH-12), I calculated the Sustainable Growth rate using Value Line's projected financial metrics for each company in the proxy group for the years 2014, 2015 and 2017-2019. I then compared those estimates to Value Line's expected earnings growth for each company (for example, I considered whether a given company's 2014 sustainable growth factors explained the company growth in earnings from end of 2013 to the end of 2014). As also shown in Exhibit No.___ (RBH-12), Value Line frequently expects actual earnings growth to exceed the growth rate indicated by the Sustainable Growth formula. Consequently, the assumption that the Sustainable Growth estimate accurately reflects future growth may be too limiting.

Q. WHAT WERE YOUR SPECIFIC ASSUMPTIONS WITH RESPECT TO THE PAYOUT RATIO?

A. As noted in Tables 6 and 7 (above), in both DCF models for the first period, I relied on the first year and long-term projected payout ratios reported by Value Line[36] for each of the proxy companies. In my three-stage DCF analysis, I then assumed that by the end of the second period (*i.e.*, the end of year 10), the payout ratio will converge to the long-term industry median of approximately 67.23 percent.[37] As noted earlier, the two-stage DCF model does not allow for that gradual transition period; rather, it abruptly shifts to the long-term industry median in the first year of the second stage.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSES?

A. As shown in Exhibit No.___ (RBH-1), the two-stage DCF analysis produces an ROE range of 9.74 percent to 10.03 percent with a mean ROE of 9.88 percent based on a three-month averaging period. Similarly, the three-stage DCF analysis produces an ROE range of 9.62 percent to 10.08 percent with a mean ROE of 9.84 percent based on the same three-month averaging period.

36 As reported in the Value Line Investment Survey for each of my proxy group companies as "All Div'ds to Net Prof."

37 The 67.23 percent average median payout ratio was calculated based on data from 1990 to the present for all 47 companies included in the Value Line electric utility universe. Source: Bloomberg.

Q. ARE THE RESULTS OF YOUR ANALYSIS GENERALLY CONSISTENT WITH THE PROJECTED MARKET VALUE OF THE PROXY COMPANIES?

A. Yes they are. As shown in Exhibit No.___ (RBH-2), the results of my two-stage DCF analysis using mean growth rates produce a median expected proxy group company P/E ratio of 15.52, while the results of my three-stage DCF analysis produce a median expected proxy group company P/E ratio of 15.66. These results are highly consistent with the industry historical range of P/E ratios, shown in Exhibit No.___ (RBH-3).

Q. HOW DOES THE TIMING OF DIVIDEND PAYMENTS IN YOUR MULTI-STAGE DCF MODEL DIFFER FROM THE CASH FLOW ASSUMPTIONS USED BY STAFF IN THE COMPANY'S MOST RECENT RATE CASE?

A. I have adopted the mid-year convention, which assumes that an annualized dividend payment is received mid-year in order to more accurately approximate the actual quarterly cash flows that stockholders receive. For the remaining portion of the current year dividend, the model discounts the payment as if it had been received by the stockholder at end-of year. As noted by Duff & Phelps "[c]ommon practice in business valuation is to assume that the net cash flows are received in the middle of the year."[38]

In contrast, in the Company's last rate case Staff's DCF model assumed dividends are received at the end of each year. Considering that Staff"s proxy group companies' dividends are paid on a quarterly basis, assuming (as Staff did) that the entire dividend is paid at the end of the year essentially defers the timing of those cash flows and does not

[38] Duff & Phelps, 2014 Valuation Yearbook: Guide to Cost of Capital, at 1-4.

reflect the time value of money.[39] Since Staff uses a model with annual dividend payments, a reasonable approach would be to assume that cash flows are received in the middle of the year, such that half the quarterly dividend payments occur prior to the assumed dividend payment date (*i.e.*, the "mid-year convention").

Capital Asset Pricing Model Analysis

Q. PLEASE BRIEFLY DESCRIBE THE CAPM.

A. The CAPM is a risk premium approach that estimates the market Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [3], the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$k_e = r_f + \beta(r_m - r_f) \qquad [3]$$

where:

k_e = the required market ROE

β = Beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole.

Under the CAPM's assumptions, the term $(r_m - r_f)$ represents the Market Risk Premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified

[39] The Chartered Financial Analyst ("CFA") Institute's program curriculum notes: "Money has time value in that individuals value a given amount of money more highly the earlier it is received. Therefore, a smaller amount of money now may be equivalent in value to a larger amount received at a future date. The time value of money as a topic of investment mathematics deals with equivalence relationships between cash flows with different dates. Mastery of time value of money concepts and techniques is essential for investment analysts." 2011 CFA Curriculum Level I, Volume 1 at 255-256.

away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} x \, \rho_{j,m} \quad [4]$$

where σ_j is the standard deviation of returns for company "*j*"; σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. Thus, the Beta coefficient represents both relative volatility (*i.e.,* the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM MODEL?

A. I used the three-month average yield on 30-year Treasury bonds as my estimate of the risk-free rate.

Q. IN PRIOR CASES THE COMMISSION HAS RELIED ON AN AVERAGE OF THE YIELDS ON TEN-YEAR AND 30-YEAR TREASURY BONDS AS THE RISK-FREE RATE.[40] PLEASE EXPLAIN WHY YOU HAVE RELIED ON THE 30-YEAR TREASURY BOND YIELD AS THE RISK-FREE RATE.

A. In supporting the use of the average yield of the ten- and 30-year Treasury bonds as the risk-free rate, the Commission relied on a presumption that the risk-free rate should match the holding period of an investor in the proxy companies' equity securities.[41] However, the risk-free rate should be determined by the timing of the cash flows generated by the underlying assets and not by the investor's holding period. That is, the

[40] *See*, for example, 2011 O&R Rate Order, at 75.
[41] *Ibid.*

value of an asset does not change because the investor pool shifts from people with one holding period to people with a different holding period. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued[…] Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate, since the company will continue to exist beyond those five years.[42]

The CFA program also notes the risk-free rate used in the CAPM should match the timing of the expected asset's cash flows:

> A risk-free asset is defined here as an asset that has no default risk. A common proxy for the risk-free rate is the yield on a default-free government debt instrument. In general, the selection of the appropriate risk-free rate should be guided by the duration of projected cash flows. If we are evaluating a project with an estimated useful life of 10 years, we may want to use the rate on the 10-year Treasury bond.[43]

Likewise, Duff & Phelps further clarifies that the characteristics of the investor (which would include the investor's holding period) is not the relevant consideration when assessing the cost of capital:

> The cost of capital is a function of the investment, not the investor. In other words, the characteristics of a particular investor does not directly change the characteristics of the investment being analyzed.
>
> The cost of capital comes from the marketplace, and the marketplace is comprised of a pool of investors "pricing" the risk of a particular asset. It therefore represents the consensus assessment of the pool

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42 Morningstar Inc., Ibbotson SBBI 2013 Valuation Yearbook, at 44.
43 2011 CFA Curriculum Level I, Volume 4 at 52.

> of investors that are participants in a particular market. The term "market" refers to the universe of investors who are reasonable candidates to fund a particular investment.[44]

A similar approach to selecting the risk-free rate is recommended by Pratt and Grabowski in *Cost of Capital*: "In theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[45] To that point, a 2004 paper titled "Applying The Capital Asset Pricing Model" by Professor Robert Harris reviews current practices for application of the CAPM and, when summarizing best current practices, concludes "[t]he risk-free rate should match the tenor of the cash flows being valued."[46]

In essence, the longer the time period over which an investment's cash flows are received, the more sensitive the value of the investment is to changes in the required rate of return. It is important to note that it is not an investor's holding period that determines the risk of an asset; a significant change in value can happen over a very short time period when the required rate of return changes. Investors in utility equity securities commit capital to an investment that will produce cash flows over an indefinite time period. For example, in the Company's last rate proceeding, Staff relied on a DCF model that assumed investors would receive cash flows (*i.e.*, dividends) for 200 years.[47] Because utility companies represent long-duration investments, it is appropriate to use yields on long-term Treasury bonds as the risk-free rate component of the CAPM. In my view, the 30-year Treasury bond is the appropriate security for that purpose.

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44 Duff & Phelps, 2014 Valuation Handbook: Guide to Cost of Capital, at 1-6.

45 Shannon Pratt and Roger Gabrowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

46 Paper cited with permission of author.

47 *See,* Prepared Exhibits of Staff Finance Panel, Case 11-E-0408, Exhibit___(FP-8).

Q. WHAT WOULD BE THE IMPLICATION FOR DCF CALCULATIONS IF IT WERE ASSUMED UTILITY STOCK INVESTORS WERE ONLY CONCERNED WITH THE EXPECTED CASH FLOW OF THE SECURITIES OVER A 20-YEAR PERIOD (*I.E.*, THE COMMISSION'S ASSUMED HOLDING PERIOD)?

A. If the holding period is 20 years, the only way the DCF result can remain constant (or reasonable) is if the stock is sold at the prevailing market price at the end of that period. And as discussed above, the prevailing market price when the stock is sold will assume cash flows in perpetuity. In other words, *even if an investor were to hold a share of stock for 20 years, they only would earn their required return if the stock is sold to an investor that values the shares assuming cash flows in perpetuity*. The same is true if the initial holding period is seven years, ten years, 32 years, 87 years, or any other horizon. It is, therefore, the perpetual nature of equity, not the holding period of the investor that determines the ROE under the DCF model. If equity were not perpetual, the shares would hold no value at the end of the twenty year holding period and the ROE estimates would be implausibly low.

Q. WHAT WOULD THE DCF RESULT BE ASSUMING AN INVESTOR HAD A 20-YEAR HOLDING PERIOD AND THERE WAS NO TERMINAL VALUE AT THE END OF THAT PERIOD?

A. As shown in Exhibit No.__ (RBH-10), assuming the Commission's 20-year holding period with no terminal value, the mean and median ROE would be 2.75 percent, and 2.94 percent, respectively, both of which are below the three-month average of the 30-year Treasury rate (3.27 percent). Those results support the point made earlier in my Direct Testimony: the relevant term of the risk-free rate is not a function of an individual investor's holding period. Rather, the risk-free rate should reflect the perpetual nature of equity. Since the longest-dated Treasury security is 30 years, that is the appropriate term.

Q. PLEASE DESCRIBE YOUR ESTIMATE OF THE MARKET RISK PREMIUM USED IN YOUR CAPM.

A. The estimated Market Risk Premium is based on the expected return on the S&P 500 Index, less the current 30-year Treasury bond yield. To estimate the market required return, I calculated the market capitalization weighted average ROE based on the Constant Growth DCF model, which expresses the Cost of Equity as the sum of the expected dividend yield and the expected long-term growth rate. To do so, I relied on data from two sources: (1) Bloomberg; and (2) Value Line, both of which are widely accepted sources of market information. With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using one-half the analyst growth rate projection), and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the companies for which Bloomberg provided both dividend yields and consensus growth rates. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* Market Risk Premium estimate. In the case of Value Line, I performed the same calculation, again using companies for which five-year earnings growth rates were available. The results of those calculations are provided in Exhibit No.___ (RBH-5).

Q. HOW DID YOU APPLY YOUR PROJECTED MARKET RISK PREMIUM ESTIMATES?

A. I relied on the projected Market Risk Premia to calculate the CAPM model using the three-month average 30-year Treasury bond yield as the risk-free rate.

Q. IS YOUR CALCULATION OF THE *EX-ANTE* MARKET RISK PREMIUM CONSISTENT WITH THE METHODOLOGY RELIED UPON IN PREVIOUS CASES BEFORE THE COMMISSION?

A. I believe so. The Commission has relied upon the calculation of a projected Market Risk Premium, based on the difference between the estimated *ex-ante* required market return for the S&P 500, as provided by Merrill Lynch and the risk-free rate.[48] As a practical matter, that approach is consistent with the Market DCF-derived *ex-ante* Market Risk Premium estimates discussed above (*see* also Exhibit No.___ (RBH-5).

Q. WHAT BETA COEFFICIENTS DID YOU USE IN YOUR CAPM ANALYSIS?

A. With respect to the Beta coefficient, I considered two methods of calculation. My first approach employs the average reported Beta coefficient from Bloomberg and Value Line for each of the proxy group companies. While both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00, Value Line calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two years of data. For my second approach, I calculated Beta coefficients over a more recent time period to provide a more current view as to investors' perspectives with respect to "systematic" risk.[49]

48 *See*, for example, 2011 O&R Rate Order, at 77.

49 *See*, Exhibit No.___ (RBH-6).

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE MEAN ADJUSTED BETA COEFFICIENT FOR YOUR PROXY GROUP.

A. As noted in Equation [4] discussed earlier, the Beta coefficient is calculated as the ratio of the standard deviation of returns for the subject company and the market, respectively, multiplied by the correlation of returns between the two. I therefore calculated the "raw" Beta coefficient for each member of the proxy group, based on Equation [4], and adjusted those raw Beta coefficients to address the tendency to regress toward the market Beta coefficient of unity. For the purpose of that calculation, I used weekly returns, and calculated the standard deviation and correlations over the 12-month period ended September 30, 2014. Averaging those results produces an adjusted Beta coefficient of 0.753 (*see* also Exhibit No.___ (RBH-6).

Q. HOW AND WHY DID YOU ADJUST THE RAW BETA COEFFICIENT?

A. I adjusted my raw Beta coefficient consistent with the methodology used by Bloomberg. This approach multiplies the raw Beta coefficient by 0.67, and adds 0.33 to that product. The purpose of such adjustments is to reflect the results of substantial academic research indicating that, over time, raw Beta coefficients tend to regress to the market mean of 1.00.[50]

[50] The regression tendency of Beta coefficients to converge to 1.0 over time is well known and widely discussed in financial literature. (*See, e.g.,* Blume, Marshall E., *On the Assessment of Risk*, The Journal of Finance, Vol. 26, No. 1, March 1971, at 1-10).

Q. PLEASE EXPLAIN WHY YOU RELIED ON A 12-MONTH ESTIMATE OF THE PROXY GROUP MEAN ADJUSTED BETA COEFFICIENT.

A. As discussed above, the Market Risk Premium tends to change over time. In my view, the use of Beta coefficients calculated over shorter periods is consistent with the notion that market conditions, and the risk premium required by investors in response to those conditions, also may change over shorter periods.[51] In any case, by relying on both Value Line and Bloomberg, my CAPM analysis reflects Beta coefficients calculated over longer periods, as well.

