New York Public Service Commission

Electric Case ______________

Orange and Rockland Utilities, Inc.

Volume 1

Filing Letter

Tariff Leaves

Testimony

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF WITNESSES – 18-E-______

Orange & Rockland
a conEdison, inc. company

Orange and Rockland Utilities, Inc.
One Blue Hill Plaza
Pearl River, NY 10965-9006
www.oru.com

January 26, 2018

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") submits this rate filing to propose new rate plans to begin in January 2019 for electric and gas service provided in its service territory. The Company's rate filings focus on investments to further the Company's three major objectives, which are aligned with State policy objectives: (1) public and employee safety; (2) operational excellence; and (3) enhancing the customer experience. Our filings explain why maintaining and improving system operations requires certain investments, including the Digital Customer Experience and Green Button Connect programs. These investments in particular are geared toward giving customers greater control over their energy usage and allow them to more actively engage in the energy marketplace.

In addition, the Company's continuing efforts to implement advanced metering infrastructure ("AMI"), which involves the installation of smart meters in our customers homes and businesses, will enhance the customer experience by enabling the Company to provide electric and gas customers with timely feedback regarding their energy consumption. This information will empower customers to better manage their energy use, and by extension, their total bill. In conjunction with investments in advanced technologies, such as an Advanced Distribution Management System, AMI will enable the Company to monitor outages and restore service to customers more efficiently. AMI also will facilitate the consideration and deployment of innovative rate designs.

Orange and Rockland's rate filing addresses changing customer desires, advancements in technology, and federal and state regulatory policy goals. The Company is exploring non-wire and non-pipe solutions (for gas) prior to moving forward with infrastructure upgrades. The Company is developing and upgrading its Distributed Energy Resources evaluation tools. Orange and Rockland also continues to develop the capabilities necessary to perform its functions as the Distributed System Platform provider.

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 proposed rate increase for the Rate Year, *i.e.*, the twelve months ending December 31, 2019, the Company is open to negotiating a multi-year rate agreement for both services.

Electric Service

The Company seeks an increase in revenues for electric delivery of approximately $20.3 million (including gross receipts tax), resulting in an overall customer bill increase of approximately 2.3 percent, including projected supply costs.[1] This filing reflects the reduction of the Company's requested electric revenue increase resulting from the recently enacted Tax Cuts and Jobs Act. Appendix E shows the estimated effect on the Company's electric revenues by customer class, based on sales and revenues for the Rate Year. This filing explains the need for investments designed to maintain the safety and reliability of Orange and Rockland's electric system, to enable Orange and Rockland to adapt its system for increased distributed energy resources and New York State's energy future plans, to encourage electric vehicle adoption in its service territory, and to support initiatives and programs designed to enhance the customer experience.

Gas Service

The Company seeks an increase in revenues for gas delivery of approximately $4.5 million (including gross receipts tax), resulting in an overall customer bill increase of approximately 1.5 percent, including projected supply costs.[2] This filing reflects the reduction of the Company's requested gas revenue increase resulting from the recently enacted Tax Cuts and Jobs Act. Appendix F shows the estimated effect on the Company's gas revenues by customer class, based on sales and revenues for the Rate Year. Our natural gas infrastructure will require significant investment in the coming years, including through aggressive main replacement efforts, in order to enhance the safety and reliability of our gas delivery system. The Company will also seek to make gas service available to more customers in our service territory. The Company plans to leverage new technology to improve leak detection and proposes various initiatives and programs designed to enhance the customer experience. In addition, the Company seeks to expand its ability to train and test its employees and contractors.

Cost Mitigation Efforts and Other Considerations

Cost management has been, and will remain, at the core of Orange and Rockland's business processes. The Company recognizes its responsibility to manage costs on behalf of its customers and is committed to leveraging best practices 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

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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 6.7 percent.

[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 2.8 percent.

increases in its labor costs, as well as programs to improve workplace productivity and operational efficiencies. This filing discusses those efforts, including where Orange and Rockland is leveraging its relationship with Consolidated Edison Company of New York, Inc. to increase efficiency.

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

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.*, 9.60% to 11.0%) 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 forecasted Rate Year equity ratio of 48.79%.

Proposed Rate Term

While this rate filing proposes one-year rate plans for electric and gas service, we intend to explore multi-year rate plans in settlement discussions with Staff of the Department of Public Service ("Staff") and interested parties. Multi-year rate plans benefit customers by providing certainty as to the level of the Company's delivery rates over a number of years. Multi-year rate plans also facilitate implementation of the Company's projects and programs that are detailed in the rate filing.

Information Accompanying This Rate Filing

The proposed rate plans require increases to charges for electric and gas service and revisions to other provisions of the Company's Schedule for Electric Service, P.S.C. No. 3 – Electricity ("Electric Tariff") and its Schedule for Gas Service, P.S.C. No. 4 – Gas ("Gas Tariff"). Revised Tariff leaves, descriptions of changes, and revenue impacts are provided in the following appendices to this letter:

Appendix A – List of Electric Tariff Leaves
Appendix B – List of Gas Tariff Leaves
Appendix C – Description of Electric Tariff Revisions
Appendix D – Description of Gas Tariff Revisions
Appendix E – Electric Revenue Impacts
Appendix F – Gas Revenue Impacts

The tariff leaves are issued as of January 26, 2018, to become effective on February 25, 2018. The Company's expectation is that the Commission will issue appropriate orders suspending the effective date of the tariff leaves through December 31, 2018, and that the proposed electric and gas rates will become effective on January 1, 2019.

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.

The Company has also included draft Notices 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.

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 March 1, 2018. 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 January 1, 2019.

Very truly yours,

ORANGE AND ROCKLAND UTILITIES, INC.

Robert Sanchez
President and Chief Executive Officer

c: New York State Department of State, Utility Intervention Unit (via email)
Active Parties to Cases 14-E-0493 and 14-G-0494 (via email)

STATE OF NEW YORK
COUNTY OF NEW YORK

Robert Sanchez, 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 23 day of January, 2018.

DANIEL J. PERRETTI
Notary Public, State of New York
No. 4988442
Qualified in Rockland County
Commission Expires Nov. 04, 2021

Orange and Rockland Utilities, Inc. **Appendix A**
Electric Rate Case
Proposed Tariff Leaves effective February 25, 2018

P.S.C. No. 3 Electricity

11th	Revised Leaf No.	89	8th	Revised Leaf No.	278
1st	Revised Leaf No.	90	9th	Revised Leaf No.	283
4th	Revised Leaf No.	139	8th	Revised Leaf No.	284
5th	Revised Leaf No.	155	9th	Revised Leaf No.	285
3rd	Revised Leaf No.	161	9th	Revised Leaf No.	290
	Original Leaf No.	163.1	10th	Revised Leaf No.	295
4th	Revised Leaf No.	216	8th	Revised Leaf No.	309
8th	Revised Leaf No.	219	8th	Revised Leaf No.	310
5th	Revised Leaf No.	250	7th	Revised Leaf No.	312
5th	Revised Leaf No.	251	7th	Revised Leaf No.	321
6th	Revised Leaf No.	252	7th	Revised Leaf No.	322
	Original Leaf No.	252.1	7th	Revised Leaf No.	331
4th	Revised Leaf No.	253	7th	Revised Leaf No.	332
4th	Revised Leaf No.	255	9th	Revised Leaf No.	333
3rd	Revised Leaf No.	256	7th	Revised Leaf No.	336
4th	Revised Leaf No.	257	7th	Revised Leaf No.	341
3rd	Revised Leaf No.	258	1st	Revised Leaf No.	344
5th	Revised Leaf No.	259		Original Leaf No.	344.1
6th	Revised Leaf No.	260	7th	Revised Leaf No.	345
4th	Revised Leaf No.	261	8th	Revised Leaf No.	347
4th	Revised Leaf No.	262	7th	Revised Leaf No.	350
7th	Revised Leaf No.	264	8th	Revised Leaf No.	352
6th	Revised Leaf No.	266	7th	Revised Leaf No.	356
7th	Revised Leaf No.	267	8th	Revised Leaf No.	358
7th	Revised Leaf No.	268	7th	Revised Leaf No.	359
7th	Revised Leaf No.	269	8th	Revised Leaf No.	372
7th	Revised Leaf No.	270	7th	Revised Leaf No.	373
8th	Revised Leaf No.	272	7th	Revised Leaf No.	374
8th	Revised Leaf No.	274	7th	Revised Leaf No.	375
7th	Revised Leaf No.	276	2nd	Revised Leaf No.	377

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 January 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 September 30. The Risk Factor shall also be reset each January 1, and shall be equal to 20 percent of the Uncollectibles Percentage. The Credit and Collections Component will be set annually, effective each January 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, 2017 is 1.016% 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)

7.5 RENDERING OF BILLS (Continued)

(B) Retail Access Customer Billing Options (Continued)

(2) Utility Single Billing Service (Continued)

other taxes imposed on the ESCO and not required by law to be separately stated. The Company will calculate and identify the sales and use taxes associated with the ESCO charges in accordance with customer-specific tax status information provided by the ESCO and remit such amounts to the ESCO net of the POR discount and such other amounts as set forth in the Company's Consolidated Billing and Assignment Agreement. The ESCO may charge a different price per kWh for each of its customers. The customer shall be billed one rate per billing cycle and such rate will be used for billing purposes for the next bill issued to the customer and every bill thereafter until changed by the ESCO.

ESCO Billing Cost: The Company's charge for its billing service is $1.30 per Utility Single Bill per monthly billing cycle. This same charge applies whether the Company issues a Utility Single Bill for electric service only or both electric and gas services for a single ESCO. The Company will "net" or offset its remittance payments to the ESCO by the amounts due the Company for billing service charges due from the ESCO. If there is one ESCO for electric service and another ESCO for gas service on a dual service customer's account, the Company will charge each ESCO one-half of the applicable charge.

If an ESCO requests that a Utility Single Bill include an insert required by statute, regulation, or Commission order, and such insert exceeds one-half ounce, the Company will charge the ESCO for incremental postage.

(C) Customer Billing and Payment Processing Charge

A Billing and Payment Processing Charge of $1.30 per billing cycle shall be assessed on all Full Service Customers and Retail Access Customers electing the Two Separate Bills billing option under General Information Section No. 7. This charge shall be applied only once to a dual service customer bill.

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 January 1, 2019 through December 31, 2019, 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 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 customer's 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.

The applicable EJP discounts are based on the date the customer commenced service under this Rider, as shown below:

	Commencement Date		
Service Classification	Prior to 11/1/2015	11/1/2015 – 12/31/2018	On or after 1/1/2019
2 – Secondary	0%	63%	75%
2 – Primary	0%	66%	78%
3	0%	61%	72%
9	0%	62%	70%
20	0%	64%	77%
21	0%	61%	72%
22	0%	61%	70%
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 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 eligible facility; 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 eligible facility, 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.

GENERAL INFORMATION

13. SERVICE CLASSIFICATION RIDERS (Continued)

RIDER H (Continued)

ECONOMIC DEVELOPMENT RIDER

PLUG-IN ELECTRIC VEHICLE ("PEV") QUICK CHARGING STATIONS

Rider H is available to owners of PEV quick charging stations with a minimum aggregate charging capacity of 65 kW and a maximum aggregate demand of 500 kW. Stations must be newly constructed with no more than 10 kW of ancillary (non-PEV charging) load. In addition, PEV quick charging stations must be publicly accessible, such as stations located at: supermarkets, malls and retail outlets, train stations, hotels, restaurants, and parking garages and parking lots where the PEV quick charging station is open to the general public and be used by a wide variety of users. Requirements (B) and (E) and the minimum metered demand requirement of "ELIGIBILITY" shall not apply. The requirement of "LETTER OF INTENT" that customer's metered demand meets or exceeds 65 kW in two consecutive months following issuance of such letter of intent shall not apply.

The Company will provide Economic Development Discounts to PEV quick charging stations up to a maximum aggregate demand of 3 MW.

Customers taking service for the PEV quick charging station shall receive the Economic Development Discount from the date the customer commences service under this Rider through December 31, 2025.

PEV quick charging stations shall be eligible for the Revenue Test for Facility Extensions.

GENERAL INFORMATION

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

15.1 FORECAST MSC COMPONENT (Continued)

(C) Capacity

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

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

(D) Hedging Adjustment

The Hedging Adjustment will be based on the estimated costs or benefits associated with hedging instruments for the billing month. The Hedging Adjustment will be determined by dividing the estimated hedging gains/losses for the billing month by the billing month forecast of kWh sales for customers subject to the MSC.

GENERAL INFORMATION

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

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

(B) Charges

Energy Charges (per kWh)

Customers shall be subject to hourly energy charges for electric power supply set each hour of each day of the year. The energy component of such hourly energy charge will be equal to the NYISO's day-ahead Locational Based Marginal Price for Zone G.

Ancillary Services/NTAC/NYISO Transmission Charges (per kWh)

Customers shall be subject to a charge per kWh associated with ancillary services and NTAC equal to the cost per kWh for such components for the cost month two months prior to the billing month. The Ancillary Services/NTAC/NYISO Transmission Charges shall be combined and shown on the "Statement of Market Supply Charge" filed each month with the Public Service Commission.

The sum of the Energy Charge and Ancillary Services/NTAC/NYISO Transmission Charges shall be adjusted for losses using the loss factors set forth in General Information Section No. 32.

Capacity Charge (per kW of Capacity Obligation)

Customers shall be subject each month to a Capacity Charge per kilowatt of Capacity Obligation, as determined below. The Capacity Charge shall be based on the monthly auction price paid by the Company for the capacity it purchases from the NYISO adjusted for capacity related factors of the NYISO by applying the Unforced Capacity Effective percentage for the applicable capability period as posted by the NYISO. Such capacity charge shall be shown on the "Statement of Market Supply Charge" filed each month with the Public Service Commission.

The customer's Capacity Obligation, in kilowatts, is determined by the Company no less frequently than once per year. The customer's Capacity Obligation is based on the individual share of the peak load assigned to the Company and is determined based on the individual customer's peak load during the peak hour for the New York Control Area ("NYCA"). The customer's peak load is adjusted to include demand losses by multiplying it by the applicable demand loss factor set forth in General Information Section No. 32.

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, a Demonstration Project Cost Recovery component, and a Non-Wires Alternatives Cost Recovery component.

(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)

(B) Variable ECA

The Variable ECA will be determined monthly and is designed:

(1) to recover shortfalls and surpluses in auctions, day-ahead market congestion settlements, or any other adjustments related to Transmission Congestion Contracts ("TCCs") received by the Company from the NYISO;

(2) to credit to customers the Company's share of the Constellation Settlement Refund, plus any interest disbursements from NYSERDA, pursuant to the Commission's Order in Case No. 13-E-0232, issued and effective September 20, 2013;

(3) to recover costs on an as-incurred basis including, but not limited to, costs for program development, marketing, evaluation, staffing, incentives and marketing research resulting from Riders D, E, and F;

(4) to recover Standby Reliability Credits provided to customers served under Service Classification No. 25;

(5) to recover customer credits provided under SC No. 19 Special Provision C; and

(6) to recover or credit any Earnings Adjustment Mechanism ("EAM") and/or positive and negative revenue adjustments resulting from the Company's electric and customer service performance mechanisms.

The Variable ECA shall be equal to the cost components defined above divided by the Company's estimate of total customer kWh usage for the applicable billing month, rounded to the nearest $0.00001 per kWh.

(C) Reconciliation

Each month, ECA costs applicable to the Base ECA and Variable ECA incurred by the Company shall be reconciled to Base ECA and Variable ECA recoveries and any differences shall be deferred. Interest, at the Commission-approved rate for Gas Adjustment Charge refunds, will be calculated on the average of the current and prior month's cumulative over and under collections. The annual Base ECA filing submitted by the Company will include the reconciliation of Base ECA and Variable ECA actual costs and recoveries for the prior period. However, the EE Tracker Mechanism component of the Base ECA will reconcile actual collections to the target amount included in the prior year's Base ECA filing for the EE Tracker as part of the annual Base ECA filing.

GENERAL INFORMATION

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

(D) Demonstration Project Cost Recovery

The Company will establish the Demonstration Project Cost Recovery component of the ECA pursuant to the Commission’s Order in Case No. 14-E-0493, issued and effective October 16, 2015.

The Demonstration Project Cost Recovery component of the ECA is designed to recover the incremental revenue requirement associated with Demonstration Projects undertaken by the Company pursuant to the Commission’s REV Track I Order issued on February 26, 2015 in Case No. 14-M-0101.

The Demonstration Project Cost Recovery component of the ECA shall not exceed $0.00200 per kWh in any period unless a higher Demonstration Project Cost Recovery component is authorized by the Commission.

(E) Non-Wires Alternatives (“NWA”) Project Cost Recovery

The NWA Project Cost Recovery component of the ECA is designed to the recover the revenue requirement associated with Commission approved NWA projects undertaken by the Company and associated incentives until such costs are included in base rates.

For purposes of NWA project cost recovery, the Company will establish the following service classification groups:

Group 1: SC Nos. 1 and 19
Group 2: SC Nos. 2 Secondary, 20, and 25 – Rate I
Group 3: SC Nos. 2 Primary, 3, 21, and 25 – Rate II
Group 4: SC Nos. 9, 22, and 25 – Rates III and IV
Group 5: SC Nos. 4, 5, 6, and 16

The NWA project revenue requirement will be allocated to the service classification groups based on each service classification group’s percentage contribution to the system peak, as used to develop the embedded cost-of-service study in the Company’s most recently approved electric rate plan. The allocated revenue requirement will be recovered on a per kW basis for demand billed service classification groups (for Standby Service customers, the credit will be collected on a per kW of Contract Demand basis) and on a per kWh basis for non-demand billed service classification groups.

GENERAL INFORMATION

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

(F) Statement of Energy Cost Adjustment

A Statement of Energy Cost Adjustment showing the Base ECA, Variable ECA, the Demonstration Project Cost Recovery component of the ECA, 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 the Demonstration Project Cost Recovery component of the ECA. The Statement of Energy Cost Adjustment shall be made available to the public at Company offices where applications for service may be made.

For purposes of billing, the surcharges associated with collection of the Value Stack Delivery Cost Component Credits as described in Rider N and General Information Section No. 27 will be included with the Energy Cost Adjustment.

GENERAL INFORMATION

26. SYSTEM BENEFITS CHARGE ("SBC")

A System Benefits Charge ("SBC") recovers costs associated with clean energy activities conducted by the New York State Energy Research and Development Authority ("NYSERDA"). The SBC will be applied to the kWh usage on the bills of all customers served under this Schedule, excluding kWh usage delivered under Rider B, NYPA RNY Program, up to the RNY Allocation.

Except for the 10-month Statement of SBC filed to become effective March 1, 2016, the Statement of SBC will be filed on an annual basis, on no less than 15 days' notice, to become effective January 1. The Statement will set forth the Clean Energy Fund ("CEF") Surcharge Rate.

Beginning March 1, 2016, the CEF Surcharge rate collects: (1) annual authorized collections associated with NYSERDA-run clean energy activities, including the Renewable Portfolio Standard, Energy Efficiency Portfolio Standard ("EEPS"), SBC IV programs, and CEF, plus or minus any under- or over-collections associated with prior years; and (2) any over- or under-collections associated with Company-run EEPS programs authorized through 2015.

The CEF surcharge rate will be calculated by dividing the necessary collection amount by the forecasted kWh deliveries for the period in which the Statement is to be in effect.

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

The fixed components of the MFC are as follows:

	$ per kWh		
Service Classification	Commodity Procurement, IR, and Education and Outreach	Credit and Collections	Total
SC Nos. 1 and 19	$0.00411	$0.00063	$0.00474
SC Nos. 2 Secondary, 20, 4, 5, 6 and 16	$0.00265	$0.00033	$0.00298
SC Nos. 2 Primary, 3, 9, 21, 22 and 25	$0.00145	$0.00010	$0.00155

GENERAL INFORMATION

28. MERCHANT FUNCTION CHARGE ("MFC") (Continued)

(C) Uncollectibles Charge

The uncollectibles charge will be determined separately each month for: (i) SC Nos. 1 and 19, (ii) SC Nos. 2 Secondary, 4, 5, 6, 16 and 20, and (iii) SC Nos. 2 Primary, 3, 9, 21, 22 and 25. The uncollectible expense ("UC Expense") for each of these groups shall be determined monthly based on an estimate of costs recoverable through the Market Supply Charge ("MSC"), except for CESS costs, and an uncollectibles percentage ("UC Percentage") applicable to each group. UC Expense for each group will then be adjusted to reflect the Company's actual overall uncollectibles experience for the twelve month period ended the previous September 30 applicable to all electricity and gas customers eligible for the Company's Purchase of Receivables Program. UC Expense for each group, adjusted as set forth above, shall be divided by an estimate of corresponding full service kWh deliveries to determine the uncollectibles charge per kWh to be included in the MFC. The UC Percentages shall be reset annually effective January 1 based on the Company's actual uncollectibles experience for the twelve month period ended the previous September 30 applicable to all electricity and gas customers eligible for the Company's Purchase of Receivables Program.

(D) Reconciliation of MFC Components

Revenues associated with the 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 No. 29 of this Rate Schedule.

(E) Statement of Merchant Function Charge

(1) The MFC 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. The MFC will be prorated based on the number of days each MFC is in effect in a billing period.

(2) A Statement of Merchant Function Charge shall be filed with the Commission apart from this 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.

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 January 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. For the two-month period ending December 31, 2018, the MFC Fixed Component revenue target is $772,737. The MFC Fixed Component revenue target is $5,808,387 for the twelve month period commencing January 1, 2019.

"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. For the two month period ending December 31, 2018, the revenue target is $111,634. The revenue target is $803,932 for the twelve month periods commencing January 1, 2019.

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 January 1, 2019 will reconcile the period November 1, 2018 through December 31, 2018, including any prior period balances.

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 January 1, 2019 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).

The Company will file a Statement of RDM Adjustments no less than ten calendar days before February 1, 2019, on which the statement becomes effective for one year and will reflect the reconciliation of the prior RDM period of November and December 2018. Thereafter, Annual RDM Periods are the 12-month periods ending December 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 February 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	12 Month Period Commencing 1/1/19
A	$187,858
B	76,206
C	19,543
D	12,216
E	7,717
F	2,594
Unbilled Revenue	1,839
Total	$307,973

For the period November 1, 2018 through December 31, 2018, the RDM will be implemented in accordance with the methodology set forth in the Joint Proposal adopted by the Commission in its Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, issued October 16, 2015 in Case No. 14-E-0493.

(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 $4.6 million, which is 1.5 percent of the total of the Delivery Revenue Targets, the Company may implement interim RDM Adjustments by customer group on no less than ten days' notice.

GENERAL INFORMATION

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

(D) Interim RDM Adjustments (Continued)

Such interim RDM Adjustments shall normally be determined by customer group by dividing the portion of the cumulative delivery revenue excess/shortfall for each customer group by the projected kWh deliveries associated with each customer group for the subsequent twelve-month period.

The Company may implement an interim RDM adjustment for a time period other than the normal time period after consultation with Commission Staff.

These interim RDM Adjustments 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	$22.00	$22.00
(2)	Delivery Charge		
	First 250 kWh .... @	8.056 ¢ per kWh	8.056 ¢ per kWh
	Over 250 kWh .... @	9.703 ¢ per kWh	8.056 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 1 (Continued)

RATES – MONTHLY: (Continued)

(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.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION:

The sum of $22.00 monthly, but not less than $132.00 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) 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.

(B) 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.

(C) Redistribution

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

SERVICE CLASSIFICATION NO. 1 (Continued)

RESERVED FOR FUTURE USE

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) Secondary Non-Demand Billed Customers		
Metered Service	$18.00	$18.00
Unmetered Service	$17.00	$17.00
(b) Secondary Demand Service	$21.00	$21.00
(c) Primary Service	$35.00	$35.00

(2) Delivery Charges

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

Usage Charge

	Summer Months*	Other Months
All kWh ………...........@	5.963 ¢ per kWh	4.407 ¢ 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	..……....@	$3.12 per kW	$1.84 per kW
All Over 5 kW	..……....@	$20.54 per kW	$11.92 per kW
Usage Charge			
First 1250 kWh	..……....@	5.008 ¢ per kWh	3.865 ¢ per kWh
Use up to 30,000 kWh or 300 hours use of billing demand, whichever is greater	..……....@	2.828 ¢ per kWh	2.725 ¢ per kWh
Use in excess of 30,000 kWh or 300 hours use of billing demand, whichever is greater..@		2.271 ¢ per kWh	2.142 ¢ per kWh

(c) Primary Service

		Summer Months*	Other Months
Demand Charge			
All kW	..……....@	$17.22 per kW	$9.55 per kW
Usage Charge			
All kWh	..……....@	1.228 ¢ per kWh	1.228 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 2 (Continued)

RATES - MONTHLY: (Continued)

(8) 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	$12.84	$2.58
b)	Meter Service Provider Charge	$34.28	$10.99
c)	Meter Data Service Provider Charge	$15.51	$2.97
Primary Service			
a)	Meter Ownership Charge	$12.84	$4.55
b)	Meter Service Provider Charge	$34.28	$19.34
c)	Meter Data Service Provider Charge	$15.51	$3.00

(9) 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.

(10) 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 2.913¢ per kWh during the billing months of October through May and at a Delivery Charge of 11.656¢ 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 (10) 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 …..……..……@	$21.10 per kW	$11.95 per kW
	Usage Charge		
	All kWh …..……..……@	0.696 ¢ per kWh	0.696 ¢ per kWh

* June through September

SERVICE CLASSIFICATION NO. 3 (Continued)

RATES - MONTHLY: (Continued)

(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.

(8) 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	$12.84	$4.11
b)	Meter Service Provider Charge	$34.28	$17.48
c)	Meter Data Service Provider Charge	$15.51	$1.48

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	$12.00
9,500	Sodium Vapor	100	142	13.10
16,000	Sodium Vapor	150	199	15.57
27,500	Sodium Vapor	250	311	20.80
46,000	Sodium Vapor	400	488	29.13
Off-Roadway Luminaires				
27,500	Sodium Vapor	250	311	$26.96
46,000	Sodium Vapor	400	488	33.33

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	$5.94
800	Open Bottom Incandescent	62	62	5.98
1,000	Open Bottom Incandescent	92	92	8.08
2,500	Open Bottom Incandescent	189	189	10.97
2,500	Closed Bottom Incandescent	189	189	11.22
4,000	Closed Bottom Incandescent	295	295	14.21
6,000	Closed Bottom Incandescent	405	405	17.12
-	Ornamental Incandescent	200	200	12.14
4,000	Mercury Vapor Power Bracket	100	127	9.52
4,000	Mercury Vapor Street Light	100	127	10.77
7,900	Mercury Vapor Power Bracket	175	215	11.70
7,900	Mercury Vapor Street Light	175	211	13.06
12,000	Mercury Vapor	250	296	17.12
40,000	Mercury Vapor	700	786	33.57
22,500	Mercury Vapor	400	459	21.88
59,000	Mercury Vapor	1,000	1,105	42.95
130,000	Sodium Vapor	1,000	1,120	61.32
	Post Top M.V.	100	130	14.66
	Post Top M.V.	175	215	17.50
	Post Top – Offset M.V.	175	215	20.80
5,890	LED	70	74	13.13
9,365	LED	100	101	14.88
3,400	Induction	40	45	13.08
5,950	Induction	70	75	13.32
8,500	Induction	100	110	14.90
12,750	Induction	150	160	17.86
21,250	Induction	250	263	24.76

SERVICE CLASSIFICATION NO. 4 (Continued)

RATES – MONTHLY: (Continued)

(2) Additional Charge:

A. An additional $4.16 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 42 ¢ per month will be charged for a fifteen foot bracket when installed.

(3) Energy Cost Adjustment, System Benefits Charge, Transition Adjustment for Competitive Services, Revenue Decoupling Mechanism Adjustment, and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Transition Adjustment for Competitive Services, and Revenue Decoupling Mechanism Adjustment as described in General Information Section Nos. 25, 26, 29 and 30, 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) 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.

(5) 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. 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 9.210 ¢ per kWh

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

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26 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) 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 7.579 ¢ per kWh

(1b) Delivery Charge for Service Type C

Customer Charge at $24.00 per month plus
Delivery Charge at 6.699 ¢ per kWh

(2) Energy Cost Adjustment, System Benefits Charge, Transition Adjustment for Competitive Services, Revenue Decoupling Mechanism Adjustment, and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge, Transition Adjustment for Competitive Services and Revenue Decoupling Mechanism Adjustment as described in General Information Section Nos. 25, 26, 29, and 30, 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.

SERVICE CLASSIFICATION NO. 9 (Continued)

RATES - MONTHLY: (Continued)

(2) Delivery Charges

	Primary	Substation	Transmission
Demand Charge			
Period A All kW @	$ 21.77 /kW	$ 15.55 /kW	$ 8.36 /kW
Period B All kW @	$ 10.20 /kW	$ 7.03 /kW	$ 5.69 /kW
Period C All kW @	No Charge	No Charge	No Charge
Usage Charge			
Period A All kWh @	0.784 ¢/kWh	0.433 ¢/kWh	0.139 ¢/kWh
Period B All kWh @	0.784 ¢/kWh	0.433 ¢/kWh	0.139 ¢/kWh
Period C All kWh @	0.292 ¢/kWh	0.267 ¢/kWh	0.131 ¢/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, Transition Adjustment for Competitive Services and Charges for Municipal Undergrounding

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge and Transition Adjustment for Competitive Services as described in General Information Section Nos. 25, 26 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) 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.

(8) 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	$20.52	$20.52	$20.52
b)	Meter Service Provider Charge	$87.29	$87.29	$87.29
c)	Meter Data Service Provider Charge	$15.51	$15.51	$15.51

SERVICE CLASSIFICATION NO. 9 (Continued)

MINIMUM MONTHLY DEMAND CHARGE:

The minimum monthly demand charge shall be $57.80 plus the contract demand charge and the reactive power demand charge, if applicable. The contract demand charge shall be $4.20 per kW of contract demand per month for service metered at the primary voltage, or $6.90 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	$154.17 per month
Primary	Under 1000 kW	$117.35 per month
Secondary	Any kW	$14.48 per month

All other customers shall pay a customer charge as follows:

Service Voltage	Contract Demand	Customer Charge
Primary	1000 kW and over	$160.36 per month
Primary	Under 1000 kW	$123.55 per month
Secondary	Any kW	$28.78 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 @	$4.23 per kW	$6.94 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	$22.94
9,500	Sodium Vapor	100	142	24.51
16,000	Sodium Vapor	150	199	28.82
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	25.11
9,500	Sodium Vapor	100	142	26.75
16,000	Sodium Vapor	150	199	30.96
27,500	Sodium Vapor	250	311	39.47
46,000	Sodium Vapor	400	488	54.21
Flood Lighting Luminaires				
27,500	Sodium Vapor	250	311	$39.47
46,000	Sodium Vapor	400	488	54.21

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	$20.94
7,900	Mercury Vapor	175	215	24.38
22,500	Mercury Vapor	400	462	35.00
Street Lighting Luminaires				
3,400	Induction	40	45	$27.33
5,950	Induction	70	75	27.88
8,500	Induction	100	110	30.43
12,750	Induction	150	160	35.50
21,250	Induction	250	263	47.04
4,000	Mercury Vapor	100	127	23.07
7,900	Mercury Vapor	175	211	26.71
12,000	Mercury Vapor	250	296	33.64
22,500	Mercury Vapor	400	459	41.44
40,000	Mercury Vapor	700	786	61.30
59,000	Mercury Vapor	1,000	1,105	76.51
130,000	Sodium Vapor	1,000	1,120	104.75
1,000	Incandescent	92	92	18.33
2,500	Incandescent	189	189	23.45
5,890	LED	70	74	33.41
9,365	LED	100	101	36.11
Flood Lighting Luminaires				
12,000	Mercury Vapor	250	296	$33.64
22,500	Mercury Vapor	400	459	41.44
40,000	Mercury Vapor	700	786	61.30
59,000	Mercury Vapor	1,000	1,105	76.51

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 6.699 cents per kWh; or

Un-metered Service - Customer Charge at $17.00 per month plus
Delivery Charge at 6.699 cents per kWh.

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

The provisions of the Company's Energy Cost Adjustment, System Benefits Charge and Transition Adjustment for Competitive Services as described in General Information Section No. 25, 26 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) 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)

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 $0.72 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. In addition, service shall be provided hereunder for the sole purpose of plug-in electric vehicle charging pursuant to Special Provision (C).

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 $32.00

(2) Delivery Charge

Period I	All kWh @	33.570	¢ per kWh
Period II	All kWh @	12.012	¢ per kWh
Period III	All kWh @	12.012	¢ per kWh
Period IV	All kWh @	2.162	¢ per kWh

SERVICE CLASSIFICATION NO. 19 (Continued)

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:

The initial term of service shall be one year. Customers taking service hereunder shall not be entitled to service at the same location under any other service classification of this Rate Schedule until one year from the date service hereunder commenced or, thereafter, on the customer's annual anniversary date, upon five days prior written notice.

EXTENSION OF FACILITIES:

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

SPECIAL PROVISIONS:

(A) 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 Rate Schedule.

(B) Redistribution

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

(C) Price Guarantee for Residence with Plug-in Electric Vehicle(s)

A customer taking service hereunder for a residence that includes a Plug-in Electric Vehicle (“PEV”) and registers such PEV with the Company will receive a price guarantee for a period of one year commencing with the first full billing cycle after the customer registers the PEV with the Company. Under the price guarantee, the customer will receive a credit following the initial one-year period for the difference, if any, between what the customer paid and what the customer would have paid under SC No. 1 rates over that one-year period if the SC No. 1 amount is lower. The comparison (inclusive of the Increase in Rates and Charges) will be made on a total bill basis for Full Service Customers and on a delivery-only basis for Retail Access Customers.

SERVICE CLASSIFICATION NO. 19 (Continued)

SPECIAL PROVISIONS: (Continued)

(D) Separate Account for Plug-in Electric Vehicle Charging

A customer who has an SC No.1 account or a residential tenant or occupant in a building served under another service classification may take service under a separate account, billed under this service classification, for the sole purpose of charging a PEV; provided, however, that such customer will not be eligible for Special Provision (C).

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 @	$ 26.96	per kW
Period II	All kW @	$ 11.58	per kW
Period III	All kW @	$ 0.20	per kW

Usage Charge

Period I	All kWh @	6.385	¢ per kWh
Period II	All kWh @	1.535	¢ per kWh
Period III	All kWh @	0.204	¢ per kWh

SERVICE CLASSIFICATION NO. 20 (Continued)

RATES - MONTHLY: (Continued)

(8) 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	$12.84	$3.95
b) Meter Service Provider Charge	$34.28	$16.82
c) Meter Data Service Provider Charge	$15.51	$2.28

(9) 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.

(10) 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. 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 @	$ 29.13	per kW
Period II	All kW @	$ 10.27	per kW
Period III	All kW @	No Charge	

Usage Charge

Period I	All kWh @	1.487	¢ per kWh
Period II	All kWh @	1.487	¢ per kWh
Period III	All kWh @	0.130	¢ per kWh

SERVICE CLASSIFICATION NO. 21 (Continued)

RATES - MONTHLY: (Continued)

(8) 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	$12.84	$2.78
(b) Meter Service Provider Charge	$34.28	$11.83
(c) Meter Data Service Provider Charge	$15.51	$0.92

(9) 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.

(10) 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 @	$17.08 /kW	$ 10.98 /kW	$ 6.41 /kW
Period B All kW @	$ 9.75 /kW	$ 6.05 /kW	$ 5.61 /kW
Period C All kW @	No Charge	No Charge	No Charge
Usage Charge			
Period A All kWh @	0.710 ¢/kWh	0.298 ¢/kWh	0.083 ¢/kWh
Period B All kWh @	0.710 ¢/kWh	0.298 ¢/kWh	0.083 ¢/kWh
Period C All kWh @	0.120 ¢/kWh	0.090 ¢/kWh	0.042 ¢/kWh

SERVICE CLASSIFICATION NO. 22 (Continued)

RATES - MONTHLY: (Continued)

(8) 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	$20.52	$20.52	$20.52
(b) Meter Service Provider Charge	$87.29	$87.29	$87.29
(c) Meter Data Service Provider Charge	$15.51	$15.51	$15.51

(9) 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.

(10) 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 $57.80 plus the contract demand charge and the reactive power demand charge, if applicable. The contract demand charge shall be $4.20 per kW of contract demand per month for service metered at the primary voltage, or $6.90 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 (1) – (8) of this section.

(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	$36.00
Primary	$50.00

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 @	$4.98 per kW
Primary	All kW @	$5.49 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 @	$0.7658 per kW	$0.5317 per kW
Primary	All kW @	$0.6555 per kW	$0.4666 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 $85.00

Delivery Charges

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

All kW @ $8.81 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 @	$0.6799 per kW	$0.4576 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 $500.00

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 @	$6.59 per kW
Substation	All kW @	$4.21 per kW
Transmission	All kW @	$1.46 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 @	$0.6778 per kW	$0.3983 per kW
Substation	All kW @	$0.4900 per kW	$0.3314 per kW
Transmission	All kW @	$0.3824 per kW	$0.2883 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 $500.00

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 @	$5.59 per kW
Substation	All kW @	$2.99 per kW
Transmission	All kW @	$1.23 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 @	$0.5905 per kW	$0.4140 per kW
Substation	All kW @	$0.3995 per kW	$0.2682 per kW
Transmission	All kW @	$0.3194 per kW	$0.2910 per kW

* June – September

SERVICE CLASSIFICATION NO. 25 (Continued)

RATES – MONTHLY: (Continued)

(6) Metering Charges

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. The customer shall be assessed the metering charge applicable to “Customers Eligible for Mandatory DAHP” as set forth in the service classification under which the customer would receive service if it did not take service under this service classification.

(7) Market Supply Charge

Customers that purchase their energy from the Company will be subject to the Market Supply Charge set forth in General Information Section No. 15 of this Rate Schedule. Customers served under this Service Classification are eligible to purchase their energy from an Energy Service Company under the provisions of Rider I of this Rate Schedule.