Q. IS YOUR CALCULATED BETA COEFFICIENT REASONABLE RELATIVE TO THOSE CALCULATED BY VALUE LINE AND BLOOMBERG?

A. Yes, it is. As shown in Exhibit No.___ (RBH-6), the proxy group average Bloomberg, Value Line, and Calculated Beta coefficients are 0.81, 0.75, and 0.75, respectively. In light of the market dynamics noted earlier, the calculated Beta coefficient reasonably reflects current conditions, although it is not materially different than those provided by Value Line.

Q. DID YOU CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?

A. Yes. In prior proceedings, the Commission relied upon the "Zero-Beta" CAPM (the form of which is sometimes referred to as the "Empirical CAPM"[52]) in estimating the Cost of Equity. The Zero-Beta CAPM calculates the product of the adjusted Beta coefficient and the Market Risk Premium, and applies a weight of 75.00 percent to that

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51 *See* Felicia Marston, Robert Harris, Peter Crawford, *Risk and Return in Equity Markets: Evidence Using Financial Analysts' Forecasts*, in J. Guerard and M. Gultekin (eds) Handbook of Security Analysts Forecasting and Asset Allocation, JAI Press,1999)

52 *See*, for example, Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the Zero-Beta CAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

where:

k_e = the required market ROE

β = adjusted Beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole.

In essence, the Zero-Beta form of the CAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies with low Beta coefficients such as regulated utilities. In that regard, the Zero-Beta CAPM is not redundant to the use of adjusted Betas, rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the "alpha", or the constant return term.[53]

As with the CAPM, my application of the Zero-Beta CAPM uses the Market DCF-derived *ex-ante* Market Risk Premium estimate, the current yield on 30-year Treasury securities as the risk-free rate and two estimates of the Beta coefficient. The results of my

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[53] *Ibid.*, at 191. Morin notes "The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks."

market based CAPM, and Zero-Beta CAPM analyses are provided in Table 9 (below), (*see* also Exhibit No.___ (RBH-4)).

Table 9: CAPM Results

	Bloomberg Beta Coefficient	**Value Line Beta Coefficient**	**Twelve-Month Beta Coefficient**
Market-Based CAPM			
Bloomberg Market-DCF Derived MRP	11.35%	10.74%	10.79%
Value Line Market-DCF Derived MRP	10.90%	10.32%	10.36%
Zero-Beta CAPM			
Bloomberg Market-DCF Derived MRP	11.83%	11.37%	11.41%
Value Line Market-DCF Derived MRP	11.35%	10.91%	10.95%
Average CAPM		11.02%	

Flotation Costs

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs associated with the sale of new issues of common stock. Those costs include out-of-pocket expenditures for the preparation, filing, underwriting, and other costs of issuance of common stock.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE AUTHORIZED ROE?

A. In order to attract and retain new investors, a regulated utility must have the opportunity to earn a return that is both competitive and compensatory. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing its ability to attract adequate capital on reasonable terms.

Q. OVER WHAT PERIODS OF TIME ARE ISSUANCE AND FLOTATION COSTS RECOGNIZED?

A. The issuance costs associated with long-term debt reflect the incurrence of issuance costs that can be assigned a definite life or period of applicability. Those costs are amortized over the life of the debt issuance, either to maturity or upon retirement of the debt. Equity issuance or flotation costs, however, do not have a definite period of applicability, but rather have an infinite life.

Q. HAS THE COMMISSION RECOGNIZED THE NEED TO ADJUST FOR FLOTATION COSTS IN ESTABLISHING THE ROE?

A. Yes, as Staff noted in the Company's last electric rate case, "[t]he Commission has provided for recovery of anticipated issuance expenses when a public common stock issuance is reasonably expected to occur during the rate year."[54] However, given that a portion of the Company's past rate cases have been settled or included multi-year rate plans, it is unclear whether those costs have been fully recovered. Consequently, this approach does not recognize the flotation costs from past issuances that may remain embedded in the Company's Cost of Equity.

I have provided an illustrative example of the effect of flotation costs on the ROE in Exhibit No.___ (RBH-8).[55] As shown in that schedule, due to the effect of flotation costs, an authorized return of 10.27 percent would be required to realize an ROE of 10.25 percent (*i.e.*, a two basis point flotation cost adjustment). If flotation costs are not

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54 *See,* Prepared Testimony of Staff Finance Panel, Case 11-E-0408, at 102.

55 This example is based on an analysis performed by Dr. Roger Morin. *See*, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 330-332.

recovered, the growth rate falls and the ROE decreases to 10.23 percent (*i.e.*, below the required return).[56]

Q. IS THE NEED TO CONSIDER FLOTATION COSTS RECOGNIZED BY THE ACADEMIC AND FINANCIAL COMMUNITIES?

A. Yes, it is. The need to recover equity issuance costs is recognized by the academic and financial communities for the same fundamental reason that investors reasonably expect to recover the costs of debt issuances. This treatment is consistent with the philosophy of a fair rate of return. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[57]

Q. DO THE DCF AND CAPM METHODOLOGIES ALREADY INCORPORATE INVESTOR EXPECTATIONS OF A RETURN THAT COMPENSATES FOR FLOTATION COSTS?

A. No. All the models used to estimate the appropriate market Cost of Equity assume no "friction" or transaction costs, as those costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM). Therefore, it is

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56 Exhibit No.___ (RBH-8) is provided for illustrative purposes only. I have not relied on the results of the analysis in determining my recommended ROE and range.

57 Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

appropriate to consider flotation costs in determining where within the range of reasonable returns on equity O&R's return should fall.

Q. IS THERE ACADEMIC SUPPORT FOR THE INCLUSION OF FLOTATION COSTS IN THE ESTIMATE OF THE COST OF EQUITY?

A. Yes. Several economists have recognized that the flotation cost adjustment is made not to reflect current or future financing costs, but rather to compensate investors for costs incurred for all past issuances comprising the total equity portion of the Company's capitalization. An article in The Journal of Finance, for example, noted that:

> Under the conventional approach, in other words, the flotation cost adjustment is not made to reflect current or future financing costs, … it is made to compensate investors for costs incurred in *preceding* stock issues.[58]

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR PART OF THE UTILITY'S EXPENSES?

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet of the utility as "paid in capital." Flotation costs are not expenses and are not reflected in the income statement and likewise are not included in the Company's cost of service. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of flotation costs are incurred prior to the test year, but remain part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes.

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58 Cleveland S. Patterson, *Flotation Cost Allowance in Rate of Return Regulation: Comment*, The Journal of Finance, Vol. XXXVIII, No. 4, September 1983, at 1337.

Q. HAVE YOU CALCULATED THE EFFECT OF FLOTATION COSTS ON THE ROE?

A. Yes. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Based on the weighted average of flotation costs set out on Exhibit No.___ (RBH-7), a flotation cost of 0.621 percent is derived from the costs incurred by O&R's parent company, CEI, in the most recent three equity issuances. Using the 0.621 percent flotation cost discussed above, I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. As shown in Table 10, and Exhibit No.___ (RBH-7), based on that calculation, an adjustment of 0.02 percent (*i.e.*, two basis points) is reflective of flotation costs for O&R.

Since the ROE estimates have been determined on the basis of the proxy companies, I also calculated the average flotation cost, based on the two most recent underwritten equity issuances for each of the proxy companies, where available. That analysis indicates an average flotation cost of approximately 0.13 percent, which results in an average flotation cost adjustment of 13 basis points.[59] Table 10 (below), provides the DCF results, adjusted for flotation costs, using first the CEI-specific costs, then the proxy group average flotation cost.

[59] This calculation is presented in Exhibit No.___ (RBH-7).

Table 10: DCF Results Adjusted for Flotation Costs

	Mean Low	Mean	Mean High
Two-Stage DCF - CEI Flotation Costs			
	9.76%	9.91%	10.06%
Two-Stage DCF - Proxy Group Average Flotation Costs			
	9.87%	10.01%	10.16%
Three-Stage DCF - CEI Flotation Costs			
	9.64%	9.86%	10.10%
Three-Stage DCF - Proxy Group Average Flotation Costs			
	9.74%	9.97%	10.21%

Weighted Average Results

Q. DID YOU ALSO PRODUCE RESULTS BASED ON THE COMMISSION'S TWO-THIRDS/ONE-THIRD WEIGHTING OF THE DCF AND CAPM RESULTS?

A. Yes, I did. In light of the Commission's past reliance on a weighting of the DCF and the CAPM results at two-thirds, and one-third, respectively, I have presented the calculated result using that methodology.[60]

Q. PLEASE DISCUSS YOUR CALCULATION OF THE WEIGHTED AVERAGE COST OF EQUITY ESTIMATE.

A. Consistent with the Recommended Decision in the Generic Finance Proceeding,[61] and with the Commission's final order in the Company's most recent litigated rate proceeding,[62] I considered the weighted average of the results of the DCF and CAPM analyses. As shown in Table 11 (below), the weighted average of the DCF and CAPM analyses is 10.26 percent, excluding flotation costs.

60 Generic Finance RD, at 60.
61 *Ibid.*
62 Case 10-E-0362, Rate Order, at 64.

Table 11: Weighted Average Analytical Results

	Results
Two-Stage DCF	9.88%
Average CAPM	11.02%
Weighted Average	10.26%

VII. BUSINESS RISKS AND OPERATING PERFORMANCE

Q. DO THE MEAN DCF AND CAPM RESULTS FOR THE PROXY GROUP PROVIDE AN APPROPRIATE ESTIMATE OF THE COST OF EQUITY FOR THE COMPANY?

A. No, the mean results do not necessarily provide an appropriate estimate of the Company's Cost of Equity. In my view, there are additional factors that must be taken into consideration when determining where the Company's Cost of Equity falls within the range of results. Those factors include two areas discussed by Company witness Saegusa: (1) the Company's extensive capital expenditure plans and (2) the Company's relatively weak cash flows which are at least partially the result of a low ratio of amortization and depreciation to capital assets. Those risk factors should be considered in terms of their overall effect on O&R's business risk, and, therefore, Cost of Equity. While I did not include any explicit adjustments to my ROE estimates for these factors, I did take them into consideration when determining where O&R's ROE falls within my range of analytical results.

Capital Expenditures

Q. PLEASE SUMMARIZE O&R'S CAPITAL EXPENDITURE PLANS.

A. As shown in Table 12 (below), O&R is planning approximately $460.00 million of capital expenditures over the 2014-2016 time frame, which is substantially above its recent spending levels. As noted in CEI's investor presentation at the 2014 Barclays Capital Energy/Power Conference, the Company forecasts significant electric and gas net plant additions over the next few years, averaging approximately $153.00 million per year.

Table 12: Orange & Rockland Capital Spending[63]

Year(s)	Capital Spending
2009A	$127
2010A	$135
2011A	$111
2012A	$137
2013A	$135
2009-2013 Average:	$129.00
2014F	$142
2015F	$160
2016F	$158
2014-2016 Average:	$153.33

In addition, a recent Staff report submitted in Case 14-M-0101 (*Reforming the Energy Vision* ("REV")) notes that New York's electric infrastructure is aging and estimates approximately $30.00 billion in capital investment is needed over the next ten years, most of which is infrastructure replacement that cannot be avoided.[64]

Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY THE SUBSTANTIAL INCREASE IN ITS PLANNED CAPITAL EXPENDITURES?

A. As with any utility faced with a substantial capital expenditure plan, the Company's risk profile is adversely affected in two significant and related ways: (1) the heightened level of

63 Source: Consolidated Edison, Inc., Investor Presentation at the 2014 Barclays Capital Energy/Power Conference, September 2-3, 2014, at 35.

64 Case 14-M-0101, Order Instituting Proceeding, April 25, 2014, Attachment 1 (Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal), at 6.

investment increases the risk of under-recovery, or the delayed recovery of the invested capital; and (2) an inadequate authorized return will put downward pressure on key credit metrics.

Q. DO CREDIT RATING AGENCIES RECOGNIZE RISKS ASSOCIATED WITH INCREASED CAPITAL EXPENDITURES?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted that:

> The real challenge for the industry is the combination of slow growth and huge investment needs. We believe that for the remainder of 2012 and beyond, state regulation will continue to be the single most influential factor for the sector's credit quality. Cost increases, construction projects, environmental compliance, and other public policy directives, together with lackluster growth, will necessitate continued reliance on rate relief requests.[65]

The rating agency views noted above also are consistent with certain observations discussed earlier in my Direct Testimony: (1) the benefits of maintaining a strong financial profile are significant when capital access is required, and become particularly acute during periods of market instability; and (2) the Commission's decision in this proceeding will have a direct bearing on the Company's credit profile, and its ability to access the capital needed to fund its investments.

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[65] S&P RatingsDirect, *Industry Economic and Ratings Outlook: U.S. Regulated Utilities Will Likely Stay On A Stable Trajectory For The Rest Of 2012 And Into 2013*, dated July 17, 2012, at 6.

Q. HAVE YOU ALSO CONSIDERED THE RELATIONSHIP BETWEEN CAPITAL EXPENDITURES AND THE EARNED RETURN ON COMMON EQUITY?

A. Yes, I have. The "DuPont" formula decomposes the Return on Common Equity into three components: (1) the Profit Margin (net income/revenues); (2) Asset Turnover (revenues/net plant); and (3) the Equity Multiplier (net plant/equity).[66] As Exhibit No.___ (RBH-13) demonstrates, based on the Value Line Electric universe, the Asset Turnover rate declined from 2003 through 2013 (the historical period covered by Value Line) and is expected to decline further through Value Line's 2017 – 2019 projection period. Over that same period, according to Value Line data, average Net Plant is expected to experience a cumulative increase of approximately 208.44 percent. Since, as noted above, the utility industry is going through a period of increased capital investment, the lag between the addition of net plant and revenue generated by those investments dilute the Asset Turnover ratio, at least in the near term.