(8) Increase in Rates and Charges

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

Orange and Rockland Utilities, Inc.
Gas Rate Case
Proposed Tariff Leaves effective February 25, 2018

P.S.C. No. 4 Gas

3rd	Revised Leaf No.	20	1st	Revised Leaf No.	80.3.9
2nd	Revised Leaf No.	24	8th	Revised Leaf No.	80.4
	Original Leaf No.	24.1	11th	Revised Leaf No.	81.1
18th	Revised Leaf No.	33.3	17th	Revised Leaf No.	82
13th	Revised Leaf No.	34	13th	Revised Leaf No.	94.9
20th	Revised Leaf No.	73	13th	Revised Leaf No.	94.10
2nd	Revised Leaf No.	73.1	16th	Revised Leaf No.	94.16
10th	Revised Leaf No.	74	4th	Revised Leaf No.	94.25
10th	Revised Leaf No.	76	14th	Revised Leaf No.	112
8th	Revised Leaf No.	79.1	6th	Revised Leaf No.	113.1
6th	Revised Leaf No.	79.2	7th	Revised Leaf No.	113.2
15th	Revised Leaf No.	80	2nd	Revised Leaf No.	113.3
17th	Revised Leaf No.	80.1	4th	Revised Leaf No.	113.4
	Original Leaf No.	80.1.1	26th	Revised Leaf No.	114
4th	Revised Leaf No.	80.3.1	29th	Revised Leaf No.	116
9th	Revised Leaf No.	80.3.2	26th	Revised Leaf No.	130
3rd	Revised Leaf No.	80.3.5	27th	Revised Leaf No.	133
2nd	Revised Leaf No.	80.3.6	13th	Revised Leaf No.	137.2
1st	Revised Leaf No.	80.3.8	8th	Revised Leaf No.	154.1

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, in any combination, 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, in any combination, 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.

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

4. SERVICE CONNECTIONS

4.1 LOCATION

The Company will determine the location and specify the type and manner of installation and connection of the service and metering equipment and will furnish this information to the customer upon request. The customer shall furnish and maintain a suitable space for service and metering equipment, readily accessible to authorized Company employees. Each separately metered building shall be supplied through an individual service pipe.

4.2 SERVICES INSTALLED BY COMPANY

(A) The Company will install service lines necessary to provide service if requested by the customer and after customer has paid to the Company the estimated cost of installing the service line minus the estimated cost of that portion of the service line that the Company is required to provide without charge in accordance with General Information Section 3.6.

(B) The customer shall have the option to provide the trenching, backfilling and/or restoration at customer's expense. Customers that provide trenching, backfilling and restoration will be eligible for an additional footage allowance for the installation of service lines beyond the footage to be provided by the Company without charge in accordance with General Information Section 3.7. Any additional footage allowance shall be limited to the Company's avoided cost of excavation up to the footage allowance specified in General Information Section 3.7. All work provided by the customer shall be performed in accordance with specifications provided by the Company. The Company reserves the right to make an inspection of the customer's trench prior to installing the service line in order to see that its specifications are complied with. Should the installation fail to be in compliance with the Company's and/or other applicable specifications or rules, the service line shall not be installed and the Company shall assess the re-inspection fee set forth in General Information Section 5.1(D) for any subsequent re-inspections of the installation.

4.3 SERVICES INSTALLED BY OTHERS

Where the customer makes arrangements for other than the Company to install service lines, the work shall be done subject to the approval of and at no cost to the Company.

GENERAL INFORMATION

4. SERVICE CONNECTIONS (Cont'd)

4.4 OUTDOOR METERING

The Company shall require all new residential dwellings to be provided with facilities supplied by the customer to accommodate outdoor metering Equipment Indoor location of meter(s) for new residential service will be approved only when the Company determines there is no suitable place outside to set the meter(s). When indoor meter location(s) are approved and utilized, free access by Company representatives to the meter(s) at all reasonable times shall be possible.

4.5 INSTALLATION BEFORE SERVICE IS REQUIRED

Whenever the Company installs service lines, service connections or appurtenant facilities at the request of an applicant who does not immediately desire service, the applicant shall bear the entire reasonable expense of providing, placing and constructing such facilities but shall be entitled to a refund whenever gas service is begun for such part of the expense as the Company is hereinbefore required to assume. The refund shall be the cost of the service lines and appurtenances, less depreciation at the rate of 3 percent per year.

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 January 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 September 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, 2017 is 1.770 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.)

6.5 RENDERING OF BILLS (Cont'd.)

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

(B) Utility Single Billing Service (Cont’d.)

next bill issued to the customer and every bill thereafter until changed by the Marketer.

Billing Cost:
The Company's charge for its billing service is $1.30 per Utility Single Bill per monthly billing cycle. This same charge applies whether the Company issues a Utility Single Bill for gas only or both gas and electric services for a single Marketer. The Company will "net" or offset its remittance payments to the Marketer by the amounts due the Company for billing service charges due from the Marketer. If there is one Marketer for gas service and another Marketer for electric service on a dual service customer's account, the Company will charge each Marketer one-half of the applicable charge.

If a Marketer requests that a Utility Single Bill include an insert required by statute, regulation, or Commission order, and such insert exceeds one-half ounce, the Company will charge the Marketer for incremental postage.

6.6 LATE PAYMENT CHARGE

(1) The Company may impose a continuing late payment charge at the rate of one and one-half percent (1 1/2%) per month to the accounts of all customers except state agencies on:

(a) the balance of any bill for service, including budget bills and any unpaid late payment charge amounts applied to previous bills, which bill is not paid by 12:01 a.m. local time 24 calendar days after the Billing Date;

(b) the amount billed for service used that was previously unbilled because service was being provided through tampered equipment, provided the Company can demonstrate either that the condition commenced since the customer initiated service or that the customer knew or reasonably should have known the original billing was incorrect; and

(c) the balance due under a non-residential deferred payment agreement except as defined in 6.12 (2)(B)(ii).

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;

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

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 (Cont'd.)

(e) Revenues associated with Fixed and Variable Transportation charges recovered through the Winter Bundled Sales Service Program

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, the costs associated with using an online auction platform, 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.)

(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 a fixed factor of adjustment as described below:

(a) For purposes of the Annual Reconciliation of gas costs and recoveries for the twelve months ending August 31, 2019 and each twelve-month period ending August 31 thereafter, the Line Loss Factor ("Annual Reconciliation LLF") will be based on the fixed factor of adjustment in effect as stated in General Information Section 12.1(A).

(b) The Company will compare the actual line loss factor for the 12-month period ending the previous August 31 ("actual LLF") to a Target Dead Band based on the Annual Reconciliation LLF. The Target Dead Band limits are set at minus two standard deviations of the Annual Reconciliation LLF ("Dead Band Lower Limit" or "DBLL") and plus two standard deviations of the Annual Reconciliation LLF ("Dead Band Upper Limit" or "DBUL").

(c) If the actual LLF falls within the Target Dead Band, there is no adjustment to the cost of gas.

(d) If the actual LLF is greater than the DBUL, the cost of gas will be adjusted by the ratio of the factor of adjustment based on the DBUL and the factor of adjustment based on the actual LLF.

(e) If the actual LLF is less than the DBLL, the cost of gas will be adjusted by the ratio of the factor of adjustment based on the DBLL and the factor of adjustment based on the actual LLF. However; if the actual LLF is less than 0%, the actual LLF shall be set to 0%.

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 January 1 of each year.

(2) 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 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. For the two-month period ending December 31, 2018, the MFC Fixed Component Lost Revenue target is $389,649. The MFC Fixed Component Lost Revenue target is $577,549 for the 12-month period commencing January 1, 2019, and each 12-month period thereafter.

"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 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. For the two-month period ending December 31, 2018, the Credit and Collections Lost Revenue Associated with Retail Access target is $114,270. The Credit and Collections Lost Revenue Associated with Retail Access target is $233,237 for the 12-month period commencing January 1, 2019, and each 12-month period thereafter.

"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. The TACS effective January 1, 2019 will reconcile the period November 1, 2018 through December 31, 2018 including any prior period balances.

(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 the twelve-month period commencing January 1, 2019 and every twelve-month period commencing January 1 thereafter, a base rate revenue imputation of $4,000,000 relating to the Interruptible Benefits described above shall be in effect until such time the imputation is reset in a base rate proceeding. 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 the Joint Proposal, dated June 5, 2015, and adopted by the Commission in its Order issued and effective October 16, 2015, in Case No. 14-G-0494.

For the two-month period commencing November 1, 2018 such imputation shall be $744,800.

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 December 31 of each year by the S.C. Nos. 1, 2, and 6 deliveries estimated for that period.

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)

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 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 December 31, 2019, and each twelve-month period ending December 31 thereafter, 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 December 31 of each year by the S.C. Nos. 1, 2, and 6 deliveries estimated for that period.

For the two-month period commencing November 1, 2018 such imputation shall be $108,400.

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.

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.)

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.)

(H) Reserved for Future Use

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

Customers shall be subject to a charge, stated on a cents per Ccf basis and shown separately on the Statement of Monthly Gas Adjustments, to recover balancing costs.

Gas is purchased under a common supply arrangement for both Consolidated Edison Company of New York and Orange and Rockland Utilities (“Companies”) as described in General Information Section No. 12.1(C). Balancing ("load following") costs shall be equal to the sum of the Companies' annualized fixed storage charges and fixed pipeline transportation charges from storage to the pipeline delivery point(s) at the boundary of the Companies' service territories utilized for balancing purposes.

The balancing cost shall be allocated to each company using fixed percentages. The fixed percentages are based on ratios of each Company's forecasted balancing requirement to the total forecasted balancing 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 balancing 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.

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 January 1, based on the Company's actual uncollectibles experience for the twelve-month period ended the previous September 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.)

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(J) Supplier Refunds (applicable to Service Classification Nos. 1, 2 and 6) (Cont'd.)

Any under- or over- recovery which results from the operation of this refund provision shall be included in the computation of the next applicable supplier refund. If the Company receives a refund from its gas supplier or suppliers where the total amount of the refund, including interest, is too small to be credited separately, such refund shall be included in the computation of the next supplier refund.

Simple interest, at the rate of interest prescribed from time to time by the Commission, shall be accrued on a supplier refund from the date of receipt of such refund by the Company until the refund and any prior period under- or over-recovery is included in the Monthly Gas Adjustment. Commencing with the date a supplier refund is included in the Monthly Gas Adjustment, interest will be accrued on the estimated monthly unrefunded balances through the end of the refund period.

Any balance of the refund remaining after the ten month's actual sales and transportation quantity and the eleventh month's estimated sales and transportation quantity will be divided by an estimate of the twelfth month's sales and transportation quantity and will be reflected in the applicable monthly adjustment for the twelfth month.

(K) Revenue Adjustments Mechanism (applicable to Service Classification Nos. 1, 2 and 6)

The Monthly Gas Adjustment shall be adjusted by a per Ccf rate to credit or charge customers for positive and negative revenue adjustments resulting from the Company’s gas and customer service performance mechanisms.

GENERAL INFORMATION

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

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(K) Revenue Adjustments Mechanism (applicable to Service Classification Nos. 1, 2 and 6) (Cont'd.)

The credit or charge for the Revenue Adjustments Mechanism shall be determined by dividing the amount to be credited or charged and any prior period reconciliation (i.e., the difference between actual collections and the target amount from the prior period's Revenue Adjustments Mechanism) by the forecasted Ccf deliveries to Service Classification Nos. 1, 2, and 6 customers for the period the Revenue Adjustments Mechanism will be in effect.

(L) System Performance Adjustment ("SPA") Mechanism (applicable to Service Classification Nos. 1, 2 and 6)

The Monthly Gas Adjustment shall be adjusted by a per Ccf rate to refund or surcharge customers for differences in actual gas losses as compared to estimated gas losses based on the actual Factor of Adjustment within a pre-determined dead-band.

For purposes of the SPA Mechanism, the Line Loss Factor ("SPA Mechanism LLF") will be based on the fixed factor of adjustment as stated in General Information Section 12.1(A).

The Company will compare the actual line loss factor for the 12-month period ending the previous August 31 ("actual LLF") to a Target Dead Band based on the SPA Mechanism LLF. The Target Dead Band limits are set at minus two standard deviations of the SPA Mechanism LLF ("Dead Band Lower Limit" or "DBLL") and plus two standard deviations of the SPA Mechanism LLF ("Dead Band Upper Limit" or "DBUL"). If the actual LLF is less than 0%, the actual LLF shall be set to 0%.

GENERAL INFORMATION

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

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(M) Non-Pipe Solutions ("NPS") Projects Surcharge (applicable to Service Classification Nos. 1, 2, and 6)

The Monthly Gas Adjustment may be adjusted by a per Ccf rate to recover the revenue requirement associated with Commission approved NPS projects undertaken by the Company until such costs are included in base rates.

The NPS Projects Surcharge shall be determined by dividing the sum of the recoverable revenue requirement detailed above and any prior period reconciliation (i.e., the difference between the amount to be recovered through the NPS Projects Surcharge and the actual amount recovered through the NPS Projects Surcharge) by the forecasted Ccf deliveries to Service Classification Nos. 1, 2, and 6 customers for the period the NPS Projects Surcharge will be in effect.

GENERAL INFORMATION

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

12.2 MONTHLY GAS ADJUSTMENT (Cont'd.)

(N) Individually Negotiated Contract Credit (applicable to Service Classification Nos. 1, 2 and 6)

The Monthly Gas Adjustment shall be adjusted by a per Ccf rate to credit firm customers for certain distribution system related revenues associated with individually negotiated contracts. The per Ccf credit shall be determined by dividing the projected annual revenues from such contracts, and any prior period reconciliations, by forecasted Ccf deliveries to Service Classification Nos. 1, 2, and 6 customers for the twelve-month period the credit will be in effect.

(O) Statement of Monthly Gas Adjustment

(1) The Monthly Gas Adjustment 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.

(2) The Statement of Monthly Gas Adjustment 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.

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 January 1, 2019, NHDD or normal heating degree days shall be 4,979 heating degree days, the average for the 10-years ended December 31, 2016.

(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 January 1, 2019			
SC No. 1	0.477	0.124	0.601
SC No. 2	0.169	0.039	0.208

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 January 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 September 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

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.....@	$156.16	$156.16
Over 3 Ccf.............@	25.293 ¢ per Ccf	31.398 ¢ 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.....@	$265.18	$265.18
Over 3 Ccf.............@	25.293 ¢ per Ccf	31.398 ¢ 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.....@	$403.67	$403.67
Over 3 Ccf.............@	25.293 ¢ per Ccf	31.398 ¢ 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.....@	$512.69	$512.69
Over 3 Ccf.............@	25.293 ¢ per Ccf	31.398 ¢ 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.....@	$ 58.93	$ 58.93
Over 3 Ccf.............@	5.058 ¢ per Ccf	6.281 ¢ 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.............@ $44.72 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.....@ $39.25
Over 3 Ccf.............@ 24.557 ¢ 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 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%. For customers commencing service under Rider E from November 1, 2015 through December 31, 2018, the EJP discount is 13.4%. For customers commencing service under Rider E after January 1, 2019, the EJP discount is 22.3%.

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")

A System Benefits Charge ("SBC") recovers costs associated with clean energy activities conducted by the New York State Energy Research and Development Authority ("NYSERDA"). 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.

Except for the 10-month Statement of SBC filed to become effective March 1, 2016, the Statement of SBC will be filed on an annual basis, on no less than 15 days' notice, to become effective January 1. The Statement will set forth the Clean Energy Fund ("CEF") Surcharge Rate.

Beginning March 1, 2016, the CEF Surcharge rate collects: (1) annual authorized collections associated with NYSERDA-run clean energy activities, including the Energy Efficiency Portfolio Standard ("EEPS"), and CEF, plus or minus any under- or over-collections for prior years; and (2) any over- or under-collections associated with Company-run EEPS programs authorized through 2015.

The CEF surcharge rate will be calculated by dividing the necessary collection amount by the forecasted Ccf deliveries for the period in which the Statement is to be in effect.

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 and unbilled 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.

(C) Delivery Revenue Targets

RPC Targets are set for each 12-month periods beginning January 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, 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 January 1, 2019	$1,029.24	$4,489.26

At the conclusion of each 12-month period ending December 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)

(D) RDM Adjustment

Annual RDM Periods are the 12-month periods ending December 31 of each year. For each customer group subject to the RDM, the Company will, at the end of each Annual RDM Period, compare Actual Delivery Revenue to the Delivery Revenue Target. If the Actual Delivery Revenue exceeds the Delivery Revenue Target, the delivery revenue excess will be refunded to customers through a customer group-specific RDM Adjustment during the RDM Adjustment Recovery Period (as described below). Likewise, if the Actual Delivery Revenue is less than the Delivery Revenue Target, this delivery revenue shortfall will be recovered through a customer group-specific RDM Adjustment from customers during the RDM Adjustment Recovery Period. Beginning with the RDM Adjustment Period effective February 1, 2020, RDM Adjustment Recovery Periods are the 12-month periods ending January 31 of each year.

Beginning with the first month following the end of each Annual RDM Period, interest at the Commission's rate for other customer provided capital will be calculated each month on the average of the current and prior month's cumulative delivery revenue excess/shortfall (net of state and federal income tax benefits).

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 February 1, the date on which the statement is proposed to be effective.

The customer group-specific RDM Adjustments will be determined on a cents per Ccf basis by dividing the total delivery revenue excess/shortfalls for the Annual RDM Period for each customer group by forecast Ccf deliveries of the associated customer group for the corresponding RDM Adjustment Recovery Period.

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

For the period November 1, 2018 through December 31, 2018 and if the Company files for new base rates to be effective on a date other than January 1 of any year beyond 2019, 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 (excluding any temporary surcharge 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.......@	$22.00
Next 47 Ccf...............@	69.548 ¢ per Ccf
All over 50 Ccf...........@	66.938 ¢ 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 Processing Charge shall be assessed in accordance with General Information Section 6.5.

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.......@	$32.00
Next 47 Ccf...............@	47.622 ¢ per Ccf
Next 4,950 Ccf...............@	45.723 ¢ per Ccf
All over 5,000 Ccf...........@	40.433 ¢ 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 Processing Charge shall be assessed in accordance with General Information Section 6.5.

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	@	$22.00
Next 47 Ccf	@	69.548 ¢ per Ccf
Over 50 Ccf	@	66.938 ¢ 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	@	$32.00
Next 47 Ccf	@	47.622 ¢ per Ccf
Next 4950 Ccf	@	45.723 ¢ per Ccf
Over 5,000 Ccf	@	40.433 ¢ 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	@	40.433 ¢ per Ccf

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 $1.30 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) All rates and charges under this Service Classification will be increased pursuant to General Information Section 15.

SERVICE CLASSIFICATION NO. 8 (Cont'd.)

RATE - MONTHLY: (Cont'd)

(1) Transportation Charge

First	100	Ccf or less per monthly billing period: $137.00
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
Over	100,000	Ccf at the Base Charge

The Base 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 Base Charge is to be effective.

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

The Base Charge shall not exceed $0.2830 per Ccf until the Company's base rates are next reset.

(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 5% 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 5% 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.

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, a charge for the weighted average cost of transportation, variable transportation and 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. The basis for the calculation of the commodity charge for the WBS gas will be set forth in the GTOP. Variable storage charges shall consist of injection and withdrawal charges for pipeline storage facilities for the period at the applicable rates and charges of each applicable pipeline. Variable transportation charges shall consist of variable charges and fuel for transportation associated with gas deliveries from storage facilities to the Company's city-gate.

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

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

Changes proposed to the Schedule for Electric Service, P.S.C. No. 3 – Electricity

The Company is filing revisions to its Schedule for Electric Service, P.S.C. No. 3 – Electricity (the "Electric Tariff"). These include revisions to: the rates under electric Service Classification ("SC") Nos. 1, 2, 3, 4, 5, 6, 9, 15, 16, 19, 20, 21, 22 and 25; the Billing and Payment Processing Charge; and the Merchant Function Charges.

In addition, the Company is proposing the following changes to the Electric Tariff:

- Amended the discounts in Rider C – Excelsior Jobs Program based on the Company's revised marginal cost of service study
- Amended the Energy Cost Adjustment to provide mechanisms to recover and/or credit customers for: (1) Non-Wires Alternative project costs and incentives; (2) Earnings Adjustment Mechanisms; (3) positive and negative revenue adjustments resulting from the Company's electric and customer service performance mechanisms; and (4) the price guarantee proposed for residences with plug-in electric vehicles ("PEVs") taking service under SC No. 19.
- Revised the Revenue Decoupling Mechanism ("RDM") to: (1) add SC Nos. 4 and 6 to the list of applicable RDM classes; (2) revise the RDM targets; (3) change the threshold associated with interim RDM Adjustments; and (4) revise language for the change in the starting month of the rate year to January
- Changed certain other mechanisms with rate years currently starting November to account for a partial rate year and to change the definition of the starting month of the rate year to January
- Introduced three new options related to PEVs: (1) a one-year price guarantee for customers taking service under SC No. 19 for residences that include PEVs and registering such PEVs with the Company; (2) an opportunity for residential customers to establish separate accounts under SC No. 19 for the sole purpose of PEV charging; and (3) a modification to the Company's Economic Development Rider, Rider H, to allow demand-billed participants that construct and own publicly accessible PEV quick charging stations with a minimum of 65 kW of aggregate charging capacity to receive the Rider H delivery rate discount through December 31, 2025
- Amended SC No. 25 to clarify that SC No. 25 customers will be assessed the MDAHP-eligible metering charges of their otherwise applicable service classification
- Revised language in the Market Supply Charge section to include on-line auction platform costs as recoverable supply costs
- Made other housekeeping changes

Changes proposed to the Schedule for Gas Service, P.S.C. No. 4 – Gas

The Company is filing revisions to its Schedule for Gas Service, P.S.C. No. 4 – Gas (the "Gas Tariff"). These include revisions to: the rates under gas Service Classification ("SC") Nos. 1, 2, and 6; the rates under Riders B and C; the Billing and Payment Processing Charge; and the Merchant Function Charges.

In addition, the Company is proposing the following changes to the Gas Tariff:

- Amended the discounts in Rider E – Excelsior Jobs Program based on the results of the Company's revised marginal cost of service study
- Revised the charge for the first 100 Ccf or less of monthly usage under SC No. 8, Interruptible Transportation and Supplemental Sales and revised the Base Charge cap
- Amended the Monthly Gas Adjustment ("MGA") to provide mechanisms to recover and/or credit customers for: (1) Non-Pipe Solution project costs; (2) positive and negative revenue adjustments resulting from the Company's gas and customer service performance mechanisms; and (3) demand revenues from gas transportation agreements
- Revised the Revenue Decoupling Mechanism ("RDM") to: (1) revise the RDM targets; and (2) revise language for the change in the starting month of the rate year to January
- Changed certain other mechanisms with rate years currently starting November to account for a partial rate year and to change the definition of the starting month of the rate year to January
- Changed the calculation of the annual line loss factor incentive and penalty and the System Performance Adjustment Mechanism
- Proposed to add a capacity charge component to Winter Bundled Sales Service ("WBSS") under SC No. 11
- Revised gas entitlements for non-residential customers and provided a further service entitlement for customers who perform the required excavation work on their property that will be used to install gas service pipe to connect to the Company's gas system
- Revised language in the Gas Supply Charge section to: (1) include on-line auction platform costs as recoverable supply costs; and (2) account for the capacity charge component of WBSS
- Reset the definition of normal heating degree days in the weather normalization adjustment
- Made other housekeeping changes

ORANGE AND ROCKLAND UTILITIES, INC.

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2019 (1) (2)
(Based on Billed Sales and Revenues)

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Low Income Discount ($000s)	Change ($000s)	Percent Change
SC1	1,507,816	197,405	301,276	317,413	(10,037)	6,100	2.0%
SC19	71,405	3,399	12,810	13,402	(51)	542	4.2%
Total Res	1,579,221	200,804	314,086	330,815	(10,088)	6,642	2.1%
SC2 Sec	838,026	23,584	140,663	146,159	0	5,496	3.9%
SC2 Sec Heat	24,064	322	2,956	3,061	0	106	3.6%
SC2 Sec ND & UM	16,612	4,662	3,901	3,778	0	(123)	-3.2%
SC20	81,753	449	11,056	11,306	0	250	2.3%
Total Secondary	960,455	29,017	158,576	164,305	0	5,729	3.6%
SC2 Pri	48,062	165	6,608	6,577	0	(30)	-0.5%
SC3	330,481	260	42,372	43,343	0	971	2.3%
SC21	35,704	25	4,655	4,767	0	112	2.4%
Total Primary	414,247	450	53,635	54,687	0	1,052	2.0%
Total Sec & Pri	1,374,702	29,466	212,211	218,992	0	6,781	3.2%
SC9 (Commercial)	472,591	48	53,067	53,268	0	201	0.4%
SC22 (Industrial)	315,174	33	34,713	35,049	0	337	1.0%
Total SC9 & SC22	787,765	81	87,779	88,317	0	538	0.6%
SC4	9,555	69	3,286	3,000	0	(287)	-8.7%
SC5	2,719	491	456	474	0	18	4.0%
SC6	6,009	2	938	970	0	33	3.5%
SC 16 -dusk-to-dawn	10,921	2,359	4,349	4,448	0	99	2.3%
SC 16 - energy only	3,594	437	664	692	0	27	4.1%
SC16 - Total	14,515	2,796	5,013	5,139	0	126	2.5%
Total Lighting	32,798	3,358	9,693	9,583	0	(110)	-1.1%
Total	3,774,486	233,709	623,769	647,708	(10,088)	13,851	2.2%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.
2. Revenue at Proposed Rates reflects the transfer of Energy Efficiency Tracker Funding from the Energy Cost Adjustment to Base Rates.

ORANGE AND ROCKLAND UTILITIES, INC.

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2019 (1) (2)
(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)	Low Income Discount ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,328,079	125,516	192,599.5	199,534.2	(3,693.9)	3,240.8	1.7%
1 / 6 1A	Non Residential	882,797	6,043	11,504.0	11,850.1	0.0	346.1	3.0%
2 / 6 IB	Commercial	4,339,943	6,020	43,449.9	43,727.6	0.0	277.7	0.6%
6 II	Large Commercial	1,296,749	101	12,052.9	12,101.2	0.0	48.3	0.4%
	Total Firm	20,847,568	137,680	259,606.2	267,213.0	(3,693.9)	3,912.9	1.5%

1. 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.
2. Revenue at Proposed Rates reflects the transfer of Energy Efficiency Tracker Funding from the Monthly Gas Adjustment to Base Rates.

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, 2019.

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 December 31, 2019, of approximately $20 million for electric and $5 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 Hon. 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: January 26, 2018

ORANGE AND ROCKLAND UTILITIES, INC.

Policy Panel – ELECTRIC/GAS

TABLE OF CONTENTS

Introduction and Purpose

Q. Would the members of the Policy Panel ("Panel") please state your names and business addresses?

A. Francis Peverly and Christina Ho. Our business address is 390 West Route 59, Spring Valley, New York 10977.

Q. What are your current positions at Orange and Rockland Utilities, Inc. ("Orange and Rockland", or the "Company")?

A. **(Peverly)** I currently serve as Vice President – Operations.

(Ho) I currently serve as Vice President - Customer Service.

Q. Please describe your educational backgrounds.

A. **(Peverly)** I hold a Bachelor of Science degree in Industrial Distribution from Clarkson University, and an MBA from Marist College. I have completed the Wharton School's Executive Development Program and am also certified as a Project Management Professional.

(Ho) I hold a Bachelor of Engineering degree in Chemical Engineering from Cooper Union, and a Master of Science degree in Earth Resources Engineering from Columbia University.

Q. Please describe your work experience.

A. **(Peverly)** Over my past 32 years in the utility business, I have progressively held several management and engineering assignments in Electric Operations, Gas Operations, and Construction Management, working for Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("Con Edison"), and Orange and Rockland. I have served in my current role for the past six years.

(Ho) I joined Con Edison in 2002 and have held various positions of increasing responsibility in the Central Engineering and Steam Operations Departments such as engineer, senior engineer and Section Manager. I have also held the position of Energy Manager in System Operations and General Manager of the Steam Services Department prior to my current role as Vice President - Customer Services for Orange and Rockland.

Q. Do you belong to any professional organizations?

A. **(Peverly)** Yes. I am 2nd Vice Chair of the Edison Electric Institute's ("EEI") Distribution Subject Area

Committee, a member of the EEI Transmission, Distribution and Metering Executive Committee, a member of NYSERDA's Grid Modernization Advisory Committee, a senior member of the Association of Energy Engineers and have served on the national advisory board for Grid Engineering for Accelerated Renewable Energy Deployment. I also sit on the Board of the Northeast Gas Association, sit on the Executive Committee of the Board for the Society of Gas Lighters, and am a member of the Executive Committee for NYSEARCH.

(Ho) Yes. I am a member of the American Society of Mechanical Engineers.

Q. Please generally describe your current responsibilities.

A. **(Peverly)** I have overall responsibility for the Company's electric and gas operations and engineering groups, which control the essential elements of the Company's business for the transmission and distribution of electricity and natural gas. I also have overall responsibility for the Company's Utility of the Future team, which the Company established to organize the Company's overall approach to the Public Service Commission's ("Commission") Reforming the Energy Vision ("REV") initiatives and distributed energy resources ("DER") integration.

(Ho) I have overall responsibility for the Company's customer service groups, including the call center, policy and compliance, billing, meter reading and collections, electric meter shops, Advanced Metering Infrastructure ("AMI") deployment, revenue protection, new business services, and energy services.

Q. Have you previously testified before the Commission or other regulatory bodies on energy matters?

A. **(Peverly)** I have not testified before the Commission but I have submitted testimony to other regulatory bodies, including the Federal Regulatory Commission and the New Jersey Board of Public Utilities.

(Ho) Yes, I testified before the Commission on behalf of Con Edison in Case 13-S-0032.

Q. What is the purpose of the Panel's testimony?

A. The purpose of the Panel's testimony is to describe the Company's core goals and the major programs and projects that the Company is planning to implement in furtherance of these goals in this rate filing. The program and projects are discussed in detail in the witness panels sponsoring these programs. Specifically, the Company’s core goals are improving public and employee safety, enhancing the customer experience, and improving operational excellence. This Panel will also describe how the Company’s pursuit of those goals aligns with State policy goals. We also note that the Company’s pursuit of operational excellence includes its ongoing measures to increase efficiency and mitigate costs.

Q. Please describe the changes occurring in the electric and natural gas industries.

A. The electric and natural gas utilities in general, and in New York State in particular, are undergoing fundamental transformation. With respect to electricity, the power grid based on one-way electric flow is transitioning to a more complex, smart, two-way electric grid with the goal of a cleaner and more resilient energy system. Various forces are driving this transition, including technological advances, state and federal policy decisions, more favorable economics for DER and natural gas, and customers' desire for more control over their energy usage. At the same time, generally low prices and the ease of use have made natural gas the fuel of choice for new customers. Due to these factors, customers that currently rely on heating oil and propane are seeking to convert to natural gas.

At the same time, the manner in which customers interact with utilities like Orange and Rockland is changing. Customers expect more personalized services, easier access to their energy usage information, and more control over when and how they use their energy.

Q. Please briefly describe Orange and Rockland's overall strategy and how this rate filing addresses this changing environment.

A. Orange and Rockland is evolving to respond to these changing customer desires, advancements in technology, and federal and state regulatory policy goals, including the State's REV goals. The Company embraces this transformative period in the industry and is making innovative strategic investments. These investments will allow the Company to continue to deliver electricity and natural gas safely and reliably while meeting customer expectations for new products and services.

In this filing, the Company outlines how its investments in pursuit of its core goals respond to the changing markets and State policy goals as described below:

1. Enhancing Public and Employee Safety: Carrying out all responsibilities safely and operating in a manner that promotes and values the safety of the general public and the Company’s employees;
2. Enhancing the Customer Experience: Actively engaging customers regarding their expectations and providing services that meet these expectations; and
3. Improving Operational Excellence: Optimizing system assets, including efficiency and non-traditional measures that further clean energy goals and maintain high levels of reliability

and resiliency while demonstrating cost consciousness.

Q. Please briefly provide some examples of the Company's efforts to meet its objectives and respond to industry changes.

A. The Company is actively engaged in identifying and implementing new technologies. As discussed in the direct testimony of the Customer Service Panel, the Company is working jointly with Con Edison to invest in digital technologies and platforms to better engage customers, including the Digital Customer Experience ("DCX") and Green Button Connect ("GBC") programs. These investments will make it easier for customers to communicate and interact with Orange and Rockland. An additional important component is the Company's investment in AMI. Smart meters are a vital element of the future distribution system and a critical building block for increased customer engagement. These meters will provide customers with more granular information to make energy decisions. This technology will also enhance Orange and Rockland's decisions regarding infrastructure investments, response to outages, and third party partnerships geared toward deploying DERs or other products and services. It will also facilitate the consideration and deployment of innovative rate designs.

To leverage fully the real-time, localized data provided by AMI, the Company is also making investments in advanced technologies, such as an Advanced Distribution Management System (“ADMS”), which will enhance reliability and resiliency. It will also substantially improve near-real time system operational awareness and control to better enable customer DER integration.

In addition, as discussed in the direct testimony of the Electric Infrastructure and Operations Panel, the Company is establishing new programs, processes and demonstration projects that will support market evolution and the Company’s development of capabilities necessary to continue its evolution as the Distributed System Platform (“DSP”) provider. As the DSP provider, the Company is using non-wires alternatives to test new opportunities to balance the grid, improve efficiency, boost reliability and resiliency, and potentially eliminate or defer the cost of some traditional transmission and distribution investments.

The Company is also committed to investing in traditional and non-traditional solutions to deliver natural gas safely. As discussed in the Gas Infrastructure and Operations Panel's testimony, this includes solutions that advance the State's clean energy objectives. In addition, that Panel discusses the Company's investments to remove or replace hundreds of miles of leak-prone pipe. The Company has also enhanced its worker training program and will enhance its gas procedures to improve safety.

Q. You have stated that operational excellence includes cost mitigation. Please describe the Company's ongoing efforts to mitigate costs and identify and achieve efficiencies.

A. Cost management has been, and will remain, at the core of Orange and Rockland's business processes. The Company recognizes its responsibility to manage costs on behalf of its customers and is committed to leveraging best practices to identify and implement opportunities to increase efficiency through both selection of capital projects and minimizing O&M. The Gas and Electric Infrastructure and Operations Panels in particular describe their processes for selecting projects and mitigating costs.

Q. Finally, please discuss the most recent Management and Operations Audit performed for Orange and Rockland.

A. In December 2014, the Commission, in Case 14-M-0001, commenced the comprehensive management and operations audit of Con Edison and Orange and Rockland in accordance with Public Service Law §66(19). The Commission selected NorthStar Consulting Group (“NorthStar”) to perform the audit and NorthStar released its Final Report on May 20, 2016. The Final Report contained 36 separate Recommendations (16 of which were applicable to Con Edison only).

Q. Is Orange and Rockland implementing the Final Report’s Recommendations?

A. In its Implementation Plan, Orange and Rockland sets forth a milestone schedule for the completion of each of the 20 applicable Recommendations. Orange and Rockland expects to be in compliance with each of the

20 applicable Recommendations by June 2018, prior to the start of the Rate Year.

Q. Have there been any other audits of the Company?

A. Yes. In August 2013, the Commission initiated Case 13-M-0314 examining utility data reporting ("Utility Data Audit") to examine the accuracy of electric interruption, gas safety, and customer service data that is regularly reported to the Commission. A report was issued and the Company has implemented all 76 of the recommendations that apply to its reporting practices, twelve of which have been accepted by Staff of the Department of Public Service ("Staff") and closed. In addition, under Case 13-M-0449, the Commission initiated an audit to examine internal staffing levels and the use of contractors at major New York State utilities. The final report for that audit included 16 recommendations for Orange and Rockland. Orange and Rockland filed an implementation plan in March 2017, which the Commission approved on December 15, 2017.

Enhancing Public and Employee Safety

Q. Please describe the Company’s continuing commitment to safety.

A. The health and safety of the Company’s employees, customers, and the public is our number one priority. This dedication to safety, whether it be employee safety, public safety, system safety, or environmental safety, is a critical component in all its decisions and actions.

Q. How does the Company demonstrate its commitment to operating safely?

A. As described in detail in the direct testimony of both the Electric and Gas Infrastructure and Operations Panels, safety is a fundamental principle of the Company’s energy system planning process.

The Gas Infrastructure and Operations Panel describes how the Company has continued its focus on safety and damage prevention. The Company has many programs in place to monitor the integrity of its gas transmission and distribution mains and respond to reports of damage. Examples of these programs include:

- Conducting periodic system infrastructure surveys and inspections;
- Responding promptly to all odor calls to expeditiously secure any leaks on either customer or Company facilities; and
- Promoting 811, the protection of underground facilities, and the use of hand tools when excavations are occurring in areas with known gas infrastructure assets.

The Company is also committed to replacing leak-prone pipe to improve the integrity of the pipeline system and reduce the risk of emergency response events. Over the past 20 years, the Company has invested over $250 million to replace 375 miles (20% of the Company’s gas system) of leak-prone pipe on its system. The Company’s replacement efforts have resulted in a stabilization of incoming leaks, which are expected to decrease over the long run as the Company removes more leak-prone pipe. Under the Company’s planned efforts to continue replacement, as described by the Gas Infrastructure and Operations

Panel, the Company will eliminate all currently defined leak-prone pipe (*i.e.,* Aldyl, bare steel, and cast iron) from its gas system by 2029.

For electric, the portfolio of planned projects incorporate system improvements and upgrades designed to maintain equipment and system assets operating within appropriate thermal and design limits, which sustains safe operating conditions for both the public and the Company's employees.

The Company's Environment Health and Safety Panel describes several new programs to improve the health and safety of the public, Company employees and contractors, and the environment. These include establishing a new driver safety program for Company employees, enhancing Company documentation of areas of known contamination within the Company's service territory and modifying procedures, and developing a mobile contractor oversight system to make it easier to observe and evaluate contractors based on their adherence to Company safety standards and work procedures.

Q. Please describe the Company's ongoing employee training initiatives and how these initiatives enhance employee and public safety.

A. As discussed in the direct testimony of the Electric and Gas Infrastructure and Operations Panels, the Company provides its operations employees and contractors with the training and qualification needed to perform their job functions safely. This includes both on-the-job training and continuing education opportunities. The Company also supplements the Federal Operator Qualification Compliance Program for gas employees with additional training to enable them to perform their jobs safely. The Company leverages its Quality Assurance Department and Environmental Health and Safety Group to perform routine audits, inspections, and field visits to verify the Company's ongoing adherence to established processes, procedures, and safety standards.

Q. Has Orange and Rockland increased its focus on health and safety beyond the Company?

A. Yes. Over the past several years, the Company has increased its public outreach efforts to communicate the importance of safety to customers and the public. For example, leveraging the Con Edison experience, the Company promotes gas safety, particularly the importance of calling 811 prior to digging and calling Orange and Rockland if one smells natural gas through its “Smell Gas Act Fast” campaign. The Company communicates these safety messages via several channels including the Company’s website, e-mail blasts, bill inserts, print publications, billboards, and various social media platforms (*e.g.*, Facebook, Twitter, and YouTube). Orange and Rockland intends to continue this practice.