In order to gain an additional perspective on the relationship between plant additions and Asset Turnover, I performed a regression analysis in which the annual change in the Asset Turnover rate was the dependent variable, and the annual change in Net Plant was the independent variable. As shown in Exhibit No.___ (RBH-13), that analysis indicates a statistically significant negative relationship between the two variables, such that as annual net plant increases, the Asset Turnover ratio decreases. This, in turn, suggests that an increase in capital expenditures also negatively affects the Return on Common Equity,

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66 The DuPont formula is commonly used by financial analysts to monitor specific operational and financial drivers of a company's earned ROE. The formula expands the calculation of the ROE into the product of three financial metrics: Profit Margin, Asset Turnover and the Equity Multiplier. That is, ROE = (earnings / revenue) x (revenue / assets) x (assets / equity).

causing greater financial stress to the utility. To the extent investors value a company based on earnings and cash flow, this additional financial strain is a key concern.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF CAPITAL INVESTMENT RISK ON THE COMPANY'S COST OF EQUITY?

A. It is clear that the Company's capital expenditure program is significant. The financial community recognizes the additional risks associated with substantial capital expenditures and the financing, regulatory and operating risks associated with those plans. In my view, therefore, the Company's capital investment plan remains an important consideration in establishing its ROE and overall rate of return.

Other Considerations

Q. ARE THERE OTHER BUSINESS RISKS THAT YOU HAVE CONSIDERED?

A. Yes, there are. The Commission recently initiated a proceeding to "consider a substantial transformation of electric utility practices to improve system efficiency, empower customer choice, and encourage greater penetration of clean generation and efficiency technologies."[67] In fact, several recent reports have identified New York as a state in which electric industry disruption resulting from distributed generation is most likely to occur first.[68] From the perspective of equity investors, distributed generation resources may lead to disruptions in the traditional cost recovery model for electric utilities and electricity markets and, therefore, introduce an additional element of uncertainty.

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67 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued April 25, 2014), at 5.

68 Deloitte Center for Energy Solutions, *The New Math: Solving the equation for disruption to the U.S. electric power industry*, 2014, at 4. *See* also Barclays Credit Research, *The Solar Vortex: Credit Implications of Electric Grid Defection,* May 20, 2014, at 4.

Moreover, as discussed by Company witness Saegusa, the scope of the proceeding suggests the Commission is considering regulatory structure changes that increase the level of uncertainty with regard to the Company's future earnings level and volatility.[69] Although it is difficult to quantify that effect, the additional risk associated with New York's changing regulatory structure and increasing penetration of distributed generation suggest an incrementally higher required ROE.

VIII. CURRENT CAPITAL MARKET ENVIRONMENT

Q. DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF CAPITAL AND REQUIRED RETURN ON COMMON EQUITY?

A. Yes. As discussed in Section VI, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. As such, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent that certain ROE estimates are incompatible with such data or inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING THE RELATIONSHIP BETWEEN CURRENT CAPITAL MARKET CONDITIONS AND THE COMPANY'S COST OF EQUITY?

A. Yes, I do. Much has been reported about the Federal Reserve's Quantitative Easing policy and its effect on interest rates. The issue as to how those policies and the

[69] Direct Testimony of Yukari Saegusa, at 21-23.

continuing level of interest rates affect utility stock prices is less clear. As discussed below, for example, while federal policy has affected interest rates, it also has been correlated with lower levels of market volatility. Generally speaking, when volatility is low, investors are willing to take on more risk and allocate capital to less defensive stocks. In essence, they are more willing to take on additional risk in expectation of realizing higher returns. Recently, however, the market appears to be providing conflicting signals. During certain periods of the past year, low volatility and low interest rates have resulted in defensive stocks such as electric utilities somewhat outperforming other sectors.

A relevant question, then, is how investors will react when the Federal Reserve completes its market intervention. A viable outcome is that investors will perceive greater chances for economic growth, which will increase the growth rates included in the multi-stage DCF model. At the same time, higher growth and the absence of federal market intervention could provide the opportunity for interest rates to increase, thereby increasing the risk free rate portion of the CAPM model. In that case, both the CAPM and DCF model would increase, producing increased ROE estimates.

At this time, however, market data is somewhat disjointed. As a consequence, it is difficult to rely on a single model (or a static weighting of the results of multiple models) to estimate the Company's Cost of Equity. A more reasoned approach is to understand the relationships among Federal Reserve policies, interest rates and risk, and assess how those factors may affect different models. For the reasons discussed below, the current market is one in which it is very important to consider a broad range of data and models when determining the Cost of Equity.

Q. PLEASE SUMMARIZE THE EFFECT OF RECENT FEDERAL RESERVE POLICIES ON INTEREST RATES AND THE COST OF CAPITAL.

A. Beginning in 2008, the Federal Reserve proceeded on a steady path of initiatives intended to lower long-term Treasury yields.[70] The Federal Reserve policy actions "were designed to put downward pressure on longer-term interest rates by having the Federal Reserve take onto its balance sheet some of the duration and prepayment risks that would otherwise have been borne by private investors."[71] Under that policy, "Securities held outright" on the Federal Reserve's balance sheet increased from approximately $489 billion at the beginning of October 2008 to $4.20 trillion by September 30, 2014.[72] To put that increase in context, the securities held by the Federal Reserve represented approximately 3.29 percent of GDP at the end of September 2008, and had risen to approximately 24.23 percent of GDP in September 2014.[73]

Q. IS THE FEDERAL RESERVE EXPECTED TO MAINTAIN THESE POLICIES?

A. The Federal Reserve began "tapering" its asset purchases in December 2013 and although the future pace of such reductions was not on a "preset course",[74] the program was completed in October 2014.[75] On September 17, 2014 the Federal Reserve issued a statement regarding "Policy Normalization Principles and Plans", in which it discussed the conditions under which, and methods by which it may reduce its holdings of

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70 *See* Federal Reserve Press Release dated June 19, 2013.

71 Federal Reserve Bank of New York, *Domestic Open Market Operations During 2012*, April 2013, at 29.

72 Source: Federal Reserve Schedule H.4.1. "Securities held outright" include U.S. Treasury securities, Federal agency debt securities, and mortgage-backed securities.

73 Sources: Federal Reserve Schedule H.4.1; Bureau of Economic Analysis, GDP data as of the fourth calendar quarter of 2013.

74 Minutes of the Federal Open Market Committee December 17–18, 2013, at 10; Minutes of the Federal Open Market Committee April 29 - 30, 2014, at 8.

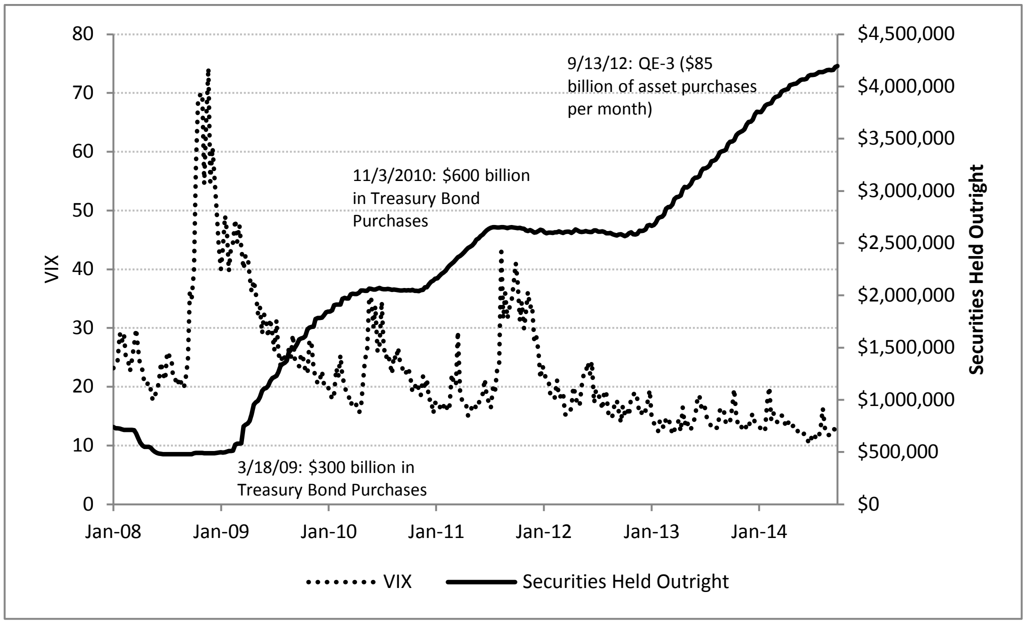
75 *See* Federal Reserve Press Release dated October 29, 2014.

securities and increase certain short term interest rates.[76] Although the Federal Reserve discussed its policy goals, no specific timelines were identified. As such, uncertainties remain in the market today and going forward. The uncertainty surrounding the timing of the Federal Reserve's future policy decisions, including the unwinding of stimulus programs, represents a risk to investors that, in my view, should be reflected in the Company's authorized ROE.

Just as market intervention by the Federal Reserve has reduced interest rates, it also has had the effect of reducing market volatility. As shown in Chart 1 below, each time the Federal Reserve began to purchase bonds (as evidenced by the increase in "Securities Held Outright" on its balance sheet), volatility subsequently declined. In fact, in September 2012, when the Federal Reserve began to purchase long-term securities at a pace of $85 billion per month, volatility (as measured by the CBOE Volatility Index, known as the "VIX") fell, and through September 2014 remained in a relatively narrow range. The reason is quite straight-forward: Investors became confident that the Federal Reserve would intervene if markets were to become unstable.

[76] Federal Reserve Press Release, *Policy Normalization Principles and Plans,* dated September 17, 2014.

Chart 1: VIX and Federal Reserve Asset Purchases



The important analytical issue is whether we can infer that risk aversion among investors is at a historically low level, implying a Cost of Equity that is well below recently authorized returns. Given the negative correlation between the expansion of the Federal Reserve's balance sheet and the VIX, it is difficult to conclude that fundamental risk aversion and investor return requirements have fallen.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSES OF CAPITAL MARKET CONDITIONS?

A. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. While I appreciate that all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, I believe that it is important to review and consider a variety of data points; doing so enables us to put in context both quantitative analyses and the associated recommendations.

IX. CAPITAL STRUCTURE

Q. WHAT IS THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. The Company's proposed capital structure consists of 48.00 percent common equity, 51.10 percent long-term debt, and 0.90 percent customer deposits. The Company has an actual, separate capital structure and the Company's projected rate year capital structure is discussed in detail in the Direct Testimony of Company witness Saegusa.

Q. PLEASE DISCUSS YOUR ANALYSIS OF THE CAPITAL STRUCTURES OF THE PROXY GROUP COMPANIES.

A. In order to assess the reasonableness of the Company's proposed capital structure, I reviewed the capitalization ratios of the individual utility operating companies owned and operated by the respective proxy group companies for the past eight quarters. As shown in Exhibit No.___ (RBH-9), the Company's proposed equity ratio (*i.e.*, 48.00 percent) is below the mean equity ratio of the proxy group companies of 52.90 percent. The Company's long-term debt ratio and customer deposit ratio of 51.10 percent and 0.90 percent respectively are within the range, albeit on the high end, of those ratios for the proxy group companies. Thus, overall, the Company's proposed capital structure ratios are reasonable compared to the proxy group.

Q. WILL THE CAPITAL STRUCTURE AND ROE AUTHORIZED IN THIS PROCEEDING AFFECT THE COMPANY'S ACCESS TO CAPITAL AT REASONABLE RATES?

A. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally generated funds; both bond-investors and rating agencies expect a significant portion of on-going capital investments to be financed with internally generated funds.

It also is important to realize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets it puts into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and equity investors.

Q. HOW DOES THE USE OF A BOOK VALUE CAPITAL STRUCTURE AFFECT THE INTERPRETATION OF ROE ESTIMATES BASED ON MARKET DATA?

A. Investors develop their return requirements in the context of market-based capital structures. As noted by Duff & Phelps:

> Although not directly observable, the cost of capital is also estimated by using market data. As stated earlier, the cost of capital is the expected rate of return on alternative investments with similar levels of risk. Investors will compare these alternative investments based on their market value, not their book carrying amounts[…] Similarly, the implied cost of equity capital for a company's stock is based on

> the share price at which it trades, and not on the company's book value per share.[77]

The ratemaking process, however, applies the allowed ROE to the book value capital structure, which will reflect a higher (lower) degree of financial leverage than the market value capital structure when the company's market-to-book ("M/B") ratio is greater than (less than) 1.00. It is important to recognize that as the firm's financial leverage increases, the financial risk also increases. Any increase in financial risk associated with the book-based capital structure would suggest a further adjustment to the required Return on Equity. Please note, however, that my ROE recommendation does not include or reflect such an adjustment.

Q. ARE ELECTRIC UTILITY COMPANIES' M/B RATIOS GENERALLY ABOVE 1.00?

A. Yes, they are. The M/B ratio equals the market value (or stock price) per share, divided by the total common equity (or the book equity) per share. The M/B ratios for the companies in both the SNL Electric index and my proxy group have been significantly greater than 1.00 since at least 2000 (*see* Chart 2).

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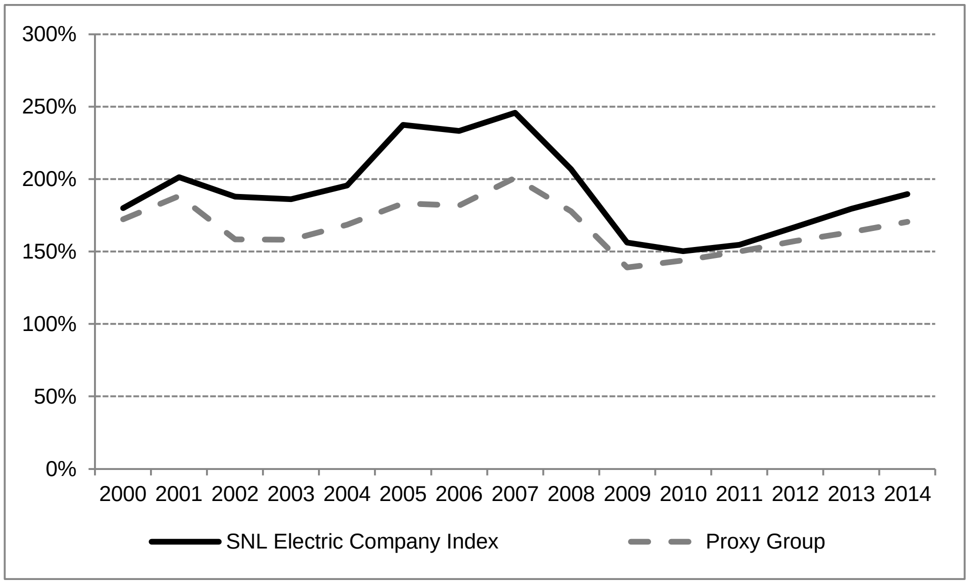
77 Duff & Phelps, 2014 Valuation Yearbook: Guide to Cost of Capital, at 1-6.

Chart 2: Historical Market-to-Book Ratios: 2000 – September 30, 2014



That result is not surprising. Book value per share is an accounting construct, which reflects historical costs. In contrast, market value per share (*i.e.,* the stock price) is forward-looking, and is a function of many variables, including (but not limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality", the regulatory climate, the equity ratio, expected capital expenditures, and the earned return on common equity.[78] Consequently, electric utility M/B ratios have deviated from 1.0 over time.

X. CONCLUSION AND RECOMMENDATION

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR RETURN ON BOOK EQUITY FOR O&R?

A. I believe that 9.75 percent to 10.50 percent is a reasonable estimate of the return required by equity investors to invest in a company of O&R's risk profile in the current capital market environment. In the event that O&R, Staff and other parties are able to negotiate

[78] *See*, for example, Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 366.

a three-year rate plan, as discussed below, my recommended return would increase by 50 basis points to reflect the additional risk associated with fixing rates during that period. My recommended return on book equity considers the results of the DCF and CAPM models, summarized in Table 13 (below), as well as the costs associated with the issuance of common stock, and the Company's need to fund substantial future capital expenditures. Applying the Commission's weightings to the Two-Stage DCF model mean result of 9.88 percent and the average of the CAPM results of 11.02 percent, results in an estimated Cost of Equity of 10.26 percent. Including an approximately two basis point adjustment for flotation costs results in a Cost of Equity of 10.29 percent.[79] Based on those analytical results, in my view, the Company's requested ROE of 9.75 percent is reasonable, especially in light of the Company's business risks relative to the proxy group.

Table 13: Summary of Analytical Results

	Mean Low	**Mean**	**Mean High**
Two-Stage DCF	9.74%	9.88%	10.03%
Three-Stage DCF	9.62%	9.84%	10.08%
	Bloomberg Beta Coefficient	**Value Line Beta Coefficient**	**Twelve-Month Beta Coefficient**
Market-Based CAPM			
Bloomberg Market-DCF Derived MRP	11.35%	10.74%	10.79%
Value Line Market-DCF Derived MRP	10.90%	10.32%	10.36%
Zero-Beta CAPM			
Bloomberg Market-DCF Derived MRP	11.83%	11.37%	11.41%
Value Line Market-DCF Derived MRP	11.35%	10.91%	10.95%
Average CAPM	11.02%		
CEI Flotation Cost	0.02%		
Proxy Group Flotation Cost	0.13%		
Weighted Average Cost of Equity (2/3 * Two-Stage DCF) +(1/3 * CAPM)			
Three-Month Average (including CEI Flotation Cost)		10.29%	

[79] Difference due to rounding.

Finally, I note that the ROE estimates developed throughout my Direct Testimony assume that the book value-based capital structure is the relevant basis of determining the degree of financial leverage. As discussed above, to the extent that investors develop their return requirements in the context of market-based capital structures, the degree of financial leverage is considerably less than that which is reflected in the book value-based amounts. The incremental leverage associated with the book-based capital structure would suggest a further adjustment to the required Return on Equity. As noted above, however, my ROE recommendation does not include or reflect such an adjustment.

XI. STAY-OUT PREMIUM

Q. WHAT ARE THE IMPLICATIONS FOR THE COMPANY'S COST OF EQUITY IF IT WERE TO AGREE TO A MULTI-YEAR STAY-OUT PERIOD?

A. It is important to consider the potential effect that increases in the general level of interest rates would have on the Company's stock price and its Cost of Equity. As discussed earlier, electric utility companies are long duration investments whose valuations are sensitive to changes in the required rate of return. Consequently, the interest rate risk to which equity holders are exposed relate to the long end of the yield curve, *i.e.*, the 30-year Treasury yield. In light of the relatively low level of long-term Treasury rates compared to their historical range, it is reasonable to assume that on balance, long-term rates are more likely to increase than decrease during the term of the stay-out period, representing a significant element of risk for equity investors.

While the Company has not proposed a multi-year rate plan, with associated stay-out periods, in its two rate filings, I note a three-year stay-out period was included in the settlement of O&R's 2011 electric rate case.[80] Consequently, for illustrative purposes, I will assume a three-year stay-out period in the application of the analytical models used to estimate the stay-out premium. My recommendation may differ for stay-out periods of other lengths.

Q. HOW HAS THE STAY-OUT PREMIUM BEEN CALCULATED IN PRIOR PROCEEDINGS BEFORE THE COMMISSION?

A. It is my understanding that in prior proceedings involving a three-year stay-out period, the stay-out premium has been calculated by taking one-half of the difference between the five-year average yields on three and one-year Treasury Notes. Staff has noted that such a calculation is meant to give guidance to the Commission in arriving at an appropriate premium.[81]

Q. WHAT ARE YOUR CONCERNS WITH THAT APPROACH?

A. My primary concern is that the methodology for calculating the premium appears unrelated to the underlying risks that it is intended to mitigate. First, as discussed earlier, given the relatively long equity duration and asset lives associated with electric utility operations, the risks associated with changes in capital market conditions are focused on long-term interest rates. Second, putting aside that fundamental issue, it also is the case that the shape and slope of the yield curve is not constant over time, such that a relatively

[80] 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 June 15, 2012), at 1-2.

[81] *See,* Case 09-E-0428, Prepared Testimony of Staff Finance Panel, at 106-107.

flat slope at the short-end of the curve may produce an inadequate premium relative to that which would be derived from the long-end of the curve. Finally, it is unclear how the 50.00 percent adjustment factor relates to the mitigation of company-specific risks over the term of the stay-out period.

For much the same reason that the Market Risk Premium component of the CAPM is an *ex-ante* measure, it stands to reason that the stay-out premium also should at least consider forward-looking data. Moreover, if the risk associated with the stay-out period is that the Company's Cost of Equity will increase as a result of changes in the level of interest rates, then (as discussed above) the relevant security is the 30-year Treasury security. And, with the ongoing tapering of QE discussed above, the risk of increasing rates may be particularly high as the magnitude of the Federal Reserve's asset purchases continue to decline.

Q. DID YOU CALCULATE THE STAY-OUT PREMIUM USING THE COMMISSION'S TRADITIONAL APPROACH?

A. Yes, I did. As shown in Exhibit No.___ (RBH-14), over the five-year period ended September 30, 2014, the average yield on the three-year Treasury Note was 0.76 percent, while the average yield on the one-year Treasury Note was 0.20 percent. The difference between those two average yields is 0.56 percent; one-half of that amount equals approximately 0.28 percent, or 28 basis points.

Q. DID YOU ALSO CALCULATE THE STAY-OUT PREMIUM BASED ON THE DIFFERENCE IN CURRENT AND PROJECTED LONG-TERM TREASURY YIELDS?

A. Yes, I analyzed the difference between current and projected yields on 30-year Treasury bonds. As of September 30, 2014 the three-month average yield on the 30-year Treasury bond was 3.27 percent. For the projected Treasury bond yields, I relied on the Blue Chip Financial Forecast's 2017 projected yield of 5.10 percent, which reasonably approximates the end date for the rate plan.[82] The difference between the current and projected yields is 183 basis points. Given the long-duration nature of electric utility equity investments and the risk of increase in long-term Treasury yields, risk to equity investors are substantially greater the risk suggested by calculating the difference in short-duration Treasury yields.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE DEVELOPMENT OF AN ESTIMATE OF THE STAY-OUT PREMIUM?

A. Yes, I do. Given the uncertainty currently observed in the financial markets, the traditional approach may no longer provide the appropriate compensation for the additional risks perceived by utility equity investors. While the Commission's traditional approach and my alternative approach both rely on measures of Treasury yields, the risk differential between utility common equity and Treasuries should be considered in setting an ROE premium. Given that on the date of investment, an investor in Treasury Bonds is virtually guaranteed to collect that Bond's coupon payment, the risk of investment in utility common equity is significantly greater. That is, there is a significantly greater risk that a utility equity investor will fail to realize the required return if the company itself is

[82] Blue Chip Financial Forecasts, Vol. 33, No. 6, June 1, 2014, at 14.

not recovering the cost of service in its rates or is precluded from addressing unexpected cost increases or external financial shocks through the regulatory structure. Given the level of instability in interest rates and risk perceptions in current financial markets, utility equity investors require a larger premium to offset the increased risk assumed by agreeing to a stay-out period. Even investors in utility bonds, which are less risky than utility common equity, demand a premium above Treasury rates.

Moreover, the importance of that risk premium may be highlighted by the reliance on a standard calculation methodology to estimate the Company's ROE. Insofar as investors are aware of a standard formulation used to estimate the Company's ROE, that formulation becomes, to a certain extent, incorporated by the investment community. Such a focus on the analytical results of the models chosen to estimate the ROE and not the reasonableness of the overall results concentrates the risks to investors on the chance that, for example, the DCF results materially change. In the context of the CAPM model, for example, changes in the required Return on Equity are directly related to changes in long-term interest rates, resulting in an inverse relationship with stock prices (ceteris paribus). As discussed earlier in my Direct Testimony, utilities are comparatively long duration securities that are sensitive to changes in the returns required by investors. In that regard, the relevant issue is not movements along the yield curve, but rather the extent to which the Cost of Equity may increase during the stay-out period.

Aside from the effect of changes in long-term interest rates, equity valuations remain at risk to increases in broad market instability, rotation out of the utility sector on the part of institutional investors, unexpected credit contractions, and other factors that affect both fundamental equity valuations and investor trading patterns. If the Company is foreclosed from adjusting the market-required ROE during a period of higher price instability, investors will necessarily incorporate a larger risk premium than in periods of greater equity stability. To the extent that, on balance, those factors represent greater downside risk, the stay-out premium should recognize that uncertainty. In that regard, given that the Company forgoes the ability to recover the costs associated with increases in the Cost of Equity during the stay-out period, the premium may be considered the cost associated with insuring against such adverse market movements.

Finally, apart from my disagreement with the use of one- and three-year Treasury securities as the relevant benchmark for measuring the additional risk assumed by investors with a three-year stay-out period, simply on a technical basis, the use of only half the differential in establishing the stay-out premium also is not reasonable. In the case of bonds (in particular Treasuries), the investor in the longer maturity instrument is virtually assured to collect the entire differential between the two rates. Investors require, and receive, the entire difference in interest rates, not half of that difference, for investing in the longer maturity security. As such, even if the one- and three-year Treasury yields were the appropriate benchmark, the use of only one-half of the differential substantially understates the indicated risk premium.

Q. WHAT IS YOUR RECOMMENDATION AS TO THE APPROPRIATE LEVEL OF THE STAY-OUT PREMIUM?

A. I do not believe that one-half of the five-year average difference between the one- and three-year Treasury yields is the appropriate measure of the incremental risks incurred by equity investors in the current market environment. In my view the potential for, and consensus expectations of, a substantial increase in the level of long-term Treasury yields also should be given consideration in the determination of the stay-out premium. For the reasons discussed earlier, I believe that the approach used in prior proceedings does not appropriately capture the market's view of the risk associated with a stay-out period. On balance, after considering the Commission's traditional approach and the likelihood of increased long-term rates, I believe that a stay-out premium of up to 50 basis points is reasonable for purposes of the initial application of this change in methodology.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF THE
REFORMING THE ENERGY VISION PANEL

Q. Would the members of the Reforming the Energy Vision Panel ("Panel") please state their names and business address?

A. Donald Kennedy, whose business address is 390 West Route 59, Spring Valley, New York 10977, and Jack Deem, Sergej Mahnovski and Cheryl Ruggiero, all of whose business address in 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity and what are your professional backgrounds and qualifications?

A. **(Kennedy)** I am employed by Orange and Rockland Utilities Inc. ("Orange and Rockland", "O&R" or the "Company") as the Director of Customer Energy Services.

In 1998, I graduated from the State University of New York, Rockland Community College, with an Associate Degree in Math and Science. In 2002, I graduated from the State University of New York, Empire State College, with a Bachelor of Science in Business Administration. In 2010, I graduated from Walden University with a Masters of Business Administration. I joined the Company as a Meter Reader in 1981. I have since held the positions of Supervisor - Meter

Reading, Senior Supervisor - Customer Accounting, Manager - Customer Service, Director – Customer Service, and Director of New Business Services prior to my present position. In my current position, I am responsible for the oversight of energy efficiency, demand response, renewable energy, retail choice and low income programs for Orange and Rockland

(**Deem**) I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or "CECONY"), an affiliate of Orange and Rockland, as the Department Manager - Regulatory Filings in the Corporate Accounting Department. In December 1990, I received a Bachelor of Science Degree in Policy & Management from Carnegie Mellon University in Pittsburgh, Pennsylvania. I earned a Masters of Business Administration degree from Carnegie Mellon in June of 1996. Before returning to Carnegie Mellon for my MBA, I worked as an analyst with Barakat & Chamberlin, Inc. where I was responsible for planning and evaluating demand-side management ("DSM") programs for various utilities. In that role, I performed cost-effectiveness screening and market penetration analysis of DSM measures and programs;

prepared testimony entered on behalf of utilities during DSM cost recovery hearings, and implemented DSM tracking systems. After receiving my MBA, I worked as a consultant with Deloitte Consulting for 14 years. With Deloitte, I assisted companies improve operations by leading the implementation of finance process, system, control, and organizational improvements. I joined Con Edison in June 2010 where I took the role as Business & Solution Architect for the implementation of the Oracle Finance and Supply Chain system. I assumed my current position as Department Manager for Regulatory Filings in May 2014.

(**Mahnovski**) I am employed by Con Edison as the Director of the Utility of the Future team. The team is responsible for developing the Company's positions and strategy in the Public Service Commission's ("Commission" or "NYPSC") Reforming the Energy Vision docket ("REV Proceeding")[1], and coordinating with key business units on the evolution of the Company's technology platforms, market design, customer

[1] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Instituting Proceeding* (issued April 25, 2014) ("REV Order").

engagement, and rate and regulatory structures in support of REV. I received a Bachelor of Science degree in Chemical Engineering and a Bachelor of Arts degree in History from Stanford University in 1996, a Master of Science degree in Chemical Engineering from University of California, Berkeley in 1999, and a Ph.D. degree in Policy Analysis from the RAND Graduate School in 2006. I have also served as an Assistant Adjunct Professor at the School of International and Public Affairs at Columbia University since 2011.