Enhancing the Customer Experience

Q. Please discuss Orange and Rockland’s approach to engaging customers and enhancing the customer experience.

A. As discussed in the direct testimony of the Company’s Customer Service Panel, to achieve this goal, the Company explores evolving trends in technology and commercial markets, as well as changing consumer behaviors to anticipate future needs. Broadly speaking, customers expect more personalized products and services, want access to more data/information regarding the products and services they consume, and use mobile devices and other forms of technology to communicate and conduct transactions.

To better align with these technology trends, the Company is changing how it communicates and engages with its customers. The Company is broadening its presence, particularly via online forums (*e.g.*, Company website, and social media sites). The Company has and will continue to work jointly with Con Edison on developing methods to increase the Company's presence on these channels of communication as their importance increases.

Q. Please provide examples of the programs and projects the Company is planning to enhance the customer experience.

A. As further described in the direct testimony of the Customer Service and Electric Infrastructure and Operations Panels, the Company is investing in several new and existing programs to improve the customer experience. These investments include:

- DCX: Initiative to upgrade the Company’s customer facing digital platforms (*e.g.*, website, mobile app, “My Account” portal) to standardize the look and feel, make it easier for customers to navigate and find information, and to provide operability regardless of how the platforms are accessed (*e.g.*, mobile phone, desktop computer).
- Community Distributed Generation (“CDG”) and Value of DER (“VDER”), which includes new billing procedures to distribute credits from CDG facilities to project subscribers and to transition to a Value Stack methodology designed to capture the true value of energy exported to the Company’s distribution system.
- Electric Vehicles (“EV”) includes programs to encourage EV adoption in its service territory through rebates and Company investment in EV charging stations, new time of use rates, and an education and outreach

initiative to customers around key EV topics, including ownership costs, environmental benefits, charging options, and available incentives.

- Energy Efficiency Programs that build upon the Company's existing residential and commercial and industrial Energy Efficiency Transition Implementation Plan ("ETIP") programs by introducing new programs aimed at increasing efficiency of customers' energy use and DER adoption. These new programs will provide customers with additional options to manage their energy usage and become more educated energy consumers.

Q. Please describe the technology upgrades needed to support this enhanced customer engagement.

A. To leverage fully the capabilities of the programs above, the Company is investing in its underlying technology infrastructure. With these new programs comes the need to increase data storage capacity, upgrade software so that systems are able to communicate with one another, and increase analytical capabilities, while protecting customers' personally identifiable information.

To do so, the Company must make continued investments to upgrade its existing systems and platforms such as the Customer Information Management System ("CIMS"). For example, to fully leverage the functionality of the DCX and GBC programs, the Company has invested in a new Enterprise Data Analytics Platform ("EDAP").

Improving Operational Excellence

Q. Please describe the Company's ongoing efforts to improve operational excellence.

A. The Company is constantly monitoring the condition of its infrastructure, identifying reliability risks, and implementing solutions to eliminate or mitigate identified risks. The Company upgrades or replaces (with a focus on upgrades) assets that have reached either thermal or operating limits, reached or are nearing the end of useful life, become obsolete, or exhibited degraded performance. The Company also continuously identifies current and future electric and gas infrastructure needs and develops both traditional and non-traditional solutions to address these needs. For electric, the Company considers the impact of existing and planned DER assets interconnecting to the distribution system, as well as existing and proposed efficiency programs and other load modifiers when developing potential solutions. As the Company replaces electric and gas transmission and/or distribution assets, as well as substation infrastructure, it uses newer, more advanced assets, or when appropriate, evaluates non-wires alternatives. The Company chooses the optimum solution to meet the electric and gas system needs, whether traditional or non-traditional. For gas, the company has a well-established Distribution Integrity Management Plan to identify gas system threats.

Q. Please discuss the gas and electric infrastructure and technological investments Orange and Rockland is making to maintain high levels of reliability, reduce system risk, and improve operations.

A. The Company continues to implement robust inspection and maintenance programs that provide continual assessments of its electric transmission, substation and distribution delivery systems. Consequently, the Company continues to improve its performance, which demonstrates that the Company's capital and maintenance programs are deploying expenditures effectively. The Company has also substantially increased the percentage of its Transmission and Substation system assets that meet its design standards over this same period. This has mitigated risk and improved system availability and service reliability for customers. AMI should further improve reliability as crews are dispatched more efficiently because AMI will quickly provide more granular system information.

On the gas system, the Company has replaced approximately 375 miles of leak-prone main and is committed to continuing this replacement program into the future. The Company is also on track to remove all low pressure systems (which includes all cast-iron mains) by 2019, which will be a major milestone. In addition to the replacement of aged infrastructure, the number of backlogged leak repairs has fallen significantly. Consequently, the Company will more proactively schedule all leak repairs, improve upon its 30-minute leak response rates, and reallocate funds to enhance damage prevention efforts.

Q. Please describe how Orange and Rockland has modified its planning process to evaluate alternatives to traditional solutions to meet system needs.

A. In its electric business, the Company actively considers and evaluates non-wires alternatives to traditional solutions to relieve system capacity constraints. In conformance with the Commission’s direction, the Company has develop suitability criteria in coordination with New York State’s other major electric utilities and stakeholders to identify projects that are best suited for the competitive procurement of non-wires alternatives. Using this evaluation process, the Company has already identified several potential non-wires alternative projects. The Company’s Electric Infrastructure and Operations Panel will further elaborate on these integrated planning process improvements and the Company’s non-wires alternatives projects.

Though less mature than non-wires alternatives, the Company’s Gas Engineering and Operations groups are currently exploring, jointly with Con Edison -- how non-pipes alternatives could provide an alternative to traditional investments in gas infrastructure. The Company’s Gas Infrastructure and Operations Panel discusses this topic in greater detail.

Q. Please provide a general description of the electric programs and projects to improve electric operational excellence.

A. The Company’s capital plan includes various projects that are necessary to maintain system reliability and reduce the risk of equipment and system failures. The Company groups these capital expenditures and plant additions into the following five budget categories: (1) Risk Reduction Projects, (2) New Business Projects, (3) System Expansion Projects, (4) Replacement Projects, and (5) Resiliency Projects. As explained more fully in the direct testimony of the Company’s Electric Infrastructure and Operations Panel, many of the Company’s upcoming projects are focused on risk reduction, replacement, and resiliency. In particular, investments that increase DERs and use of AMI will help to increase system resiliency.

Q. Please discuss what Orange and Rockland is doing to integrate and enhance DERs as the DSP Provider.

A. The Company filed its initial Distributed System Implementation Plan ("DSIP") on June 30, 2016 and, along with the other Joint Utilities,[1] the Supplemental Distributed System Implementation Plan ("SDSIP") on November 1, 2016. Together, these documents laid out the Company's vision and roadmap to becoming a DSP Provider. The Company will submit its next biennial DSIP in June 2018, which will include updates and progress as to its vision and roadmap.

At this time, the Company is laying the groundwork to assume the role of DSP Provider by: (1) making necessary changes to processes and organization structure, (2) making key investments in advanced technologies to modernize the grid, and (3)

[1] In addition to Orange and Rockland, the Joint Utilities are Central Hudson Gas & Electric Corporation, Con Edison, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

establishing new programs and demonstration projects to enable DER integration and future market development.

The Company is updating and enhancing certain processes, including load forecasting, system planning, electric system management, monitoring and control, and interconnection support. In addition, the Company is making data available on its website that will further DER integration and market development. Among the information currently available, or to be available in the near term, are hosting capacity maps, system load data, forecast data, and locational maps.

The Company has also established a Utility of the Future group that coordinates with Con Edison and the other State utilities to organize and align the Company's overall approach to REV and DER integration. While there is a need to increase staffing (reflected in this filing), the Company is minimizing increases to total headcount by repurposing existing positions to meet evolving Company needs.

The Company is also making key investments in advanced technologies to modernize the grid and enable DER integration and distribution market development. The SDSIP outlined the Joint Utilities' perspective on the stages of DSP development and the key investments required at each stage. Orange and Rockland is in the process of implementing such technologies, including AMI and an ADMS. The Company is also evaluating and, in some cases, moving forward with new investments in data analytics, advanced communications infrastructure, and a Distributed Energy Resources Management System.

In addition, as discussed in the direct testimony of the Company's Electric Infrastructure and Operations Panel, the Company is preparing for future distribution market development through new programs and demonstration projects. This includes the ongoing Customer Engagement and Marketplace Platform, as well as newly proposed demonstration projects related to Energy Storage and Smart Home rates.

Q. Is the Company proposing earnings adjustment mechanisms ("EAMs")?

A. Yes. The Commission has stated that EAMs "are both a fair and a necessary means of promoting change." The Company's electric base rate filing accordingly includes a proposal for EAMs that promote change. The Company updated these proposals from its February 2017 EAM petition (in Case 14-M-0101 and Case 16-M-0429)[2] based on feedback and additional guidance provided by the Commission and Staff. As detailed more fully in the direct testimony of the Company's EAM Panel, the Company is proposing to implement EAMs in the following four categories: (1) System Efficiency, (2) Energy Efficiency, (3) Interconnection, and (4) AMI/Customer Engagement. All of these proposed EAMs are geared to providing the Company with an economic incentive to promote the changes necessary to integrate DERs that will help to increase the use of clean energy and system resilience.

[2] CASE 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*

Case 16-M-0429 – *In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision*

Q. Please describe the programs and projects Orange and Rockland is seeking to fund as part of its rate filing to improve gas operational excellence.

A. The focus of the Company’s capital projects is the enhancement of its natural gas system to provide for safe and reliable delivery of natural gas to its customers. To achieve this goal, the Company is investing in enhanced damage prevention programs. The Company will also invest in system reinforcements to improve reliability and will replace/upgrade several regulator stations that are forecasted to surpass their useful life. Finally, the Company will continue to make the necessary investments to serve new customers and residential developments that are interested in natural gas service.

Beyond these projects, the Company is also investing in several programs in its ongoing effort to achieve operational excellence. For example, Gas Operations plans to establish an improved training center for Company employees and contractors. The Company also plans on hiring a dedicated training specialist that will provide continuing education and testing to enable Company employees and contractors to execute their work in a safe and efficient manner. Gas Engineering also plans to implement several upgrades to its planning system (*e.g.*, GPS coordinates of buried pipe and new analytical tools) that will improve the accuracy of its system/project designs, reduce the amount of time required to locate gas facilities in the field, and improve damage prevention by reducing risk when work is being performed.

Contents of Filing

Q. Please identify the panels and witnesses that will provide testimony in support of the filings.

A. The table below sets forth the Company’s witness panels.

Panel	Witness(es)
Common to Electric and Gas	
Accounting	John de la Bastide / Edlyn Misquita / Wenqi Wang / Kyle Ryan
Compensation & Benefits	Hector Reyes / Susan Carson / Roselyn Feinsod (consultant) / Virginia Fischetti (consultant)
Cost of Capital	Yukari Saegusa
Customer Service	Robert Melvin / Karin Sullivan / Donald Kennedy / Keith Scerbo
Low Income	Donald Kennedy / Charmaine Cigliano
Energy Efficiency	Donald Kennedy / Charmaine Cigliano
Depreciation	Matthew Kahn / Ned Allis (consultant)
Environmental Health & Safety	Maribeth McCormick / Stephen Prall
Income Tax	Charles Lenns / Matt Kahn / Jeff Kalata
Property Tax	Stephanie Merritt/Stephen Ianello
Return on Equity	Dr. James Vander Weide (consultant)
Earning Adjustment Mechanisms	Kristen Barone / Charmaine Cigliano / Mike McGuire
Electric	
Electric Forecasting	Simar Grewal/ Leanne Attanasio
Electric Infrastructure & Operations	Angelo Regan / John Coffey / Wayne Banker /Roberta Scerbo/ Keith Brideweser
Other Electric Initiatives	Michele Hanebuth / Scott Dunwoody/ Gabriel Cano/ John Murphy
Electric Rate	William Atzl / Cheryl Ruggiero / Shajan Jacob
Electric Supply	Joseph Briscese
Demand Analysis & Cost of Service	Yan Flishenbaum / Kristen Graves / Lucy Villeta / Michael Peres
Gas	
Gas Forecasting	Patrick Hourihane / Douglas Elgort
Gas Infrastructure & Operations	Flannan Hehir / Glenn Meyers
Gas Rate	William Atzl / Cheryl Ruggiero / Eric Caban / Yan Flishenbaum
Gas Supply	Kathleen Trischitta

Q. Does this conclude your testimony?

A. Yes, it does.

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. John de la Bastide, One Blue Hill Plaza, Pearl River, New York 10965. Edlyn Misquita, 4 Irving Place, New York, New York 10003. Wenqi Wang, 4 Irving Place, New York, New York, 10003. Kyle Ryan, 4 Irving Place, New York, New York, 10003.

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

A. **(de la Bastide)** 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.

(Misquita) I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I hold the position of Assistant Controller, Corporate Accounting.

(Wang) I am employed by Con Edison. I hold the position of Department Manager - Regulatory Accounting and Revenue Requirements.

(Ryan) I am employed by Con Edison. I hold the position of Department Manager – Regulatory Filings.

Q. Please explain your educational background, work experience and current general responsibilities.

A. **(de la Bastide)** I graduated from Hofstra University in l985 with a Bachelor of Business Administration in Accounting. I was employed by Con Edison for 30 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. In November 2016, I became an employee of Orange and Rockland and assumed the role of Director of Financial Services. I am responsible for coordinating the financial, budget, administrative and regulatory activities for the senior management of Orange and Rockland. In addition, the financial services department acts as a financial liaison between the

Company, Consolidated Edison, Inc. ("CEI") and Con Edison.

(Misquita) I received a Bachelor's degree in Accounting and Audit from University of Bombay, India in 1992 and am a CPA. I joined Con Edison in 2001 in the Corporate Accounting department. In my current role as Assistant Controller, I have oversight of regulatory and accounting operations. My previous assignments include assistant controller of Financial Accounting and Reporting, business lead for the implementation of Oracle Finance and Supply Chain systems, assistant to the CEO, and department manager of Accounting Research and Procedures. Before joining Con Edison, I worked for seven years in the audit practice at Ernst & Young, India.

(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 the 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 Manager level. In May 2014, I assumed my current position as Department Manager of Regulatory Accounting and Revenue Requirements.

(Ryan) I graduated from the University of Wisconsin-Madison in 2006 after earning a Bachelor of Business Administration in Accounting and a Masters of Accountancy. I began my employment with Con Edison in 2012 as a Senior Accountant in the Accounting Research and Procedures section and was promoted to Department Manager of the section in 2014. I assumed my current position as Department Manager of Regulatory Filings in June 2017. Prior to joining Con Edison, I worked for Ernst & Young in Minneapolis, Minnesota from 2006 to 2012, ultimately reaching the position of Audit Manager. I am a licensed CPA in New York and Minnesota.

Q. Have any members of the Accounting Panel previously testified before the New York Public Service Commission (“NYPSC” or “Commission”)?

A. **(de la Bastide)** Yes. I submitted testimony before the Commission in the last electric and gas base rate cases for Orange and Rockland (Case 14-E-0493; 14-G-0494) and have submitted testimony or testified in Con Edison electric, gas, and steam rate cases (Cases 13-E-0030, 13-G-0031 and 13-S-0032).

(Misquita) No.

(Wang) I submitted testimony before the Commission in the last electric and gas base rate cases for Orange and Rockland (Case 14-E-0493; 14-G-0494) and have submitted testimony in Con Edison electric and gas rate cases (Cases 16-E-0060 and 16-G-0061).

(Ryan) 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 factors driving the need for electric and gas rate relief for the twelve months ending December 31, 2019 (“Rate Year”);
- Historic financial statements and statistical data as required by the Commission;
- Rate base for the twelve months ended September

30, 2017 ("Historic Year") through the Rate Year;

- A comparison of the projected revenues, expenses and rate base for the Rate Year to the Historic Year;
- The development of the Rate Year electric and gas revenue requirements;
- The Company's requests related to certain deferral accounting and reconciliation mechanisms; and
- The Company's forecasted financial information for the two annual periods beyond the Rate Year to provide a basis for settlement discussions regarding a multi-year rate plan.

Q. Please describe your testimony and how it is organized.

A. The Accounting Panel testimony covers the below-listed topics and exhibits. All of these exhibits were prepared under our supervision and direction, but rely on input from other Company witnesses. Certain projections will be updated based on the latest information available during the course of these proceedings.

Exhibit Title and Description	Exh. No.	E, G*
Historic Financial and Statistical Data	AP-1	E, G
Rate Base	AP-2	E, G
Operating Income	AP-3	E, G
Electric/Gas and Common Plant Forecast	AP-4	E, G

* The numbering convention for exhibits indicates whether the exhibits address electric or gas (E, G) service as follows: AP-E1, AP-E2, etc. for electric exhibits and AP-G1, AP-G2, etc. for gas exhibits. For ease of presentation, the exhibits are often referenced without the commodity designation.

As a preliminary matter, the Company would note that it is not proposing a multi-year rate plan for electric or gas in its filing. However, in addition to providing projections for the Rate Year in the AP-3 exhibits, the Company has included forecasted financial information for two annual periods beyond the Rate Year, *i.e.*, the twelve-month periods ending December 31, 2020 and December 31, 2021 (which we and other Company witnesses will refer to as “RY2” and “RY3,” respectively, for ease of reference).

III. THE NEED FOR RATE RELIEF

Q. What amount of rate relief is the Company requesting?

A. For electric, the Company is requesting approximately $20.3 million of rate relief for the Rate Year. That amount equates to approximately a 2.2% overall increase in customer bills and approximately a 6.7% increase on a delivery bill basis.

For gas, the Company is requesting approximately $4.5 million of rate relief for the Rate Year. That amount equates to approximately a 1.5% overall increase in customer bills and approximately a 2.8% increase on a delivery bill basis.

Q. What are the specific drivers of the requested rate increases?

A. The following table summarizes (in millions of dollars) the components driving the need for increased electric and gas base rate revenues:

Table 1		
Driver	**Electric**	**Gas**
New infrastructure investment, including return, depreciation and property taxes	$ 13	$ 6
ROE / Financing	5	3
Depreciation changes due to proposed rates	4	2
Sales revenue change	6	(8)

Table 1		
Driver	**Electric**	**Gas**
Other operations and maintenance expenses, including amortizations *	5	10
Income taxes	(13)	(8)
Total	**$ 20**	**$ 5**
* Gas O&M expenses are increased by $4 million and electric O&M expenses are decreased by $4 million as the result of the proposed change in common expense allocation described in Section IX of this testimony.		

Q. Please discuss the “new infrastructure investment, including return, depreciation and property taxes” 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 at current rates) plus the accompanying increase in property taxes in the Rate Year is $13 million for electric and $6 million for gas. The Electric Infrastructure and Operations Panel (“EIOP”), the Other Electric Initiatives Panel, the Gas Infrastructure and Operations Panel (“GIOP”), the Customer Service Panel, and the Environmental Health and Safety (“EH&S”) Panel explain these needs in greater detail.

Q. What impact does the return on equity ("ROE") and projected interest cost have in this rate request?

A. Under the Commission's rate order in the Company's most recent electric and gas base rate proceedings (Case 14-E-0493, Case 14-G-0494) ("2015 Rate Order"), current electric and gas rates reflect an overall rate of return of 7.06%, including an ROE of 9.0%. The weighted cost of long-term debt included is 5.35%. As discussed in the direct testimony of Company witness Saegusa, the electric and gas revenue requirements in this case reflect an overall rate of return of 7.39%, based on a 9.75% ROE and a weighted cost of long-term debt of 5.30%. Although Company witness Vander Weide provided in his direct testimony an ROE estimate of 10.3% as being appropriate for the Company, the Company's electric and gas revenue requirements reflect a 9.75% ROE. The Company selected the lower 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 forecasted Rate Year equity ratio of 48.79%. 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. Approximately $5 million of the electric revenue requirement increase and $3 million of the gas revenue requirement increase are attributable to the higher financing costs, including the cost of capital associated with growth in rate base.

Q. Please discuss the next item in the table, “depreciation changes due to proposed rates.”

A. As discussed in the direct testimony of the Depreciation Panel, the Company is proposing to change its depreciation rates. These changes account for $4 million and $2 million of the electric and gas rate increases, respectively.

Q. What effects do projected sales revenues have on the proposed revenue requirements?

A. For electric, net sales revenues are projected to decrease by $6 million, while for gas, net sales revenues are projected to increase by $8 million and the revenue requirements are reflective of these changes in sales.

Q. What are the major elements of operation and maintenance (“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 $5 million of the increase for electric and $10 million for gas. For electric, the most significant O&M increase is due to increases in labor costs, which includes adding new personnel to enhance DER integration and the customer experience. For gas, the most significant O&M increase is due to expanded and enhanced damage prevention and other safety programs. The gas increase is also impacted by the change in common cost allocation discussed below.

Q. What is the impact of the 2018 Tax Act that became effective January 2018 on the Company’s requested rate relief?

A. The Tax Cuts and Jobs Act (the “2018 Tax Act”) has a substantial mitigating impact on the Company’s requested rate relief. As discussed in detail by the Company’s Income Tax Panel, the 2018 Tax Act reduces the statutory federal income tax rate from 35 percent to 21 percent. This change in the tax law is the primary driver behind the reduction in income tax expense in the Rate Year of $13 million for electric and $8 million for gas.

The amortization of excess deferred income taxes resulting from the tax rate reductions and the income tax savings in 2018 as a result of the rate change deferred for the benefit of customers ("Excess FIT for 2018") will result in a net regulatory liability that will be refunded to electric and gas customers. As of December 31, 2017, the Company estimates $10.437 million of Excess FIT for 2018 for electric service and $4.570 million for gas service.

Q. Do any of your exhibits address in further detail the elements of the revenue requirement you have summarized?

A. Yes, Schedule 1 of the AP-3 Exhibits.

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, 2013, 2014, 2015 and 2016 and September 30, 2017.
- Schedules 6 through 10 are income statements and supporting schedules for the twelve months ended December 31, 2014, 2015 and 2016 and September 30, 2017.

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, 2013, 2014, 2015 and 2016 and September 30, 2017.
- Schedule 2 is a statement of retained earnings at December 31, 2013, 2014, 2015 and 2016 and September 30, 2017.
- Schedule 3 shows the net book value of electric or gas plant in service by primary account at December 31, 2013, 2014, 2015 and 2016 and September 30, 2017.
- Schedule 4 shows the net book value of common plant in service at December 31, 2013, 2014, 2015 and 2016 and September 30, 2017.
- Schedule 5 shows electric or gas plant in service and the average cost per customer at

December 31, 2013, 2014, 2015 and 2016 and September 30, 2017.

- Schedule 6 shows income statements for the twelve months ended December 31, 2014, 2015, 2016 and September 30, 2017.
- Schedule 7 is a statement of electric or gas O&M expenses for the twelve months ended December 31, 2014, 2015, 2016 and September 30, 2017.
- Schedule 8 of Exhibit AP-E1 shows electric operating expenses per kWh sold for the twelve months ended December 31, 2014, 2015, 2016 and September 30, 2017. 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, 2014, 2015, 2016 and September 30, 2017.
- 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, 2014, 2015, 2016 and September 30,

2017. 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. The AP-2 Exhibits 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. Please describe the presentation of rate base in the AP-2 Exhibits.

A. The presentation approach is the same for both the electric and gas rate base exhibits. There are a total of six pages in each exhibit. Page 1 summarizes the overall rate base calculation for the Historic Year and Rate Year. Page 2 shows the details of the forecasted net plant and non-interest bearing Construction Work in Process (“CWIP”) calculation, as shown on page 1, lines 1 to 11. Page 3 provides the details of the working capital components, unamortized premium & discount and customer advance construction, as shown on page 1, lines 12 to 14. Page 4 provides the details of the current and projected deferred balance from reconciliation mechanisms, as shown on page 1, line 15. Page 5 shows the details of accumulated deferred federal and state tax balances, as shown on page 1, lines 17 to 18. Page 6 provides a detailed calculation of the Earning Base Capitalization Adjustment amount, as shown on page 1, line 21. For all rate base items, common balances were allocated based on the updated common expense allocation factors detailed in Section IX of this testimony.

A. Rate Base Components

Q. What rate base items are included in the rate base calculation on Exhibit AP-2, page 1?

A. Exhibit AP-2, page 1, shows the overall average rate base calculation for the Historic Year and Rate Year. The rate base components include the net plant, CWIP not subject to the Allowance for Funds Used During Construction (“AFUDC”), working capital, unamortized premium & discount, customer advance construction, net regulatory deferral from reconciliation mechanisms, accumulated deferred income taxes and earning base capitalization adjustment to rate base.

B. Average Net Plant Summary

Q. What rate base items related to net plant investment are included on Exhibit AP-2, page 2?

A. Exhibit AP-2, page 2 includes projected net plant and a portion of CWIP not subject to AFUDC. Net Plant includes utility plant in service, the allocated portion of common utility plant, plant held for future use and accumulated provision for depreciation.

Q. How did you determine the average balance of Net Plant and CWIP not subject to AFUDC?

A. Both are based on capital budget models and the standard thirteen point average methodology used in ratemaking.

C. Detailed Development of Working Capital, Unamortized Premium & Discount, and Customer Advance Construction

1. Working Capital

Q. Please explain the rate base component labeled "Working Capital" on page 1 of the AP-2 exhibits.

A. The detailed elements of working capital rate base are shown on page 3 of the AP-2 exhibits. Working capital rate base contains three categories:

Materials and Supplies, Prepayments and Cash Working Capital.

a. Material and Supplies

Q. How did you determine the average balance of Materials and Supplies rate base on page 3 of the AP-2 exhibits?

A. The Company has taken the same approach used in past Company rate cases. The Rate Year forecast of Materials and Supplies inventory generally represents the Historic Year amount escalated using the general escalation factor. For gas, we excluded from the rate base inventory balances of gas stored underground and Liquefied Natural Gas in storage.

b. Prepayment

Q. What is included in the “Prepayments” category of working capital rate base on page 3 of the AP-2 exhibits?

A. The prepayment component of working capital rate base includes Local Property Taxes, Remarket, Computer License, Insurance, NYPSC Assessment and New York State Gross Receipts Tax.

Q. Please explain how you developed the Rate Year Rate base amount for the Prepayment items?

A. All prepayments except for the prepaid property taxes were projected at the Historic Year amount plus general inflation. Prepaid property taxes, the predominant prepayment item, were forecasted to increase based on the projected level of property tax bills.

c. Cash Working Capital

Q. Please explain the allowance for the cash working capital component of working capital rate base on page 3 of the AP-2 exhibits.

A. We determined the cash working capital component of working capital rate base following well-established Commission practice, which includes applying the 1/8 FERC Working Capital Formula. As such, we performed separate calculations of the rate base amount for electric and gas. For each, we started with projected total O&M expense from Schedule 6 of the AP-3 exhibits and eliminated the expenses listed below to arrive at the level of O&M expense that would be subject to the 1/8 FERC Working Capital Formula.

For electric, we eliminated purchased power and fuel expense, uncollectible reserve, low income, storm allowance, Manufactured Gas Plant (“MGP”)/Superfund Site, R&D, system benefit charge, renewable portfolio charges, Pomona DER program, REV Demo Projects, Energy Efficiency, Monsey and 18A regulatory commission expense.

For gas, we eliminated purchased gas expense, uncollectible reserve, low income, MGP/Superfund Site, R&D, system benefit charge and 18A regulatory commission expense.

For electric, while fuel and purchased power is eliminated from the 1/8 FERC Working Capital Formula, a separate working capital adjustment is made to account for the time lag between when fuel costs are paid to the New York Independent System Operator and other agencies on a weekly basis and when payments are collected from customers. This additional element of the cash working capital allowance adds $10 million to the cash working capital rate base for electric as shown on page 3 of the AP-2 exhibits.

2. Unamortized Premium & Discount and Customer Advance for Construction

Q. Please explain the unamortized premium/discount and expense and customer advance for construction on page 1 of the AP-2 exhibits.

A. The unamortized premium/discount and expense reflects the unamortized balance of debt discounts, premiums and expenses, as additions to rate base. Customer advance for construction represents the amount billed to customers and others for the construction necessary to provide utility service to their premises (rather than for general system service) and represent a reduction to rate base. The Historic Year levels of these items were carried forward to the Rate Year.

D. Net Deferrals/Credits from Reconciliation Mechanism

Q. Are deferral balances net of deferred income taxes?

A. Yes, the deferral balances are net of deferred income taxes.

Q. Please explain each item on AP-2 exhibit, page 4.

A. For detail on lines 1-32 of AP-E2 exhibit, page 4, and lines 1-23 of AP-G2 exhibit, page 4, please refer to Section VII of this testimony.

Line 24 (G), Underground Gas Storage represents the Company’s investment in gas stored underground. The Historic Year levels of underground gas storage were carried forward to the Rate Year.

Line 33 (E)/Line 25 (G), Unbilled Revenues represents the accrual of unmetered revenues that have not been billed to customers. The Historic Year levels of unbilled revenues were carried forward to the Rate Year.

Line 34 (E)/Line 26 (G), Deferred Fuel represents the average over/under collection balance related to such costs. The Historic Year levels of deferred fuel were carried forward to the Rate Year.

Line 35 (E)/Line 27 (G), MTA Surtax represents the average balance of the Metropolitan Transportation Authority (“MTA”) surcharge paid, but not yet collected from customers. The Historic Year levels of MTA Surtax were carried forward to the Rate Year.

Line 36 (E)/Line 28 (G), Merchant Function Charges represents the average over/under collection balance related to such costs. The Historic Year levels of Merchant Function Charges were carried forward to the Rate Year.

E. Detailed Development of Accumulated Deferred Income Taxes

Q. How were Accumulated Deferred Federal Income Taxes on page 5 of the AP-2 exhibits developed?

A. Accumulated Deferred Federal Income Taxes for plant-related items were developed using data from the Company’s capital budget and tax depreciation models. The Company calculates the rate base impact for federal deferred income taxes by using a proration methodology that is required by U.S. Treasury Regulation §1.167(I)-1h(6)(ii). The Internal Revenue Service has determined that any revenue requirement calculation that employs a future test period is subject to the proration requirement. Accordingly, in calculating the deferred taxes associated with the Rate Year, a proration is required that provides a weighted average to the monthly deferred tax activity arising under the Company’s projections. The Company applied this methodology in this case to avoid non-compliance with IRS normalization rules.

Q. How were Accumulated Deferred State Income Taxes on page 5 of the AP-2 exhibits developed?

A. Accumulated Deferred State Income Taxes for plant-related items were developed using data from the Company’s capital budget and tax depreciation models. The forecasted rate year balance is based on 50% of beginning and 50% of ending forecasted balance.

Q. How were Deferred Investment Tax Credits on page 5 of the AP-2 exhibits developed?

A. Deferred Investment Tax Credits are amortized over the average service lives of the property that generated the tax credits. The forecasted rate year balance is based on the historical year balance plus the future forecasted amortization.

F. Rate Base Over/Under Capital Adjustment

Q. Please explain rate base over/under capitalization adjustment on AP-2 Exhibits, page 6.

A. Rate base over/under capitalization adjustment on AP-2 Exhibits, page 6, reflects the required adjustment to rate base to make earnings base equal to capitalization. This EB/Cap Adjustment has been required by the Commission in past proceedings to synchronize rate base plus interest bearing items (together, “Earnings Base”) with the total capitalization employed in utility service. Line 42 on AP-2 Exhibit, page 6, shows the EB/Cap adjustment amount to each electric and gas rate base. The EB/Cap adjustment amount is calculated by taking the total capitalization amount in line 40 less the rate base balance on line 22.

VI. CAPITAL EXPENDITURES AND PLANT ADDITIONS

Q. Please describe the Company’s presentation of its capital expenditure projections and related plant additions, as set forth in the AP-4 Exhibits.

A. Schedule 1 presents the Company’s forecasted electric and gas capital expenditures from the end of the Historic Year through the Rate Year and for later periods. Schedule 2 presents the electric and gas plant additions for those same periods. Supporting testimony is provided by the Company’s EIOP, Other Electric Initiatives Panel and GIOP. Common plant capital expenditures and plant additions are presented on Schedules 3 and 4, respectively. Schedules 3 and 4 are presented on a corporate rather than a commodity basis. The Company’s allocation of costs between gas and electric operations is discussed in Section IX of this testimony.

Q. Has the Accounting Panel prepared and presented in its exhibits projections of any common capital projects?

A. Yes, we have developed projections for the Mainframe Upgrade. The Orange and Rockland mainframe environment runs critical corporate applications. Our information technology department has determined it is operationally necessary to upgrade the mainframe and associated devices through multiple projects between 2018 and 2022. If the Company does not do so, there is potential for performance issues with the Customer Information Management System (“CIMS”), Work Management System (“WMS”), AMI system, and other essential business functions. The upgrades are described in greater detail in a white paper included in the AP-4 exhibits, Schedule 5. The white paper includes a thorough description of the Mainframe Upgrade project, projected costs, and an expanded explanation of the business need for the project.

Other common capital projects proposed by the Company are described by the Customer Service and EH&S Panels.

Q. Are there any other capital projects that the Accounting Panel would like to discuss further?

A. Yes. First, as described more fully by the Customer Service Panel, the Company is working with Con Edison to identify a new Customer Information System ("CIS") to replace CIMS, O&R's current CIS. The companies have hired a consultant to develop a business case that, upon completion, will be shared with Staff for their review and feedback.

Consistent with normal accounting practices, the initial development costs for this capital project will be considered part of CWIP and accrue any appropriate carrying charges. The Company will propose a cost recovery mechanism for the project when filing its business case.

Second, as discussed by the EIOP, the electric revenue requirement presented in this filing does not reflect capital or O&M costs related to the Indian Point contingency projects (Case 12-E-0503) or upgrades to the Sugarloaf-Shoemaker transmission line (Cases 12-T-0502, 13-E-0488, *et al.*). The Company reserves the right to seek the Commission's authorization to recover any such costs by surcharge, by increase in base rates, or by other means, as determined by the Commission.

VII. INCOME STATEMENTS AND RATES OF RETURN

Q. Please describe how the Company's forecasted cost of service was developed.

A. Exhibit AP-3, Schedule 2, Page 1, is a summary of the 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 rate developed for this proceeding. State and Federal 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 2 of the exhibits. The adjusted results for the Historic Year are summarized in column 3.

Column 4 reflects Rate Year adjustments, which include program changes, amortizations, escalation, and other such drivers of variances between the normalized Historic Year and Rate Year. Column 5 reflects the Rate Year absent a rate change and column 6 reflects the rate change. Column 7, which is a summation of columns 5 and 6, shows operating income, average rate base and rate of return for the Rate Year.

Q. Was 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 subdivided into necessary components to forecast the various changes in that cost element. Schedules 3 through 17 of Exhibit AP-E3 and Exhibit AP-G3 support the cost of service components related to sales and revenues, amortization of regulatory deferrals, other operating revenues, O&M expenses, depreciation, taxes other than income taxes, state and federal income taxes and interest synchronization.

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 the projections of sales and delivery revenues. The amounts are shown on Exhibit EFP-1 and Exhibit GFP-1, 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 charges 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 the Monsey Non-Wires Alternative (“NWA”) Project, Pomona Distributed Energy Resources (“DER”) Program, REV Demonstration (“REV Demo”) Projects, Site Investigation and Remediation (“SIR”) costs, and Excess FIT for 2018. For the Monsey NWA Project, Pomona DER Program, and

REV Demo Projects, the Company proposes an amortization period of ten years in order to align cost recovery with customer benefits. The Company proposes an amortization period of five years for SIR costs, consistent with Commission's prior treatment of this deferral.

For the deferral balance related to Excess FIT for 2018, which arose as a result of the 2018 Tax Act, the Company proposes to amortize the balance over the average remaining life of the current plant-in-service for each service. 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. While most of the amortizations for the Rate Year will continue being charged through Regulatory Debits, shown on Schedule 2, Page 2 of Exhibit AP-E3 and Exhibit AP-G3, amortizations related to SIR costs, Energy Efficiency, Monsey, Pomona and REV Demo Projects shown on Schedule 6 will be amortized through O&M. Please note that Schedule 6 shows all amortizations in total and is then adjusted for MGP and other Environmental Sites, Energy Efficiency, Monsey, Pomona, REV Demo Projects, and Excess FIT for 2018 to produce a net amortization charge for the Rate Year of $2.944 million for electric and $2.277 million for gas.

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 of Exhibit AP-E3 and of Exhibit AP-G3, 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 are as follows:

Line 1, 18A Assessment: This item represents the amounts collected from customers relating to the Public Service Law §18-a(6) ("18-a") temporary assessment (Case 09-M-0311), which phased out in

2017 with the last surcharge collection made on December 31, 2017.

Line 2, Customer Portfolio Shared Earnings: This item represents excess earnings that is due to customers from Rate Year 1 of the preceding electric and gas cases (Cases 14-E-0493 and 14-G-0494). This balance will be updated during the course of the proceeding to reflect excess earnings related to Rate Year 2 for both electric and gas.

Line 3, Deferred Tax Liabilities Carrying Charge: This item 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.

Line 4, Environmental Carrying Charge: This item represents interest to refund to customers on environmental spending under-runs in accordance with the environmental expense reconciliation mechanism.

Line 5, Energy Efficiency: This item represents the amounts to collect from customers for Energy Efficiency program costs, which the Company is proposing to amortize over a three-year period as discussed in Section X.C.6 of this testimony.

Line 6, Excess FIT for 2018: This item represents amounts to pass back to customers associated with the federal income tax difference between the level embedded in rates at 35 percent and the new federal tax rate of 21 percent for calendar year 2018 under the 2018 Tax Act. The Company proposes to amortize these amounts over the average remaining life of the assets. This is discussed in more detail in the Income Tax Panel's direct testimony.

Line 7, Interest on Pollution Control Debt: This item 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. This recovery is a result of two additional months of amortization beyond October 31, 2018.

Line 8, Interest Repair Allowance/Bonus Depreciation: This item represents the amounts to recover from 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. This recovery is a result of two additional months of amortization beyond October 31, 2018.

Line 9, Low Income: This item represents amounts to be recovered from customers related to the Company's Low Income Program. The 2018 projected deferral balance reflects an increase in low income program credits pursuant to the New Bill Discount Program effective on January 1, 2018. As detailed by the Company's Gas and Electric Rate Panels and Low Income Panel, the Company is implementing a new rate design effective RY1 to provide Commission authorized credits to customers enrolled in the Low Income Program.