Prior to joining Con Edison in February 2014, I managed citywide energy and sustainability policy for the New York City Mayor’s Office. From September 2010 until February 2014, I served as New York City’s point person on energy, first as Director of the Office of Energy Policy and Senior Advisor at the Department of Environmental Protection and then Director of Energy Policy in the Mayor’s Office. In October 2012, I was appointed by former Mayor Michael Bloomberg as Director of the Office of Long Term Planning and Sustainability (“OLTPS”), merging the City’s energy and sustainability offices. As

Director of OLTPS, I managed a team responsible for citywide energy policy and New York City's comprehensive sustainability and resilience plans. I also served as Chairman of the New York City Energy Policy Task Force, Chairman of the New York City Energy Efficiency Corporation, and board member of the New York State Smart Grid Consortium.

Prior to joining the City in March 2010, I was a Director in the Global Power Group at IHS CERA, and prior to that, a Doctoral Fellow at RAND Corporation.

(Ruggiero) I am employed by Con Edison as the Department Manager of the O&R Rate Design section of the Rate Engineering Department. I received a Bachelor of Science Degree in Electrical Engineering from Polytechnic University in 2000 and a Master of Business Administration Degree in Finance from Baruch College in 2009. In 2000, I began my employment with Con Edison as a Management Intern with rotational assignments in Electric Operations, Engineering Services, and Gas Operations. In July 2001, I accepted a position as an Associate Engineer in Distribution Engineering. In November 2005, I accepted a position as a Senior Analyst in Rate

Engineering and have since held titles of increasing responsibility. I was promoted to my current position in March 2013.

Q. Have you previously submitted testimony to the Commission?

A. (**Kennedy**) Yes, I submitted rebuttal testimony in the Company's last gas base rate case (*i.e.*, Case 08-G-1398).

(**Deem**) No, I have not.

(**Mahnovski)** Although I have not submitted testimony to the Commission on behalf of the Company, I have testified before the Commission on behalf of the City of New York in the 2013 CECONY rate cases (Case 13-E-0030/13-G-0031/13-S-0032).

(**Ruggiero**) Yes, I have testified before the Commission in Cases 10-E-0362 and 11-E-0408. I also have submitted testimony before the New Jersey Board of Public Utilities and the Pennsylvania Public Utility Commission.

Q. What is the purpose of the Panel's direct testimony in this proceeding?

A. The Panel's direct testimony discusses how the Company plans to begin to address, during the Rate

Year (*i.e.*, the 12 months ending October 31, 2016)("Rate Year") and subsequent years, the Commission's policy objectives as articulated in the REV Proceeding. The Company welcomes the Commission's consideration of this matter and is already gaining critical experience that will provide a strong starting point for ongoing work to provide customers more options to manage their energy profile, integrate more Distributed Energy Resources ("DER") into our system, and develop a dynamic DER market in New York. As part of these efforts, the Panel presents a DER demonstration project that the Company proposes to implement in order to defer capital infrastructure investment required to meet short- and long-term customer energy needs.

Q. Please discuss the current status of the REV Proceeding.

A. In the REV Order, the Commission announced its initiation of "a proceeding to consider a substantial transformation of electric utility practices to improve system efficiency, empower customer choice, and encourage greater penetration of clean generation and efficiency technologies." The REV Order stated that the proceeding would move forward on two parallel tracks. The first track ("Track One") will focus on Distributed System Platform ("DSP") related issues, as well as the impacts on wholesale markets, opportunities for customer engagement, and other essential related issues. The second track ("Track Two") will focus on regulatory changes and ratemaking issues. After extensive input from interested parties, on August 22, 2014, Staff of the Department of Public Service ("Staff") issued: Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues ("Track One Straw Proposal"). Interested parties, including the Company, have submitted initial and reply comments regarding the Track One Straw Proposal. A Commission Order addressing the Track One Straw Proposal is currently expected during the first quarter of 2015. Staff is expected to issue its Straw Proposal on Track Two Issues in January 2015. The Company has supported the Commission's efforts in this area and stands as a partner with the Commission and Staff in implementing its vision.

Q. Are there any developments in the Company's service territory that are consistent with the Commission's expressed vision?

A. Yes. As regards distributed assets, the Town of Clarkstown, in partnership with a third party, has completed a 2.3 MW solar energy project built on 13 acres of decommissioned capped landfill. Although the largest such project in the Company's service territory, it follows numerous smaller projects that have resulted in 1200 solar installations on the O&R system at this time. Also, the New York State Energy Research and Development Authority ("NYSERDA") has proposed a micro-grid concept in New City at the Rockland County and Clarkstown municipal complexes. And, earlier this year, Orange County announced the launch of Energize NY, a program that would help commercial property owners by providing critical support, tools, and long-term financing to implement clean-energy upgrades for their buildings. Regarding utility efforts, in addition to the items discussed below, the Company proposes in its contemporaneous electric and gas rate filings to begin the installation of an AMI metering system in its service territory and to construct a compressed natural gas ("CNG") fueling facility. As discussed in the direct testimony of the Company's AMI Panel, AMI is a foundational technology that will enable customer participation in DER programs that will help them manage their energy profile more effectively, thereby expanding DER in the Orange and Rockland service territory.

Q. Does the Company expect to pursue other REV related projects prior to and during the Rate Year?

A. Yes, the Company expects to pursue projects that are consistent with the Commission's central vision of REV, *i.e.*, increasing the penetration of DER resources throughout New York State and animating DER markets. Depending on developments in the REV Proceeding, these projects may include the following:

- Identify and procure additional data acquisition and communications technologies to support the envisioned DSP market functionalities. As noted in the Track One Straw Proposal (p. 38), the Company will focus on the following initial priorities:

- Real-time DER monitoring;
- Real-time network monitoring;
- Enhanced fault detection/location;
- Automated feeder and line switching; and
- Automated voltage and Volt-Ampere Reactive ("VAR") control.

In developing these functionalities, the Company will employ a transparent technology mapping process, which will help all stakeholders better understand the technologies needed to enable DSP functionality. The Company will also be working with other stakeholders to develop operations and communications protocols, procedures, tariffs, market rules and market procedures.

- Develop and file an Efficiency Transition Implementation Plan ("ETIP") which describes the portfolio of energy efficiency programs that the Company will implement beginning in 2016. The ETIP will serve as the bridge between the Company's current energy efficiency program efforts and its expanded demand-side efforts envisioned under REV. The Company also will assist in improving the tracking and monitoring of energy efficiency measures across New York State.

- Explore new business relationships and models which will facilitate the Company's partnering with customers and developers so as to increase the penetration of DER resources and animating DER markets throughout the Company's service territory. Initially, this effort is anticipated to be focused in the Pomona load area, where the Company can leverage its plans for Advanced Metering Infrastructure ("AMI") deployment, and seek other opportunities to implement new business models for DER deployment, working with a variety of third parties.
- Explore the feasibility of implementing an electric vehicle charging demonstration project, as well as community solar initiatives.
- Develop a mechanism for the procurement of large-scale (*i.e.*, Main Tier) renewables beginning in 2016.

- Participate in the development of data sharing processes that will give DER providers the information they need, consistent with cyber security and customer privacy requirements, to effectively site DER in areas where they are needed most. To the extent possible, the Company will also consider innovative tariff rate structures related to information.
- Develop a customer portal that will allow the Company's customers to (i) access their energy usage information, (ii) transfer such information to third party providers that they designate, and (iii) shop for and purchase DER and other energy-related value-added services from third-party providers.

Q. Does the Company propose any other actions in support of the Commission's vision?

A. Yes, the Company proposes to facilitate further development of an asset base of distributed resources by developing and issuing a Request for Information ("RFI") that seeks to identify potential resource development initiatives and other approaches that may enhance the available energy pool in its service territory and provide demand relief in areas where doing so may defer the need to build additional utility infrastructure. The Company plans to develop this RFI with input from other parties that share its commitment to partner in achieving the Commission's vision.

Q. What sort of resource and/or demand relief initiatives may result from the Company's RFI?

A. Given the nascent state of the distributed resource market in its service territory, the Company believes that its RFI may produce both innovative uses of technology, as well as, new business models. The Company further believes that it can use the information gained through this process to develop demonstration projects and provide for the possible deferral of upcoming infrastructure construction projects.

Q. What capital infrastructure investment is the Company seeking to defer through the implementation of the DER pilot program?

A. As discussed in the direct testimony of the Electric Infrastructure and Operations Panel, the Company is seeking to defer the construction of a new substation in Pomona, Rockland County, New York ("Pomona substation"). The Company forecasts that electric load will grow by 4.5 MW over the next seven years in northwest Rockland County, particularly due to the proposed Patrick Farm residential subdivision project. The capital cost of the substation is estimated to be $55.7 million, which includes $20 million for the substation and $35.7 million to construct a 138kV underground line loop from the West Haverstraw Substation as the new transmission source for the Pomona Substation. Absent the Company's implementation of a DER demonstration project, the Company will need to commence construction of the new Pomona Substation by 2019 and complete construction by 2021.

Q. Please describe the proposed demonstration project.

A. The proposed demonstration project will focus on the development of distributed energy resources and demand reduction alternatives in northwest Rockland County that will both stimulate the developing marketplace and reduce peak demand, thereby improving service reliability and resiliency. The Company will seek multiple solution providers so that numerous approaches and technologies can be evaluated to determine the best aggregate solutions. Alternatives to be considered include, but are not limited to:

- Targeted energy efficiency ("EE");
- Demand response ("DR") such as air conditioning ("A/C") and appliance cycling technologies;
- Customer behavior modification strategies (*i.e.*, potential coordination with Time of Use rates);
- Clean (*i.e.*, gas fired and solar) distributed generation ("DG"); and
- Energy storage.

As discussed in the testimony of the Company's AMI Panel, the Company's implementation of AMI will serve as a foundation for the DER demonstration project. For example, AMI will enable the collection of granular data that will enhance customers' ability to manage their energy use, the ability of third parties to offer customer-specific solutions, and the Company's ability to improve system modeling.

The Company proposes to offer commercial and industrial customers in the targeted area EE measures, through a direct install program (similar to the Company's current small business direct install program). As discussed in more detail below, the Company also proposes to implement a residential/small business A/C cycling program. Various energy technologies will be implemented in stages and the project will be tiered to capture varying levels of demand reduction. For example, EE measures resulting from a direct install program will be made available to commercial customers in the area, which include small retail, restaurants, a large shopping complex and a small pharmaceutical manufacturer. Under the existing EE programs offered today by O&R and NYSERDA, customer energy savings and program funding are focused on reducing energy consumption (MWh), not peak demand reduction (MW). The demonstration project will include coverage of the installation costs for some direct install measures and increased rebates. For measures not included in the direct install component (*e.g.*, replacement of HVAC units), increased rebates will be offered to reduce the barrier of upfront capital investment, in conjunction with the newly formed Green Bank financing, if available.

Q. What other approaches would the demonstration project include?

A. Other approaches include a turn-key application for clean DG. The Company will solicit third party providers that can provide such turn-key applications. The Company believes that greater efficiencies may be available if it owned and operated some of the DG alternatives, following development by a third party. However, the Company proposes to work with third parties to approach large customers in the Pomona area to gauge customer interest in hosting a DG project, either gas fired or solar. The Company proposes to purchase and pay for the installation of the units at a large commercial customer location in the Pomona area. The Company will also investigate the potential of siting gas fired DG and/or a solar installation at the Company's Mt. Ivy work-out location.

Q. Does the Company propose a residential component to this demonstration project?

A. Yes, there would be a residential component because the Pomona area is mainly comprised of residential customers whose participation would be critical to achieving the project's goals. That component would include implementation of a residential and small business A/C cycling program within the Pomona area. The program would provide participating customers with a smart programmable thermostat containing ZIGBEE technology, which the Company would install, along with an annual program incentive to participate over a seven year period. Using AMI technology, on system peak demand days, the Company would send a signal to the participants' thermostat, raising the set point 3-5 degrees, which will cause the A/C to cycle off for approximately 20 minutes. At the end of the 20 minute period, the thermostat will be set back to the original set point. Businesses could also be offered incentives to participate, thereby increasing the potential for A/C cycling related demand reduction.

Q. Will the Company work with parties such as NYSERDA to implement its DER demonstration project?

A. Yes. The Company will work closely with NYSERDA and builders of new residential developments to incentivize the construction of energy efficient homes. As a supplement to the NYSERDA incentive of between $2,000 and $8,000 per home, O&R could provide additional incentives, for the use of energy star appliances containing the ZIGBEE chip for appliance cycling, AC cycling, in home energy controls (behind the meter) or solar installations. A/C and appliances such as dishwashers and pool pumps would be cycled on system peak demand days. To do so, the Company would send a signal to the participant's appliance, shutting the appliance down during the cycling period. A/C cycling would work as previously described above.

Q. Would the proposed demonstration project also include utility-side solutions?

A. Yes. The Company would implement energy storage technologies to supplement the other DER project components during peak periods to off-set customer demand.

Q. What other efforts would be required for such a demonstration project?

A. Given the developing nature of such a project, the Company can only estimate apparent efforts and their associated costs. For example, the project would require promotion of a comprehensive customer engagement strategy that incorporates direct marketing to customers and enhanced customer outreach and education, including through engagement with community groups, key community stakeholders and government organizations. The Company would work with State and local governments and non-government organizations, and with existing market partners and emerging market participants.

Q. What means does the Company currently employ to inform and educate customers on energy-related topics and Company activities such as the DER demonstration program?

A. The Company communicates to its customers through bill inserts, newsletters, the Company's website, and other media, such as radio and television advertisements, social media, in-person participation at some energy fairs and community events. Also, the Company has one employee dedicated to community outreach and education. To date, the Company's

Customer Energy Services Department has worked to address its customers' needs in the energy services arena, mainly through weekend and evening efforts. In the past year, the Customer Energy Services Department participated in approximately three events per month ranging from school energy fairs to home shows. Almost all of the events were in response to invitations from events' sponsors. Interactions with other stakeholders including public officials are handled by the Company's Public Affairs department. The Corporate Communications department manages the publication of key corporate messages primarily through the print media.