Line 10, Medicare Part D: This item represents the deferral of amounts to be recovered related to estimated Medicare Part D tax benefits. This recovery is a result of two additional months of amortization beyond October 31, 2018.

Lines 11 & 16, MGP and Other Environmental Sites: These items represent amounts to be recovered related to recovery of SIR costs primarily associated with former MGP sites over a five-year period. This item is discussed in more detail in the EH&S Panel's direct testimony.

Line 12, Non-Officer Management Variable Pay: This item reflects amounts to pass back to customers associated with actual variable pay that was lower than the allowance in rates for RY1, pursuant to the reconciliation mechanism contained in the Company's current electric and gas rate plans.

Line 13, NorthStar Management Audit Fees: This item reflects audit fee amounts to collect from customers related to the comprehensive management and operations audit performed by NorthStar Consulting Group that was completed in February 2016.

Line 14, NYSIT Rate Change: This item represents the amounts to refund to customers relating the reduction in the New York State Income Tax rate from 7.1% to 6.5%. Please note that that the projected deferral balance at December 31, 2018 reflects an adjustment for $35,000 that was inadvertently over-amortized for electric and under-amortized for gas for the period of November 2016 - October 2017, while tying to the correct amounts in total for the amortization allowances pursuant to the Company's current electric and gas rate plans.

Line 18, Plant Reconciliation: This item reflects the amount of estimated carrying charges to be passed to customers in accordance with the net plant reconciliation mechanism under the Company's current electric and gas rate plans.

Line 19, Property Tax Refunds: This item reflects the amount to collect from customers related to various property tax refunds secured by the Company. This recovery is a result of two additional months of amortization beyond October 31, 2018.

Line 20, Property Taxes: This item is reflected in Schedule 14 of Exhibit AP-E3 and Exhibit AP-G3, and will be discussed in the Taxes Other Than Income Taxes section of this testimony.

Line 23, Rate Case Incentives: This item reflects the amounts to collect from customers as a result of financial incentives, achieved under the Company's current electric and gas rate plans, related to reductions in residential service terminations (electric/gas) and incentives for replacing leak prone gas pipe (gas). Please note that the Company reflected one hundred percent of the incentives earned in 2017 as a deferral balance to be recovered from customers despite only one third being recorded in the general ledger in 2017. The lag in financial statement recognition is due to the alternative revenue program guidance within Accounting Standards Codification ("ASC") 980, Regulated Operations. The Company's proposal for recovery of future EAMs and positive and negative revenue adjustments is discussed within Section XI of this testimony.

Lines 15, 17, 21, 22 for Pensions/OPEBs, R&D and Rate Case Costs: These items are reflected in Exhibit AP-E3 and Exhibit AP-G3, Schedule 6, and will be discussed in the O&M expense section of our direct testimony.

2. <u>Applicable to Electric Only</u>

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 are as follows:

Line 24, CAIDI Safety Deferral: This item represents amounts to pass-back to customers related to a negative revenue adjustment recorded in December

2015. A significant outage that occurred as a result of equipment failure and the subsequent shutdown of a substation in Middletown, NY, impacted the Customer Average Interruption Duration Index ("CAIDI") performance mechanism.

Line 25, Competitive Unbundling - Customer Information: This item represents amounts to recover from customers related to costs for retail access that were incurred prior to December 2010.

Line 26, Conservation Cost: This item represents costs to recover from customers as a result of the additional amortizations that will continue through December 31, 2018.

Line 27, Interest on Storm Reserve: This item represents the deferral of interest amounts to be passed back to customers in accordance with the Company's major storm cost recovery mechanism.

Line 28, Monsey NWA: This item represents costs to recover from customers associated with the Monsey NWA project. We propose to recover these costs over a 10-year period, as discussed in more detail in Section X.C.4 of this testimony.

Line 29, Plant Reconciliation – 14-E-0493: This item represents costs to recover from customers associated with carrying charges for 2015 annual plant true-up recorded in November 2015, where the Company was allowed to accrue carrying charges on the actual plant expenditures over the target. This item also reflects amortizations approved in the Company's 2014 electric base rate case (Case 14-E-0493).

Line 30, Pomona DER: This item represents costs to recover from customers associated with Pomona DER program costs authorized in the Company's 2014 electric base rate case (Case 14-E-0493). The 2015 Rate Order authorized recovery of these costs over a 10-year period.

Line 31, Reactive Power: This item represents the amounts to pass-back to customers relating to the reactive power demand charge.

Line 32, REV Demo Projects: This item represents costs to recover from customers associated with REV Demo Projects. We propose to recover these costs over a 10-year period, as discussed in more detail in Section X.C.3 of this testimony.

Line 33, Sale of Warwick: This item 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. This pass-back is a result of two additional months of amortization beyond October 31, 2018.

Line 34, Smart Grid: This item represents amounts to collect from customers as a result of two additional months of amortization beyond October 31, 2018.

Line 35, Storm Deferral: This item represents amounts to be recovered from customers under the major storm costs reconciliation mechanism related to Hurricane Irene and Superstorm Sandy.

Line 36, Stray Voltage Savings: This item represents the amount to collect from customers resulting from stray voltage inspection cost savings as a result of two additional months of amortization beyond October 31, 2018.

Line 37, Tree Trimming: This item represents the amounts to pass-back to customers for differences between tree trimming costs provided in rates and actual expense under the tree trimming reconciliation mechanism under the Company's current electric rate plan.

Line 38, Workers Compensation Asbestos: This item represents the amounts to pass-back to customers because the Company's current electric rate plan reflected an allowance that was inadvertently included in the revenue requirement.

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 are as follows:

Line 24, Case 05-G-1594 interest on revenue deferral: This item represents amounts to pass-back to customers due to the over-collection resulting from the additional amortization that will be booked beyond October 31, 2018.

Line 25, Customer Outreach Program: This item represents the amount to collect from customers as the Company will pass back two extra months of the amortization allowance beyond October 31, 2018.

Line 26, Gas Economic Development Enhancement Pilot Program: This item represents amounts to pass back to customers due to the over-collection resulting from the additional amortization that will be booked beyond October 31, 2018.

Line 27, Pension Phase-in: This item represents the deferred amount to be passed back to customers related to pension phase-in allowance provided in the Company's 2014 gas base rate case (Case 14-G-0494). The pass-back is due to the two extra months of the amortization allowance beyond October 31, 2018.

Line 28, Tax on Health Insurance Plans: This item represents the amount to pass back to customers related to the new excise taxes that were scheduled to become effective under the Affordable Care Act in 2018 but were never actualized. This item is discussed in more detail in Section X.A.3 of this testimony.

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

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:

Line 1, AMR/AMI Meter Reading and Change out Fee: This item was forecasted using the projected level of fees to be collected during RY1 through RY3. The Meter Reading fee is assessed to any customer who opts-out of AMI ($10/month for single service; $15/month for dual service) and the Meter Change Out fee is a charge that is assessed to customers who want their AMI meter removed.

Line 2, Customer Reconnect Fees: This item was forecasted using a three-year average.

Line 3, Late Payment Charge ("LPC") Revenues: This item was forecasted by multiplying an LPC factor of 0.58% for electric and 0.37% for gas to the Rate

Year sales revenues. The LPC factor represents the ratio of actual LPCs to actual total electric and gas sales revenues in the Historic Year, respectively.

Line 4 & 5, Pike Corning ESA and TSA: These items relate to revenues that are paid to O&R by Corning Natural Gas Holding Corporation ("Corning") for services provided under the Transition Services Agreement, Gas Supply Agreement, and Electric Supply Agreement as a result of sale of Pike County Light & Power Company to Corning. O&R is not expected to provide any transition services to Corning for Rate Years 1 through 3.

Line 6, POR Discount: This item was forecasted by carrying forward the Historic Year level.

Line 7, Shared Meter Assessment: This item represents fines for improper use of shared metering, which was forecasted using a three-year average.

Line 15 (E) & 11 (G) Joint Use Rents: This item relates to carrying charges billed for facilities such as the Spring Valley Operating and Distribution Centers and the Blooming Grove and Middletown facilities that provide benefits to the Company's subsidiary, Rockland Electric Company ("Rockland Electric" or "RECO"). This item was forecasted by annualizing the current monthly carrying charge level.

Lines 18-24 (E) and Lines 12-21 (G): 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 Gas Volume and Revenue Forecasting Panel included them in their sales revenues forecast or because they are collected from or credited to customers through a separate surcharge.

Lines 25-33 (E) and Lines 22-31 (G): 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.

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-3 are as follows:

Lines 8 & 14 Agency Checks Dishonored and Other: These items were forecasted by carrying forward the Historic Year level.

Line 9, Acceller Inc.: When a new customer or existing customer who is moving calls the Company to start service, the Company asks if they wish to be transferred to Acceller to have their cable and telephone connected. This facilitates the customer's move into or within the service territory. The Company is paid a fee for every customer it transfers to Acceller, regardless of whether the customer connects cable or phone service. These revenues were projected based on the Historic Year level.

Lines 10 & 11, Bad Check Charges and Collection Charges: These items were forecasted using a three-year average.

Line 12, NYSERDA: When homeowners obtain a loan from the New York State Energy Research and Development

Authority ("NYSERDA"), they can repay the loan through their utility bill by using the on-bill recovery financing program. The Company then remits the payments 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 the Historic Year level.

Line 13, Solar Application Fee: This item relates to fees associated with solar installation. This is a state-set fee for applicants who want to install distributed generation or energy storage systems for facilities 50kW or more, which is projected using historic level of revenues.

Line 16, Pole Attachment and Parity Billings: This item pertains to rent collected from cable, Competitive Local Exchange Carriers, private customers and telephone companies for use of Company poles. More specifically, for parity billings a carrying charge is assessed to telephone companies if specific ownership parity ratios are not maintained in accordance with joint use agreements.

The projection was a based on a 1% increase in pole attachment and parity billings from the historic period and any new known contract increases. The forecast also reflects an adjustment to remove parity billings from Frontier Communications ("Frontier") due to sale of poles to Frontier effective 10/22/2015.

Line 17, Other Rents: This item relates to rent received from parties due to their use of electric property owned by the Company such as poles and transformers. These revenues were projected based on the Historic Year level.

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-3 are as follows:

Line 8, Access Fines: This item refers 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.

Line 9, R&D Ventures: This item refers 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 13 of the AP-3 Exhibits regarding depreciation.

A. For Schedule 13 of the AP-3 Exhibits, we have included a monthly depreciation expense summary at the existing depreciation rate and at the proposed depreciation rate for the period October 2017 to December 2021. Depreciation expense at the proposed rate was included in the revenue requirement calculation shown in AP-E3 for electric and AP-G3 for gas. Information in Schedule 13 on depreciation expense at the existing rate is for comparison purposes only.

E. Taxes Other Than Income Taxes

Q. Describe the development of Taxes Other than Income Taxes.

A. Schedule 14 of the AP-3 Exhibits present taxes other than income taxes for the Historic Year and for RY1-RY3. Taxes other than income taxes include Property Taxes, Payroll Taxes, Revenue Taxes, Taxes on Health Insurance, and Other Taxes.

The Property tax forecast is addressed in the direct testimony of the Property Tax Panel. The amortization of property tax deferral amounts identified on Schedule 4 of the AP-3 Exhibits, represent a three-year recovery of the under-collection of property taxes under the reconciliation mechanisms included in the Company's current electric and gas rate plans.

The Payroll taxes were determined by applying the employer payroll tax rate to the forecasted direct labor expense increases.

The Revenue taxes were determined based on the estimated revenue multiplied by the effective tax rates.

The Taxes on Health Insurance are based on thresholds that are subject to change based on future Consumer Price Index changes. The Company's proposal to reconcile Taxes on Health Insurance is further explained in Section X.A.3.

Finally, we have assumed the Historic Year level of other miscellaneous taxes, escalated by the general escalation factor, will be representative of the Rate Year level after normalizing for an adjustment in the other taxes reserve upon completion of a tax audit by New York State.

F. Income Taxes

Q. Please describe how the calculations of State and federal income tax expenses were performed.

A. The computation of State income tax is shown on Schedule 15 of the AP-3 Exhibits. Starting with operating income before income taxes, we then show the various tax adjustments required to determine taxable income, which we multiply by the statutory rate of 6.5% to determine the State income tax. We note the calculations exclude the MTA surcharge rate of 1.53%, which is recovered as part of the current MTA surcharge mechanism.

The computation of federal income tax is shown on Schedule 16 of the AP-3 Exhibits. Starting with operating income before income taxes, we then show the various tax adjustments required to determine federal taxable income, which we multiply by the statutory rate of 21% to determine the current federal income tax. We then show the calculation of deferred federal income tax and the amortization of the deferred excess federal income tax to arrive at the total federal income tax expense.

G. Interest Synchronization

Q. Please explain Schedule 17 of the AP-3 Exhibits.

A. Schedule 17 shows the calculation of the interest deduction included in Schedules 15 and 16 of those exhibits. The majority of long-term debt has been issued by Orange and Rockland for itself and its subsidiary utility, Rockland Electric. This "synchronization" adjustment is necessary in order to allocate the proper level of interest expense to each company. The adjustment has been calculated in the same manner as has been employed in previous O&R rate cases.

VIII. <u>OPERATION AND MAINTENANCE EXPENSES</u>

Q. Please explain the development of O&M Expenses shown on Schedule 6 of the AP-3 exhibits.

A. Schedule 6 shows the derivation of the projected expenses in the Rate Years 1, 2 and 3 from the Historic Year expense. Various Company witnesses, including the Accounting Panel, explain any adjustments.

Q. Please summarize the projected net changes to the level of O&M expenses during the Historic Year to the Rate Year.

A. For electric, the Historic Year level, after adjusting for the proposed change in the common allocation factor, of $302.6 million is forecasted to increase by $7.0 million for a Rate Year level of $309.6 million.

For gas, the Historic Year level, after adjusting for the proposed change in the common allocation factor, of $137.9 million is forecasted to decrease by $2.9 million for a Rate Year level of $135.0 million.

The line items included in these totals, and their corresponding figures, are detailed on AP-3 Schedule 6.

Please note that these figures represent overall electric and gas O&M expenses, which include fuel and purchase power and other types of reconciled costs that do not impact the revenue requirement.

A. Development of O&M

Q. How were O&M costs developed for the Rate Year?

A. The Company began with Historic Year O&M costs and updated them to reflect the Company's new allocation ratios discussed in Section IX of this testimony. The updated O&M figures are shown in Schedule 6 of the AP-3 exhibits of both services.

Next, the Company made adjustments to bring the costs forward to the Rate Year. Adjustments made to expense levels were due to normalizations (Schedule 8), program changes (Schedule 9), general escalation (Schedule 20), and labor escalation. The Company's approach to each adjustment is described below.

1. General Escalation

Q. Please describe how you escalated costs due to inflation.

A. The general escalation rate is applied to costs anticipated to increase at the rate of inflation as measured by the Gross Domestic Product ("GDP") price deflator. For certain expenses, the escalation factor is specifically tailored to the particular expense item, such as medical insurance costs addressed by the Company's Compensation and Benefits Panel, and is presented as a program change.

Additional detail on generally escalated costs is included in Schedule 20 of the AP-3 exhibits.

Q. Please describe how the general escalation rate was applied in developing projected revenue requirements.

A. The actual GDP deflator, used to escalate various non-labor elements of the cost of service, as addressed throughout our direct testimony and the direct testimony of other witnesses, was published as of October 2017 by the U.S. Bureau of Economic Analysis. The quarterly forecasts for 2017 and 2018 are from the Blue Chip Economic Indicators dated October 2017. The annual forecast for 2019 and forward is from the Blue Chip Economic Indicators dated October 2017. Using these forecasts, the projected cumulative effect of inflation from the Historic Year to the Rate Year is 4.45 percent.

2. Labor Escalation

Q. Please describe the labor cost escalation factors used in your projections.

A. Labor cost escalation factors are applied to labor-related elements of expense. Labor escalation is reflected on Exhibit AP-3, Schedule 6.

With respect to employees of the Company’s bargaining unit, Local 503 of the International Brotherhood of Electrical Workers (“Local 503”), labor cost escalation was projected based on the terms of the collective bargaining agreement in effect. On February 22, 2017, the Company and Local 503 reached a new collective bargaining agreement. The agreement will be in effect until May 31, 2019. The agreement provided, among other things, for the following general wage increases: 3% on June 1, 2017 and 3% on June 1, 2018. 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 October 2016 through December 2016; 2.75% from January 2017 through May 2017; 3.00% from June 2017 through December 2018; and 2.00% for January 2019 through December 2021. The labor costs for employees paid monthly, including escalation applicable to the normalizing adjustments and program changes explained earlier, were calculated by first applying a salary increase of 3.00% per year effective October 2016 through December 2018 and 2.00% for January 2019 through December 2021. 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.

Q. Expand further on the one percent productivity adjustment.

A. As noted above, the Company's labor escalation rates for the Rate Year are reflective of 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.

3. Normalization

Q. Please describe the normalization of O&M costs for the Rate Year.

A. The Company eliminated from the elements of expense ("EOEs") those amounts that are nonrecurring, out of period, or for which the Company has decided to not seek recovery in this proceeding. The Company also annualized amounts that were not fully recognized in the Historic Year in order to develop Rate Year costs. Additional detail on normalized costs is found in Schedules 6 and 8 of the AP-3 exhibits.

4. Program Changes

Q. Please describe how O&M costs were adjusted due to program changes.

A. The Company adjusted O&M costs based on documented, planned program changes. These program changes are driven by the business needs of the Company. Estimated costs associated with these programs and additional detail regarding these costs are included in Schedule 9 of the AP-3 exhibits.

5. Line Item Descriptions

Below are detailed descriptions of each type of expense and a designation to which commodity(ies) it applies (E- Electric, G- Gas). For the Historic Year amount, any adjustments, and the Rate Year forecast for each line item, please see Schedules 6, 7, 8, and 9.

Line 1, Fuel and Purchased Power: (E, G) This item tracks projected fuel and purchased power costs. The Rate Year forecast includes program changes and normalizations discussed in detail in the direct testimony of the Electric and Gas Volume and Revenue Forecasting Panels.

Line 2, A&G Health Ins. And Capital Overhead: (E, G) _This line represents the capitalized portion of A&G overhead costs applicable to construction activities, including general office salaries and expenses, and health insurance premiums. The Historic Year expense is escalated by the labor escalation factor to arrive at the Rate Year level.

Line 3, Bond Administration & Bank Fees: (E, G) This item includes bank fees, revolving credit fees, line of credit fees, and credit rating agencies fees. The Historic Year expense is escalated by the general escalation factor to arrive at the Rate Year level.

Line 4, Company Labor - Corporate and Shared Services: (E, G) This item reflects labor charges related to the various corporate and shared services departments. The total Rate Year forecast includes a program change for electric related to two Corporate Communications Transmission Network Operations and Support employees and one Information Technology Planning employee who will be hired as of the beginning of the Rate Year. The annual cost for these positions will be allocated 93 percent to Con Edison and 7 percent to O&R. The program changes are discussed in detail in the direct testimony of the EIOP. Additionally, a summary of all labor-related normalizations and program changes is included in Schedule 22 of Exhibit AP-3. We escalated the Historic Year expense, the normalizations and program changes discussed above by the labor escalation factor to arrive at the Rate Year amount.

Line 5, Company Labor - Customer Operations: (E, G) This item reflects labor charges related to the Company's Customer Operations departments. The total electric Rate Year forecast reflects a program change of one additional employee under the expanded energy efficiency program to be hired in June 2019. This program change is discussed in detail in the direct testimony of the Energy Efficiency Panel. Program changes for both electric and gas also reflect the addition of one additional New Business Services Engineer and six Technical Programmers to the Customer Systems department. The annual cost for the Technical Programmer positions will be allocated 93 percent to Con Edison and 7 percent to O&R. The program changes are discussed in detail in the direct testimony of the Customer Service Panel. Finally, program changes for both electric and gas reflect a reduction of 12 positions, primarily meter readers, in connection with efficiencies associated with the Company's AMI program effective as of the beginning of the Rate Year. This program change is also discussed in the direct testimony of the Customer Service Panel. We escalated the Historic

Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 6, Company Labor - Electric/Gas Operations: (E, G) This item reflects labor charges related to the Company's Electric and Gas Operations departments. The electric and gas Rate Year forecast includes a normalization to adjust for a net increase of 28 employees (22 management, 6 union) during the Historic Year whose annualized salaries were not fully captured within the Historic Year. The electric program change includes four additional Equipment Technicians to perform installation, maintenance and testing of electric field devices, one additional Firewall Administrator, and one additional Smart Grid Operating Supervisor, all of whom would be employed as of the beginning of the Rate Year and are discussed in further detail in the direct testimony of the Other Electric Initiatives Panel. The electric program change also includes one additional DER Integration Financial Analyst to be hired as of the beginning of the Rate Year, as discussed in the direct testimony of the EIOP. The gas program change includes two additional Gas Troubleshooters and the hiring of one Training Specialist effective at the beginning of the Rate Year. These changes are discussed in detail in the direct testimony of the GIOP. We escalated the Historic Year expense and any program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 7, Company Labor - Engineering: (E, G) This item relates to labor charges related to the Company’s Engineering department. The total electric Rate Year forecast reflects a program change including one additional Underground Engineer and one distribution SCADA Engineer effective as of the beginning of the Rate Year. These program changes are discussed in detail in the direct testimony of the Other Electric Initiatives Panel and EIOP, respectively. There is no program change for gas. We escalated the Historic Year expense and any program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 8, Company Labor - Substation Operations: (E only) This item relates to labor charges related to the Company’s Substation Operations departments.

The total electric Rate Year forecast reflects a program change including two additional Substation Operations employees within the relay group effective as of the beginning of the Rate Year. This change is discussed in detail in the direct testimony of the Other Electric Initiatives Panel. We escalated the Historic Year expense and any program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 9, Customer Billing Postage: (E, G) This item reflects the costs of mailing monthly bills to customers. The Historic Year expense is escalated by the general escalation factor to arrive at the Rate Year amount.

Line 10, Employee Welfare Expense: (E, G) this item relates to the Company's costs related to a number of employee benefits including, but not limited to, medical, dental, prescription drug, vision coverage, tuition reimbursement and the Company match for the Thrift Savings Plan. The amounts are net of credits such as employee contributions and capitalized amounts. The rate year normalization is related to one time credits received from the Company's insurance carriers during the Historic Year. The Rate Year forecast includes program changes to reflect projected costs for the Rate Year. The Compensation and Benefits Panel provides additional detail regarding the factors contributing to the amount of the program change.

Line 11, Executive Variable Pay: (E, G) The Rate Year forecast is normalized to eliminate the cost of the executive variable pay plan. The Company is not seeking to recover these costs through rates in this proceeding, but this should not be interpreted as the Company waiving its rights to seek the recovery of such costs in future rate proceedings.

Line 12, Facilities: (E, G) This item reflects non-labor charges related to the Company’s Facilities and Field Services departments, such as building maintenance and janitorial services. We then escalate the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 13, Information Technology: (E, G) This item reflects non-labor charges related to the Company’s Information Technology departments, such as technology support, software maintenance and application services as well as mainframe computers in general. The total Rate Year forecast for electric includes program changes related to Oracle OMS product maintenance discussed in detail in the direct testimony of the Other Electric Initiatives Panel. We then escalate the Historic Year expense and any program changes by the general escalation factor to arrive at the Rate Year amount.

Line 14, Informational Advertising: (E, G) This item relates to informational advertising directed to customers. The Historic Year expense is escalated by the general escalation factor to arrive at the Rate Year amount.

Line 15, Injuries & Damages/ Workers Compensation: (E, G) This item reflects the costs of Injuries & Damages/ Workers Compensation expenses. For electric, the Company made a normalization related to deferred charges for asbestos workers compensation reflecting reconciliation to a rate target. The Rate Year forecast includes program changes to reflect projected costs for the Rate Year, which are primarily derived from projected claims net of recoveries. We escalated the Historic

Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 16, Institutional Dues & Subscription: (E, G) This item includes membership fees paid to the American Gas Association, Edison Electric Institute, and other association dues and membership fees. We escalate the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 17, Insurance Premium: (E, G,) This item includes insurance premiums the Company incurs for items such as property insurance and workers compensation insurance. The Rate Year forecast includes program changes to reflect projected costs for the Rate Year. We then escalate the Historic Year expense and the program change by the general escalation factor to arrive at the Rate Year amount.

Line 18, Intercompany Shared Services: (E, G) This item reflects intercompany billing between the Company, CEI and Con Edison. We escalate the Historic Year expense by the general escalation factor to arrive at the Rate Year amount. O&R is billed a share of the total costs of CEI and 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.

Line 19, Legal and Other Professional Services (E, G) This item includes the cost of outside legal counsel and consultants. The program changes are calculated by taking the three-year average of expenses from 12-month periods ended September 2015 to 2017. We then escalate the Historic Year expense and the program change by the general escalation factor to arrive at the Rate Year amount.

Line 20, Load Dispatching: (E) This item represents the costs incurred in load dispatching activities for system control. The Historic Year expense is escalated by the general escalation factor to arrive at the Rate Year estimate.

Line 21, Low Income: (E, G) This item relates to the credits given to customers enrolled in the Company's Low Income Program. A normalizing adjustment has been made to remove all such credits from O&M. As detailed by the Company's Gas and Electric Rate Panels and Low Income Panel, the Company is implementing a new rate design to provide Commission authorized credits to customers enrolled in the Low Income Program.

Line 22, Ops - Corporate and Shared Services: (E, G) This item relates to the non-labor charges of the Company's Corporate and Shared Services departments. The total Rate Year forecast includes program changes that are discussed in detail in the direct testimony of the EH&S Panel, which include a Motor Vehicle Collision Reduction Program and measures to make security enhancements that are applicable to both electric and gas, as well as a Spill Response Staffing Supplementation Program and a Contaminated Site Reference Document Collection and Maintenance Program, which are applicable to electric. Additionally, the GIOP details a program change addressing training facility needs for gas. Further, an adjustment is made to normalize an out of period write-off adjustment related to CWIP and OWIP. We escalate the Historic Year expense, the normalization and program changes discussed above by the general escalation factor to arrive at the Rate Year amount.

Line 23, Ops - Customer Operations: (E, G) This item relates to the non-labor charges of the Company’s Customer Operations departments. The Rate Year forecast includes program changes discussed in the direct testimony of the Customer Service Panel, which include an Enterprise Data Analytics Platform, Green Button Connect, No-Fee Debit/Credit Card Transactions, AMI Customer Engagement, and the Customer Engagement Marketplace Platform, all of which are applicable to both electric and gas. Further, a normalization adjustment is made to annualize the Historic Year expense for the Company’s Digital Customer Experience program. We then escalate the Historic Year expense, normalizing adjustment and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 24, Ops - Electric/Gas Operations: (E/G) This item relates to non-labor charges related to the Company’s Electric and Gas Operations departments. The Rate Year forecast for electric includes program changes discussed in the Other Electric Initiatives

Panel, including an Ash Tree Mitigation Program, Tipping Point software costs, and NERC compliance consultant costs. The electric forecast also includes a program change for costs associated with the Company's Electric Vehicle Program, which is addressed in the testimony of the EIOP. The Rate Year forecast for gas includes program changes discussed in detail in the direct testimony of the GIOP, including the three elements of the Company's Damage Prevention Plan, the Service Line Definition Inspections Program, and the Residential Methane Detector Program. We then escalate the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 25, Ops - Engineering: (E, G,) This item relates to non-labor charges related to the Company's Engineering departments. The Rate Year forecast includes program changes for electric related to maintenance costs for the Interconnection Online Application Portal, which are discussed in the direct testimony of the EIOP. The Rate Year forecast includes program changes for gas related to the Work Procedure Review Program, Pipeline

Integrity/Risk Consulting services, and NRG Mapping enhancements, all of which are discussed in the direct testimony of the GIOP. We then escalate the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 26, Ops - Substation Operations: (E, G) This item relates to non-labor charges related to the Company’s Substation Operations departments. We escalate the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 27, Other Compensation: (E, G) This line includes expenses related to officer and non-officer long-term equity grants, which are made up of time based and performance based restricted stock. As discussed in the Compensation and Benefits Panel’s direct testimony, the Company is seeking to recover non-officer long-term equity grants. The normalization adjustment eliminates the cost of the officer long-term equity grants. The Company is not seeking to recover these eliminated costs through rates in this proceeding, but is not waiving any of its rights to seek the recovery of such costs in future rate proceedings. The Rate Year forecast includes program changes to reflect projected costs for the Rate Year. The projection is based on the stock price of $80.82 and the number of outstanding shares of 5,941 at June 30, 2017.

Line 28, Pension and OPEB Costs: (E, G) This line reflects the actuarially determined level of expenses for employee pensions and OPEBs, which was based on two studies performed by the Company’s actuary, Conduent Human Resource Services, each dated May 26, 2017, for pensions and OPEBs, respectively. The studies incorporate the Company’s actual historical experience supplemented by assumptions of future activity. Assumptions used in the forecast of pensions include a discount rate of 4.25 percent and an expected return on plan assets of 7.50 percent. OPEB projections were based on a discount rate of 4.20 percent and an expected return on plan assets of 5.70 percent for the Management Retiree Health VEBA, 6.20 percent for the Management Retiree Life Insurance VEBA and 6.70 percent for the Weekly Retiree Health and Life VEBA, projecting from January 1, 2017.

Q. Please summarize the estimate of the Rate Year employee pensions/OPEBs expense.

A. The net amount of the actuarially determined level of expense for employee pensions/OPEBs and other payments, after adjusting for the new common allocation factor and normalizing for deferred charges recorded to reconcile to Historic Year targets, is $23.5 million ($15.7 million allocable to electric and $7.8 million allocable to gas). The Rate Year forecast includes program changes to reflect projected costs for the Rate Year. The Rate Year estimated cost is $28.5 million ($19.1 million allocable to electric and $9.4 million allocable to gas). This increase in accounting cost is due to several factors, two of which are described in further detail. For one, the projection reflects the adoption of new pension and OPEB accounting guidance issued by the Financial Accounting Standards Board ("FASB") effective in 2018 and adopted by the Commission in Case 17-M-0363. The new guidance prohibits the Company from capitalizing the non-service cost portion of pension/OPEB expenses. As a result, during the Rate Year, the

Company is only able to capitalize approximately 60% of the costs it otherwise would have been able to under previous FASB guidance. (The Company notes that the fringe rate applied to capital labor projections is also reflective of this change in guidance). Additionally, for Management OPEBs, costs for the past several years, including the Historic Year, have been offset by the amortization of prior service cost credits as a result of cost-saving changes to Management retiree health and life insurance benefits implemented in 2012. Those credits become fully amortized prior to the start of the Rate Year, which in turn increases the Rate Year expense.

Q. Does this line item include Supplemental Retirement Income Plan (“SRIP”) costs?

A. Yes. Officer and non-officer SRIP costs are included in this line item, as they relate to the Company’s long-term performance based compensation for management employees. The Company’s Compensation and Benefits Panel addresses the reasonableness of this aspect of the Company’s compensation scheme.

Line 29, RCA - Amort. of Energy Efficiency: (E) This topic is further addressed in Section VII.B of our direct testimony.

Line 30, RCA - Amort. of Monsey: (E) This topic is further addressed in Section VII.B of our direct testimony.

Line 31, RCA - Amort. of MGP/Superfund: (E, G) This topic is further addressed in Section VII.B of our direct testimony.

Line 32, RCA- Amort. of REV Demo: (E) This topic is further addressed in Section VII.B of our direct testimony.

Line 33, RCA- Amort. of Pomona DER Program (E): This topic is further addressed in Section VII.B of our direct testimony.

Line 34, Regulatory Commission Expense- 18A: (E, G) The Rate Year forecast is normalized to remove the 18-a Surcharge Assessment during the Historic Year. The 18-a Surcharge Assessment was discontinued effective January 1, 2018.

Line 35, Regulatory Commission Expense- All Other: (E, G) This item includes costs to manage regulatory proceedings. We normalize this cost for the Rate Year.

Line 36, Regulatory Commission Expense- General and R&D: (E, G) The program change is forecasted based on the latest NYPSC Assessment letter dated August 2017, excluding refunds, for the 2017-2018 State fiscal year ending March 31, 2018. The Company will update this element of expense based on any additional NYPSC Assessment letters received during these proceedings. We then escalate the Historic Year expense and the program change by the general escalation factors to arrive at the Rate Year amount.

Line 37, Renewable Portfolio Charges: (E) This program change matches expenses that are collected as a separate surcharge through the Energy Cost Adjustment ("ECA") with the related ECA revenues to avoid a revenue requirement effect. The projected Rate Year expenses for this line and line 41, System Benefit Charge, decreased as a result of the Company's proposal to recover energy efficiency program expenses through base rates rather than the ECA surcharge. The energy efficiency program and related cost recovery is discussed further in Section X.C.6 of this testimony.

Line 38, Rent: (E, G) This item represents general rents paid to lease various properties or land on which the Company operates. The Historic Year expense is escalated by the general escalation factor to arrive at the Rate Year estimate.

Line 39 Research & Development: (E, G) This item relates to non-labor charges related to the Company's R&D department. We escalate the Historic Year expense, after normalizing for deferred charges recorded to reconcile to Historic Year targets, by the general escalation factor to arrive at the Rate Year amount.

Line 40, Storm Allowance: (E) This item represents storm related costs. The Company projected the costs to be at the level that is currently allowed in Case 14-E-0493. The program change reflects the adjustment to bring the Historic Year level to the level currently allowed. We then escalate the Historic Year expense and the program change by the general escalation factor to arrive at the Rate Year amount.

Line 41, System Benefit Charge: (E, G) This program change matches energy efficiency expenses that are collected as a separate surcharge through the ECA/monthly gas adjustment ("MGA") with the related ECA/MGA revenues to avoid a revenue requirement effect. The projected Rate Year expenses for this line and line 37, Renewable Portfolio Charges, decreased as a result of the Company's proposal to recover energy efficiency program expenses through base rates rather than the ECA/MGA surcharge. The energy efficiency program and related cost recovery is discussed further in Section X.C.6 of this testimony.

Line 42, Uncollectible Reserve - Customer: (E, G) This item represents a provision and write-off of customer accounts receivables that are not expected to be recovered by the Company. The Company's uncollectible factor, *i.e.*, write-offs as a percent of revenues, for electric and gas equates to $0.42/$100 for the Historic Year, which we then applied to Rate Year levels of sales revenues for both electric and gas.

Line 43, Uncollectible Reserve - Sundry: (E, G) This item represents a provision and write-off of miscellaneous accounts receivables which are not expected to be received by the Company. The Rate Year amount includes program changes to reflect a twelve-month annualized average for the period December 2016 through November 2017.

Line 44, Worker's Comp NYS Assessment: (E, G) This item represents fees levied against employers by the New York State Workers' Compensation Board. The fees consist of a single assessment, which covers the board's various administrative and operational expenses related to administering the law, as well as a 50-5 assessment (for self-insured employers such as the Company). The Rate Year forecast includes program changes to reflect projected costs for the Rate Year. We then escalate the Historic Year expense and the program change by the general escalation factor to arrive at the Rate Year amount.

Line 45, All Other: (E, G) This line item includes miscellaneous and general expenses that did not fit into other categories of expense discussed above.

The Historic Year expense is projected to be the Rate Year amount.

Line 46, Company Labor – Fringe Benefit Adjustment: This adjustment represents the net increase in employee welfare expenses and workers' compensation due to labor-related normalizations and the change in projected labor costs through program changes as sponsored by various Company witnesses. We escalated the adjustment by the general escalation factor to arrive at the Rate Year amount.

IX. 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 subsidiary is 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 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 both utilities, costs are allocated through the use of common expense clearing accounts and allocations.

Q. Is the Company proposing to update its common expense allocation factors in these proceedings?

A. Yes, as required by the 2015 Rate Order, the Company has evaluated the proper allocation of common expenses and common plant in these proceedings and proposes to update its allocation factors. The following table shows the currently effective allocation factors, those the Company proposes be adopted and the related amount of Historic Year expense associated with the changes.

Table 2

	Current Allocation			Proposed Allocation		
	O&R - E	O&R - G	RECO	O&R - E	O&R - G	RECO
All Companies - E&G (A0 Split)	57.63%	23.83%	18.54%	56.88%	24.59%	18.54%
O&R E&G (C0 Split)	70.75%	29.25%		66.93%	33.07%	
Historic Year O&M Impact of Change (000's)				($3,828)	$3,828	

Q. Please explain how the proposed allocation factors were calculated.

A. The proposed allocation factors were based on a four-part formula consisting of number of customers, net revenues, O&M expenses, and net plant balances for the twelve months ended December 31, 2016. The percentage of each service’s amounts compared to the total amount was then calculated to result in the new proposed allocation factor of 66.93 percent to electric and 33.07 percent to gas.

Q. How have the proposed allocation factors been incorporated into the presentation of the Historic Year expense?

A. The Company first downloaded the Historic Year general ledger detail and mapped the general ledger detail into O&M EOEs. The EOEs were then further broken out among electric and gas services. The Company next isolated the amounts that were the result of common expenses being allocated across electric and gas service from those that were directly charged to services. We then reallocated the allocated amounts to electric and gas services using the proposed allocation factors. The ‘new’ allocated amounts were added to the directly charged amounts for each service to arrive at the updated Historic Year expenses by EOE. This amount is shown in Exhibit AP-3, Schedule 6, under the column “Revised 12 Months Ended September 30, 2017 After Common Allocation % Change”.

Q. How did you allocate common expenses between electric and gas services if they applied to RECO as well as O&R?

A. Historically, the common expense split between O&R and RECO has been 81.46 percent allocated to O&R and 18.54 percent allocated to RECO. The current filing maintains the same allocation between O&R and RECO, but updates the common allocation split within O&R to reflect the allocation factor between electric and gas discussed above. The resultant allocation is indicated in the A0 Split row of Table 2 above.

Q. Do the new allocations affect the Company's depreciation expense?

A. Yes, the new allocations are applied to total depreciation of common plant, resulting in a shift in depreciation expenses from electric to gas.

Q. Do the new allocations affect the Company's deferred tax balances?

A. Yes, the new allocations are applied to the deferred tax balances of common plant, resulting in a shift in accumulated deferred taxes from electric to gas.

X. RECONCILIATIONS AND DEFERRED ACCOUNTING

A. Continuing Deferral or Reconciliation Mechanisms

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 Market Supply Charge, ECA, Gas Supply Charge and MGA, reserve accounting for major storm costs, reconciliation mechanisms for pensions and OPEBs, the Pomona DER program, SIR costs, low-income program costs, property taxes and costs related to legislative, regulatory and related actions. The Company also proposes to continue the reconciliation mechanisms for net plant and tree trimming costs, which are downward-only reconciliation mechanisms in favor of customers.

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 Post-retirement 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." The supply rider mechanisms similarly protect the Company and customers from volatility. Other reconciliation mechanisms, such as those related to the SBC and low-income program benefits, 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.

1. Major Storm Reserve (Electric)

Q. Are you proposing to update the target, or base rate allowance level, for the major storm cost reserve applicable to electric operations?

A. Yes. The RY1 amount shown in Exhibit AP-E3, Schedule 6, Line 40, reflects the target applicable in RY2 of the current rate case, adjusted for the effect of general inflation over the linking period.

Q. Are there additional clarifications associated with major storm reserve accounting that should be addressed in this proceeding?

A. Yes. As further addressed in EIOP testimony, the rate order issued in this proceeding should confirm that the Company may charge to the major storm reserve costs above $100,000 per storm incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a "major storm," but which ultimately does not do so.

2. Property Taxes (Electric and Gas)

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. In Cases 14-E-0493 and 14-G-0494, the Commission approved a full and symmetrical property tax reconciliation mechanism for gas and electric. For electric, the mechanism expired after two rates years. For gas, the mechanism is still in effect. The Company proposes that the mechanism continue for gas and be re-established for electric.

Q. Why does the Company believe that a full and symmetrical property tax reconciliation mechanism is appropriate?

A. The Company's Property Tax Panel explains at length why property taxes are not subject to reasonable estimation. Absent a full and symmetrical reconciliation mechanism, these circumstances result in the potential for a significant windfall for either customers or the Company at the expense of the other. There should be no such opportunity. In addition, 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.

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. 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. 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 these concerns in past cases. For example, 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.

3. Taxes on Health Insurance (Electric and Gas)

Q. Please describe the Company’s current reconciliation mechanism for Taxes on Health Insurance.

A. When the Company’s prior rate plans were established, new excise taxes were scheduled to become effective under the Affordable Care Act in 2018. Because the settlement in Cases 14-E-0493 and 14-G-0494 contemplated a two-year rate plan for electric and a three-year rate plan for gas, only the RY3 gas revenue requirement included expected excise taxes under the Act. As the amounts were indefinite, the gas rate plan included a reconciliation whereby actual excise taxes incurred were reconciled with the amounts allowed in rates.

Q. Does the Company propose to continue the reconciliation?

A. Yes. The Company proposes to continue the current gas reconciliation and establish a comparable one for electric service. As discussed in the direct testimony of the Compensation and Benefits Panel, the excise tax is now scheduled to become effective in 2020. The excise tax is based on thresholds that are subject to change based on future Consumer Price Index changes. Due to the uncertainty in the threshold amounts, there could be considerable variation from the actual taxes incurred and the level forecasted in rates. Moreover, there continue to be attempts to overturn provisions of the Act through legislative or judicial action. As a result, it is possible the excise tax will not become effective at all. Given such ambiguity, a reconciliation mechanism is appropriate for both gas and electric service to protect the interests of both the Company and customers.

B. Terminated Deferrals or Reconciliation Mechanisms

Q. Which deferral or reconciliation mechanisms that are currently in effect does the Company propose be terminated?

A. The Company proposes that three deferral or reconciliation mechanisms that are currently in effect be terminated.

1. SIR – Rate Base Reconciliation (Electric and Gas)

Q. Please describe the Company's rate base reconciliation mechanism related to SIR.

A. Under its current rate plan, to the extent the Company's deferred SIR cost balances (net of accruals, recoveries, and other offsets) vary from the level reflected in rate base during each Rate Year, the Company accrues a carrying cost at the pre-tax rate of return.

Q. Is the Company proposing to continue such a mechanism in this filing?

A. No. The Company is proposing to eliminate the reconciliation. To the Company's best knowledge, this is an atypical provision for utility rate plans.

2. Deferred Income Taxes – Rate Base Reconciliation (Electric and Gas)

Q. Please describe the Company's rate base reconciliation mechanism related to Deferred Income Taxes.

A. Under its current rate plan, to the extent the Company's accumulated deferred FIT balances for ACRS/MACRS/ADR or the Repair Allowance vary from the level reflected in rate base during each Rate Year, the Company accrues a carrying cost at the pre-tax rate of return.

Q. Is the Company proposing to continue such a mechanism in this filing?

A. No. The Company is proposing to eliminate the reconciliation. To the Company's best knowledge, this is an atypical provision for utility rate plans.

3. Reliability Surcharge Mechanism (Gas)

Q. Does the Company currently have a surcharge mechanism in place to allow it to recover any costs associated with main replacement above the targets established under its current Gas Rate Plan?

A. Yes. Under the current Gas Rate Plan, the Company established a Reliability Surcharge Mechanism

("RSM") to recover the carrying costs associated with incremental capital expenditures for leak prone pipe replacement not provided for in base rates (*i.e.*, when both the mileage replaced and the associated cost of replacement exceed the amounts provided for in base rates in aggregate over the term of the Gas Rate Plan).

Q. Is the Company proposing to continue such a mechanism in this filing?

A. No. The Company is proposing to eliminate the RSM. The RSM requires the Company to manually adjust its accounting records to reconcile the incremental capital expenditures associated with the replacement of leak prone pipe above the established levels. The Company has determined there is a high likelihood that the costs of manually tracking and reconciling these costs would outweigh any potential recovery opportunities under the RSM.

C. New Deferral or Reconciliation Mechanisms

Q. Does the Company propose to establish any new deferral or reconciliation mechanisms?

A. Yes. The Company proposes number of new deferrals or reconciliations, each of which is detailed below.

1. <u>AMI Capital Expenditures (Electric and Gas)</u>

Q. Has the Company included any costs associated with AMI implementation in the electric and gas revenue requirements in this rate filing?

A. Yes. The electric and gas revenue requirements reflect the Average AMI Plant In Service Balances (excluding removal costs). Consistent with the Commission's November 16, 2017 Order in Case 17-M-0178, the Company tracks electric and gas AMI capital expenditures separately from other capital expenditures. The Company proposes in this proceeding that net plant reconciliation for AMI capital expenditures be implemented for a single category of AMI capital expenditures that includes amounts allocated to both electric and gas customers. As such, any regulatory asset/liability at the end of the electric or gas rate plan will not result in a debit/credit for disposition to the Company or customers because it may reverse over the remaining AMI project implementation. Any credit due electric or gas customers or debit due to the Company will be determined upon project completion, after computing net plant associated with actual aggregate expenditures for both electric and gas net plant. If at the completion of the project the actual net plant amount for a service is above the net plant target for that service, the Company will be able to defer carrying charges associated with the net plant overage for that service to the extent the capital expenditures associated with the AMI deployment do not exceed the overall project capital cap of $98.5 million.

2. Credit Card Payment of Utility Bills (Electric and Gas)

Q. Please explain the Company's proposal related to fees associated with customer usage of credit and debit cards for payment of utility bills.

A. As described in the Customer Service Panel's direct testimony, the Company is proposing to include in base rates the estimated fees associated with customers making credit card and debit card payments. This will eliminate the per-transaction cost to our customers and the Company will incur the aggregate cost of processing such payments for recovery from customers.

Q. Please explain why the Commission should authorize a reconciliation mechanism associated with customer credit and debit card usage fees.

A. The Company is unable to estimate the number of customers who would switch from their current method of payment and use a credit or debit card if the current credit and debit card fee is eliminated. As a result, the Company is not yet in a position to reasonably forecast the level of credit and debit card fees to be incurred.

Q. How does the Company propose to reconcile any under- or over-recoveries of credit and debit card fees?

A. The Company proposes to defer actual costs above or below the annual target reflected in rates for future recovery from or credit to customers, as applicable.

3. <u>REV Demonstration Projects (Electric)</u>

Q. Has the Company included any costs associated with the REV Demo Projects in the proposed electric revenue requirement?

A. Yes. The Company’s base rates reflect the recovery of the costs to be incurred of approximately $3.2 million in addition to recovery of previously unrecovered costs, estimated to be approximately $4.1 million at the conclusion of the linking period. The Company has amortized the cost of the REV Demo Projects over a ten-year period. The annual cost recovery in base rates ranges from $0.6 to $0.7 million per year. Exhibit AP-3, Schedule 4, line 32 shows the annual amortization of the REV Demo Project costs. The preliminary forecast of amounts to be spent is discussed in the direct testimony of the EIOP. The Company proposes to reconcile and defer on an annual basis any revenue requirement difference between the level reflected in base rates and the actual level of costs.

4. Monsey NWA (Electric)

Q. Has the Company included any costs associated with new NWA projects in the proposed electric revenue requirement?

A. Yes, as detailed in the direct testimony of the EIOP, the Company is pursuing a NWA solution in the Monsey substation area. The electric revenue requirement reflects program costs of $6.5 million, amortized over ten years. The annual cost recovery in base rates is equivalent to approximately $5,000 in RY1, $357,000 in RY2, and $646,000 in RY3. Exhibit AP-E3, Schedule 4, line 28, shows the annual amortization of the program costs. The preliminary forecast of amounts to be spent is discussed in the direct testimony of the EIOP. The Company proposes to reconcile and defer on an annual basis any revenue requirement difference between the level reflected in base rates and the actual level of costs incurred.

5. Platform Service Revenue (Electric)

Q. Is the Company proposing to treat any revenue as a Platform Service Revenue ("PSR")?

A. Yes. As detailed by the Company's EIOP, the Company proposes that revenue generated from the sale of products and services from the My ORU Store, as well as advertising and other program income, be treated as a PSR. Consistent with the Track 2 Order, the Company proposes that 80 percent of any profit generated by the MY ORU Store be returned to customers and 20 percent be retained by the Company. The 80 percent to be shared with customers will be deferred for customer benefit until base rates are reset.

6. Energy Efficiency Program (Electric and Gas)

Q. Has the Company included any costs associated with its energy efficiency program in the electric and gas revenue requirements?

A. Yes. The electric revenue requirement reflects the net energy efficiency program costs of $23.10 million (forecasted energy efficiency program costs of $29.46 million ($7.96 million in RY1, $9.48 million in RY2, and $12.02 million in RY3) minus $6.36 million previously collected and unspent, as detailed in the testimony of the Energy Efficiency Panel), amortized over three years. The annual cost recovery in base rates is equivalent to approximately $0.54 million in RY1, $3.69 million in RY2, and $7.70 million in RY3. Exhibit AP-E3, Schedule 4, line 5 shows the annual amortization of the program costs. The gas revenue requirement reflects energy efficiency program costs of $1.61 million ($0.54 million in each of RY1-3), amortized over three years. The preliminary forecast of amounts to be spent and the rationale for offsetting the electric RY1 costs by the $6.36 million previously collected and unspent is discussed in the testimony of the Energy Efficiency Panel. The Company proposes to reconcile and defer on an annual basis any revenue requirement difference between the level reflected in base rates and the actual level of costs incurred.

7. Unidentified NWAs and Non-Pipeline Solutions (Electric and Gas)

Q. What is the Company's proposed accounting treatment for NWAs and non-pipeline solutions ("NPSs") that have not been included in base rates, but are later identified and implementation begins in the Rate Year?

A. In the event a new NWA or NPS is implemented in the Rate Year and results in the Company displacing a capital project reflected in the Average Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Plant In Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA/NPS in the ECA/MGA. In the event the carrying charge on the net plant of any displaced project is higher than the NWA/NPS recovery, the difference will be deferred for the benefit of customers.

The costs incurred by the Company for implementation of NWAs/NPSs during the Rate Year, including the overall pre-tax rate of return on such costs, will be recovered over ten years. Recovery of such costs will be through the ECA/MGA. Unrecovered NWA/NPS costs, including the return, will be incorporated into the Company’s base rates when electric or gas base delivery rates are reset.

The GIOP also discusses incurring R&D costs to explore potential NPSs. The Company currently anticipates that any R&D spend could be absorbed within the Company’s current R&D spending plan. However, to the extent that such costs cause the Company to exceed its R&D budget, the Company requests to recover any excess costs through the MGA. Please see the direct testimony of the Electric and Gas Rate Panels for further detail on ECA/MGA recovery of NWA/NPS costs.

8. Anticipated Laws and Regulations (Gas)

Q. Does the Company propose full reconciliation of costs associated with certain anticipated laws and regulations?

A. Yes, as detailed below, the Company proposes recovery of costs associated with anticipated regulations pursuant to the Pipeline Safety Act of 2011.

Q. Aren't these circumstances covered by the "new laws and regulations" provision you propose continue?

A. Yes. However, application of the new laws provision would subject these expenditures to a dollar threshold. While a dollar threshold has been applied for unanticipated costs resulting from a change in law or regulations not anticipated at the time rates are set, a threshold should not apply when the potential circumstance is known at the time rates are set, although the details of implementation are not.

Q. Is there precedent for the Commission permitting reconciliation of costs incurred as a result of anticipated laws?

A, Yes. In various Con Edison rate cases (*e.g.*, Cases 13-E-0030, *et al.*, 16-E-0060, *et al.*), the Commission has adopted provisions for full reconciliation of costs associated with specific anticipated changes in law. In the most recent Con Edison gas rate case, the Commission adopted such a provision for anticipated costs associated with the same law at issue here.

Q. Why is the Company proposing recovery for additional costs that are expected to be incurred to implement new regulations developed pursuant to the Pipeline Safety Act of 2011?

A. As discussed in the GIOP testimony, a number of regulations under the Pipeline Safety Act of 2011 are under consideration, but have yet to be promulgated. Although the Company anticipates compliance costs will be significant, the Company does not know the timing of when it will need to be in compliance with the regulations or the full scope of work that the Company will need to undertake to comply with the regulations. As such, the Company has not included any projected compliance costs for the anticipated regulations in this filing (although it has included projected costs for compliance with existing regulations stemming from the Act). Given that the new regulations are anticipated and compliance costs are expected to be substantial, the Company proposes to defer O&M expenses in excess of the Company’s current Rate Year projection for costs related to compliance with the Pipeline Safety Act of 2011. Similarly, the Company proposes that if capital expenditures resulting from compliance with the Pipeline Safety Act of 2011 cause the Company to exceed its aggregate net plant target, the Company be permitted to defer carrying charges on the amount of net plant that exceeds the aggregate net plant target.

XI. OTHER ACCOUNTING ISSUES

A. Accounting for Positive/Negative Revenue Adjustments and EAMs

Q. Is there accounting guidance necessitating accounting and ratemaking changes in this proceeding?

A. Yes. Under ASC 980, Regulated Operations, EAMs and the positive and negative revenue adjustments stemming from the Company’s gas, electric and customer service performance mechanisms fall under the definition of alternative revenue programs. Under this guidance, the recording of deferred revenue related to alternative revenue programs may not be recorded for GAAP reporting until the collection is determined to be within 24 months from the end of the annual period in which they are recognized. As such, the Company is proposing a recovery mechanism that will allow for recording of revenues at the time the revenue adjustments are assessed and EAMs are earned.

Q. What does the Company propose in regards to the timing recognition of these alternative revenue items?

A. In order to resolve the timing issue described above, the Company proposes to collect positive and negative revenue adjustments through the ECA/MGA. The Company currently reports on whether it has met the targets in its electric, gas and customer service performance metrics in the first quarter of each calendar year and calculates whether any negative or positive revenue adjustments are appropriate. The Company proposes that it begin collecting any calculated revenue adjustments through the ECA/MGA effective June 1 each year. The collections will be subject to adjustment if the Commission determines that the Company's calculations should be corrected.

As discussed by the Company's EAM Panel, the Company proposes a similar approach for EAMs. The Company will file annual reports by March 31 that discuss whether it has earned any EAMs. The Company proposes that it begin collecting any earned EAMs through the ECA effective June 1 each year. The collections will be subject to adjustment if the Commission determines that the Company's incentive calculations should be corrected.

B. Property Tax Sharing

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, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for O&R), net of costs incurred to achieve them, that exists under the current electric and gas rate plans with one modification. In many instances, the Company is able to negotiate future assessment reductions in a property tax settlement, which is more efficient than pursuing lengthy litigation in an attempt to obtain a concrete refund award. The sharing mechanism should be modified to include savings from such settlements. The Company's approach to calculating savings and its underlying rationale for proposing to share in such savings is explained by the Company's Property Tax Panel.

This modification to the tax 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 recent property tax settlements have produced material future benefits for customers.

C. Impact of Generic Proceedings

Q. Are there any other subjects you would like to address?

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, including fundamental changes in the Reforming the Energy Vision (Case 14-M-0101) and associated proceedings. 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. Details of the revenue requirement for the Rate Year and the two following twelve-month periods, ending December 31, 2020, and December 31, 2021, are presented in the AP-3 exhibits. The Company's filing also includes capital expenditure projections for calendar years 2022 through 2023.

Q. What is the basis of the financial information presented in the AP-3 Exhibits?

A. Various Company witnesses have presented forecasts extending beyond the Rate Year. There are also proposals by various witnesses, including the Accounting Panel, which 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.

XIII. FUND REQUIREMENTS AND SOURCES

Q. Are the Company's projected sources and applications of funds presented in the Company's filing?

A. Yes. Schedule 18 of the AP-3 Exhibits, presents a statement of sources and application of funds for the Rate Year for electric and 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.

XIV. FINANCIAL RATIOS

Q. Please describe Schedule 19 of the AP-3 Exhibits.

A. Schedule 19 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, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
DEPRECIATION PANEL

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 Matthew Kahn. My business address is 4 Irving Place, New York, New York.

My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Mr. Kahn, 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 manage the functions related to book and tax depreciation. I also support the income tax compliance and accounting functions for Con Edison and its regulated affiliates (including Orange and Rockland).

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. I am a member of the Society of Depreciation Professionals (“SDP”).

Q. Mr. Allis, by whom are you employed and in what capacity?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC (“Gannett Fleming”), where I am Project Manager, Depreciation and Technical Development. I am responsible for conducting depreciation, valuation and original cost 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 Gannett Fleming’s proprietary depreciation software, training of depreciation staff, and the development of solutions for technical issues related to depreciation.

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 am the current president of SDP. 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. I was re-certified as a depreciation professional in March 2017. 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 the position of Supervisor, Depreciation Studies. In March 2017, I was promoted to my current position of Project Manager, Depreciation and Technical Development.

Q. Have the members of the Depreciation Panel previously testified before any utility commission on the subject of utility plant depreciation?

A. **(Kahn)** Yes. I have testified on the subjects of depreciation and income tax before the New York Public Service Commission ("NYPSC") on behalf of O&R and its corporate affiliate, Con Edison.

(Allis) Yes. I have testified on the subject of depreciation before the NYPSC, the Florida Public Service Commission, the Nevada Public Utilities Commission, the District of Columbia Public Service Commission, the New

Jersey Board of Public Utilities, the California Public Utilities Commission, the Connecticut Public Utilities Regulatory Authority, the Rhode Island Public Utilities Commission, and the Federal Energy Regulatory Commission (“FERC”).

Q. What is the purpose of your testimony in this proceeding?

A. The Depreciation Panel’s testimony:

- Presents the depreciation study performed by Gannett Fleming for the Company’s electric, gas and common plant;
- Explains the rationale for using Iowa survivor curves in the depreciation study (rather than the h-type survivor curves used in previous O&R depreciation studies);
- Presents annual depreciation accruals as of September 30, 2017 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”) as of September 30, 2017, 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; and
- Discusses the Company’s recovery of unrecovered costs for legacy meters due to the implementation of its Advanced Metering Infrastructure (“AMI”) program.

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. Kahn, is presented in exhibits prepared under our supervision and direction. The exhibits applicable to Electric Plant are:

- Exhibit ___ (DP-E1) entitled: “Orange and Rockland Utilities, Inc., 2016 Depreciation Study, Electric and Common Plant as of December 31, 2016;”
- Exhibit ___ (DP-E2) entitled: “Orange and Rockland Utilities, Inc., Electric and Common Plant, Summary

of Annual Depreciation Rates as of September 30, 2017;" and

- Exhibit ___ (DP-E3) entitled: "Orange and Rockland Utilities, Inc., Electric and Common Plant, Summary of the Computed Reserves for Depreciation as of September 30, 2017."

The exhibits applicable to Gas Plant are:

- Exhibit ___ (DP-G1) entitled: "Orange and Rockland Utilities, Inc., 2016 Depreciation Study, Gas and Common Plant as of December 31, 2016;"
- Exhibit ___ (DP-G2) entitled: "Orange and Rockland Utilities, Inc., Gas and Common Plant, Summary of Annual Depreciation Rates as of September 30, 2017;" and
- Exhibit ___ (DP-G3) entitled: "Orange and Rockland Utilities, Inc., Gas and Common Plant, Summary of the Computed Reserves for Depreciation as of September 30, 2017."

Q. Please summarize any changes to depreciation expense levels due to Gannett Fleming's depreciation recommendations.

A. As set forth in their direct testimony, the Company's Accounting Panel has computed, based on depreciation rates we have supplied, that depreciation expense will increase in the Rate Year by $11.2 million (*i.e.*, from $43.4 million to $54.6 million) for electric plant and by $4.5 million for gas plant (*i.e.*, from $20.9 million to $25.4 million).

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 under the Uniform System of Accounts 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 followed?

A. Yes.

Q. Are the methods and procedures used in the depreciation study consistent with the Company’s past practices?

A. Yes. The methods and procedures used in this study are the same as those used in past depreciation studies conducted by the Company, as well as depreciation studies presented by other companies in rate proceedings before the NYPSC. The approach is to determine depreciation rates based on the straight-line method, broad group average service life procedure and the whole life technique.

We note that the survivor curve estimates in the current study, while based on the same method of estimation as in previous studies, use Iowa type survivor curves. This is a change from the h-type survivor curves used in previous studies for the Company. As we discuss later in our testimony, the Iowa type survivor curves are more widely used in the utility industry and have been used by other New York utilities.

Q. Please describe the presentation of the depreciation study in your exhibits.

A. The electric depreciation study, set forth in Exhibit ___ (DP-E1), and the gas depreciation study, set forth in Exhibit ___ (DP-G1), are each 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-6 of both Exhibit ___ (DP-E1) and 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, 2016, and the calculated annual depreciation accrual and applicable depreciation rate for each plant account or subaccount. The section beginning on page VII-1 of each Exhibit presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-1 of each Exhibit presents the results of the salvage analysis. The section beginning on page IX-1 of each Exhibit presents the depreciation calculations related to surviving original cost as of December 31, 2016.

Q. Please explain how each depreciation study was performed.

A. Each 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 service life of each group of assets in a systematic and rational manner.

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 over which the original cost of plant will be depreciated. For example, with an average service life of 25 years, annual depreciation is $1/25^{th}$, 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, and all else being equal, the longer the average service life, the lower the annual depreciation rate and the lower the annual depreciation expense. Conversely, the shorter the average service life, the higher the annual depreciation rate and the higher the annual depreciation expense.

Q. What part does net salvage play in the determination of depreciation rates?

A. Depreciation is intended to recover the full cost of the Company’s assets over the period of time they are providing service. The full cost of an asset includes both the original cost when the asset was installed and the net salvage at the end of the asset’s life. Thus, in addition to providing for recovery of the original cost of plant over its estimated average service life, 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 few exceptions, most plant assets result in negative net salvage upon retirement, with removal costs exceeding salvage value. Salvage and removal cost 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 NYPSC's Uniform System of Accounts, the service value of an asset is allocated evenly 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 service life and net salvage study consisted of compiling historical data from records related to O&R's plant; analyzing the 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 the data and information along with the average service lives and net salvage factors used by other electric utilities to form judgments of average service lives 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 these visits?

A. A field review of O&R's property as part of the depreciation study was made during September 2017. A field review was also conducted in June 2014 for the Company's previous depreciation study. 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. 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 2016 were analyzed. The transactions included additions, retirements, transfers and the related balances.

Q. What method was used to analyze the 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 it 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 O&R used in past depreciation studies and is the overwhelmingly predominant 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 performed for 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 (or life tables) which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the 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 survivor 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. Take the Iowa 50-R1.5, for example. The first designation indicates an average service life of fifty years. The second designation indicates a right-moded, or R, type curve (the mode occurs after average life for right-moded curves). The third designation indicates a relatively low height of 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 NYPSC. 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. While the h-system of curves had been used in the past by New York utilities, there are currently very few utilities in the country that still use h-curves.

Q. What type of survivor curves have you proposed to use in the 2016 Depreciation Study?

A. For the current study, we recommend the use of Iowa type survivor curves. This represents a change from the h-type curves used in the Company's previous study. However, the Iowa curves are, to our knowledge, used in every U.S. jurisdiction, including in New York by Central Hudson Gas and Electric, Rochester Gas and Electric, New York State Electric and Gas, National Fuel Gas and Niagara Mohawk. In contrast, the h-curves are, to our knowledge, not used anywhere outside of New York. Further, the h-curves tend to have long "tails," meaning that these curves forecast that a portion of property will survive much longer than the average service life of a given depreciable group. These types of life characteristics are not common for most types of utility property. In contrast, the Iowa curves typically provide a more reasonable retirement dispersion pattern for most types of utility assets. For these reasons, it is appropriate to use Iowa type survivor curves for O&R.

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 2016 and each account was analyzed over a period that best represents the overall service life of the property in the account. For most accounts, the full period of time (1952-2016) was used. For certain accounts, shorter periods were used to adjust for anomalies and other account-specific factors. The life table for the 1952-2016 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 $225,085,951 having been exposed to retirement. Consequently, the retirement ratio is 0.0016 ($357,761 / $225,085,951) and the survivor ratio is 0.9984 (1 – 0.0016). The percent surviving for the next age interval (*i.e.*, age 1.5) of 99.84 percent is calculated by multiplying the percent surviving of 100.00 percent at age 0.5 by the survivor ratio at age 0.5 of 0.9984. This life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 45-S0 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, 2016 is presented on pages IX-27 through IX-29. The calculations are based on the 45-S0 survivor curve and 15% 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 $4,551,459 and theoretical reserve of $37,954,956 for the account are brought forward to the table on page VI-4. The reserve variation of $3,364,745 shown on page VI-4 is calculated by subtracting the $37,954,956 theoretical reserve from the book reserve for the account of $41,319,701.

Q. Please describe how the proposed net salvage factors were determined.

A. Consistent with well-established industry practices, the net salvage factors were determined using informed judgment that considered 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 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.

Q. Are the net salvage analyses and approach you used to reflect net salvage in depreciation rates consistent with authoritative depreciation texts?

A. Yes. 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. These texts 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.

Q. Are the methods used in the depreciation study for the net salvage analysis widely accepted in the industry?

A. Yes. The net salvage analysis used in the Company's depreciation study is the predominant approach in the utility industry. In the vast majority of jurisdictions, including New York, 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 Company's depreciation study. This approach is consistent with the NYPSC Uniform System of Accounts, the ratemaking practices of 45 other state regulatory commissions, and the ratemaking approach of the FERC.

III. 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 your testimony?

A. For electric plant, the amounts we will address are summarized on Exhibit ___ (DP-E3). This Exhibit indicates that for total electric plant as of September 30, 2017, the Accumulated Provision for Depreciation per books, or book reserve, amounted to approximately $430.9 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 $408.5 million. The computed reserve recommended by Gannett Fleming amounted to approximately $449.3 million. This Exhibit also indicates that the book reserve is approximately $22.4 million, or 5.49 percent more than the computed reserve based upon existing rates and is approximately $18.4 million, or 4.09 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, 2016, the book reserve amounted to approximately $233.6 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 $229.4 million. The computed reserve recommended by Gannett Fleming amounted to approximately $253.6 million.

This Exhibit also indicates that the book reserve is approximately $4.2 million, or 1.84 percent more than the computed reserve based upon existing rates and is approximately $20.0 million, or 7.89 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. These Exhibits indicate that for total common plant at December 31, 2016, the book reserve amounted to approximately $108.5 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 $113.2 million. The computed reserve recommended by Gannett Fleming amounted to approximately $112.8 million. This Exhibit also indicates that the book reserve is approximately $4.7 million, or 4.19 percent less than the computed reserve based upon existing rates and, excluding the unrecovered reserve adjustment for amortization, is approximately $4.3 million, or 3.85 percent less than the computed reserve based upon the rates recommended by Gannett Fleming.

Q. Do you 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 NYPSC's typical 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.

IV. ADVANCED METERING INFRASTRUCTURE

Q. Please discuss the Company's recovery of its investment in "legacy" meters due to the implementation of its AMI program.

A. AMI is a technology for improving efficiencies related to meter reading and providing other system and customer benefits, as discussed in the direct testimony of the Company's Customer Service Panel. These initiatives involve installing electric "smart meters" across O&R's service territory, resulting in the phasing-out of the older, "legacy" technology (*i.e.*, electro-mechanical and solid state meters) before they are fully depreciated. According to the current schedule, the installation of new meters will be completed by the end of 2022, as detailed in the AMI implementation plan. Depreciation accruals on the legacy meters cease upon their retirement even though they have not been fully depreciated. As a result, separate consideration of the appropriate cost recovery vehicle for the undepreciated basis is required.

Q. What is the Company’s proposal regarding the recovery of the remaining book cost for electric meters that will be retired due to the implementation of AMI?

A. The Company proposes to implement a separate recovery via depreciation expense of the electro-mechanical and solid state meters that will be retired starting in the Rate Year. This method would continue until the completion of the implementation of the AMI meter technology across the Company’s service territory (currently scheduled to be completed in 2022), or until rates are reset in the Company’s next base rate proceeding.

Q. What level of meter retirements have been reflected in the Company’s forecast?

A. The Company’s capital budget forecast reflects a level of meter retirements that factors in AMI deployment. As a result, by using the Company depreciation forecast, the Company will no longer continue to recover the asset costs of the existing meters over the average service lives and net salvage factors that are currently in effect, but will commence depreciation accruals for the new AMI meters. Upon completion of the installation of AMI meters, the Company currently projects that there will be $23.6 million of unrecovered book costs associated with the legacy meters.

Q. What is the Company’s proposal for addressing the remaining unrecovered investment in legacy meters upon completion of the implementation of AMI?

A. The Company is proposing that the net remaining unrecovered costs, upon completion of the implementation of AMI, would be deferred to a regulatory asset. The Company would amortize the remaining unrecovered costs of the legacy meters over a fifteen-year period.

Q. How has the Company determined the estimated unrecovered cost of those legacy meters?

A. As of December 31, 2016, the net book value for electric meters that will be replaced during the implementation of the AMI program was approximately $27.8 million. The Company has projected that upon completion of the AMI implementation plan, the remaining unrecovered costs will be approximately $23.6 million for electric meters, if there is no additional consideration provided for the legacy meter costs. The reduction from the current net book value to the projected unrecovered costs is the result of continuing to recover the meter costs that remain in service at current depreciation rates.

Q. What is the result of adopting the Company’s proposal for a separate recovery of these legacy meter costs via an additional allowance for depreciation expense to commence in the Rate Year?

A. The Company’s proposal is to begin a straight-line recovery of the estimated unrecovered meter costs over a fifteen-year period. In adopting the Company’s proposal to commence recovery of its estimated unrecovered legacy meter costs in the Rate Year, the Company projects the net remaining unrecovered costs upon completion of the implementation of AMI to be reduced from $23.6 million to $16.4 million.

Q. What is the annual level of expense associated with a fifteen-year period for recovery of the unrecovered meter costs?

A. A fifteen-year straight-line recovery would result in an annual depreciation expense of approximately $1.57 million for the electric service.

Q. Is this a reasonable level for recovery of the legacy meter costs when compared with the current approved depreciation rates for the legacy meter accounts?

A. Yes. If we applied the currently approved depreciation rates for the legacy meter accounts, and assumed no retirements due to the implementation of AMI, the result would be an annual depreciation expense of approximately

$1.59 million.

Q. What has been the NYPSC’s practice regarding the recovery of depreciation reserve deficiencies that resulted from the retirement of assets before their costs have been fully recovered?

A. Historically, the NYPSC has addressed the recovery of depreciation reserve deficiencies through a separate amortization over periods ranging from ten to twenty years. Most recently, the Staff recommended amortization of the remaining unrecovered costs of Con Edison’s legacy meters over fifteen years upon completion of its AMI implementation plan.

Q. The recovery periods for electric meters to be retired are on the high end of the range for historical amortizations of reserve deficiencies for the electric service. Do you believe a shorter recovery period would be more appropriate?

A. Yes, conceptually a shorter recovery period (*e.g.*, the five years in which AMI is expected to be implemented) would be more appropriate to recover these costs. That said, given the additional depreciation expense customers will bear for the new AMI meters and the impact of other depreciation rate changes that we are recommending that the NYPSC authorize in this case, the Company is not requesting that the NYPSC authorize a shorter recovery period at this time.

As the Staff Depreciation Panel (pp. 33-34) noted in Con Edison’s most recent electric and gas rate cases (Case 16-E-0060; Case 16-G-0061):

> This will make the amount to be recovered from customers less costly in the long-run and reduce inter-generational inequities due to the early retirements. This proposed treatment effectively begins a quasi-amortization in that the anticipated future reserve deficiency will be reduced during the AMI rollout. A 15-year amortization period is reasonable to recover these costs and consistent with the Order Establishing Rates for Electric Service, issued March 25, 2008, in Case 07-E-0523, wherein the Commission limited the recovery of the Company’s depreciation reserve deficiency to a 15-year amortization.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
DIRECT TESTIMONY OF
INCOME TAX PANEL

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.

My name is Jeffrey Kalata and my business address is 4 Irving Place, New York, New York.

My name is Matthew Kahn and my business address is 4 Irving Place, New York, New York.

Q. By whom are you employed, in what capacity and what are your professional backgrounds and qualifications?

(Lenns) We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I am the Vice President – Tax at Con Edison. I have a Bachelor's Degree 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 the 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 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 five 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. 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 Institute of Certified Public Accountants.

(Kalata) I earned a Bachelor of Science degree in Business Administration with a concentration in accounting from Bowling Green State University. I joined Coopers & Lybrand LLC in 1986 and held a number of financial and audit positions before leaving as Senior Manager of Business Assurance in 1997 to serve as Group Accounting Manager for North American Refractories Co. with responsibilities for all financial reporting, accounting and tax functions. I joined FirstEnergy Corp. and was elected Assistant Controller in October 1999. At FirstEnergy, I had responsibilities for various accounting areas (accounts payable, payroll, property accounting and budgeting/planning), and was responsible for oversight of the external financial reporting and accounting research activities for FirstEnergy and its subsidiaries. In 2007, I transferred to FirstEnergy’s tax department as Director, Tax, to head the tax accounting function over income taxes and general taxes. In 2013, I joined Con Edison's tax department as Director, Tax, and direct activities over the income tax accounting and compliance groups, as well as the book and tax depreciation groups.

I have testified as an expert witness in utility rate cases in Ohio and assisted in the preparation of rate cases in New York, Pennsylvania, New Jersey and West Virginia. I am an active participant of the Edison Electric Institution Taxation Committee and American Gas Association Taxation Committee. I am a Certified Public Accountant in the State of Ohio and a member of the American Institute of Certified Public Accountants, the Ohio Society of Certified Public Accountants and Chartered Global Management Accountants.

(Kahn) 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. I am a Section Manager in the Tax Department at Con Edison. I manage the functions related to book and tax depreciation. I also support the income tax compliance and accounting functions.

Q. What is the purpose of the Panel's direct testimony in this proceeding?

A. The Panel's direct testimony:

1. Discusses the impact of the enactment of the Tax Cuts and Jobs Act (the "Act") on Con Edison's corporate affiliate, Orange and Rockland Utilities, Inc.'s (the "Company") electric and gas revenue requirements; and
2. Addresses the impact of the Act on our customers' electric and gas bills.

TAX REFORM

Q. What is the Act?

A. The Act is federal income tax legislation, signed into law on December 22, 2017. The Act, with respect to utilities, reduces the statutory federal income tax rate from 35% to 21%, revokes bonus depreciation for utilities in favor of Modified Accelerated Cost Recovery ("MACRs"), allows full deductions for interest expense, and requires the normalization of excess deferred income taxes ("EDFIT") resulting from the tax rate reductions.

Q. What impact will the reduction in the corporate federal income tax rate have on the Company?

A. The Company's revenue requirement will decrease as a result of the reduced federal income tax rate. In the Rate Year (*i.e.*, the twelve months ending December 31, 2019), the Company's cost of service will include federal income tax expense computed at the 21% statutory rate.

Q. Has the Company incorporated the reduction in the federal income tax rate into the calculation of the revenue requirement in its electric and gas rate filings?

A. Yes. The Company has reflected the lower income tax rate in its calculation of federal income tax expense ("FIT") in Schedule 16 of Exhibits AP-E3, and AP-G3.

Q. What is the estimated impact on the revenue requirement resulting from the rate reduction?

A. The Company estimates a reduction in income tax expense in the Rate Year, as a result of the reduced federal income tax rate, in the amount of $12 million for electric and $6 million for gas.

Q. What impact will the change in tax depreciation rules have on the Company?

A. Subject to transition rules impacting self-constructed assets, beginning on September 27, 2017, the Company is no longer entitled to claim bonus depreciation on plant additions. Rather, the Company computes tax depreciation using MACRs lives and rates. This change in a normalized temporary difference will not impact the Company's total income tax expense, but will increase its current federal income tax expense and will reduce deferred federal income tax expense in an equal amount.

Q. Does the Act have any additional ratemaking related impacts?

A. Yes. As a result of the tax rate reduction, the Company must compute EDFIT. EDFIT represents the excess of deferred income taxes calculated at prior statutory rates over deferred taxes calculated at the new 21% statutory rate. A portion of EDFIT relates to accelerated depreciation rates and shorter tax lives, and a portion relates to asset basis differences.

Q. What is the impact of EDFIT on the Company’s electric and gas customers?

A. Deferred federal income taxes are included in the income tax component of cost of service. Accordingly, EDFIT will result in a net regulatory liability that must be refunded to customers of both electric and gas services.

Q. What is the estimated amount of EDFIT that the Company has calculated?

A. As of December 31, 2017, the Company estimates $64 million of EDFIT for electric service, and $52 million of EDFIT for gas service. These estimates include both the plant-related and non-plant related temporary differences.

Q. What is the Company’s proposal for refunding to customers the EDFIT?

A. In order to stabilize customer rates, the Company proposes to refund all EDFIT over the average remaining useful lives of plant assets for electric and gas services. Under the Tax Reform Act of 1986 and the Act, EDFIT associated with accelerated depreciation and shorter lives cannot flow back to customers any quicker than the remaining lives of plant assets.