Q. How would the Company change its outreach and education approach in undertaking the proposed demonstration project?

A. The Company would add two dedicated outreach and education positions within the Customer Energy Services department in order to facilitate customer engagement for the demonstration project, as well as future projects. These two positions will be funded at a salary of $85,000 per position, excluding overheads. These additional resources would provide a centralized focus for the Company's outreach and education efforts, better serve business and community needs and provide customers with increased opportunities to convey their needs and concerns to the Company. In addition, the Company proposes to develop an annual outreach and education operating budget to promote the DER demonstration programs. These dedicated customer O&E resources will implement a customer outreach and education plan ("O&E Plan") that will enhance the Company's effectiveness in communicating facts and details regarding the DER demonstration project and information on how to save energy, through participation in that project. As part of its O&E Plan, the Customer Energy Services Department will seek out opportunities to meet with customers within the Pomona area in person at a variety of events, including periodic Town Hall Meetings and personal consultations with customers and businesses within the area. Issues to be addressed will include: (i) energy conservation advice, such as unplugging second refrigerators, closing off unused rooms, and the benefit of installing low-cost weatherization measures; (ii) energy technology and programs available to customers including, energy storage, DG and demand response; (iii) energy efficiency measures and tips for the home and business, such as lighting and programmable thermostats and appliance controls; and (iv) information on smart grid, meter communications and peak pricing. These encounters will provide an opportunity for Company representatives to listen to the concerns of its customers; to respond to questions on a multitude of issues; to explain utility bills; and to promote energy efficiency programs for the Company and for NYSERDA. In addition, these outreach and education enhancements would allow for customer engagement in the reformed energy vision.

Q. How does the Company propose to manage the DER demonstration project?

A. In order to implement the DER demonstration project, the Company requires the flexibility to respond to market needs and opportunities. Accordingly, the Company will request that it be given broad flexibility to work with third parties and customers to support distributed resource asset development, nurture innovative approaches to market development and develop business terms that will achieve desired outcomes. Such terms would include consideration of customer, utility and/or third party ownership, lend/lease, and co-ownership of materials and assets including development of assets installed within customer premises and located behind the utility meter.

Q. How does the Company propose to track the progress of the various programs included in the DER demonstration project?

A. In order to track progress and assess whether non-traditional customer-side solutions are providing the necessary demand reduction, AMI would be used to capture data needed to evaluate the demand response, DG and DR. The data captured will be used to determine the efficiency of each program. The Company will develop and use checkpoints on the solutions’ progress and prepare contingency alternatives in the event that necessary reductions are not achieved. In addition to the specific checkpoints noted above, the Company would continue to track project progress, both at the overall DER demonstration project and individual program levels. The Company would follow a disciplined project lifecycle that includes Initiation, Planning and Design, Implementation, Monitoring and Controls, and Closing so that any delivery risks (deployment delay, cost over-run, impact level) may be identified early and mitigated quickly. To accomplish this, the Company proposes the establishment of a program design/evaluator position to oversee the DER demonstration project. The salary of the program design/evaluator will be $95,000, excluding overheads.

Q. Is the Company proposing to earn a return on its investment in the DER demonstration project?

A. Yes. The purpose of this demonstration project is to explore the potential for utilizing DER as a least-cost alternative to delaying capital investment, thereby reducing overall cost of service. The Company proposes to earn its approved rate of return on the DER investment. If successful, the DER demonstration program will allow the Company to delay the need to make traditional investments. Consistent with the vision of the REV proceeding, ratemaking should make the Company indifferent to whether it invests in traditional or non-traditional solutions, as well as whether it invests in customer-side or utility-side solutions. Accordingly, earning a return on the costs for these programs, and recovering these costs over a period as described herein, would be consistent with the Commission's REV policy objectives, as currently being explored in the REV Proceeding. If such a demonstration project provides the positive expected results, the Company would seek to implement additional programs in the future and earn its approved rate of return on any similar projects proposed and implemented. The Company also proposes that the Commission establish up to a 100 basis point incentive on these investments to encourage the Company to not only invest in non-traditional solutions, but also have a direct interest in the overall program success. The basis point incentive would be incremental to Orange and Rockland's authorized rate of return if the Company achieves demand reduction targets of the demonstration project. Based on initial estimates, the value of the 100 basis point incentive if all targets are met would be $280,000 to be recovered over the same time frame as the carrying charges for these investments.

The Company also proposes that the Commission establish a sharing of the net savings of the demonstration project, with the Company receiving 50 percent of the net savings. To calculate net savings, we first calculate the benefit of delaying the substation. That is equal to the difference between the net present value of all revenue requirement streams associated with a 2021 installation relative to the net present value of all revenue requirement streams associated with a 2025 implementation. Net savings are then calculated as the benefit of delay less the net present value of the costs to achieve the delay. Approval of the proposed incentives will align customer, Company and Commission interests to achieve performance targets.

Q. How long does the Company project that it can delay construction of the Pomona substation if the demonstration project were to be implemented?

A. The Company estimates that the implementation of the DER demonstration project would allow it to defer construction of the Pomona Substation from between one and four years (*i.e.*, from 2022 to 2025). Such a construction delay would result in present-worth projected annual customer savings (through the avoidance of interest and project carrying costs) of approximately $3.0 million per year for a total of $11.6 million through 2025.

Q. What is the estimated cost of the Company's DER demonstration project?

A. The Company estimates that such a project would cost approximately $ 9.5 million based on its sense of the solutions currently available. However, the transformative nature of this and other projects in support of an evolving marketplace may positively impact that cost providing further cost savings to customers.

Q. How does the Company propose to recover the incremental costs that it would incur in implementing the Commission's REV related policies and/or in implementing a demonstration project such as the one described above?

A. At the time of this rate filing, the Commission has not issued an order addressing the Track One Straw

Proposal. Moreover, as noted by the Track One Straw Proposal (p. 78), "The comprehensive, complex and transformative nature of REV will require years of iterative planning and increasingly granular design determination, which should begin as soon as the Commission makes a policy decision to proceed." The Company recognizes significant progress will be made toward REV objectives during the course of the 11-month rate case process, and that many specifics will evolve over this period. Given this uncertainty, the Company is unable to forecast accurately the incremental operation and maintenance ("O&M") and capital costs that it will incur during the Rate Year on REV related projects, at this time. In light of these circumstances, the Company has not included any REV related costs in its requested revenue requirement in this proceeding. Rather, as discussed in the direct testimony of the Company's Electric Rate Panel, the Company is proposing that it be allowed to recover the incremental costs it incurs on REV related projects through a separate surcharge ("REV Surcharge"), including for the costs of demonstration programs. As discussed in the testimony of the Company's Electric Rate Panel, the REV Surcharge will be a component of the Energy Cost Adjustment that is charged to all customers.

Q. What types of incremental costs would be recovered through the REV Surcharge?

A. The costs to be recovered through the REV Surcharge would include program costs for customer-side and utility-side demand management programs that specifically address identified distribution system needs, other potential demonstration projects, as well as expenditures necessary to begin deployment of foundational investments such as the development of the DSP. The REV Surcharge would include carrying charges on both capital expenditures and customer incentives and program costs, O&M costs, income taxes, property taxes and other taxes, costs of third party engagement, incentives paid for achieving defined outcomes, and the costs to set up new programs or tools for customers, including customer outreach and education enhancements. The carrying charge would be based on the overall rate of return authorized in this proceeding.

Q. Over what time period would such costs be recovered?

A. The Company proposes a five-year and ten-year recovery period for customer-side and utility-side expenditures, respectively, for REV-related projects.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Q. Would the members of the Smart Grid Panel ("Panel") please state your names and business addresses.

A. Joe White, 390 West Route 59, Spring Valley, New York, 10977.

Jeremy McVey, 390 West Route 59, Spring Valley, New York, 10977.

John Murphy, 71 Dolson Avenue, Middletown, NY, 10940.

Q. By whom are you employed, in what capacity, and what are your backgrounds and qualifications?

A. **(White)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R", or the "Company"), as a Department Manager – Technology Engineering in the Smart Grid Department. I have a B.S. Degree in Electrical Engineering from Auburn University and 15 years of increasing responsibilities in utility operations and engineering. Prior to joining Orange and Rockland, I spent 14 years at Southern Company where I worked in various capacities at the subsidiaries of Alabama Power Company, Savannah Electric & Power Company, Mississippi Power Company and Georgia Power Company in electric transmission, distribution systems and resource policy and planning. I have a background in areas of Transmission Area Maintenance, Transmission Line Design, Distribution Region Operations, and Distribution Material Standards, where I served as the Lead Product Engineer for Insulators and Lighting Materials for all of Southern Company. Within the utility industry, I served on various regional committees as part of the Southeast Electric Exchange Working Groups for Overhead, Underground, Joint-Use, Transformers, NESC and Pole Line Hardware Committees.

I joined Orange and Rockland in 2013 as a Principal Engineer in the Performance and Operational Engineering Department, where I was a Principal Reliability Engineer focused on analyzing electric system performance and outage data, frequent customer complaints, and regulatory inquiries. I led teams to identify and address worst performing circuits within the Company's service territory and helped select circuits that could benefit from storm hardening and system resiliency projects. I recently assumed my current position of Department Manager of Smart Grid Technology Engineering.

(McVey) I am employed by Orange and Rockland as the Section Manager – Distribution Control Center. I have a B.S. Degree in General Engineering from the United States Military Academy at West Point, a Masters Degree in Business Administration from the University of Maryland, and 12 years of increasing responsibilities in utility operations. Prior to coming to Orange and Rockland, I spent three years at Consolidated Edison Company of New York, Inc. ("Con Edison") where I worked as an Overhead Supervisor and before that I served for five years in the Army's Corps of Engineers. I joined Orange and Rockland in 2005 as a Distribution Supervisor in the Distribution Control Center.

(Murphy) I am employed by Orange and Rockland as Manager – Electric Operations. I have a B.B.A. Degree in Finance from St. Bonaventure University and 18 years of increasing responsibilities in utility finance and operations. I spent 12 years in Finance where my responsibilities included assisting in the coordination and preparation of rate case filings and related analyses and proposals for Orange and Rockland and its two wholly-owned utility subsidiaries, Rockland Electric Company ("RECO") and Pike County Light & Power Company. In 2008, I was promoted to Manager-Electric

Operations. In this position, I am responsible for the Electric Overhead and Underground Line Groups, including the Equipment Technician Group.

Q. Have any members of the Panel previously testified before the Public Service Commission ("Commission")?

A. No.

Q. Please briefly explain the purpose of the Panel's testimony in this proceeding.

A. Orange and Rockland has been implementing distribution automation since the early 1990's on its electric distribution system. As part of its plans for distribution automation and technology expansion on its electric distribution delivery system the Company constructed a two circuit proof of concept project in the West Nyack area of its service territory ("West Nyack Project") that includes remote real time monitoring and operator control systems, as well as fully automated centralized real time decision making command and control systems. This project was partially funded by the New York State Energy Research and Development Authority ("NYSERDA"). In addition, the Company, as a sub-awardee to Con Edison's Smart Grid Infrastructure Grant ("SGIG") and its Smart Grid Demonstration Grant ("SGDG"), both pursuant to the American Recovery and Reinvestment Act of 2009, expanded upon the two circuit West Nyack Project to develop a small system of five circuits within RECO's service territory ("RECO Demonstration Project"). One of the goals of the RECO Demonstration Project was to determine the ease of expansion and to identify means of reducing the installation costs prior to implementing distribution automation on an expanded, service territory wide basis.

The Company also contracted, through Con Edison, with the Electric Power Research Institute ("EPRI") and worked collaboratively with Brookhaven National Laboratory ("BNL") and Electrical Distribution Design ("EDD"), an engineering consulting firm in Blacksburg Virginia, to conduct a study that would identify cost savings that could be derived from the implementation of Orange and Rockland's distribution technology enhancements and distribution automation concepts. The area selected for this study is adjacent to and contiguous with the two proof of concept circuits included in the West Nyack Project, and will expand the distribution technology and automation enhancements to 14 additional circuits. The results of this study demonstrated that the Company's approach and methodology of integrating advancements in communications technology and command and control systems into existing and new electric distribution system infrastructure will provide improvements in system reliability, system resiliency, energy conservation, and energy reduction, as well as cost savings. Orange and Rockland is presently undertaking a three-year expansion of this enhanced distribution technology and automation on these 14 circuits. This expansion project is being partially funded by NYSERDA. The installation of enhanced distribution automation, when coupled with state of the art command and control systems, will result in improved system reliability, deferred capital investment, energy conservation, and improved overall efficiency benefits. Some of the equipment and technologies to be implemented with the Company's enhanced distribution technology, automation and communications may also assist with the facilitation of renewable resources and energy storage devices, and simplify the integration and installation of new and emerging technologies such as, micro-grids and Plug in Hybrid Electric Vehicles ("PHEV").

Q. How much has the Company budgeted for the expansion of Distribution Technology and Automation enhancements?

A. The Company presently has within its budgets $3,500,000 that will be used for the expansion of distribution technology and automation enhancements on it electric distribution delivery system. The estimated cost to complete the expansion across the Company's entire service territory is $71.3 million. The Company plans to complete this expansion over an 18-year period by using the funding within its distribution automation and Smart Grid Resiliency Blankets, and is requesting additional capital funding of $500,000 annually (as noted below in the Funding Request Chart) to achieve this expansion over an 18-year period.

Funding Request:

(.000)	HistoricalYear (2014)	Forecast RY1	Forecast RY2	Forecast RY3	Forecast Total
O&M Amount	$0	$50	$50	$50	$150
Capital Amount	$0	$500	$500	$500	$1,500

Q. Please describe the cost/benefit analysis performed relating to the Company's initial Smart Grid proof of concept projects/programs.

A. As noted above, Orange and Rockland has worked collaboratively with BNL and EDD, and has contracted, through Con Edison, with EPRI to identify and quantify tangible cost savings that can be realized from Orange and Rockland's implementation of enhanced distribution technology and automation concepts. Orange and Rockland, BNL and EDD have identified areas where tangible cost savings could be realized. Using Orange and Rockland's Distribution Engineering Workstation ("DEW") software and its Integrated System Model ("ISM"), Orange and Rockland and BNL performed detailed calculations on a system of 14 New York circuits to determine improvements in circuit efficiency that can be achieved through phase balancing and optimal capacitor sizing and placement. Using these optimized circuits, EDD then performed calculations to determine the incremental improvement in efficiency that result by adding a real time coordinated Volt / VAR control system. EDD also performed a Conservation Voltage Reduction ("CVR") analysis on these circuits to determine the potential energy savings that could be achieved through the use of a coordinated Volt / VAR control system in CVR mode. In addition, Orange and Rockland prepared an analysis of the effects that adding automation could have on the deferral of a major capital project. Also analyzed were the effects that automation can potentially have on storm resiliency. EPRI performed an economic analysis and prepared a report that identified that the savings from these areas provided positive economic benefits as well as positive societal benefits. This report provides a qualitative measure to the value of the various methodologies and technologies used. The full EPRI report is provided as Exhibit ___ (SGP-E1).