Therefore, the Company’s proposal is to refund in customer rates all EDFIT over the average remaining useful life of the plant assets.

Q. What is the average remaining useful life of the plant assets for electric and gas services?

A. As of December 31, 2017, the average composite remaining useful life for electric and gas plant assets is approximately 46 years and 53 years, respectively.

Q. What is the impact on the revenue requirement in the Rate Year, resulting from the Company’s proposal to refund all EDFIT over the average remaining useful lives for its electric and gas services?

A. The Company estimates a reduction in the revenue requirement related to the reversal of excess deferred federal income taxes in the Rate Year of $3.3 million for the electric service, and a reduction of $1.5 million in the revenue requirement for the gas service. The Company would note that the amounts reversing in the Rate Year are reversing at the Average Rate Assumption Method (“ARAM”). These estimate amounts, and the rate of reversal, are tied to the currently existing book depreciation rates. Any change in book depreciation rates will result in a change to the amount of EDFIT reversing in the Rate Year. For example, an acceleration of book depreciation rates will increase the amount of EDFIT reversing in the Rate Year, and any deceleration of book depreciation rates will reduce the amount of EDFIT reversing in the Rate Year.

Q. What is the Company's proposal for accounting for the impact of the Act prior to the Rate Year?

A. The Company proposes deferral accounting, with interest at the Company's overall rate of return, for the effect of the change in federal tax law between the date of enactment (*i.e.*, January 1, 2018) and the beginning of the Rate Year (*i.e.*, January 1, 2019). For both electric and gas service, the Company will calculate the difference in income tax expense each month for the lower federal income tax rate, include the amount of EDFIT that reverses in 2018, and gross-up these amounts. The Company will record the results of these monthly calculations as a reduction to other revenues, with an offset to a regulatory liability. The Company has calculated an estimated amount for this regulatory liability and will amortize it over the average composite remaining useful life. The estimated regulatory liability is $10.437 million for electric service and $4.570 million for gas service. In order to stabilize customer rates, the Company proposes to amortize these amounts over the average composite remaining lives of the electric and gas plant assets and has reversed $.227 million for electric service and $.086 million for gas service in the Rate Year.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.

PROPERTY TAX PANEL – ELECTRIC & GAS

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ORANGE AND ROCKLAND UTILITIES, INC.

PROPERTY TAX PANEL – ELECTRIC & GAS

I. INTRODUCTION

Q. Would each member of the Property Tax Panel ("Panel") please state your name and business address?

A. Stephen Ianello and Stephanie J. Merritt. Our business address is 4 Irving Place, New York, New York.

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

A. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison") and our responsibilities include the property tax functions for Con Edison's affiliate, Orange and Rockland Utilities, Inc. ("O&R" or "the Company").

Q. Please explain your educational background, work experience and current general responsibilities.

A. **(IANELLO)** I have a Bachelor's Degree in English from the College of the Holy Cross, a Juris Doctorate (cum laude) from Suffolk University Law School, and an LL.M in Taxation from New York University Law School. I have been with Con Edison for 27 years specializing in tax law. I started my career at Con Edison in 1990 in the Tax Department as an attorney, moved to the Law

Department and was promoted to Assistant General Counsel and then returned to the Tax Department as Tax Director. I handle federal, state and local tax issues facing the Company including compliance, audits, controversies, and monitoring evolving tax developments. In addition, my work involves executive compensation matters, payroll issues, property tax matters, and evaluating and drafting tax legislation that affects the Company and energy industry. I am admitted to practice law in the State of New York and the Commonwealth of Massachusetts. Prior to joining Con Edison, I spent approximately four years as a trial attorney with the IRS Office of Chief Counsel, Manhattan District. Before that, I practiced law in a small general practice firm in New York concentrating in real estate, litigation and trusts and estates.

(MERRITT) I graduated from Le Moyne College in 2004 with the degree of Bachelor of Science in Accounting as well as a Bachelor of Arts in Economics. Currently, I am pursuing a Masters of Business Administration Degree in

Accounting and Finance from Syracuse University. I have been employed by Con Edison since 2005 and have held various positions of increasing responsibility within the Finance area. After approximately two years in Corporate Accounting, I transferred to the Tax Department where I was promoted to Staff Accountant in the Financial Accounting and Regulatory Depreciation Group. In that position, my major responsibilities included the preparation and interpretation of the Company’s depreciation studies in connection with rate proceedings. In that role, I assisted in over ten rate proceedings for Con Edison; O&R; Rockland Electric Company (O&R’s New Jersey utility subsidiary); and Pike County Light & Power Company (O&R’s former Pennsylvania utility subsidiary). In 2010, I began working in the Property Tax Group. I started as the Accounting Supervisor and rose to the position of Senior Tax Accountant in 2014. In September 2015 I was promoted to Section Manger – Local Taxes. I have held my current position of Department Manager – General Tax since June 2017. My responsibilities include oversight of the sections and personnel responsible for taxes other than income taxes, including all local, excise, sales and use taxes.

Q. Have any members of the Property Tax Panel previously testified before any regulatory commission on property taxes?

A. **(Ianello)** No.

(Merritt) I have testified before the Commission on property taxes in the following Con Edison base rate cases: Cases 13-E-0030, 13-G-0031, 13-S-0032, 16-E-0060 and 16-G-0061.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of the 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 estimate the level of its property tax obligations and describes the corresponding need for a full and symmetrical property tax reconciliation, as proposed in the direct testimony of the Company's Accounting Panel;
- Discusses the Company's efforts to pay no more than its fair share of property taxes; and
- Discusses the Company's proposal to retain 14% estimated future tax savings, regardless of whether it is in the form of a refund or in the form of future property tax reductions.

Q. Please explain the general basis upon which property taxes levied upon the Company are determined.

A. The Company pays two types of property taxes: real estate and special franchise. Real estate taxes include taxes on land and the structures and/or equipment erected or affixed to the land. Special franchise taxes are levied on utility equipment located on or under the public streets and highways.

For Real estate taxes, local assessors value real property and commercial buildings, such as the Company’s Spring Valley Operations Center, by examining comparable sales or rental data.

For special franchise taxes, New York 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 many of the local assessors in the Company’s service territory determine value by using a Reproduction Cost New Less Depreciation (“RCNLD”) methodology for utility structures and/or equipment. RCNLD calculates what it would cost to reproduce the utility structures and/or equipment 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. The RCNLD methodology is used only to value certain of the Company's structures and all of its equipment.

III. SUMMARY OF RECENT AND PROJECTED PROPERTY TAXES

Q. Please provide some background on the amount of property taxes paid by the Company.

A. The Company pays County & Town, School, Village and special district (*e.g.*, fire, library) property taxes on its land and the structures and/or equipment erected or affixed to the land in Orange, Rockland, and Sullivan Counties.

Q. What was the amount of the Company's electric property taxes for the Historic Test Year?

A. For the Historic Test Year in these proceedings (*i.e.*, the twelve months ended September 30, 2017) the tax payments amounted to $39.9 million for electric and to $23.4 million for gas, for a total of $63.3 million.

Q. What is your forecast of property taxes for the Rate Year (*i.e.*, the twelve months ending December 31, 2019)?

A. For the Rate Year (which we may also refer to as "RY1" for ease of reference), we have forecasted a property tax expense of $42.0 million for electric and $25.0 million for gas, for a total of $67.0 million.

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 were the Company's actual electric and gas property taxes paid for calendar year 2017. Then we developed an overall escalation percentage to develop the forecasted amounts. The escalation percentage we developed is based on recent historical tax payment information from calendar years 2012 through 2017.

Q. Why does the Company use an overall escalation percentage rather than forecast property taxes separately for each taxing entity?

A. As discussed further in Section IV, it is not practicable to specifically forecast property taxes for each of the many different municipalities, school districts and other special districts to which the Company pays property taxes. Each entity has many factors affecting its financial needs each year, and the Company does not have the information necessary to make useful projections.

Q. What was the five-year annual average escalation rate you determined?

A. The five-year annual average escalation rate was 6.78%.

Q. Did you use that 6.78% annual escalation rate to develop your forecast of property taxes for the Rate Year?

A. No, we used a 4% escalation rate.

Q. Why is it appropriate to use a 4% escalation rate?

A. At this time we believe that a 4% escalation rate will be representative of the escalation rate applicable during the Rate Year. Since 2015, the year-over-year percentage increases in property taxes for the Company have been below 6.5%.

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 evaluating general economic conditions, property values, the Company’s and municipalities’ efforts to control property taxes, and the Company’s construction activities compared to other construction in the area. It should not be just a rote mathematical exercise; informed judgment should also be applied. As explained below, we judge that 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.

Q. On what do you base that judgment?

A. There are a few important factors. First, economic circumstances today are markedly different than in recent years. The historic 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. Generally, municipalities and school districts raised property tax rates during that time, as property tax is sometimes the only source of revenue or the “last” source of revenue used to balance budgets. Second, local taxing authorities, especially school districts, remain under enormous pressure from their communities to minimize their tax levy increases.

Q. How did you reflect the 2% cap law under the New York State real property tax law (*i.e.*, N. Y. General Municipal Law Section 3-C) with respect to property taxes in your analyses?

A. We made no effort to specifically reflect the 2% cap law in our analyses. The legislation limits are not dispositive, as they may be overridden by a 60% vote of the governing body of the local government or a 60% vote of school district voters. In addition, there are exclusions that limit the reach of the cap. For instance, there are exclusions for court orders or judgments against the governing body or school district. There are also exclusions for contributions to employee retirement funds beyond specified limits. Other exclusions require computations to determine what the legislation refers to as a “quantity change factor,” which may allow the tax levy to increase above the cap due to development. There are also exclusions that will allow school districts to increase the tax levy for certain expenditures associated with facilities, capital equipment, debt service, lease expenditures, and transportation debt service, subject to the approval of the qualified voters where required.

Q. Are you sponsoring an exhibit containing the computation of the five-year average escalation rate?

A. Yes, we are sponsoring Exhibit PTP-1 entitled "Orange and Rockland Utilities, Inc., Five-Year Average of Property Taxes Paid" for that purpose. This exhibit summarizes the tax payments made for the last six calendar years and computes the five-year average for the Company.

Q. Was Exhibit PTP-1 prepared by you or under your direction and supervision?

A. Yes.

Q. Will the Company provide any updates related to property taxes during this proceeding?

A. As indicated earlier, the base levels used to forecast the Company's property taxes were the actual electric and gas property taxes paid in 2017. Because no estimates were used, an update related to property taxes is not necessary for this proceeding.

IV. INABILITY TO REASONABLY FORECAST PROPERTY TAXES

Q. Why do you believe that an accurate forecast of the Company's property taxes is not practicable?

A. The Company's property taxes increase for two reasons: tax rate increases due to municipality/school district revenue needs and increased assessments. Both of those items are influenced by many factors, making it difficult to estimate future property taxes. Regarding tax rates, in New York State, the main revenue source to balance local municipal and school budgets is property taxes. Forecasting revenue needs in a particular county, town, village, school district, is difficult to accurately predict because of various moving parts and factors. The need for revenue is impacted by inflation, local economic conditions, local labor contracts, social issues, and other revenue sources available (*e.g.*, state aid, sales taxes). Regarding assessments, as a ***rule of thumb***, changes are driven by the Company's growth in infrastructure investment needed to support the Company’s efforts to provide safe and reliable electric service to our customers.

Q. Does the Panel support continuing full reconciliation of property taxes in order to address the uncertainty of the Company’s level of property taxes for the Rate Year?

A. Yes. Due to the difficulty in forecasting property taxes accurately, and the Company’s limited ability to mitigate against the variability and uncertainty, the Panel believes continuing an accounting and ratemaking mechanism that fully insulates customers and the Company from property tax forecast variations is reasonable and appropriate. This reconciliation mechanism is discussed in detail in the direct testimony of the Company’s Accounting Panel.

Q. Do you believe that full and symmetrical property tax reconciliation lessens the Company’s incentive to mitigate its property tax liability?

A. No, not at all. As we will explain in greater detail later in our testimony, and as the Company has explained in numerous rate proceedings, meetings with the Staff of the Department of Public Service ("Staff"), and annual reports to the Commission of the Company's activities regarding property taxes, the Company has a long history of actively fighting to reduce the Company's property tax burden. Challenges to unfair assessments, litigation, lobbying efforts to seek favorable legislation, and aggressively pursuing available property tax benefits are a normal course of business for the Company.

Q. Has the Commission previously approved the full reconciliation of property taxes?

A. Yes, in Orange and Rockland's most recent electric and gas base rate cases, *i.e.*, Cases 14-E-0493 and 14-G-0494, the Commission approved full property tax reconciliation. In addition, in Case 08-E-0539, a proceeding in which the Commission established electric base 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), the Commission approved full property tax reconciliation.

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, and the Commission concluded that would not be the case. In its *Order Setting Electric Rates*, issued April 24, 2009 in Case 08-E-0539 (pp. 106-107), the Commission stated:

> 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.

Accordingly, given the variability and uncertainty we have discussed above, 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 both reasonable and appropriate.

V. EFFORTS TO MINIMIZE PROPERTY TAXES

Q. Please summarize the Company's efforts to minimize property taxes.

A. The Company has aggressively challenged its property tax assessments in an effort to pay no more than its fair share of property taxes. The Company has been and remains very concerned with the level of property taxes in its service territory and the impact of these 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 tax rate is a function of revenue needs divided by assessments. The Company has no influence on the tax rates that municipalities set. Therefore, the Company's main effort is to focus on the fairness of assessments in a particular municipality.

Q. How do you determine which assessments should be challenged?

A. Each year we review our property assessments to determine if they fall within a range of reasonableness under an RCNLD valuation. This approach to valuation begins with the original cost of property, which is then trended to the current time period using Handy Whitman indices to arrive at an estimated cost to reproduce the property today. That valuation is then reduced by depreciation. The RCNLD methodology develops what is considered the current market or full value of utility property and the method is used for valuation purposes by the ORPTS and many of the local assessors. If the actual assessments are 25% higher than the RCNLD calculations and the property tax dollar amounts involved are significant, the Company files complaints with the applicable taxing authorities.

Q. Please describe the tax controversy process.

A. As indicated, we monitor the assessed values of the Company's properties and take action for each property that we feel is not fairly assessed. Each municipality's assessing authority publishes a tentative assessment roll on an annual basis. The roll includes the annual tentative assessed values for each property located in the jurisdiction. If a taxpayer disagrees with the tentative assessment for their property, they may file an administrative complaint during a designated grievance period. During that period, in order to determine if any assessments should be challenged, the Company undertakes a review of their assessments to determine whether they fall within a range of reasonableness when calculated under RCNLD. If the assessments exceed the pre-determined range of reasonableness, a grievance is filed with the applicable taxing authority. The municipality must respond to the administrative complaint and it has been the Company's general experience that complaints are denied. Accordingly, after the tentative assessment roll becomes final, the Company files tax certiorari petitions with the applicable court to formally contest the final assessments. We first attempt to settle these complaints through negotiation, as we believe that a settlement is a more cost effective way of reducing our tax burden than more costly prolonged litigation, which requires independent appraisals, retention of outside counsel, and 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. Has the Company been successful in recent challenges?

A. Yes. As detailed in our 2017 Property Tax Reduction Reports filed with the Commission in March 2017, during 2015 O&R reached settlements with the City of Middletown and the Towns of Blooming Grove, Clarkstown, Orangetown, and Ramapo.

Q. Please discuss the settlements achieved in with the Towns of Clarkstown, Orangetown, and Ramapo.

A. The settlement principles the Company agreed to with the Towns of Clarkstown, Orangetown, and Ramapo were novel in that the assessment methodology is locked in for ten years unless central assessment becomes the law in New York State. In addition, the new methodology allows for the ORPTS depreciation lives and removal cost factors and, most significantly, an increased depreciation allowance. The tax savings for the Company’s customers from these settlements are significant. In Clarkstown, we estimate the tax savings to be $3,530,000 over the ten-year term of the agreement. We estimate the tax savings for Orangetown to be $1,788,000 over the ten-year term of the agreement. In Ramapo, we estimate the tax savings to be $6,347,000 over the ten-term of the agreement. Actual savings will likely exceed these estimates, as the Company adds new plant in these municipalities. The Company negotiated these settlements in lieu of seeking refunds of prior years’ taxes through litigation. Both sides agreed to prospective tax reductions, as neither side wanted to engage in costly litigation.

Q. Please discuss the settlements achieved with the City of Middletown and the Town of Blooming Grove.

A. Regarding the City of Middletown, O&R commenced proceedings challenging the assessments for years 2010 through 2014 on a parcel of property that used to contain a liquid propane tank farm. The tanks were removed from service in 2009, and sold and removed from the property in 2011. However, the City of Middletown never reduced its assessment of the property. O&R has negotiated a settlement with the City of Middletown, and we estimate the tax savings to be $555,300 over the six-year term of the agreement.

O&R also commenced proceedings against the Town of Blooming Grove challenging the 2013 and 2014 assessments on O&R's Blooming Grove office building. Subsequently, O&R and the Town of Blooming Grove entered into a settlement with respect to the 2015 assessment, resulting in an estimated tax savings of $1,849,000 over the three–year term of the agreement.

Q. Are you sponsoring an exhibit related to the settlements?

A. Yes, we are sponsoring Exhibit PTP-2 entitled "Orange and Rockland Utilities, Summary of Negotiated Property Tax Settlements" for that purpose. This exhibit summarizes the term of the recent settlements and the tax savings expected over the terms of those settlements.

Q. Was Exhibit PTP-2 prepared by you or under your direction and supervision?

A. Yes.

Q. Does the Company ever challenge its special franchise taxes?

A. 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 at O&R. 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 impairment in desirability or useful life resulting from factors external to the property. 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. Does the Company receive EO benefits on it special franchise taxes in the Company's service territory?

A. No. Although we have applied to ORPTS for EO benefits on the Company's electric and gas plant in the past, thus far ORPTS has denied the Company's applications.

Q. Why has ORPTS denied the Company's request for EO benefits?

A. ORPTS' methodology to determine economic obsolescence is to (identify the impairment value by) calculating the five-year average achieved return on rate base and compare it with the five-year modified required rate of return based on the capital structure. If the modified required rate of return based on the capital structure exceeds the achieved return on rate base, then the impairment's loss of value is measured by taking this difference and dividing it by the modified required rate of return to determine the economic obsolescence factor and subsequent EO benefits.

Q. Was this calculation performed for 2016?

A. Yes. In 2016, the five-year achieved return on rate base was 4.9801% and the five-year modified required rate of return based on the capital structure was 4.8118%. Based on these values, ORPTS denied the Company's request for EO benefits.

Q. Does the Company also pursue legislative avenues to mitigate its property tax liabilities?

A. Yes, the Company pursues and/or supports changes in law that could result in a reduction of its property tax liability. Although the Company is not advocating any specific property tax legislation at this time, it activity monitors state and local property tax issues and analyzes its legislative options.

Q. Does the Company keep the Commission and Staff apprised of the Company's efforts to reduce its property tax obligations?

A. Yes. The Company prepares an annual report to the Commission of its efforts to reduce its property tax obligations. The report is filed with the Commission each March. The Company also meets with Staff to update them on property tax issues. Legislative efforts and accounting and assessment issues have regularly been part of that agenda.

Q. Have you considered the effects of the Commission's ongoing Reforming the Energy Vision ("REV") proceeding (Case 14-M-0101) in your property tax forecasts?

A. Although we have not included anything in our forecasts to reflect the impact of REV, we believe REV increases uncertainty related to property taxes, which argues further for full and symmetrical property tax reconciliation. For example, over time, integrating REV into a utility's planning and operations may result in decreases in certain utility capital spending. Conversely, a utility's investment in large scale renewables may result in increases in utility capital spending. Decreases in capital investments will likely result in lower aggregate assessments for utilities shifting responsibility for property taxes to other taxpayers. Further, the current assessment practice does not include utility investments on customers' premises up to or behind the meters (*e.g.*, meters and services from the curb in are not currently assessed). Solar panels, if owned by the homeowner, may increase the homeowner's property tax as arguably the home is more valuable than a comparable home without solar panels. Nor do we know how battery storage, located on customer premises and owned by the utility will be taxed. Finally, utility property may become impaired by distributed generation thereby leading to increased depreciation allowances for functional or economic obsolescence, thereby further decreasing utility assessments.

Q. Despite the Company's efforts to minimize property taxes, 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.

VI. DISPOSITION OF PROPERTY TAX BENEFITS ON FUTURE PROPERTY TAX REDUCTIONS

Q. Please discuss the Company's proposal regarding the disposition of property tax benefits from property tax settlements.

A. The electric and gas rate plans under which the Company is currently operating provide that the Company shall retain an amount equal to 14% of the property tax refunds and/or credits allocated to electric/gas operations against future tax payments. Consistent with the Commission's long-standing policy of allowing utilities to retain a percentage of tax refunds to encourage them to challenge questionably imposed taxes, these provisions should be reauthorized in these proceedings. Moreover, the mechanisms should be modified to account for the most common outcome of tax challenges: settlements for future savings.

Q. Why is a modification needed to account for such settlements?

A. Although our efforts to seek tax refunds occasionally produce actual refunds or credits, these are extremely difficult to obtain from governmental entities. A future assessment reduction is often the solution to this problem because the Company obtains a property tax reduction and the governmental entity avoids both the current cash outlay of a refund and the administrative burden of getting a credit approved. Municipalities also prefer settlements for future assessment reductions because it facilitates their financial planning. There are also overarching benefits to settlements in general, as they avoid costly litigation for the Company and municipalities as well as help maintain a cooperative working relationship between the parties. As settlements are the preferable outcome for governmental entities and the Company alike, the Company should be entitled to retain 14% of tax savings resulting from property tax settlements, for the same reasons that the Company is entitled to retain 14% of property tax refunds and credits, net the cost to achieve. This builds on the sound regulatory policy to provide the Company a meaningful incentive in its property tax reduction efforts. The modification gives the Company flexibility in settling property tax reduction claims in the most efficient way possible. Absent the modification, the Company is disincentivized from accepting settlements for future reductions in lieu of cash. The Company is effectively penalized by accepting such future reductions in lieu of cash because it is denied retention of the equitable share the Company earned through its efforts.

Q. How does the Company propose to collect its share of future tax savings?

A. As with refunds and credits obtained through litigation, the Company will file a petition explaining the terms of any settlement agreement and requesting authorization to share in the tax savings. Once the initial petition is approved by the Commission, the Company will make annual compliance filings with a savings calculation to demonstrate the savings that resulted from the settlement. For example, where the Company’s settlement agreements for future tax savings are the result of a change in assessment methodology, the Company will calculate annual savings by taking the difference in assessments between the pre-settlement and settlement methodologies and multiplying that difference by the prevailing equalization and property tax rate. Forty-five days after the compliance filing, if Staff has not raised any issues with the Company regarding the calculation, the Company will defer 86 percent of the calculated savings for customer benefit and retain 14 percent of the calculated savings.

Q. Does that conclude your direct testimony?

A. Yes, it does.

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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 a Vice President and Treasurer of 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. Yes. I submitted testimony on behalf of Orange and Rockland in Cases 14-E-0493 and 14-G-0494.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony discusses (1) the current financial market environment, (2) the Company’s historic and projected capital structure and cost of capital, and (3) the Company’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 rebounded sharply since the Great Recession and financial crises in 2008. The U.S. is currently in its eighth year of economic expansion. U.S gross domestic product grew at a robust annual rate of 3.2% in the third quarter of 2017, the fastest in more than two years despite the impact of two hurricanes. The unemployment rate has dropped from a high of 10.0% in October of 2009 to 4.1% in November 2017. The U.S.

equity market is trading at or near all time highs and valuations are above historical averages. The S&P 500 stock index, a proxy for the U.S. equity market, is trading at approximately 18x forward twelve month earnings compared with a 10-year average of 14x. Valuations in the utilities sector are also above the historical long-term averages. Utility stocks, often viewed by investors as bond surrogates, are trading at a premium to historical valuation measures as investor search for yield in the current interest rate environment. Investor confidence in the equity market is near an all time high. The Chicago Board Options Exchange Volatility Index (“VIX”), a measure of investors expectation of equity market volatility or risk, reached 9.14% on November 3, 2017, the lowest recorded level in its 27-year history.

On the fixed income side, the U.S. fixed income market is now in its third decade of a bull market run. Investors have been willing to invest money at record low yields as they look to put funds to work in an artificially low interest rate environment. The yield on Moody’s Baa Corporate Bond Index recently stood at 4.27% (December 22, 2017), just slightly above the record low of 4.15%

reached on December 15, 2017. Interest rates on government securities remain at historical lows and are even negative in a number of countries. Record low yields have been driven in large part by unprecedented actions taken by the U.S. Federal Reserve and central banks around the world in response to the 2008 financial crisis. The Federal Reserve and other central banks have injected a substantial amount of liquidity into their respective economies through multiple rounds of quantitative easing. Quantitative easing is the practice of using money, newly created by the central banks, to buy mortgage-based and government securities. The practice increases liquidity by injecting money supply into the economy and suppressing interest rates by driving the prices of the mortgage-based and government securities up and yields on those securities down.

Q. Has the Federal Reserve taken action to scale back the unprecedented actions it took after the 2008 financial crisis?

A. Yes. Starting in January 2014, the Federal Reserve gradually began to reduce the amount of its bond purchases, ending these purchases completely in October 2014, and signaled an end to its ultra-loose monetary policy. In the December 2015 meeting of the Federal Open Markets Committee(“FOMC”), the Federal Reserve raised the Federal Funds rate by 25 basis points (“bps”) further signaling the end of an easing cycle and the beginning of a hiking cycle. Subsequent to the December 2015 Federal funds rate increase, the FOMC has hiked rates by 25 bps four times (at the December 2016, March 2017, June 2017 and December 2017 meetings). The Federal funds rate target range currently stands at 1.25%-1.50%. The Federal Funds rate is the interest rate at which a depository institution lends funds maintained at the Federal Reserve to another depository institution overnight. The Federal Funds rate is generally only applicable to the most creditworthy institutions when they borrow and lend overnight funds to each other. The Federal Funds rate is one of the most influential interest rates in the U.S. economy, because it affects monetary and financial conditions, which in turn have a bearing on key aspects of the broad economy including employment, growth and inflation.

Q. Has the Federal Reserve provided any guidance on the Federal Funds rate beyond 2017?

A. Yes. The Federal Reserve publishes a forecast of the

Federal Funds rate for 2018, 2019, 2020 and longer run. The projections are based on the individual assessments of the Federal Reserve Board members and Federal Reserve Bank presidents. In the lastest forecast (December 13, 2017), the median of the FOMC participants' assessments of appropriate monetary policy puts the Federal Funds rate at 2.1%, 2.7% and 3.1% for 2018, 2019 and 2020, respectively. The forecast implies a 70 bps increase in the Federal Funds rate in 2018 from 2017 levels or approximately three 25 bps rate hikes.

Q. Has the Federal Reserve announced any policy changes with respect to its bond buying program that will likely put upward pressure on interest rates?

A. In September 2017, the Federal Reserve announced that it has embarked on an effort to reduce its $4.5 trillion balance sheet. In its September 2017 meeting, the FOMC stated:

> The Committee intends to gradually reduce the Federal Reserve's holdings of Treasury securities and agency securities--agency debt and agency mortgage-backed securities (MBS)--by decreasing the reinvestment of the principal payments it receives from securities holdings.

The Federal Reserve began reducing its balance sheet in October 2017 by $10 billion for the month and plans to raise that amount gradually in the months to come. Jerome Powell, the nomimee for the Chair of the Federal Reserve, expects the Federal Reserve's balance sheet to shrink to about $2.5 trillion to $3.0 trillion over the next three to four years.

Q. Are there any additional developments at the Federal Reserve that could increase the upward bias on interest rates?

A. While the nomination of Jerome Powell to replace Janet Yellen as the Chair of the Federal Reserve is not expected to bring significant changes to the Federal Reserve's stance on monetary policy, the FOMC is expected to become more hawkish in 2018. A hawkish stance on monetary policy implies favoring tighter monetary policy (*i.e.*, higher interest rates) to guard against inflation vs a dovish stance which favors looser monetary policy (*i.e.*, lower interest rates) to spur economic growth. The FOMC is expected to become more hawkish as more dovish voting members (Federal Reserve Presidents Charles Evans and Neel Kashkari) are rotated off the committee and are replaced by more hawkish voting members (Federal

Reserve Presidents John Williams and Loretta Mester). It is the voting members on the FOMC who determine whether changes to the Federal Funds rate are appropriate.

Q. Are there any other developments that will change the composition of the Federal Reserve?

A. Yes. The Federal Reserve board currently has three vacancies that need to be filled by the current Administration and a fourth will become vacant when Janet Yellen leaves the Board after her successor takes over as Chair. Filling these vacancies with more hawkish members could further accelerate the pace of future interest rate hikes. In November 2017, President Trump nominated Marvin Goodfriend, a professor of economics at Carnegie Mellon University, to fill one of the vacancies. Mr. Goodfriend is expected to be more hawkish on interest rates. He has argued that the Federal Reserve should focus on controlling inflation using a minimalist approach. Mr. Goodfriend is also a proponent of gauging the Federal Reserve’s monetary policy decisions against measures such as the Taylor Rule.

Q. What is the Taylor Rule?

A. The Taylor Rule is a formula, developed by Stanford University economist John Taylor, that provides recommendations for how a central bank should set short-term interest rates based on prevailing economic conditions. The Federal Reserve Bank of San Francisco describes the Taylor Rule as:

> Specifically, the rule states that the "real" short-term interest rate (that is, the interest rate adjusted for inflation) should be determined according to three factors: (1) where actual inflation is relative to the targeted level that the Fed wishes to achieve, (2) how far economic activity is above or below its "full employment" level, and (3) what the level of the short-term interest rate is that would be consistent with full employment. The rule "recommends" a relatively high interest rate (that is, a "tight" monetary policy) when inflation is above its target or when the economy is above its full employment level, and a relatively low interest rate ("easy" monetary policy) in the opposite situations.

The Federal Reserve Bank of Atlanta, estimated that the Taylor Rule formula prescribed an average short-term rate of 3.44% for the 4th quarter of 2017 vs. an average actual Federal Funds rate of 1.20%.

Q. In addition to the monetary policy changes mentioned above, are there also potential fiscal policy changes that could impact interest rates?

A. On December 22, 2017, President Trump signed the Tax Cuts and Jobs Act ("TCJA") into law. A major element of the TCJA was the reduction of the corporate tax rate from 35% to 21%. The Trump Administration has suggested that the TCJA could accelerate the rate of sustained economic growth to above 3% compared to the approximately 2.0% average growth for the past three years. Any increase in the growth rate of the economy risks an increase in the rate of inflation in a low interest rate and low unemployment environment. Given that one of the Federal Reserve's objectives for monetary policy is maintaining price stability, any signs of an increase in the rate of inflation could be met with interest rate hikes beyond what is currently priced in by the fixed income market. In addition, the TCJA is expected to encourage corporations with large cash balances held overseas to repatriate that money. The TCJA sets a one-time mandatory tax of 8 percent on illiquid assets and 15.5 percent on cash and cash equivalents in U.S. business profits now held overseas. Corporations, such as Apple, Alphabet and Microsoft, have parked large cash reserves offshore in an effort to avoid paying U.S. taxes. Some of this cash is held in the form of U.S. Treasury securities which may need to be sold in order for this cash to be repatriated. A liquidation en masse of U.S. Treasury securities could pressure the price of these securities and increase their yields and thus interest rates. As evidence of the impact of tax reform on interest rates, 30-year U.S. Treasury yields jumped by 14 bps between December 19 and 20, the largest two day move in 2017, as the U.S. House of Representatives and U.S. Senate passed the TCJA.

Q. Is there any evidence that corporations with large, overseas cash reserves are already planning to repatriate these reserves?

A. Yes, on January 17, 2018, Apple announced that it will pay an one-time repatriation tax of $38 billion.

Q. What challenges do the current financial market conditions of artificially low interest rates, high equity valuations and low volatility present to the Company?

A. Taking the aforementioned factors into account, one of the main challenges faced by the Company is its ability to earn a fair rate of return. A confluence of factors including Staff of the Department of Public Service's ("Staff") approach to setting cost rates for debt and equity, signals pointing to a rising interest rate environment, and elevated utility equity market valuations expose the Company to the risk that it will not be able to earn its cost of capital. Staff's approach to setting cost rates for debt based on current interest rates ignores the risks of rising rates as the Federal Reserve begins to hike interest rates and reduce its balance sheet. And the current interest rate environment and historically-high utility equity market valuations are exacerbating the flaws of Staff's reliance on a formulaic approach to determining a fair return on equity. In particular, Staff's discounted cash flows ("DCF") model is, according to testimony of the Staff Finance Panel (p. 43) filed in Niagara Mohawk Power Corporation current electric and gas base rate cases (Cases 17-E-0238 and 17-G-0239), producing return on equity results that are:

> below what the "average" or "typical" investor in the proxy group would require at this time.

Cost of capital determinations that are below what investors would require could negatively impact the Company’a ability to efficiently access the capital markets.

Q. Has Staff proposed any fixes to the Commission’s DCF methodology?

A. Yes. Staff has altered its DCF methodology by recommending the use of the mean DCF result instead of the median result.

Q. Does Staff’s update of the DCF methodology adequately address the flaws in Commission’s approach?

A. No. Staff’s update fails to address the fundamental flaws with Commission’s ROE methodology. It merely offers a comestic patch to cover up the flaws exposed by the current market conditions.

Q. What additional challenges are faced by the Company in the current environment?

A. Volatility in the bond market has been and will continue to be one of the Company’s most significant challenges as the Company continually needs to access this market to raise capital. We expect volatility to increase in the financial markets. Short-term interest rates may rise both earlier and more quickly in 2018 in anticipation of further actions by the Federal Reserve given the fact that the markets are forward-looking. As evidence of this, the mere hint of the Federal Reserve's decision to start tapering its monetary easing policy in May 2013 sent ten-year Treasury bill rates higher by 46 bp for the month. A 46 bp move in one month (or an increase of 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 bill rates since 1990 (*see*, Exhibit___(YS-1), which was prepared under my supervision and direction). And on a relative basis, a 25% move ranked in the top 99.5 percentile of changes in monthly ten-year Treasury bill rates since 1990. A rise in volatility would likely lead investors to require a higher rate of return to compensate them for the additional risks that they will have to bear given this increased volatility.

Geopolitical events also have the potential to increase volatility in the capital markets. World events like those from the past two years including but not limited to: the United Kingdom’s decision to withdraw from the European Union, North Korea’s nuclear tests and missile launches, and the results of the 2016 U.S. presidential elections (and subsequent indictments of officials of the Administration), can produce shocks that could affect the Company’s ability to access capital markets efficiently.

CAPITALIZATION AND COST OF CAPITAL

Q. What capital structure do you believe should be used in the context of a rate case proceeding?

A. I believe the use of the Company’s stand-alone capitalization would be appropriate.

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 the Company’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.*, 12 months ending December 31, 2019)?

A. Yes, it does.

Q. Has the Company prepared a required rate of return exhibit?

A. Yes. The document entitled "ORANGE AND ROCKLAND UTILITIES, INC. & SUBSIDIARIES –– RATE OF RETURN REQUIRED FOR THE RATE YEAR –– THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2019," is set forth as Exhibit YS-2, Schedule 1.

Q. Please describe any projected changes in O&R's long-term debt and how such changes have been incorporated into the required rate of return for the Rate Year.

A. The Company has issued and expects to issue the following debentures:

- During the linking period (*i.e.*, October 1, 2017 through December 31, 2018): $100 million of Debentures, Series A 2018, 4.940% to be issued September 2018, due September 2048.
- During the Rate Year: $125 million of Debentures, Series A 2019, 5.450% to be issued September 2019, due September 2049.

Q. Please describe how you developed the cost of long-term debt.

A. Exhibit YS-2, Schedules 4 and 5, present the detailed calculation of the cost of the long-term debt at

September 30, 2017 and for the thirteen-month average ending December 31, 2019, 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. The Company has used forecasts of Treasury bond rates from the publication *Blue Chip Financial Forecasts*, plus a spread to Treasury bond rates based on indicative quotes from financial institutions. The *Blue Chip Financial Forecasts* consist of the consensus forecast of approximately 45 economists. This approach provides more reasonable forecast results than simply using the most current Treasury bond rates. At the update stage of this proceeding, Exhibit YS-2, Schedule 5, will be revised 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. Do you believe that current Treasury rates provide the best estimate of future long-term interest rates?

A. No. The position of Staff in recent base rate proceeedings that current rates are the best estimate of future long-term interest rates relies on a single academic paper that the Company believes is not relevant.

Q. Can you explain the flaw in Staff's position?

A. Yes. In the direct testimony of the Staff Capital Stucture Panel (pp. 53-54) submitted in recent Con Edison electric and gas base rate cases (*i.e.*, Case 16-E-0060 & 16-G-0061), Staff states that:

> The reason we recommend the use of the most recent actual Treasury yield is because relatively short-term movements in long-term interest rates are difficult to forecast. Such forecasts are not only poor predictors of the magnitude of the expected change in interest rates, they are not even reliable with respect to the direction of the change. Instead, the best estimate of future long-term interest rates is no-change; in other words, the

current rates of these debt instruments. Recent actual Treasury yields should be employed, rather than future estimated yields, which are used by the Company.

Q. Does Staff offer any evidence to support their position?

A. Yes. Staff references a study titled, “On Forecasting Long-Term Interest Rates: Is the Success of the No-Change Prediction Surprising?”, by Dr. James E. Pesando in the Journal of Finance, September 1980. This study relies upon research entitled *Econometric Models and Current Interest Rates: How Well do They Predict Future Rates,* from J. Walter Elliott and Jerome R. Baier published in 1979. The Company believes that both papers are not relevant to the discussion of forecasted interest rates in this rate case. Pesando and Elliot/Baier argue that short-term movements in long-term interest rates are not “forecastable.” Their analyses determined that current long-term interest rates (*i.e.*, a no-change prediction) outperformed “unconditional predictions” in forecasting long-term interest rates one month forward. But Pesando cautioned that when a longer forecasting timeframe was used, the outperformance of the no-change prediction no longer held. When Pesando looked over a one-year forward period, the results were very different. In his research, Pesando notes the following when comparing the results from the one-month study to the one-year study:

> These figures highlight the fact that it is short-run movements in long-term rates which are not likely to be "forecastable" under the joint hypothesis of market efficiency and a time-invariant term premium.

The Company is setting the cost of debt rates anywhere from three months to three years forward and therefore this timeframe is not consistent with the Pesando and Elliot/Baier research.

Q. What is a better method than using current rates to forecast rates?

A. A forward looking measure of rates is a better forecasting method. Examples of forward looking measures are the forward rate curve or a consensus of economists' estimates contained in the *Blue Chip Financial Forecasts*. The forward rate is the rate you can lock in today to borrow in the future and can be interpreted as the market's consensus forecast of interest rates. I believe a consensus forecast of Treasury rates, such as that produced by Blue Chip Financial, provides a more reasonable estimate rather than simplistically relying on current rates.

Q. Please describe the method used to project the Company's equity balances through December 31, 2019.

A. The average equity of O&R at December 31, 2019, excluding Other Comprehensive Income was projected from October 1, 2017 using the following steps:

1. The forecast earnings for October 1, 2017 to December 31, 2019 were added to the September 30, 2017 equity balance; and
2. The forecast dividends to Consolidated Edison, Inc. ("CEI") for October 1, 2017 to December 31, 2019 (*i.e.*, $11.0 million for the three months ending December 31, 2017, $45.0 million for the twelve months ending December 31, 2018, and $46.0 million for the twelve months ending December 31, 2019) were subtracted from the September 30, 2017 equity balance.

Q. What stand-alone capital structure for the Company results from the calculations that you described?

A. Exhibit YS-2, Schedule 1, shows the forecasted capital structure for the thirteen months ending December 31, 2019 of 50.31% long-term debt, 0.90% of customer deposits, and 48.79% common stock equity. The Company has no preferred stock outstanding.

Q. Does Exhibit YS-2 also show the forecasted capital structure, based on a thirteen-month average, for the twelve months ending December 31, 2020 and December 31, 2021?

A. Yes. Schedules 2 and 3 of Exhibit YS-2 show the capital structure for those periods. These schedules show that the debt ratio would increase to 50.42% of the Company’s capital structure in 2020 and then decrease to 50.18% in 2021 as old debt matures and new debt is issued. These schedules also show that the customer deposit ratio would decrease modestly, and the equity ratio would decrease to 48.73% in 2020% and increase to 49.01% for the twelve-month periods ending December 2020 and 2021, respectively.

Q. Would the use of the Company’s forecasted common stock equity ratio developed under the methodology described above be reasonable in the calculation of the revenue requirement?

A. Yes. Exhibit___(YS-2), which was prepared under my supervision and direction, demonstrates that the Company’s forecasted common stock equity ratio is below the mean equity ratio of a group of comparable utility operating companies of 50.1%.

Q. Are you requesting that the capital structure, upon which the revenue requirements are calculated in the Company’s electric base rate filing, use an equity ratio of 48.79%?

A. No. For purposes of calculating the revenue requirements in this rate filing, 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 the Company in order to minimize the contested 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 lower than the level the Company believes is reasonable based on the Company’s standalone capital structure.

Q. What return on equity is the Company proposing be used for purposes of developing a revenue requirement in these filings?

A. For the reasons discussed in the direct testimony of the Company’s Accounting Panel, the Company proposes a 9.75%

return on equity ("ROE") be used. O&R is using a different metholodogy to formulate this ROE, as presented by Company witness Vander Weide, which I will discuss later in my testimony.

Q. Using this capital structure and cost of long-term debt and the return on equity, what overall rate of return is the Company proposing in this case?

A. The overall rate of return is 7.39% as shown on Exhibit YS-2, 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 interrelated financial challenges: (A) the capital intensive nature of its business, (B) flat demand growth for electricity, (C) its unusually weak cash flows, (D) the restrictions that regulation places on its ability to respond to unfavorable developments in its environment, and (E) its dependence on the market to fund its capital needs.

Q. Please discuss 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 Cambridge Energy Research Associates presentation titled *Post Fukushima: If not nuclear, what energy mix?* (June 2, 2011), the electric utility industry is the most capital intensive industry as measured by the ratio of total assets to total revenues. As shown on Exhibit___(YS-3), which was prepared under my supervision and direction, the Company's capital intensity can be demonstrated by the fact that its ratio of net fixed assets per dollar of revenues is 2.4, versus 0.9 for the average S&P 500 company and 0.2 for the median company. Capital intensity amplifies risk for investors because capital intensive businesses have to recover much larger fixed costs (interest and depreciation) before achieving a return on their investment. The Company'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 issuances and equity 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 also wait longer for 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 value 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 40% of its capital expenditures in the form of depreciation for the twelve months ended December 31, 2016.

Due to the long depreciation lives established in rates, this dynamic is likely to continue for many years. As shown on Exhibit___(YS-4), which was prepared under my supervision and direction, by way of comparison, the average S&P 500 company recovered 143% of its capital expenditures through depreciation and amortization. This would have placed O&R near the bottom 10% of companies in the S&P 500 that had meaningful recovery rates. CEI (which had a 28% capital expenditure recovery rate) had the second-lowest recovery rate among the 28 utilities in the S&P 500 as shown on Exhibit___(YS-4), which was prepared under my supervision and direction. This would have placed O&R in the bottom half among the 28 utilities in the S&P 500. The average recovery rate for the utility companies in the S&P 500 was 47%.

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 that 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. While the Commission’s willingness to explore the implementation of earnings adjustment mechanisms (“EAMs”) may provide utilities with an opportunity to earn positive incentives, the lack of a track record with EAMs in New York State prevents any definitive conclusions. 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 how flat demand growth for electricity presents a financial challenge.

A. The Company's total retail electric sales volume has grown by an average annual rate of just 0.17% over the last five years. Flat demand growth for electricity, coupled with the capital intensive nature of the business, puts upward pressure on the unit cost of electricity as the recovery of capital is spread over a smaller base.

Q. Please describe how the Company's weak cash flows present a financial challenge.

A. Because the Company will continue to be challenged by its weak cash flows and lack of positive free cash flows, O&R will continue to be more dependent on external funding.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to Exhibit___(YS-5), which was prepared under my supervision and direction.

Q. Have any of credit rating agencies commented on the Company's weak cash flows?

A. Yes. S&P Global, in an August 7, 2017 report included as Exhibit__(YS-6), lowered the Company's standalone credit profile ("SACP") from A- to BBB+. S&P Global commented that:

> The revised SACP reflects our expectations for financial measures that we expect will consistently reflect the lower end of the range for the company's current financial risk profile relative to peers, including funds from operations (FFO) to debt ranging from 13%-14%.

Q. Are there any additional factors that could further weaken the Company's cash flows?

A. Yes. The aforementioned TCJA has several provisions that will likely negatively impact the cash flows of the utilities sector. The two provisions with the highest impact are the lower corporate tax rate and loss of bonus depreciation. The lower corporate tax rate will require utilities to write-down the amount of deferred tax liabilities on the utilities' books leading to a reduction of cash flows. The loss of bonus depreciation will lower depreciation expense and increase taxable income.

Q. Have any of the rating agencies evaluated the impact of the TCJA on the utilities sector?

A. Yes. Moody's published a report titled, "Corporate tax cut is credit positive, while effects of other provisions vary by sector" on December 21, 2017. In this report Moody's describes the TCJA as having a negative cash flow impact on the utilities sector:

> Based on our preliminary analysis, all else being equal, the fall in cash flows is significant for many companies. Out of our portfolio of 215 regulated utilities and their holding companies, we expect that up to 20% of them will see meaningful declines in key financial metrics. As shown in the table below, for this subset of most exposed companies, we estimate that the ratio of cash flow from operations pre-working capital (CFO pre-WC) to debt will on average fall about 133 basis points. If

> not addressed, this could lead to negative rating actions.

Q. Subsequent to publishing this report, has Moody's taken any rating actions in the utility sector as a result of TCJA?

A. Yes. On January 19, 2018, Moody's changed the rating outlooks of 24 regulated utilities and utility holding companies from "stable" to "negative". The rating outlooks for CEI, Con Edison and Orange and Rockland were revised from "stable" to "negative".

Q. What reasons did Moody's provide to support the rating outlook changes?

A. In the report, included as Exhibit__(YS-7), Moody's wrote:

> The change in outlook to negative from stable for the 24 companies affected in this rating action primarily reflects the incremental cash flow shortfall caused by tax reform on projected financial metrics that were already weak, or were expected to become weak, given the existing rating for those companies. The negative outlook also

> considers the uncertainty over the timing of any regulatory actions or other changes to corporate finance policies made to offset the financial impact.

Q. What are the implications of a negative outlook?

A. A Moody's rating outlook is an opinion regarding the likely rating direction of a company over the medium term. A negative outlook indicates a higher likelihood of a negative ratings change.

Q. What factors will Moody's consider in deciding whether a ratings downgraded is warranted?

A. Moody's stated that it will continue to monitor the financial impact of tax reform on each company over the next 12 to 18 months. Moody's focus will be on:

> …regulatory approach to rate treatment and any changes to corporate finance strategies. This will include balance sheet changes dues to the reclassification of excess deferred tax liabilities as a regulatory liability and the magnitude of any amounts to be refunded to customers.

Q. Did Moody's provide their views on potential regulatory offsets to the negative cash flow impact of TCJA?

A. Yes. Moody's is of the view that potential regulatory offsets could include accelerated cost recovery of certain regulatory assets or future investment; changes to the equity layer or allowed ROEs in rates, and other actions.

Q. Please describe how restrictions on the Company's business imposed by the Commission present a financial challenge.

A. The Company is subject to various regulatory restrictions that limit its ability to react to unfavorable circumstances. For example, the Company must provide service as requested, even if doing so entails significant investment upon unfavorable terms. 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 non-utility companies, Orange and Rockland has a limited 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. The Commission also routinely requires earnings sharing mechanisms, which serve to limit earnings opportunities, as a component of base rate case settlements. 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.

Q. Please describe 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 $100 million in 2018, $125 million in 2019, $50 million in 2020 and $75 million in 2021. The Company will need the assurances of positive cash flows and favorable regulatory support to continue to market this debt at reasonable rates.

Each time O&R markets its debt securities, investors will assess the risks they would bear if they invested in the Company in light of the challenges identified above. Their assessment of these risks is, and will be, priced into the cost of debt each time 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's capital investment needs. To raise this capital at a reasonable cost, the Company must remain an attractive investment 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 and what type of debt does the Company have outstanding?

A. As of September 30, 2017 O&R had $662 million of long-term debt. The Company also had letters of credit outstanding in an amount of $25 million. Letters of credit represent an additional capital need which must be met, requiring the Company to compete for scarce funds in a highly 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 Orange and Rockland?

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 those offered by the Company.

Q. What are the current ratings on Company debt?

A. The long-term, senior unsecured debt ratings are A3, A-, and A- by Moody’s, S&P, and Fitch, respectively. The short-term debt is rated P-2, A-2, and F2, respectively. All ratings have a negative outlook.

Q. Are bond ratings the correct indicator of the risks to shareholders?

A. No. The priority of bondholders’ claim on the Company means that shareholders are subject to a higher level of risk. 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 through a drop in the share price and/or through a lower dividend.

Q. Why do companies such as O&R need to maintain 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. In addition, utilities may have to access the capital market in response to a natural catastrophe (*e.g.*, Superstorm Sandy). When utilities are forced to pay high rates, these rates will remain 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 the Company to pay for energy that must be delivered, no matter the price. Only A-1/P-1 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, non A-1/P-1 borrowers, if they had access, paid significantly higher rates.

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 the Company 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.

Q. Please explain why maintaining its current debt ratings is important for O&R.

A. The Company has a significant continuing construction program which must be funded in large part by debt financing. Access to credit markets will be restrictive for lower quality creditors. In addition, a part of the Company'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 60,000 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 or other 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 the Company, 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 the people who own CEI shares, either directly or indirectly, provide to the Company?

A. They provide the capital that the Company needs above and beyond what debt investors provide. Their capital allows the Company to provide 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. For example, instead of paying for a new substation as it is constructed, customers can 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?

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 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 a defined geographic area 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 direct testimony of Company witness Vander Weide, it dates back to the *Hope* and *Bluefield* cases. The United States Supreme Court in those cases established that in determining the fairness or reasonableness of a utility’s allowed 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.

Q. Is the Commission's methodology consistent with the general standards for fair and equitable returns for investors?

A. No. The Commission's two-thirds weighting of the DCF model and one-third weighting of the Capital Asset Pricing Model ("CAPM") present three primary problems.

Q. Please describe the problems with the Commission's methodology.

A. First, the DCF model and the CAPM methodology do not fulfill the comparable earnings standard adopted by the United States Supreme Court in the *Hope* and *Bluefield* cases. That is, neither method provides information about the earned returns on investments in other enterprises having corresponding risks. Second, the DCF model should use the book value share price as an input rather than the market value share price since the resulting return on equity is applied to a book value measure of rate base. Using a market value share price in the DCF model understates the return on equity when the market value share price is above the book value share price. This is a weakness of the DCF model that was acknowledged by Staff in Case 91-M-0509 (the so-called “Generic Finance Proceeding”). Specifically, as noted by the Recommended Decision in Case 91-M-0509 (p. 55), Staff recognized that:

> …the DCF approach tends to produce returns higher than necessary when stocks are selling below book, and lower than necessary when stocks are selling above book.

Despite this acknowledged weakness, the Recommended Decision in the Generic Financing Proceeding chose to place two-thirds of the weighting on this flawed methodology.

Third, by rejecting the comparable earnings method, the Recommended Decision in the Generic Financing Proceeding narrows the use of methods from three to two to calculate retun on equity. The practice of using just two methods is out of step with both the academic literature and with the practices in most, if not all other, jusrisdictions in the United States. Stewart Myers, a prominent finance scholar, stated in “On the Use of Modern Portfolio Theory in

Public Utility Rate Cases: Comment," Financial Management, p. 67, Autumn 1978:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively.

Moreover, although repeatedly relied on for ratemaking, the Recommended Decision in the Generic Finance Proceeding was never formally adopted by the Commission, thereby precluding any understanding, or opportunity to challenge, the Commission's reasons for rejecting the proposal from Staff, the utilities and other stakeholders.

Q. Has Staff begun to express concerns with the flaws in the Commission's ROE methodology and the current output results?

A. Yes. The Staff Finance Panel, in Cases 17-E-0238 and 17-G-0239, acknowledged the shortcomings of their DCF approach, namely the fact that their DCF model ROEs are below what is required by investors.

Q. Did Staff offer any explanation as to why their model is producing ROE's below what is required by investors?

A. Yes. The Staff Finance Panel (p. 42) attributes the low ROE output to several developments in the markets:

> Specifically, the Federal Reserve's "go slow" approach on raising interest rates in recognition of the economy's continued slow growth appear to have had an impact. Investors recently have pursued less risky investments including utility stocks, thereby pushing the S&P 500 Utilities Index to a record high of 274.95 in the month of June 2017. Demand for utility shares has driven up prices of utility stocks and increased the market-to-book ratio (MBR) of our proxy group. In contrast, in August 2012 when Staff filed testimony in NMPC's last rate cases (12-E-0238/12-G-0239), the average MBR for Staff's proxy group was approximately 1.43x. Our current proxy group

MBR is 2.0x, which represents a 40 percent increase over the period. Additionally, price to earnings (P/E) ratios are generally at or near all-time highs for most utilities, which demonstrates there has been an investor shift to lower risk utility stocks.

Q. Is Staff's explanation for the low ROE output of the Commission's model consistent with the flaws outlined by the Company?

A. Yes. As discussed above, the Commission's application of the DCF model using market values instead of book values produces returns lower than necessary when stocks are selling above book value as is the case in the current market.

Q. Has Staff proposed any fixes to the Commission's methodology?

A. Yes. As discussed earlier, Staff has altered its DCF methodology by recommending the use of the mean DCF result instead of the median result.

Q. Does Staff's update of the DCF methodology adequately address the flaws in Commission's approach?

A. No. As discussed earlier, Staff’s update fails to address the fundamental flaws with Commission’s ROE methodology.

Q. Is the Company proposing to use an additional method for calculating return on equity in this case?

A. Yes. As set forth in the direct testimony of Company witness Vander Weide, the Company is proposing to use a comparable earnings method in addition to the DCF and CAPM methods and ascribe a weighting of one-third to each of the three methods.

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 Commission’s rate orders.

Q. How do the Commission’s rate orders influence investors’ evaluation of the first identified return consideration?

A. The first factor, the headline rate of return 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 demonstrate in this case and have demonstrated 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 as compared with other states (based on data from Regulatory Research Associates (“RRA”)) to demonstrate the consistency of this practice (Exhibit___(YS-8), which was prepared under my supervision and direction).

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 be among the lowest returns in the country.

Q. Staff has pointed to the various regulatory recovery mechanisms authorized by the Commission as a justification for the low authorized ROEs granted to New York State utilities. Do you agree with Staff's position?

A. No I do not. The regulatory recovery mechanisms that New York State provides are not distinctive among the U.S. regulatory jurisdictions. As set forth in Exhibit___(YS-9), which was prepared under my supervision and direction, many of the mechanisms put in place by the Commission are currently in use in other jurisdictions. Accordingly, the Company does not believe that these mechanisms compensate for the low ROEs consistently granted by the Commission.

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. O&R does not fare well in the comparison. When looking at the five-year historical average return on book equity, the Company had a return that would have placed it near the bottom third of S&P companies with meaningful available data. The return for the average S&P company was 18.4%. The comparable return on book equity for O&R was 9.8%.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to Exhibit___(YS-10), which was prepared under my supervision and direction.

Q. Are companies typically valued by investors at their book value?

A. No, they are valued by investors based on their future business prospects. Exhibit___(YS-11), which was prepared under my supervision and direction, 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 23% of this universe for this important measure of investor perceptions and expectations, even after the financial crisis which severely affected the financial sector and other industries.

Valuation methods such as the 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 CAPM methodology suffers from similar flaws. Market-derived returns must be applied to market equity values. There is no theoretical basis to do otherwise.

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 other revenue or expense adjustments. To the extent that such adjustments are made to real costs, 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 a system where potential negative revenue adjustments are far larger than potential positive incetives, as well one-way true-ups of costs--burdens which have been imposed in New York rate decisions--to realize significantly lower returns than the headline authorized return. All of these aspects of New York rate orders produce asymmetry in expected returns, which a rational potential equity investor would judge as ultimately 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. How would an investor assess the fourth factor: the restrictions the regulator places on the scope of the business?

A. The adverse impact of the last factor is less quantifiable because it consists of opportunities foreclosed to the Company and thus to the investor.

Restrictions on investments in generation in New York, and the punitive indirect restrictions on affiliate company capitalization, reduce the value of the Company to its owners, but in ways that are difficult to quantify explicity.

Q. Have the shortcomings in the treatment of the Company been reflected in equity analysts' views of the CEI?

A. Yes. As of January 5, 2018, CEI ranked as 503rd of the 505 companies in the S&P 500 in terms of analyst buy/sell rankings (see Exhibit___(YS-12), which was prepared under my superivision and direction).

CONCLUSION

Q. Please summarize your testimony regarding the financial challenges facing the Company.

A. 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 the financing of 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.
RATE OF RETURN

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BEFORE THE
NEW YORK PUBLIC SERVICE COMMISSION

ORANGE AND ROCKLAND UTILITIES, INC.

CASE NOS. 18-E-____ AND 18-G-____

PREPARED DIRECT TESTIMONY OF JAMES H. VANDER WEIDE
ON BEHALF OF
ORANGE AND ROCKLAND UTILITIES, INC.

I. <u>INTRODUCTION AND PURPOSE</u>

Q. Please state your name, title, and business address.

A. My name is James H. Vander Weide. I am President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q. Please describe your educational background and prior academic experience.

A. I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, Professor, and then Research Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than thirty-five years. I am now retired from my teaching duties at Duke. A summary of my research, teaching, and other professional experience is presented in Appendix 1.

Q. Have you previously testified on financial or economic issues?

A. Yes. As an expert on financial and economic theory and practice, I have participated in more than five hundred regulatory and legal proceedings before the public service commissions of forty-five states and four Canadian provinces, the Federal Energy Regulatory Commission, the National Energy Board (Canada), the Federal Communications Commission, the Canadian Radio-Television and Telecommunications Commission, the U.S. Congress, the National Telecommunications and Information Administration, the insurance commissions of five states, the Iowa State Board of Tax Review, and the North Carolina Property Tax Commission. In addition, I have prepared expert testimony in proceedings before the U.S. District Court for the Northern District of California; the U.S. District Court for the District of Northern Illinois; the U.S. District Court for the Eastern District of Michigan; the U.S. District Court for the District of Nebraska; the U.S. District Court for the District of New Hampshire; the U.S. District Court for the Eastern District of North Carolina; the U.S. Bankruptcy Court for the Southern District of West Virginia; the Montana Second Judicial District Court, Silver Bow County; the Supreme Court of the State of New York; and the Superior Court, North Carolina.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Orange and Rockland Utilities, Inc. ("O&R" or the "Company") to prepare an independent appraisal of the required rate of return on equity for the Company's regulated utility operations in New York and to recommend an allowed rate of return on equity ("ROE") for these operations that is fair, that allows the Company to attract capital on reasonable terms, and that allows the Company to maintain its financial integrity. O&R is a wholly-owned subsidiary of Consolidated Edison, Inc. ("CEI"). I also provide an assessment of the Company's capital structure to be used for rate making purposes, as proposed in the direct testimony of Company witness Yukari Saegusa.

II. SUMMARY OF TESTIMONY

Q. How do you estimate O&R's required rate of return on equity?

A. I estimate O&R's required rate of return equity by: (1) applying several standard cost of equity estimation methods to financial data for a proxy group of electric utilities of comparable risk; and (2) calculating the average expected rate of return on book equity for the group of electric utilities.

Q. Why do you apply cost of equity methods to a proxy group of comparable risk utilities rather than solely to the Company?

A. I apply my cost of equity methods to a proxy group of comparable risk utilities because: (1) the Company is not publicly-traded; and (2) standard cost of equity methods such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured. Since these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to one or more proxy groups of comparable companies. In utility regulation, the practice of using comparable companies, called the comparable company approach, is further supported by the United States Supreme Court standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of comparable risk.[1]

Q. Why do you believe it is important to use more than one analytical approach to estimate the Company's cost of equity?

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 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. However, as a practical matter, all models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints.

Thus, I believe it is prudent and appropriate to use multiple methodologies in order to reduce the uncertainty that may be associated with the assumptions and inputs of any single approach. It is further appropriate to apply reasoned judgment in considering the results generated by each individual approach.

Q. What required rate of return on equity do you find for the utility operations of O&R in this proceeding?

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[1] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield Water Works"); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope Natural Gas")*

A. On the basis of my studies, I find that the required rate of return on equity for the utility operations of O&R is 10.3 percent. This conclusion is based on my application of standard cost of equity estimation techniques, including the DCF model and the CAPM, to a proxy group of electric utilities of comparable risk and my calculation of the average expected rate of return on book equity for that group of electric utilities.

Q. Do you have exhibits accompanying your testimony?

A. Yes. I have prepared or supervised the preparation of Exhibit ___(JVW-1), which consists of eleven schedules and five appendices that accompany my direct testimony.

III. ECONOMIC AND LEGAL PRINCIPLES

Q. What is the economic definition of the cost of capital?

A. Economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

Q. What role does the cost of capital play in the allocation of capital in the capital markets?

A. The cost of capital is a hurdle rate, or cut-off rate, for investment in a company or project. Investors will only invest in a company or project if they expect to earn a return on their investment that is at least as large as the return they expect to receive on other investments of comparable risk.

Q. Do all investors have the same position in the company?

A. No. Debt investors have a fixed claim on a company's assets and income that must be paid prior to any payment to the company's equity investors. Since the company's equity investors have only a residual claim on the company's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

Q. What is the overall or average cost of capital?

A. The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a company's capital structure.

Q. Can you illustrate the calculation of the overall or weighted average cost of capital?

A. Yes. Assume that the cost of debt is 7 percent, the cost of equity is 13 percent, and the percentages of debt and equity in the company's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by 0.50 times 7 percent plus 0.50 times 13 percent, or 10.0 percent.

Q. How do economists define the cost of equity?

A. Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Q. How do economists measure the percentages of debt and equity in a company's capital structure?

A. Economists measure the percentages of debt and equity in a company's capital structure by first calculating the market value of the company's debt and the market value of its equity. Economists then calculate the percentage of debt by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market value of debt and equity. For example, if a company's debt has a market value of $25 million and its equity has a market value of $75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q. Why do economists measure a company's capital structure in terms of the market values of its debt and equity?

A. Economists measure a company's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q. Why do investors measure the expected return and risk on their investment portfolios using market value weights rather than book value weights?

A. Investors measure the expected return and risk on their investment portfolios using market value weights because: (1) the expected return on a portfolio is calculated by comparing the expected value of the portfolio at the end of the investment period to its current value; (2) the risk of a portfolio is calculated by examining the variability of the return on the portfolio around its expected value; and (3) market values are the best measure of the current value of the portfolio. From the investor's point of view, the historical cost, or book value of their investment, is generally a poor indicator of the portfolio's current value.

Q. Is the economic definition of the weighted average cost of capital consistent with regulators' traditional definition of the average cost of capital?

A. No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book values of debt and equity in a company's capital structure.

Q. Will investors have an opportunity to earn a fair return on the value of their equity investment in the company if regulators calculate the weighted average cost of capital using the book value of equity in the company's capital structure?

A. No. Investors will only have an opportunity to earn a fair return on the value of their equity investment if regulators either calculate the weighted average cost of capital using the market value of equity in the company's capital structure or adjust the cost of equity for the difference in the financial risk reflected in the market value capital structures of the proxy companies and the financial risk reflected in the company's rate making capital structure.

Q. Are the economic principles regarding the fair return for capital recognized in any United States Supreme court cases?

A. Yes. These economic principles, relating to the supply of and demand for capital, are recognized in two United States Supreme Court cases: (1) *Bluefield Water Works*; and (2) *Hope Natural Gas Co*. In the *Bluefield Water Works* case, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties. [*Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).]

The Supreme Court recognizes here that: (1) a regulated company cannot remain financially sound unless the return it is allowed to earn on the value of its property is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated company will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In the *Hope Natural Gas* case, the Supreme Court reiterates the financial soundness and capital attraction principles of the *Bluefield Water Works* case:

> From the investor or company point of view it is important that

> there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).]

The Supreme Court recognizes that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

IV. BUSINESS AND FINANCIAL RISKS

Q. How do investors estimate the expected rate of return on specific investments, such as an investment in O&R's regulated utility operations?

A. Investors estimate the expected rate of return in several steps. First, they estimate the amount of their investment in the company. Second, they estimate the timing and amounts of the cash flows they expect to receive from their investment over the life of the investment. Third, they determine the return, or discount rate, that equates the present value of the expected cash receipts from their investment in the company to the current value of their investment in the company.

Q. Are the returns on investment opportunities, such as an investment in O&R, known with certainty at the time the investment is made?

A. No. The return on an investment in O&R depends on the Company's expected future cash flows over the life of the investment, including both the return on and the return of capital. Since the Company's expected future cash flows are uncertain at the time the investment is made, the return on the investment is also uncertain.

Q. You discuss above that investors require a return on investment that is equal to the return they expect to receive on other investments of similar risk. Does the required return on an investment depend on the risk of that investment?

A. Yes. Since investors are averse to risk, they require a higher rate of return on investments with greater risk.

Q. What fundamental risk do investors face when they invest in a company such as O&R?

A. Like all investors, investors in utilities such as O&R face the fundamental risk that their realized, or actual, return on investment will be less than their required return on investment.[2]

Q. How do investors attempt to measure investment risk?

A. Investors attempt to measure investment risk by estimating the probability, or likelihood, of earning less than the required return on investment, including both a return on and a return of their capital investment. For investments or projects with potential returns distributed symmetrically about the expected, or mean, return, investors can also measure investment risk by estimating the variance, or volatility, of the potential return on investment.

Q. Do investors distinguish between business and financial risk?

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[2] In my discussion of business and financial risk, I focus on the generic risks of regulated electric utility operations because O&R receives approximately 77 percent of its operating revenues and 80 percent of operating income from its regulated electric utility operations; and the risks of the Company's regulated natural gas operations are broadly similar to the risks of the regulated electric utility operations. The New York Public Service Commission has typically relied on electric utility proxy groups to establish the cost of equity for both the gas and electric operations of the combination utilities in the state.

A. Yes. Business risk is the underlying risk that investors will earn less than their required return on investment when the investment is financed entirely with equity. Financial risk is the additional risk of earning less than the required return when the investment is financed with both fixed-cost debt and equity.

Q. What are the primary determinants of an electric utility's business risk?

A. The business risk of investing in electric utility companies such as O&R is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

Q. How does demand uncertainty affect an electric utility's business risk?

A. Demand uncertainty affects an electric utility's business risk through its impact on the variability of the company's revenues and its return on investment. The greater the uncertainty in demand, the greater is the uncertainty in the company's revenues and its return on investment.

Q. What causes the demand for electricity to be uncertain?

A. Electric utilities experience both short-run and long-run demand uncertainty. Short-run demand uncertainty is caused by the strong dependence of electric demand on the state of the economy and weather patterns. Long-run demand uncertainty is caused by: (1) the sensitivity of demand to changes in rates; (2) the efforts of customers to conserve energy; (3) the potential development of new energy efficient technologies and appliances; (4) the improved economics of distributed generation; (5) the ability of some customers to generate their own electricity by installing solar panels, for example, or by investing in distributed energy resources; and (6) in a rapidly changing industry environment, the uncertain impact of changing governmental regulations and subsidies both on the price of electricity and on regulators' ability to assure that utility investors have an opportunity to earn a fair rate of return on their investment.

Q. How does short-run demand uncertainty affect an electric utility's business risk?

A. Short-run demand uncertainty affects an electric utility's business risk through its impact on the variability of the company's revenues and its return on investment. The greater the short-run uncertainty in demand, the greater is the uncertainty in the company's yearly revenues and return on investment.

Q. How does long-run demand uncertainty affect an electric utility's business risk?

A. Long-run demand uncertainty affects an electric utility's business risk through its impact on the utility's revenues over the life of its capital investments. Long-run demand uncertainty produces risk for electric utilities because investments in electric utility infrastructure are long-lived and irreversible. If demand turns out to be less than expected over the life of the investment, a utility may not be able to generate sufficient revenues over the life of the investment to cover its operating expenses and earn a fair long-run return on the capital it has invested in its network.

Q. Does O&R experience demand uncertainty?

A. Yes. O&R experiences both short-run and long-run demand uncertainty. The Company experiences short-run demand uncertainty as a result of economic cycles such as recessions, when fewer homes are being built, fewer new businesses are being started, and factories are running at less than full capacity. O&R experiences long-run demand uncertainty when it invests in major long-lived plant, equipment, and information systems that are expected to provide service over many years. If future actual demand turns out to be less than the forecast demand at the time an investment was made, the Company's revenues over the life of the investment may be insufficient to allow the Company to earn a fair return on the investment.

Q. Do O&R's rate plans include revenue decoupling mechanisms?

A. Yes.

Q. Do the Company's revenue decoupling mechanisms reduce demand or revenue uncertainty?

A. As noted above, O&R experiences both short-run and long-run demand and revenue uncertainty. Revenue decoupling mechanisms impact short-run revenue uncertainty, but have a much weaker impact on long-run revenue uncertainty. Investors recognize that the regulated utility industry is changing rapidly and that utility regulators such as the New York Public Service Commission ("Commission") are considering changes in the utility industry structure, such as those envisioned in the Reforming the Energy Vision ("REV") proceeding (Case 14-M-0101). Investors also recognize that demand and revenue uncertainty are greater in the long-run than in the short-run.

Q. Do most of the utilities in your cost of equity studies also have revenue decoupling and cost adjustment mechanisms that reduce demand or revenue uncertainty?

A. Yes. A Regulatory Research Associates report entitled, *Regulatory Focus – Adjustment Clauses (A State-by-State Overview),* dated August 22, 2016, confirms that most of the utilities in my cost of equity studies have decoupling and cost adjustment mechanisms.

Q. Why is the wide availability in the utility industry of revenue decoupling mechanisms relevant to your cost of equity conclusions?

A. The wide availability of revenue decoupling mechanisms in the utility industry is relevant because it supports my conclusion that O&R's investment risk is similar to the investment risk of the proxy electric utilities I use to estimate O&R's cost of equity.

Q. Why are an electric utility's operating expenses uncertain?

A. Operating expense uncertainty arises as a result of: (1) high volatility in fuel prices or interruptions in fuel supply; (2) variability in maintenance costs and the costs of materials; (3) uncertainty over outages of the company's energy delivery systems; (4) uncertainty of expenses required to recover from storm damage; (5) uncertainty regarding the cost of purchased power; (6) the prospect of increasing employee health care and pension expenses; and (7) the prospect of increased expenses for security, including cybersecurity.

Q. Do O&R's rate plans include cost adjustment mechanisms that, in part, reduce the Company's operating expense uncertainty?

A. Yes. The Company's rate plans include cost adjustment mechanisms that reduce the impact of unexpected operating expenses on the Company's earnings. However, investors are aware that the utility industry operating environment is changing rapidly and that regulators' ability may have limited ability to assure recovery of operating expenses in the long run. In addition, investors recognize that regulators focus on the impact of rates on customers' total monthly bills. Accordingly, even if a utility's capital and operating costs are increasing substantially, regulators may have limited willingness to increase distribution rates.

Q. Why are utility investment costs uncertain?

A. The electric utility business requires large investments in the plant, equipment, and information systems required to deliver electricity to customers. The future amounts of required investments in plant, equipment, and information systems are uncertain as a result of: (1) demand uncertainty; (2) the changing economics of alternative energy delivery technologies; (3) uncertainty in environmental regulations and clean air requirements; (4) uncertainty in the costs of construction materials and labor; and (5) uncertainty in the amount of additional investment required to provide safe and reliable service. Furthermore, the risk of utility investment is increased by the irreversible nature of the company's investments in utility plant, equipment, and information systems. For example, if an electric utility invests in developing distributed energy platforms that allow customers to manage their own energy requirements, and customers use these platforms to reduce their use of the company's energy delivery services, the company may not be able to recover the capital investments it makes to provide electric delivery services.

Q. Have the Company's capital expenditures increased in recent years?

A. Yes. The Company's capital expenditures increased from $142 million in 2014 to $160 million in 2015 and $166 million in 2016. The Company is projecting capital expenditures of $192 million in 2017, $209 million in 2018, and $200 million in 2019.[3]

Q. If major capital expenditures increase an electric utility's business risks, why do electric utilities undertake such expenditures?

A. Electric utilities make capital expenditures in order to upgrade or replace infrastructure; improve the performance of their energy delivery infrastructure; expand their energy infrastructure to satisfy the need to serve new customers and/or meet changing energy requirements of existing customers; maintain the reliability and safety of the electric delivery network; satisfy new environmental requirements; and respond to changing regulatory requirements. O&R has been granted a franchised service territory and has the legal obligation to serve the current and future electric delivery needs of that service territory. The investments required to provide this service are a necessary cost of providing utility service.

Q. You note above that high operating leverage contributes to the business risk of electric utilities. What is operating leverage?

A. Operating leverage is the increased sensitivity of a company's earnings to sales variability that arises when some of the company's costs are fixed.

Q. How do economists measure operating leverage?

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3 *See* Consolidated Edison, Inc., 2016 Annual Report, p. 29.

A. Economists typically measure operating leverage by the ratio of a company's fixed expenses to its operating margin (revenues minus variable expenses), which is frequently approximated by the ratio of assets to revenues.

Q. What is the difference between fixed and variable expenses?

A. Fixed expenses are expenses that do not vary with output (that is, Kwh sold), and variable expenses are expenses that vary directly with output. For electric utilities, fixed expenses include the capacity component of purchased power costs, the fixed component of operating and maintenance costs, depreciation and amortization, and taxes. In certain jurisdictions, fuel expenses and the variable component of purchased power costs are the primary variable costs for electric utilities.

Q. Do electric utilities experience high operating leverage?

A. Yes. As noted above, operating leverage increases when a company's commitment to fixed costs rises in relation to its operating margin on sales. The relatively high degree of fixed costs in the electric utility business arises primarily from: (1) the average electric utility's large investment in assets compared to revenue; and (2) the relative "fixity" of an electric utility's operating and maintenance costs. High operating leverage causes the average electric utility's operating income to be highly sensitive to demand and revenue fluctuations.

Q. Can an electric utility reduce its operating leverage by purchasing, rather than generating, electricity?

A. No. Electric utilities that purchase power under long-term contracts generally pay both a fixed capacity charge and a variable charge that depends on the amount of electricity purchased. Since the fixed capacity charge is designed to recover the seller's fixed costs of generating electricity, electric utilities generally experience the same degree of operating leverage when they purchase power as when they generate power.

Q. How does operating leverage affect a company's business risk?

A. Operating leverage affects a company's business risk through its impact on the variability of the company's profits or income. Generally speaking, the higher a company's operating leverage, the higher is the variability of the company's operating profits.

Q. Does regulation produce uncertainty for electric utilities?

A. Yes. Investors' perceptions of the business and financial risks of electric utilities are strongly influenced by their views of the quality of regulation. Investors are aware that regulators in some jurisdictions have been unwilling at times to set rates that allow regulated companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric utilities operating in those jurisdictions. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Q. Do investors have access to information regarding the quality of regulation in making investment decisions?

A. Yes. Investors have access to numerous sources that evaluate the quality of the regulatory environments in which utilities operate. For example, rating agencies and equity research analysts such as Value Line and Regulatory Research Associates offer evaluations on the quality of regulatory environments. These sources inform investors regarding the extent to which regulators in various jurisdictions have been willing to set rates at a level that will allow utilities an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment.

Q. Do investors take information regarding the quality of regulation into account when determining their required rate of return on investment?

A. Yes. An investor's required rate of return on an equity investment in an electric utility is directly related to his/her perception of risk: the higher the perception of regulatory risk, the higher the required return.

Q. Are you aware of any additional regulatory risks facing O&R at this time?

A. Yes. I am aware that the Commission instituted the REV proceeding in April 2014 (Case 14-M-0101) to consider and implement a new vision for the future of the electric utility industry in New York State. Since that time, the Commission has issued two major orders (the Framework Order issued on February 26, 2015, and the Track Two Order, issued on May19, 2016) to begin implementing REV. As described in the Framework Order (p. 7), "A driving purpose of REV is to leverage the power of markets to reduce the total customer bill by increasing deployment of non-regulated third-party capital, and by supporting utility reliance on DER [distributed energy resources] as an integral grid resource."