Q. Will Orange and Rockland require additional full time employees to design, operate and maintain these new technologies, systems and equipment associated with enhanced distribution technology, automation, and distribution system management implementation as part of a sustainable business critical model?

A. Yes. The Company will need additional employees in its Engineering, System Operations and Electric Operations organizations to provide the requisite workforce to design, operate and maintain all of these new technologies, equipment and systems that constitute incremental and expanding workload. Orange and Rockland will need to add two full time employees for engineering design and systems development, three full time employees for System Operations to provide distribution system management oversight and operating support from its control room, and five full time employees for Electric Operations to facilitate field installation / construction for all new devices and equipment, and continuing maintenance and troubleshooting support for all field devices and systems.

Q. Please describe the need for two additional Engineering employees.

A. Currently, the Technology and Automation Engineering department is staffed by the following six engineers whose functions are summarized as follows: one Distribution Supervisory Control and Data Acquisition ("DSCADA") engineer, one Distribution Automation Engineer focusing on project implementation and oversight, one Technology engineer focusing on field device communications, one Technology Engineer focusing on equipment sizing, placement, specification, installation, setup and commissioning, one DEW Engineering System Administrator, and two Protection Engineers responsible for distribution system protection, power quality and the interconnection of distributed generation, distributed resources and renewables with the Company's electric distribution delivery system. The expansion of enhanced distribution technologies and automation systems across the Company's service territory will require two additional Technology Engineers that will focus their efforts on the expansion and implementation of these new technologies and systems across the distribution system, while providing Engineering support for Electric Operations personnel who will be installing, maintaining and troubleshooting the new equipment and systems.

A supplementary benefit for these two additional positions are the roles they will assume as crew leaders and system analysts during system emergencies and major storm events that will enhance the Company's capability to provide improved response and system restoration during these events.

The cost for each of these two engineering positions is $115,000 (O&M).

Q. Please describe the need for the three additional System Operations personnel.

A. Orange and Rockland's Distribution Control Center ("DCC") is located within the Company's Energy Control Center, and is responsible for the real-time operation and oversight of the Company's distribution system. The primary operating authorities that oversee and control the system on a daily basis are Control Authorities for All Distribution ("CAAD"). The CAADs control all safety setups for lineman working on the distribution system, and through coordinated switching, control the energizing and de-energizing of the distribution lines. The Company presently has seven CAADs that operate within a 24/7 shift schedule. The Company's implementation and expansion of enhanced distribution technologies, automation and smart control systems is producing a substantial and incremental workload for the CAADs with respect to the need for increased training, job knowledge, and expanded operational awareness and system oversight. Based on these expanding and incremental responsibilities, the Company has determined that the DCC will require three additional CAADs. These additional CAAD positions will be strategically scheduled to assist covering the most active times of day. The CAAD positions affect all aspects of Operations during normal conditions, and are essential to effectively manage the distribution system for restoration and recovery efforts during storms and system emergency conditions. Through comprehensive job task analysis, the Company has determined that on average the CAAD has 17 hours of work for each 12 hour day. As a result, the CAAD's situational awareness is compromised with each additional task that is required. The expansion of responsibilities to operate the DSCADA system and the new field technologies will result in such additional tasks and efforts to manage, oversee and realize the attendant benefits offered. The continued introduction of DSCADA technologies into the Company's distribution system will increase the daily tasks of the CAAD. From pre-work switching and clearance setups to DEW situational awareness and alarm responses, the CAAD's roles and responsibilities are increasing exponentially. A supplementary benefit to additional CAADs is the improved management and control room oversight that will be available during emergency and storm events. These additional CAADs will maximize the use of DSCADA systems during emergency situations and facilitate the safe and reliable operation of the system on an everyday basis.

The Company is filling these three System Operations positions in 2014 at a cost of $91,000 (O&M) per position.

Q. Please describe the need for the four additional Electric Field Operations personnel.

A. Orange and Rockland will need to add four Distribution Equipment Technicians to support the expansion of the Company's distribution technology and automation enhancement, and perform the necessary field work associated with the installation, testing, commissioning, inspection and maintenance of all field equipment and intelligent electronic devices ("IED"). These devices include switched capacitor banks, automated switches, and reclosers, as well as associated controls, remote terminal units, sensing and monitoring technologies, and communications equipment. In addition, the Distribution Equipment Technicians will respond to system emergencies and support emergency restoration efforts and public safety during these events. The annual cost for each of these four positions is $107,000, with approximately 80% charged to O&M. The capital portions of their salaries will be charged directly to the projects on which they are working.

Q. Please describe the need for one Equipment Technician Supervisor.

A. The Company will require one Equipment Technician Supervisor to supervise and manage the four new Distribution Equipment Technicians. This position will be responsible for the supervision and assignment of work to crews for all activities associated with construction, installation, maintenance, removal, repairs, operation and inspection of these distribution technologies, equipment and IEDs. In an effort to continue to comply with the ever changing technology, this position will be required to develop internal policies and guides for the group, as well as, address training requirements for field personnel. Furthermore, this Supervisor will be required to respond to system emergencies and be assigned accordingly to support safety and restoration efforts during major storms and system events. The annual cost for the Equipment Technician Supervisor is $125,000 (O&M).

Q. Does that conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
KEITH C. SCERBO – ELECTRIC

Q. Please state your name and business address.

A. My name is Keith C. Scerbo. My business address is 390 West Route 59, Spring Valley, NY 10977.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") as Director of New Business Services. In this position, I manage the installation of electric and gas services for Orange and Rockland.

Q. Please summarize your educational background and business experience.

A. In 1991, I graduated from the Juniata College with a Bachelor's Degree in Business Management. Later that year, I joined the Company as a Customer Accounting Representative. I have since held the positions of Customer Systems Analyst – Customer Accounting, Business Analyst - Customer Information Management System ("CIMS"), Lead Business Analyst - CIMS, Sr. Specialist - CIMS, and Section Manager - CIMS prior to my present position.

Q. Have you ever testified before the New York State Public Service Commission?

A. No, I have not.

Q. What is the purpose of your direct testimony in this proceeding?

A. I will testify to the Company's proposal to add one new Project Manager in the New Business department to manage applications submitted by customers for Photovoltaic installations, as well as the projected costs associated with this position for the 12 months ending October 31, 2016 ("Rate Year" or "RY1"). While, as discussed by the Company's Accounting Panel, the Company is not proposing a multi-year rate plan in this electric rate case, my testimony will also present projected costs associated with the Project Manager position for the two years following the Rate Year in this proceeding. For the sake of convenience, I refer to these two years as RY2 (*i.e.*, the 12 months ending October 31, 2017) and RY3 (*i.e.*, the 12 months ending October 31, 2018).

Q. Why is the Company proposing to add a new Project Manager?

A. Since 2011, applications from customers for photovoltaic ("PV") installations have been handled by two Company engineers, as additions to their job responsibilities. The two Company engineers will continue to perform functions within their areas of expertise, including analysis on PV systems, verifying impacts and upgrades that may be required; performing the final inspections on commercial systems and larger or unique residential systems; performing all regulatory functions related to proceedings on interconnection requirements and proposed rule changes; and performing all PV research and development work. The new employee will focus on the project management functions, including reviewing and verifying all applications for completeness and accuracy; establishing the project in the Company's project management system; reviewing the customers' existing electric service; processing all application fees; performing the initial DG screening; coordinating all necessary work at the customer's location with other Company departments; answering all customer inquiries; coordinating job scheduling; monitoring job status; communicating with customer contractors; and managing all PV related documentation and procedures. As demonstrated in the table below, in the Company's service territory, as PV options have decreased in price, their popularity has increased.

	PV Applications Received	PV Systems Installed
2011	50	32
2012	224	126
2013	659	410
2014*	622	501
*2014 is August YTD		

Applications received for 2011 as compared with 2014 have increased the workload to a rate over 13 times the 2011 rate. This significant increase has resulted in the need for a new Project Manager to manage the applications and installation process for customers interested in PV systems.

Q. Are there additional PV Project concerns?

A. Yes, the continued increase of new PV applications and final interconnection requests have resulted in an increase in the average processing time by the Company for PV applications to 15 days. The New York Standardized Interconnection Requirements indicate that application processing must be completed within ten days. The additional employee requested is needed in order to address the current processing delays, which are negatively impacting the overall customer experience.

Q. What is the cost associated with adding this new position?

A. The cost for this new position is \$85,000 in RY1, \$87,000 in RY2 and \$90,000 in RY3.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
WAYNE A. BANKER

Q. Please state your name and business address.

A. Wayne A. Banker and my address is 390 West Route 59, Spring Valley, New York 10977.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") as Chief Engineer of Distribution Engineering. I received a Bachelor of Science degree in Electrical Engineering in 1991 from Clarkson University in Potsdam, New York and a Masters of Business Administration in 2000 from Iona College – Hagan School of Business, in New Rochelle, New York. I am a registered professional engineer in the State of New York. I have worked for Orange and Rockland as an underground Distribution & Transmission Engineer, as Divisional Field Engineer for Electrical Operations Department, and my present position as Chief Distribution Engineer for Distribution Engineering Department.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present and support O&R's proposed incremental Storm Hardening initiatives, along with the incremental personnel requirements necessary for the Company's Electrical Engineering and Operations organizations to implement these initiatives effectively.

Incremental Storm Hardening Program

Q. Does the Company satisfy its obligations regarding the provision of safe and reliable service?

A. Yes. The Company fully meets the statutory requirement to provide safe and reliable service to its customers. Nonetheless, it continues to explore ways to further enhance service reliability, as well as harden certain infrastructure and improve system resiliency when major weather related events affect the Company's service territory.

Q. Please discuss how the Company developed its proposed storm hardening initiatives.

A. After the major storms of 2011 (*i.e.*, Hurricane Irene and the October Snowstorm) and Superstorm Sandy in 2012, the Company, in February 2013, formed a team (*i.e.*, the Storm Hardening Team) to explore methodologies and alternatives focused on storm hardening and system resiliency. The mission of the Storm Hardening Team was to identify opportunities to improve storm reliability on the Company's electric system and make recommendations for improvements, considering costs and other critical factors. The Storm Hardening Team divided into five sub-teams, consisting of subject matter experts from Operations and Engineering. These sub-teams focused for six months on analyzing opportunities in the following areas: undergrounding, automation and circuit reconfiguration, system materials and construction standards, system maintenance, and vegetation management.

The high-level conclusions and recommendations for each of these areas are discussed below.

Undergrounding

The Undergrounding team was formed to determine if installing facilities below ground, as opposed to overhead, can provide a cost-justifiable, hardening or resiliency benefit. Considering the expense of undergrounding, the team targeted conversion of overhead where it would prove most beneficial. In addition to existing construction, the team examined the Company's current design practice for new substation exits to determine if it meets storm hardening requirements. The Undergrounding team analyzed existing double circuit construction, storm-damage- prone circuits, and critical transportation crossings, and recommended the following:

- Where feasible, eliminate and/or reduce double circuit construction supplying common load areas;
- Install new underground exits to a point of path independence;
- Selectively underground portions of double circuits with a history of extensive storm damage;
- Evaluate critical road crossings; and
- Selectively use spacer cable systems.

The team considered converting the Company's entire distribution system to underground. The team concluded that this effort would be cost prohibitive, could not be completed in a reasonable amount of time, and would involve challenges with other stakeholders that customers would not embrace. The team also considered eliminating double circuit construction completely and found that a targeted approach would be more prudent, particularly because certain double circuits have minimal tree exposure. The probability of success of each of the above recommendations is high and the intuitive hardening benefit is proven.

Automation and Circuit Reconfiguration

Automation has proven to be one of the most effective solutions in enhancing system resiliency. The Automation and Circuit Reconfiguration team reviewed the application and design standard of existing automation technologies on the Company's distribution system and explored new technologies available for mainline and spur automation. The team also explored ways to improve circuit configuration with alternative design oriented solutions.

After analyzing the Company's distribution system to identify areas where increased automation would have the greatest resiliency benefit, the Automation and Circuit Reconfiguration team recommended the following:

- More prolific use of reclosing devices;
- Use of Supervisory Control and Data Acquisition ("SCADA") load break switches on main lines;
- Strategic use of single and three phase spur automation;
- Auto loop design standard enhancements;
- Segment customer count and distance reduction; and
- Closing single and three phase gaps on the overhead distribution system.

<u>System Construction</u>

The System Construction team looked for opportunities to both harden the system and make it more resilient. The team investigated whether the system can be constructed to more effectively reduce storm related outages and if there are construction methods available that would allow for continued operation if damage occurs.

The System Construction team reviewed the benefits of moving to National Electrical Safety Code's ("NESC") Grade B grade of construction, reconstructing double circuit distribution pole lines to minimize customer exposure, using aerial cable construction, using spacer cable construction, using breakaway connectors, upgrading feeders to 900 amps, using composite poles, modifying pole loading calculations using 1" of ice vs. ½" (which is the NESC standard for heavy loading districts), and changing the size of guy wire to strengthen the system.

After exhaustive analysis, the System Construction team recommended that the Company maintain the distribution system, as a general matter, at its current NESC Grade C grade of construction. However, for critical poles such as major equipment poles, high use junction poles or transportation crossings, the team recommended that a move to a higher grade construction by increasing pole size and strength may be warranted. With regard to double circuit poles, the team recommended that reconstruction be considered on a case by case basis. There are many options and the best alternative depends on system conditions at specific locations. The use of breakaway connectors will be limited, and installed as part of a pilot program; the technology is not mature enough to install on a broader scale. Composite poles will also be used on a limited basis as part of a pilot program. While the poles may provide some hardening benefit, there are other issues to consider, such as the ability for other parties to attach their facilities.

System Maintenance

The System Maintenance team evaluated the Company's existing maintenance programs to determine if opportunities exist to make the electric delivery system less susceptible to storm damage or improve the Company's ability to recover from damage resulting from a storm event.

The Company's electric 138kV and 69kV high voltage system is primarily an overhead system with almost 80% of the structures constructed from wood components. Wood is an efficient, readily available and cost effective construction material. However, it is a natural material vulnerable to the weather and subject to attack from insects and animals. The majority of defects and failures on the electric delivery system result from decay and destruction by natural forces. Orange and Rockland can harden its system by replacing wood components with steel, particularly where practical on its high voltage system. In areas where the shoreline has eroded pole foundations, thereby compromising poles' strength as part of the original design, stream bank stabilization efforts are undertaken to restore the ground to a safe condition. Other recommendations, such as the purchase of wetland matting, are the result of the difficulty in accessing some facilities in order to make repairs during storms.

Aggressively inspecting and replacing poles that are defective provides a benefit during storms, where survival of defective poles is scarce.

Vegetation Management

The Vegetation Management team was formed to review the Company's existing vegetation management programs and practices to determine if opportunities exist to make the electric delivery system less susceptible to storm damage caused by vegetation contact.

As previously noted, the Company's electric system is primarily an overhead system, portions of which are situated in heavily treed areas. This potential conflict with local vegetation is an exposure that has been mitigated through aggressive pruning and tree removal. The vegetation management that the Company has completed over several previous maintenance cycles has increased the aerial space between vegetation and live conductors and reduced the number of tree-caused outages. While performance has improved, there are further opportunities to improve reliability by targeting certain vegetation management practices.

The Vegetation Management team identified the following opportunities:

- Expanded clearance standards for the mainline conductors from the substation to the circuits first mainline protective device;
- Enhanced hazard tree program;
- Use of branch reduction techniques;
- Conduct an urban tree health study;

- Perform an off right-of–way (“ROW”) hazard tree survey; and
- Target enhancements to municipality-identified critical infrastructure.

Q. Is the Company proposing to undertake any new programs to enhance service reliability in its service territory?

A. Yes, the Company is proposing to initiate Incremental Storm Hardening and System Resiliency Programs that will provide its customers with an enhanced level of service reliability throughout the year and particularly during major weather-related events.

Q. Why is the Company proposing these new programs?

A. Customers continue to place an increasing reliance on electricity for highly specialized uses, such as computers, security systems, high definition flat screen televisions, broadband access equipment (*e.g.*, modems), automatic garage door openers, timers for outdoor and indoor lighting, clock thermostats, automatic sprinkler systems, and other programmable devices. Greater dependence on these high tech applications has made the Company’s customers less tolerant of service interruptions. To meet its customers’ evolving needs, as described above, the Company has evaluated measures that can be taken to reduce further even the present low number of service interruptions.

Q. Please describe the additional incremental Storm Hardening and System Resiliency Programs that the Company is proposing.

A. Consistent with the conclusions and recommendations of the Company’s Storm Hardening team as discussed above, this incremental program will be utilized to further storm harden targeted portions of the Company's electric delivery system from the effects of major storms. Specifically, the Company proposes to implement the additional incremental Storm Hardening and System Resiliency Programs are described in more detail below.

Selective Undergrounding

The selective undergrounding program will replace with underground construction one of the circuits from an existing overhead double circuit distribution corridor that has a history of higher exposure to outage incidents. This proposed plan will install approximately two miles of selective undergrounding each year. Such selective undergrounding should serve to decrease customer outages, shorten outage duration, and help to avoid outages resulting from major storm events, in a cost effective manner. The Company envisions that this program will be ongoing for at least 20- to 30-years. The current plan for 2015 is to convert from overhead to underground construction portions of the following overhead circuits: 6-7-13, 6-9-13, and Line 7. These circuits are located adjacent to the Port Jervis substation and have limited or no accessibility because of backyard construction and existing tree conditions. This work is scheduled to start in late 2014 and be completed in 2015. Another project identified is the undergrounding a portion of Transmission Line 51 with an underground transmission system increasing its thermal ratings and eliminating two crossings of Line 51 over Transmission Lines 52 and 60 in this area, thereby reducing the exposure to a triple circuit transmission outage. The Company will commence this project in 2015, and the estimated in-service date is June 2016. This project is further detailed in the direct testimony of the Company's Electric Infrastructure and Operations Panel.

Enhanced Overhead System Construction

Storm resilient, enhanced overhead system construction alternatives, such as spacer cable systems, will be installed in targeted applications to replace conventional construction, as well as fill in gaps to establish new circuit ties in the overhead distribution system that will provide storm hardening and system resiliency in a combined solution. Filling in gaps and establishing new circuit ties reduces the amount of radial distribution and provides a more storm resistant overhead system. This should improve the resiliency of the distribution system and allow for reduced outage durations and outage avoidance. The Company envisions this as a program that will be ongoing for at least 20- to 30-years.

Enhanced Transportation Crossings

This program will address distribution crossings of major highways, railroads, and waterways with more storm resistant systems. Existing transportation crossings will be upgraded with poles that are capable of withstanding higher wind loads or replaced with total underground systems where this type of upgrade makes sense. Reinforced and updated equipment typically means less damage incurred, which reduces customer outages. It also improves the availability of emergency routes during storm conditions. The Company envisions this as a program that will be ongoing for at least 20- to 30-years.

Transmission Pole Replacement

This program will address transmission poles that are typically older structures along active railroads, supporting conductors crossing highways, and other Company transmission facilities that provide critical infrastructure and system reliability. The existing poles in this program will be replaced with steel poles since they are stronger and more resistant to storm conditions, thus resulting in hardening the system with increased reliability at these critical locations. These projects are prioritized based on age, condition, and location. The Company envisions this as a program that will be ongoing for many years.

Q. Please describe how the projects are identified and prioritized for the Storm Hardening and System Resiliency Programs that the Company is proposing?

A. A segment storm performance review was developed as another tool that could be utilized to identify potential storm hardening projects for certain segments based upon performance during storm events from 2010 to the present. This segment storm performance review uses storm outage data based on the following categories: number of interruptions, number of customers affected, customer outage minutes/hours, customers served, customer weighting, and System Average Interruption Frequency Index ("SAIFI") (*i.e.*, average number of interruptions that a customer would experience annually). Each category of outage data is weighted based on various performance factors and a ranking is determined. Each rank is calculated with its weights in the overall rating and then used to rank each segment in an overall priority list. The following is the outage data weightings used for this process:

- Number of interruptions: The number of interruptions on a segment is a good indication of segment performance during a weather-related event. This category has a weighting of 45%.
- Number of customers affected by the segment: The numbers of customers affected depicts the segment's impact on the outage(s) that occurred on the system. This indicator will show any areas of improvement regarding sectionalizing opportunities, circuit ties, and automation. This category has a weighting of 15%.
- Number of customers served by the segment: The numbers of customers served has a considerable impact on the exposure of that segment. While this indicator may not have a negative performance, depending on the customer count, the segment may qualify for review according to our reliability circuit enhancement program. This category has a weighting of 10%.
- Customer weighting: Certain customers on the system are targeted for restoration and special consideration based upon their impact to safety for the general public and well-being of the community at large. Hospitals, emergency management facilities, schools, heating and cooling centers are some of the customer focused restoration areas that are indicated in this grouping. Segments that have these types of customers are weighted and should have more focused attention in segment analysis when reviewing storm performance. This category has a weighting of 25%.

- SAIFI for a given circuit: Each segment's SAIFI is calculated and used to compare the customer experience on a uniform basis. This category has a weighting of 5%.

Q. What is the projected cost and timing of implementing the Storm Hardening and System Resiliency Programs?

A. The Company is proposing to implement selected storm hardening projects in 2015. Projects presently anticipated for construction will include both undergrounding of existing overhead facilities and alternative overhead construction projects. During the period from January 2015 until October 2015, the Company estimates spending of $9.8 million in capital and $910,000 in operation and maintenance ("O&M") costs. These costs and the proposed amounts in the following rate years are detailed below for each of the following storm hardening and resiliency programs:

Selective Undergrounding

The selective undergrounding program relies on an annual distribution blanket that will provide funding for the replacement with underground construction one of the circuits from an existing overhead double circuit distribution corridor and a transmission project that the will underground a portion of Line 51. The costs for selective undergrounding program are set forth in the table below.

	01/15 -10/15		**Forecast RYE 2016 (11/15-10/16)**		**Forecast RYE 2017 (11/16-10/17)**		**Forecast RYE 2018 (11/17-10/18)**		**Forecast Total**	
	O&M	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**
PR.20968699 – UG Line 51 Upgrade		**$1,271,100**		**$857,100**						**$857,100**

PR. 20457923 – Storm Hardening UG Projects – NY		**$3,642,600**		**$2,483,100**		**$2,573,300**		**$2,417,100**		**$7,473,500**
Totals		**$4,913,700**		**$3,340,200**		**$,2,573,300**		**$2,417,100**		**$8,330,600**

Enhanced Overhead System Construction & Transportation Crossings

The Company has identified several distribution projects for these enhanced programs which will provide for storm hardening and system resiliency. The costs for these projects are set forth in the table below.

	01/15 -10/15		**Forecast RYE 2016 (11/15-10/16)**		**Forecast RYE 2017 (11/16-10/17)**		**Forecast RYE 2018 (11/17-10/18)**		**Forecast Total**	
	O&M	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**
PR.20468300 - Tallman - Spook Rock Rd Recon Phase II	**$150,100**	**$600,400**								
PR.20468395 - Goshen Turnpike-Midland Lakes Road to Step	**$166,100**	**$664,300**								
PR.20468399 - Pearl River - Erhardt Road (Townline to Blauvelt)	**$156,300**	**$625,300**								
PR.20468874 - Orangeburg - Kings Highway Tie to Hickey	**$150,700**	**$602,800**								
PR.20945921 - Pine Island - County RT 1 Conversion (Lower Road to Pine Island Tie)	**$262,700**	**$1,050,700**								
PR.20946000 - Suffern – Maplewood Blvd (NY Portion of Fox Lane)	**$25,000**	**$100,000**								
PR.20468882 - Orangeburg - Kings Highway (PIP to RT 303)			**$62,800**	**$251,200**					**$62,800**	**$251,200**
PR.20945930 - Pine Island - Pulaski Highway to Feagles Road			**$75,000**	**$300,000**					**$75,000**	**$300,000**
PR 20468387 - Goshen Turnpike - Route 302 to Midland Lake Road			**$193,300**	**$773,200**					**$193,300**	**$773,200**

PR.20468880 - Orangeburg - Kings Highway (RT 340 to PIP)					**$99,400**	**$397,500**			**$99,400**	**$397,500**
PR.20945924 -Pine Island - County RT 1 to Pulaski Highway					**$130,200**	**$520,900**	**$46,300**	**$185,100**	**$176,500**	**$706,000**
PR.20468944 -Goshen Turnpike - Shawangunk Road to Route 302							**$182,800**	**$731,200**	**$182,800**	**$731,200**
PR.20468935 -Chester - Pine Hill Road (Kings Highway to Black Meadow							**$239,800**	**$959,000**	**$239,800**	**$959,000**
Totals	**$910,900**	**$3,643,500**	**$331,100**	**$1,324,400**	**$229,600**	**$918,400**	**$468,900**	**$1,875,300**	**$1,029,600**	**$4,118,100**

Transmission Pole Replacement

This program will be funded by an annual blanket to replace existing wooden transmission poles with steel structures to strength transmission line structures along transportation corridors and near critical facilities. The costs for these overhead pole replacements are set forth in the table below.

	01/15 -10/15		**Forecast RYE 2016 (11/15-10/16)**		**Forecast RYE 2017 (11/16-10/17)**		**Forecast RYE 2018 (11/17-10/18)**		**Forecast Total**	
	O&M	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**
PR.20457790 – Storm Hardening OH TL – NY		**$1,240,000**		**$989,000**		**$1,246,400**		**$1,674,200**		**$3,909,600**
Totals:		**$1,240,000**		**$989,000**		**$1,246,400**		**$1,674,200**		**$3,909,600**

Q. How does the Company propose to recover the costs associated with its proposed Storm Hardening and System Resiliency Programs to commence in 2015?

A. The costs of these programs are included in the revenue requirement of the Company's base rate filing in this proceeding.

Incremental Personnel

Q. Does the Company have any human resource needs relating to the Company's ongoing initiatives, and/or its projected future capital project requirements and service reliability endeavors?

A. Yes. The incremental employees described below are engineering and operating personnel that direct charge their time to the applicable jurisdiction based on the actual work performed. The estimated percentage of the cost of these employees allocable to the Company is detailed in the direct testimony of Company's Accounting Panel.

Underground Engineer for Distribution Engineering Dept.

The Company's capital budget, and the associated number of projects, has been increasing in order to satisfy customers growing expectations on reduced number of outages and shorter restoration times during storm events. This trend is expected to continue, as presently identified by the Company's proposed incremental storm hardening and system resiliency studies. Based on the projected workload and a review of current engineering man-hours available, the Company has determined that additional resources will be required. This incremental engineering position will be responsible for the design, approval requirements, and construction oversight for various project installations on the distribution electric system with an emphasis on underground projects required for storm hardening. This engineer also will be required to prepare project specifications, obtain all field and environmental permits, and develop detailed project schedules/ budgets. Other responsibilities include construction supervision, operations support, and attendance at regulatory and industry meetings.

Q. What is the estimated annual cost for this position?

A. The Company estimates that the annual cost for this position will be $180,000, of which 16% will be O&M and 84% will be capital and charged to the specific projects being worked.

Q. How does the Company propose to recover the cost of this position?

A. The Company has added this position in the third quarter of 2014 and the cost of this position is included in the revenue requirement of the Company's electric base rate filing in this proceeding.

Q. Is the Company proposing to add any other positions?

A. Yes.

Operations Administrative Coordinator

With the incremental increases in storm hardening and resiliency work performed by the Company's contractor group, there is an incremental increase in the amount of administrative work and analysis required. Field supervisory staff has been performing some of these added duties, taking time away from field oversight. To facilitate the productive and safe operation of the field workforce, the work needs to be re-tasked to this requested position. The Company will add this position in late 2014 and estimates that the annual cost for this position will be $65,600, all

O&M. The cost of this position is included in the revenue requirement of the Company's electric base rate filing in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.