In addition, the Company has informed me that the Commission has begun a number of related proceedings to implement the REV vision, including, for example, the New York State Clean Energy Standard (Case 15-E-0302) and the Value of Distributed Energy Resources (Case 15-E-0751). In Case 15-E-0302, the Commission adopted a clean energy standard requiring that 50 percent of New York State's electricity be generated from renewable energy resources by 2030. In Case 15-E-0751, the Commission initiated proceedings to establish a methodology for valuing distributed energy resources and designing rates for competitive DER providers. Because the REV proceedings are designed to encourage reliance on competitive markets and increase the deployment of non-regulated third-party capital, they increase the risk that O&R may not have an opportunity to recover its cost of providing energy services in the future.

Q. You note that financial leverage increases the risk of investing in electric utilities such as O&R. How do economists measure financial leverage?

A. Economists generally measure financial leverage by the percentages of debt and equity in a company's capital structure. Companies with a high percentage of debt compared to equity are considered to have high financial leverage.

Q. Why does high financial leverage affect the risk of investing in an electric utility's stock?

A. High financial leverage is a source of additional risk to utility stock investors because it increases the percentage of the company's costs that are fixed, and the presence of higher fixed costs increases the variability of the equity investors' return on investment.

Q. Can the risks facing O&R be distinguished from the risks of investing in companies in other industries?

A. Yes. The risks of investing in electric energy companies such as O&R can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risks of investing in O&R are increased because of the greater capital intensity of the electric energy business and the fact that most investments in electric energy facilities are largely irreversible once they are made. Second, unlike returns in competitive industries, the returns from investment in O&R are largely asymmetric. That is, there is little opportunity for O&R to earn more than its required return, and a significant chance that the Company will earn less than its required return.

Q. Have you read the testimony of Company witness Saegusa regarding the risks of investing in O&R?

A. Yes. Company witness Saegusa discusses four financial challenges facing O&R, including the capital intensive nature of its business, O&R's unusually weak cash flows and low ROEs, the restrictions regulation places on the Company's ability to respond to unfavorable developments, and the Company's dependence on the financial markets to fund capital needs.

Q. Do you agree with witness Saegusa's assessment of the challenges facing O&R?

A. Yes.

Q. Are the risks of investing in O&R's natural gas utility operations similar to the risks of investing in the Company's electric utility operations?

A. Yes.

Q. What conclusion do you reach from your analysis of business and financial risk?

A. I conclude that O&R's business and financial risks are higher than at the time of the Company's previous rate proceedings and that the higher risk of investing in O&R should be reflected in a higher allowed return on equity.

V. O&R'S REQUIRED RATE OF RETURN ON EQUITY

Q. How do you estimate the required rate of return on equity for O&R's electric utility operations?

A. I estimate O&R's required rate of return on equity by applying several cost of equity estimation methods to a group of comparable-risk electric utilities and calculating the average expected rate of return on book equity for the comparable group of electric utilities.

Q. What methods do you use to estimate the cost of equity for O&R's electric utility operations?

A. I use the DCF model and the CAPM. The DCF model assumes that the current market price of a company's stock is equal to the discounted value of all expected future cash flows. The CAPM assumes that the investor's required rate of return on equity is equal to the expected risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

Q. How do you use the comparable earnings method to calculate O&R's required rate of return on equity?

A. As I explain above, I use the comparable earnings method to estimate O&R's required rate of return on equity by calculating the average expected rate of return on book equity for a comparable group of electric utilities because the U.S. Supreme Court states in the *Hope Natural Gas* case that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).] This language is consistent with both a capital attraction standard, as measured by the cost of equity, and a comparable earnings standard, as measured by calculating the expected rate of return on equity for a group of comparable-risk companies.

A. THE DISCOUNTED CASH FLOW MODEL

Q. Please describe the DCF model.

A. The DCF model is based on the assumption that investors value an asset because they expect to receive a sequence of cash flows from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a company's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF model is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;
i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a company's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S	=	Current price of the company's stock;
$D_1, D_2 \ldots D_n$	=	Expected annual dividend per share on the company's stock;

P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, g, this equation can be solved for k, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the expected dividend yield component of the annual DCF model, and the term g is called the expected growth component of the annual DCF model.

Q. Are you recommending that the annual DCF model be used to estimate the cost of equity for O&R's electric utility operations?

A. No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression of the present value of future dividends if dividends are paid annually at the end of each year. Since the companies in my comparable group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model should be used to estimate the cost of equity for these companies. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present value of a quarterly stream of dividend payments. A complete analysis of the implications of the quarterly payment of dividends on the DCF model is provided in Appendix 2. For the reasons cited there, I employed the quarterly DCF model throughout my calculations, even though the results of the quarterly DCF model for my companies are approximately equal to the results of a properly applied annual DCF model.

Q. Please describe the quarterly DCF model you use.

A. The quarterly DCF model I use is described on Schedule 1 and in Appendix 2. The quarterly DCF equation shows that the cost of equity is: the sum of the future expected dividend yield and the growth rate, where the dividend in the dividend yield is the equivalent future value of the four quarterly dividends at the end of the year, and the growth rate is the expected growth in dividends or earnings per share.

Q. How do you estimate the quarterly dividend payments in your quarterly DCF model?

A. The quarterly DCF model requires an estimate of the dividends, d_1, d_2, d_3, and d_4, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by (1 + g), where *g* is the expected growth rate.

Q. Can you illustrate how you estimate the next four quarterly dividends with data for a specific company in your proxy group of electric utilities?

A. Yes. In the case of ALLETE, the first electric utility company shown in Schedule 1, the last four quarterly dividends are equal to 0.520, 0.520, 0.535, and 0.535, and the growth rate is 5.0 percent. Thus dividends, d_1, d_2, d_3, and d_4 are equal to 0.546, 0.546, 0.562, and 0.562 [0.520 x (1 + .05) = .546 and 0.535 x (1 + 0.05) =

0.562]. (As noted previously, the logic underlying this procedure is described in Appendix 2.)

Q. How do you estimate the growth component of the quarterly DCF model?

A. I use the I/B/E/S analysts' estimates of future earnings per share ("EPS") growth reported by Thomson Reuters.

Q. What are the analysts' estimates of future EPS growth?

A. As part of their research, financial analysts working at Wall Street companies periodically estimate EPS growth for each company they follow. The EPS forecasts for each company are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent three to five-year forecasts of EPS growth.

Q. What is I/B/E/S?

A. I/B/E/S is a division of Thomson Reuters that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each company. Investors use the mean forecast as an estimate of future company performance.

Q. Why do you use the I/B/E/S growth estimates?

A. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q. Why do you rely on analysts' projections of future EPS growth in estimating the investors' expected growth rate rather than looking at past historical growth rates?

A. I rely on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' EPS growth forecasts to estimate future earnings growth.

Q. Have you performed any studies concerning the use of analysts' forecasts as an estimate of investors' expected growth rate, g?

A. Yes. I prepared a study with Willard T. Carleton, Professor Emeritus of Finance at the University of Arizona, which is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

Q. Please summarize the results of your study.

A. First, we performed a correlation analysis to identify the historically-oriented growth rates which best described a company's stock price. Then we did a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices,* University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented or sustainable growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented or sustainable growth measures in predicting a company's stock price. Researchers at State Street Financial Advisors updated my study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Q. What stock prices do you use in your DCF model?

A. I use a simple average of the monthly high and low stock prices for each company in my comparable group of electric utilities for the three-month period ending September 2017. These high and low stock prices were obtained from Thomson Reuters.

Q. Why do you use the three-month average stock price in applying the DCF method?

A. I use the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

Q. Do you include an allowance for flotation costs in your DCF analysis?

A. Yes. I include a five percent allowance for flotation costs in my DCF calculations.

Q. Please explain your inclusion of flotation costs.

A. All companies that have sold securities in the capital markets have incurred some level of flotation costs, including underwriters' commissions, legal fees, and printing expense, for example. These costs are withheld from the proceeds of the stock sale or are paid separately, and must be recovered over the life of the equity issue. Costs vary depending upon the size of the issue, the type of registration method used and other factors, but in general these costs range between three percent and five percent of the proceeds from the issue [see Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," The Journal of Financial Research, Vol. XIX No 1 (Spring 1996), 59-74, and Clifford W. Smith, "Alternative Methods for Raising Capital," Journal of Financial Economics 5 (1977) 273-307]. In addition to these costs, for large equity issues (in relation to outstanding equity shares), there is likely to be a decline in price associated with the sale of shares to the public. On average, the decline due to market pressure has been estimated at two percent to three percent [see Richard H. Pettway, "The Effects of New Equity Sales upon Utility Share Prices," Public Utilities Fortnightly, May 10, 1984, 35—39]. Thus, the total flotation cost, including both issuance expense and stock price decline, generally ranges from five percent to eight percent of the proceeds of an equity issue. I believe a combined five percent allowance for flotation costs is a conservative estimate that should be used in applying the DCF model in these proceedings. A complete explanation of the need for flotation costs is contained in Appendix 3.

Q. How do you select your electric utility proxy company group?

A. I select all the electric utilities followed by Value Line that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have an I/B/E/S long-term growth forecast; and (4) are not the subject of a merger offer that has not been completed. In addition, I do not include a result that is less than one hundred basis points above the forecasted yield for the company's bond rating for the reason that the cost of equity must exceed the expected cost of debt. I further note that each of the utilities included in my comparable group has an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3.

Q. Why do you eliminate companies that have either decreased or eliminated their dividend in the past two years?

A. The DCF model requires the assumption that dividends will grow at a constant rate into the indefinite future. If a company has either decreased or eliminated its dividend in recent years, the assumption that the company's dividend will grow at the same rate into the indefinite future becomes questionable.

Q. Why do you eliminate companies that are the subject of a merger offer that has not been completed?

A. A merger announcement can sometimes have a significant impact on a company's stock price because of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers produces DCF results that tend to distort a company's cost of equity.

Q. Please summarize the results of your application of the DCF model to your electric utility group.

A. As shown on Schedule 1, I obtain an average DCF result of 9.6 percent for my electric utility group.

B. CAPITAL ASSET PRICING MODEL

Q. What is the CAPM?

A. The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q. How do you use the CAPM to estimate the cost of equity for your proxy companies?

A. The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use a forecasted yield to maturity on 20-year Treasury bonds of 4.1 percent, obtained using data from Value Line and the U.S. Energy Information Administration ("EIA"). For my estimate of the company-specific risk, or beta, I use both the current average 0.68 Value Line beta for my group of utilities and the 0.90 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio. For my estimate of the expected risk premium on the market portfolio, I use two approaches. First, I estimate the risk premium on the market portfolio using historical risk premium data reported in the 2017 Valuation Handbook for the years 1926 through 2016, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. How do you obtain the forecasted yield to maturity on 20-year Treasury bonds?

A. I obtain the forecasted yield to maturity on 20-year Treasury bonds using data from Value Line and EIA. Value Line forecasts a yield on 10-year Treasury notes equal to 3.7 percent. The spread between the average yield on 10-year Treasury notes (2.2 percent) and 20-year Treasury bonds (2.53 percent) is 33 basis points. Adding 33 basis points to Value Line's 3.7 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 4.03 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, Sep. 1, 2017). EIA, Jan. 2017, forecasts a yield of 3.75 percent on 10-year Treasury notes. Adding the 33 basis point spread between 10-year Treasury notes and 20-year

Treasury bonds to the EIA forecast of 3.75 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 4.08 percent. The average of the forecasts is 4.1 percent (4.03 percent using Value Line data and 4.08 percent using EIA data).

1. Historical CAPM

Q. How do you estimate the expected risk premium on the market portfolio using historical risk premium data developed by Ibbotson® SBBI®?

A. I estimate the expected risk premium on the market portfolio by calculating the difference between the arithmetic mean total return on the S&P 500 from 1926 to 2017 (11.96 percent) and the average income return on 20-year U.S. Treasury bonds over the same period (5.01 percent). Thus, my historical risk premium method produces a risk premium of 6.9 percent (11.96 – 5.01 = 6.94).

Q. Why do you recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500?

A. I recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500 because, in my opinion, the arithmetic mean return is the best approach for calculating the return investors expect to receive in the future. For an investment which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future. A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in Schedule 2.

Q. Why do you recommend that the risk premium on the market portfolio be measured using the income return on 20-year Treasury bonds rather than the total return on these bonds?

A. As discussed above, the CAPM requires an estimate of the risk-free rate of interest. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free.

Q. What CAPM result do you obtain when you estimate the expected risk premium on the market portfolio from the arithmetic mean difference between the return on the market and the yield on 20-year Treasury bonds?

A. Using a risk-free rate equal to 4.1 percent, an electric utility beta equal to 0.68, a risk premium on the market portfolio equal to 6.9 percent, and a flotation cost allowance equal to 18 basis points, I obtain an historical CAPM estimate of the cost of equity equal to 9.0 percent for my electric utility group (4.1 + 0.68 x 6.9 + 0.18 = 9.0) [See Exhibit__(JVW-1) Schedule 3]. (I determine the flotation cost allowance by calculating the difference in my DCF results with and without a flotation cost allowance.)

Q. Is there any evidence from the finance literature that the application of the historical CAPM may underestimate the cost of equity?

A. Yes. There is substantial evidence that: (1) the historical CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0; and (2) the CAPM is less reliable the further the estimated beta is from 1.0.

Q. What is the evidence that the CAPM tends to underestimate the cost of equity for companies with betas less than 1.0 and is less reliable the further the estimated beta is from 1.0?

A. The original evidence that the unadjusted CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and is less reliable the further the estimated beta is from 1.0 was presented in a paper by Black, Jensen, and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy (1979), Banz (1981), Fama and French (1992), Fama and French (2004), Fama and MacBeth (1973), and Jegadeesh and Titman (1993).[4]

Q. Can you briefly summarize these articles?

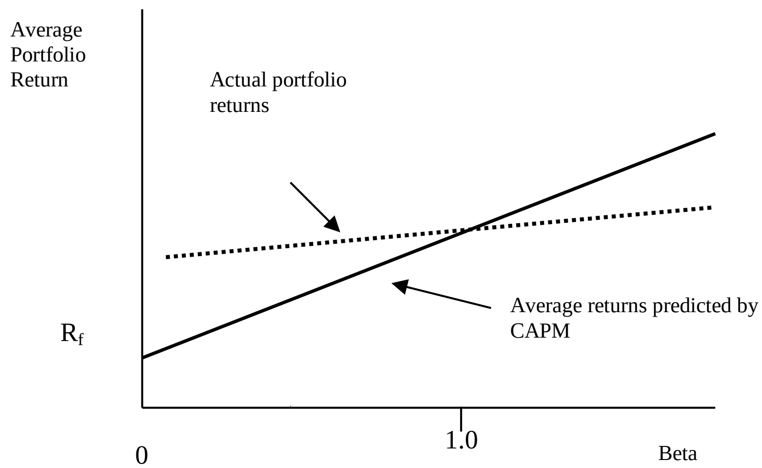
A. Yes. The CAPM conjectures that security returns increase with increases in security betas in line with the equation:

$$ER_i = R_f + \beta_i \left\lfloor ER_m - R_f \right\rfloor,$$

where ER_i is the expected return on security or portfolio i, R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and β_i is a measure of the risk of investing in security or portfolio i (see Figure 1 below).

4 Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in *Studies in the Theory of Capital Markets*, M. Jensen, Ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence," *Journal of Financial Economics* 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," *Journal of Financial Economics* (March 1981), pp. 3-18; Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Returns," *Journal of Finance* (June 1992), 47:2, pp. 427-465; Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives* (Summer 2004), 18:3, pp. 25 – 46; Narasimhan Jegadeesh and Sheridan Titman, "Returns to Buying Winners and Selling Losers: Implications for Stock Market Efficiency," *The Journal of Finance*, Vol. 48, No. 1. (March 1993), pp. 65-91.

FIGURE 1
AVERAGE RETURNS COMPARED TO BETA
FOR PORTFOLIOS FORMED ON PRIOR BETA



Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that the relationship between returns and betas is inconsistent with the relationship posited by the CAPM. As described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 1 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 1 than the solid line, they generally agree that the dotted line lies above the solid line for portfolios with betas less than 1.0 and below the solid line for portfolios with betas greater than 1.0. Thus, in practice, scholars generally agree that the CAPM underestimates portfolio returns for companies with betas less than 1.0, and overestimates portfolio returns for portfolios with betas greater than 1.0.

Q. Do you have additional evidence that the CAPM tends to underestimate the cost of equity for utilities with average betas less than 1.0?

A. Yes. As shown in Schedule 4, over the period 1937 to 2017, investors in the S&P Utilities Stock Index have earned a risk premium over the yield on long-term Treasury bonds equal to 5.74 percent, while investors in the S&P 500 have earned a risk premium over the yield on long-term Treasury bonds equal to 6.08 percent. According to the CAPM, investors in utility stocks should expect to earn a risk premium over the yield on long-term Treasury securities equal to the average utility beta times the expected risk premium on the S&P 500. Thus, the ratio of the risk premium on the utility portfolio to the risk premium on the S&P 500 should equal the utility beta. However, the average utility beta at the time of my studies is approximately 0.69, whereas the historical ratio of the utility risk premium to the S&P 500 risk premium is 0.90 (5.74 ÷ 6.08 = 0.90). In short, the current 0.69 measured beta for electric utilities significantly underestimates the cost of equity for the utilities, providing further support for the conclusion that the CAPM underestimates the cost of equity for utilities at this time.

Q. Can you adjust for the tendency of the CAPM to underestimate the cost of equity for companies with betas significantly less than 1.0?

A. Yes. I can implement the CAPM using the 0.90 beta I discuss above, which I obtain by comparing the historical returns on utilities to historical returns on the S&P 500.

Q. What CAPM result do you obtain when you use a beta equal to 0.90 rather than an electric utility beta equal to 0.69?

A. I obtain a CAPM result equal to 10.5 percent using a risk free rate equal to 4.1 percent, a beta equal to 0.90, the historical market risk premium equal to 6.9 percent, and a flotation cost allowance of 18 basis points (4.1 + 0.90 x 6.9+ 0.18= 10.5). (*See* Schedule 5.)

Q. What is the average of your two historical CAPM results?

A. The average of my two historical CAPM results is 9.7 percent ((9.0 percent + 10.5 percent) ÷ 2 = 9.7 percent). I use 9.7 percent as my estimate of the historical CAPM cost of equity.

2. DCF-Based CAPM

Q. How does your DCF-Based CAPM differ from your historical CAPM?

A. As noted above, my DCF-based CAPM differs from my historical CAPM only in the method I use to estimate the risk premium on the market portfolio. In the historical CAPM, I use historical risk premium data to estimate the risk premium on the market portfolio. In the DCF-based CAPM, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. What risk premium do you obtain when you calculate the difference between the DCF-return on the S&P 500 and the risk-free rate?

A. Using this method, I obtain a risk premium on the market portfolio equal to 8.5 percent (see Schedule 6).

Q. What CAPM result do you obtain when you estimate the expected return on the market portfolio by applying the DCF model to the S&P 500?

A. Using a risk-free rate of 4.1 percent, an electric utility beta of 0.68, a risk premium on the market portfolio of 8.5 percent, and a flotation cost allowance of 18 basis points, I obtain a CAPM result of 10.0 percent for my electric utility group. Using a risk-free rate of 4.1 percent, an electric utility beta of 0.90, a risk premium on the market portfolio of 8.5 percent, and a flotation cost allowance of 18 basis points, I obtain a CAPM result of 11.9 percent. The average of these two results is 11.0 percent (10.0 + 11.9) ÷ 2 = 11.0), and I use 11.0 percent as my estimate of the DCF-based CAPM cost of equity.

C. COMPARABLE EARNINGS METHOD

Q. What is the comparable earnings method for estimating the required rate of return on equity?

A. The comparable earnings method estimates the required rate of return on equity by calculating the expected rate of return on book equity for a group of comparable risk companies. The U.S. Supreme Court states in the *Hope Natural Gas* case that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).] The comparable earnings approach implements the *Hope* standard by calculating the expected rate of return on equity for a group of comparable-risk companies.

Q. What comparable risk companies do you use to estimate O&R's required rate of return on equity using the comparable earnings method?

A. I use the same comparable-risk electric utilities that I use to estimate O&R's cost of equity using the DCF method.

Q. How do you calculate the expected rate of return on book equity for these comparable-risk electric utilities?

A. I estimate the expected rate of return on book equity for each company by calculating the average expected rate of return on book equity reported by The Value Line Investment Survey for the years 2017, 2018, and 2020 – 2022.

Q. Do you make any adjustments to Value Line's reported expected rates of return on book equity?

A. Yes. Value Line calculates its expected rates of return on book equity by dividing each company's expected earnings by its estimate of the company's year-end equity. Because a rate of return based on year-end equity understates the rate of return on the average equity investment during the year, I adjust Value Line's estimates to reflect expected rates of return on average equity for the year. My method for calculating the expected rate of return on average book equity for the comparable companies is described in the notes accompanying my exhibit.

Q. What average expected rate of return on book equity do you obtain for your group of comparable-risk utilities?

A. The average expected rate of return on book equity for this group of comparable-risk utilities is 11.0 percent (see Schedule 7).

VI. RECOMMENDED RATE OF RETURN ON EQUITY

Q. Based on the results of your DCF, CAPM, and comparable earnings analyses, what is your recommended allowed rate of return on equity for O&R?

A. Based on the results of my DCF, CAPM, and comparable earnings analyses, I recommend that O&R be allowed to earn a rate of return on equity equal to 10.3 percent.

Q. How do you arrive at your recommended 10.3 percent allowed rate of return on equity for O&R?

A. I arrive at my recommended 10.3 percent allowed rate of return on equity for O&R by giving a one-third weight to the results of my DCF analysis, a one-third weight to the average result of my CAPM analyses, and a one-third weight to the result of my comparable earnings analysis (see TABLE 1 below).

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	MODEL RESULT	WEIGHT	WEIGHTED RESULT
DCF	9.6%	33%	3.20%
CAPM – Historical	9.8%		
CAPM – DCF-based	11.0%		
Average CAPM	10.4%	33%	3.45%
Comparable Earnings	11.0%	33%	3.67%
Average	10.3%		

VII. TESTS OF REASONABLENESS

Q. Do you conduct any tests of the reasonableness of your recommended 10.3 percent allowed return on equity for O&R?

A. Yes. To test the reasonableness of my recommended 10.3 percent allowed return on equity for O&R, I calculate the average Value Line expected return on book equity for a group of low-risk industrial companies; and I estimate O&R's cost of equity using two versions of the risk premium approach to estimating the cost of equity.

A. EXPECTED RATE OF RETURN ON BOOK EQUITY FOR GROUP OF LOW-RISK INDUSTRIAL COMPANIES

Q. Why do you test the reasonableness of your cost of equity recommendation by calculating the average Value Line expected return on book equity for a group of low-risk industrial companies?

A. I test the reasonableness of my cost of equity recommendation by calculating the average Value Line expected return on book equity for a group of low-risk industrial companies because, as I discuss above, the U.S. Supreme Court found in the *Hope* case that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).]

Q. How do you select the group of low-risk industrial companies you use to test the reasonableness of your 10.3 percent cost of equity estimate in this proceeding?

A. I select all industrial companies in the Value Line universe of companies that pay dividends, have a Safety Rank of 1, a beta in the range .50 to .75, and Financial Strength equal to or greater than A. The average ratings for the identified group of low-risk industrials are Safety Rank, 1; beta, .73; and Financial Strength, A+.

Q. What is the average expected rate of return on book equity for your group of low-risk industrial companies?

A. The average expected rate of return on book equity for the identified group of low-risk industrial companies is 25.9 percent (see Schedule 8). The average expected rate of return on book equity is 18.5 percent if all results equal to or above 30 percent are excluded from the average.

B. RISK PREMIUM ANALYSIS

Q. Please describe the risk premium method of estimating the cost of equity.

A. The risk premium method is based on the principle that investors expect to earn a return on an equity investment that reflects a "premium" over the interest rate they expect to earn on an investment in bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q. Does the risk premium approach specify what debt instrument should be used to estimate the interest rate component in the methodology?

A. No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks to the interest rate on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q. Does the risk premium approach require that the same companies be used to estimate the stock return as are used to estimate the bond return?

A. No. For example, many analysts apply the risk premium approach by comparing the return on a portfolio of stocks to the income return on Treasury securities such as long-term Treasury bonds. In this widely accepted application of the risk premium approach, the same companies are not used to estimate the stock return as are used to estimate the bond return, since the U.S. government is not a company.

Q. How do you measure the required risk premium on an equity investment in your group of publicly-traded electric utilities?

A. I use two methods to estimate the required risk premium on an equity investment in electric utilities. The first is called the *ex ante* risk premium method and the second is called the *ex post* risk premium method.

1. *Ex Ante* Risk Premium Method

Q. Please describe your *ex ante* risk premium approach for measuring the required risk premium on an equity investment in electric utilities.

A. My *ex ante* risk premium method is based on studies of the DCF expected return on a group of electric utilities compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY}	=	the required risk premium on an equity investment in the proxy group of companies,
DCF_{PROXY}	=	average DCF estimated cost of equity on a portfolio of proxy companies; and
I_A	=	the yield to maturity on an investment in A-rated utility bonds.

I then perform a regression analysis to determine if there is a relationship between the calculated risk premium and interest rates. Finally, I use the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity, I then add the required risk premium to the forecasted interest rate on A-rated utility bonds. As noted above, one could use the yield to maturity on other debt investments to measure the interest rate component of the risk premium approach as long as one uses the yield on the same debt investment to measure the expected risk premium component of the risk premium approach. I choose to use the yield on A-rated utility bonds because it is a frequently-used benchmark for utility bond yields. A detailed description of my *ex ante* risk premium studies is contained in Appendix 4, and the underlying DCF results and interest rates are displayed in Schedule 9.

Q. What cost of equity do you obtain from your *ex ante* risk premium method?

A. As discussed above, to estimate the cost of equity using the *ex ante* risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the expected yield to maturity on A-rated utility bonds. I obtain the expected yield to maturity on A-rated utility bonds, 5.8 percent, by averaging forecast data from Value Line and the U.S. Energy Information Administration ("EIA"). For my electric utility sample, my analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 4.9 percent. Adding an estimated risk premium of 4.9 percent to the expected 5.8 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.7 percent using the *ex ante* risk premium method.

Q. How do you obtain the expected yield on A-rated utility bonds?

A. As noted above, I obtain the expected yield to maturity on A-rated utility bonds, 5.8 percent, by averaging forecast data from Value Line and the EIA. Value Line Selection & Opinion (September 1, 2017) projects a Aaa-rated Corporate bond yield equal to 5.4 percent. The September 2017 average spread between A-rated utility bonds and Aaa-rated Corporate bonds is 24 basis points (A-rated utility, 3.87 percent, less Aaa-rated Corporate, 3.63 percent, equals 24 basis points). Adding 24 basis points to the 5.4 percent Value Line Aaa Corporate bond forecast equals a forecast yield of 5.6 percent for the A-rated utility bonds. The EIA forecasts a AA-rated utility bond yield equal to 5.71 percent. The average spread between AA-rated utility and A-rated utility bonds at September 1, 2017 is 17 basis points (3.87 percent less 3.70 percent). Adding 17 basis points to EIA's 5.71 percent AA-utility bond yield forecast equals a forecast yield for A-rated utility bonds equal to 5.9 percent. The average of the forecasts (5.6 percent using Value Line data and 5.9 percent using EIA data) is 5.8 percent.

Q. Why do you use an expected or forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity?

A. I use an expected or forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. In addition, because current interest rates are depressed as a result of the Federal Reserve's efforts to keep interest rates low in order to stimulate the economy, current interest rates at this time are a poor indicator of expected future interest rates. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

2. *Ex Post* Risk Premium Method

Q. Please describe your *ex post* risk premium method for measuring the required risk premium on an equity investment in electric utilities.

A. I first perform a study of the comparable returns received by bond and stock investors over the eighty years of my study. I estimate the returns on stock and bond portfolios, using stock price and dividend yield data on the S&P 500 and bond yield data on Moody's A-rated Utility Bonds. My study consists of making an investment of one dollar in the S&P 500 and Moody's A-rated utility bonds at the beginning of 1937, and reinvesting the principal plus return each year to 2017. The return associated with each stock portfolio is the sum of the annual dividend yield and capital gain (or loss) which accrued to this portfolio during the year(s) in which it was held. The return associated with the bond portfolio, on the other hand, is the sum of the annual coupon yield and capital gain (or loss) which accrued to the bond portfolio during the year(s) in which it was held. The resulting annual returns on the stock and bond portfolios purchased in each year from 1937 to 2017 are shown on Schedule 10. The average annual return on an investment in the S&P 500 stock portfolio is 11.2 percent, while the average annual return on an investment in the Moody's A-rated utility bond portfolio is 6.6 percent. The risk premium on the S&P 500 stock portfolio is, therefore, 4.6 percent (11.2 – 6.6 = 4.6).

I also conduct a second study using stock data on the S&P Utilities rather than the S&P 500. As shown on Schedule 11, the average annual return on the S&P Utility stock portfolio is 10.6 percent per year. Thus, the return on the S&P Utility stock portfolio exceeds the return on the Moody's A-rated utility bond portfolio by 4.0 percent (10.6 – 6.6 = 4.0).

Q. Why is it appropriate to perform your *ex post* risk premium analysis using both the S&P 500 and the S&P Utilities stock indices?

A. I perform my *ex post* risk premium analysis on both the S&P 500 and the S&P Utilities because I believe electric energy companies today face risks that are somewhere in between the historical average risk of the S&P Utilities and the S&P 500 over the years 1937 to 2017. Thus, I use the average of the two historically-based risk premiums as my estimate of the required risk premium for the Company in my *ex post* risk premium method.

Q. Would your study provide a different risk premium if you started with a different time period?

A. Yes. The risk premium results vary somewhat depending on the historical time period chosen. My policy is to use the largest set of reliable historical data. I thought it would be most meaningful to begin after the passage and implementation of the Public Utility Holding Company Act of 1935. This Act significantly changed the structure of the public utility industry. Because the Public Utility Holding Company Act of 1935 was not implemented until the beginning of 1937, I felt that numbers taken from before this date would not be comparable to those taken after. (The repeal of the 1935 Act has not materially impacted the structure of the public utility industry; thus, the Act's repeal does not have any impact on my choice of time period.)

Q. Why is it necessary to examine the yield from debt investments in order to determine the investors' required rate of return on equity capital?

A. As previously explained, investors expect to earn a return on their equity investment that exceeds currently available bond yields because the return on equity, as a residual return, is less certain than the yield on bonds; and investors must be compensated for this uncertainty. Investors' expectations concerning the amount by which the return on equity will exceed the bond yield may be influenced by historical differences in returns to bond and stock investors. Thus, we can estimate investors' expected returns from an equity investment from information about past differences between returns on stocks and bonds. In interpreting this information, investors would also recognize that risk premiums increase when interest rates are low.

Q. What conclusions do you draw from your *ex post* risk premium analyses about the required return on an equity investment in electric utilities?

A. My studies provide evidence that investors today require an equity return of at least 4.0 to 4.6 percentage points above the expected yield on A-rated utility bonds. As discussed above, the expected yield on A-rated utility bonds is 5.8 percent. Adding a 4.0 to 4.6 percentage point risk premium to a yield of 5.8 percent on A-rated utility bonds, I obtain an expected return on equity in the range 9.8 percent to 10.4 percent, with a midpoint estimate equal to 10.1 percent.

Adding a 18 basis point allowance for flotation costs, I obtain an estimate of 10.3 percent as the *ex post* risk premium cost of equity.

Q. From your review of the evidence on forecasted returns on book equity for your group of low-risk industrial companies and the cost of equity results from your risk premium analyses, what do you conclude about the reasonableness of your recommended 10.3 percent allowed return on equity for O&R?

A. I conclude that my 10.3 percent recommended allowed return on equity is fair and reasonable.

VIII. REASONABLENESS OF O&R'S RECOMMENDED CAPITAL STRUCTURE

Q. What capital structure is O&R recommending in this proceeding for the purpose of rate making?

A. O&R is recommending that a capital structure containing 48 percent equity be used for rate making purposes in this proceeding.

Q. What is the average book value capital structure of your proxy electric utilities?

A. The average book capital structure of my proxy utility group contains approximately 53 percent long-term debt and 47 percent equity.

Q. From these data, what do you conclude about the reasonableness of O&R's recommended capital structure containing 52 percent debt and 48 percent equity?

A. I conclude that O&R's recommended capital structure is fair and reasonable for the purpose of rate making in this proceeding.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF

ELECTRIC FORECASTING PANEL

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ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF

ELECTRIC FORECASTING PANEL

Q. Would the members of the Electric Forecasting Panel (“Panel”) please state their names and business address?

A. Simar Grewal and Leanne M. Attanasio. Our business address is 4 Irving Place, New York, New York 10003.

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

A. **(Grewal)** I am 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 the Section Manager of Electric Revenue and Volume Forecasting in Business Finance.

(Attanasio) I am employed by Con Edison as a Senior Analyst in the Revenue and Volume Forecasting Department in Business Finance.

Q. Please briefly describe your education and business experience.

A. **(Grewal)** I received a Bachelor of Electrical Engineering Degree from the University of Minnesota – Twin Cities in 2005. I began my employment with Con Edison in the summer of 2017 in my present position. Prior to joining Con Edison, I worked in management consulting for 12 years with Deloitte Consulting LLP and Accenture LLP.

(Attanasio) I received a Bachelor's degree in Economics (Honors Program) from Ateneo de Manila University, in 1998. I also received a Master of Arts degree in Economics in 2008 and a Doctorate in Economics in 2010, both from Fordham University. I also hold the Chartered Financial Analyst® designation. Prior to joining Con Edison, I taught Economics and Statistics at Fordham and also managed the University's Master of Arts Program in International Political Economy and Development. Other positions I have held in the past involved derivatives trading and macroeconomic forecasting. In 2013, I joined Con Edison in the capacity of 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. **(Grewal)** 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. **(Attanasio)** 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. **(Grewal)** No.

(Attanasio) No.

Q. What is the purpose of the Panel's testimony?

A. We present the forecast of O&R electric system sendout, delivery volumes and revenues for the three month period ended December 31, 2017, the 12 months ending December 31, 2018, the 12 months ending December 31, 2019 ("Rate Year" or "RY1"), and the 12 month periods ending December 31, 2020 and 2021. 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

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.*, January 1, 2020 through December 31, 2020) and RY3 (*i.e.*, January 1, 2021 through December 31, 2021).

Q. What are the actual and normalized total delivery volumes for the 12 months ended September 2017 ("Historic Year")?

A. The actual total delivery volume for the Historic Year is 3,891,618 MWHs. The normalized total delivery volume for the Historic Year is 3,883,961 MWHs.

Q. Please summarize, in aggregate form, your delivery volume forecasts for the three months ended December 31, 2017, the 12 months ending December 31, 2018, and RY1 through RY3, respectively.

A. As set forth in Exhibit __ (EFP-1), Schedule 4, Page 1 of 5, for the three months ended December 31, 2017, the Company's total delivery volume forecast is 902,162 MWHs. For the 12 months ending December 31, 2018, the Company's total delivery volume forecast is 3,901,745 MWHs. For RY1, the Company's total delivery volume forecast is 3,883,642 MWHs, a decrease of 18,103 MWHs. This represents a 0.5% decrease from the 12 months ending December 31, 2018. This decrease is a result of (a) the forecasted decrease in volume; (b) the anticipated reduction from energy efficiency ("EE") programs; and (c) the customer installation of solar panels in the Company's service territory. For RY2, the Company's total delivery volume forecast is 3,882,015 MWHs. This represents an insignificant decrease of 1,627 MWHs, which keeps the volume forecast relatively flat compared to the RY1 forecast. The flat trend in volume indicates that the forecasted increase in volume makes up for the anticipated decrease in energy usage associated with the EE programs and customers' installation of solar panels. For RY3, the Company's total delivery volume forecast is 3,854,542, a decrease of 27,473 MWHs. This amounts to a 0.7% decrease from the RY2 forecast. The slight volume growth forecasted is not enough to offset the anticipated decline in energy usage associated with the EE programs and customers installation of solar panels.

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, primary excluding small primary, lighting, and other public authority. These major classifications are comprised of various O&R service classes.

<u>Econometric Time Series Models</u>

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. Econometric time series models are used 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

Q. What modeling periods did the Panel use in its forecast?

A. 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 third quarter of 2017. For the lighting and public authority models, the modeling period starts in the first quarter of 1998.

Independent Variables

Q. Please describe the independent variables used in the Company's models.

A. The econometric time series models employ two types of independent variables – weather and economic. Weather variables—in terms of heating degree days, cooling degree days, and billing days—are included in the models to account for delivery volume variations due to changes in these factors. Weather variables are included for all service classes except for lighting, whose model includes burn hours. Also included are key economic variables such as real average electric price, private non-manufacturing employment, and the number of customers.

The residential model includes real average electric price, private non-manufacturing employment, and the number of customers as explanatory variables.

The secondary model includes private non-manufacturing employment and the number of customers.

The primary model includes real average electric price and the number of customers.

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

Q. Please explain how the Company’s models are structured.

A. 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 smooths 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-1), 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 the 12 months ended September 2017.

Q. Please explain how the forecast of private non-manufacturing employment is developed.

A. The private non-manufacturing employment forecast is developed using the forecast from economic consulting firm, Moody's Analytics. 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 County and the City of Newburgh in Orange County (through 2004). The Bureau of Labor Statistics CES discontinued the Rockland County and City of Newburgh series at the end of 2004. So starting from 2005, employment figures for

Rockland and Orange Counties are estimated by applying the most up-to-date year-over-year growth rates (obtained from the 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 2.1% in 2017. It is then expected to increase by 1.4% in 2018, 0.6% in 2019, decrease by 0.1% in 2020, and increase again by 0.5% in 2021.

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 third quarter of 2017. The forecasted number of customers for the lighting class is based on an ARIMA model using quarterly data from the first quarter of 1993 through the third quarter of 2017.

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 14-E-0493. 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 to capture delivery volume losses from customers 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-1), 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 September 2017 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 are 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. In addition, burn hours were included as an explanatory variable in the energy pricing models for the lighting classes. 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 pricing models are based upon the historical data for the period August 2014 through July 2015. For purposes of this filing, revenues are priced at the rates that became effective on November 1, 2016. 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 14-E-0493. 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 14-E-0493.

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-1), 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 three months ended December 31, 2017, the 12 month period ending December 31, 2018, 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-1), Schedule 4.

A. Page one of this Exhibit __ (EFP-1) Schedule 4, shows electric delivery volumes and revenues by service classification for the three months ended December 31, 2017. 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, 2017, 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 $29,802,000, exclusive of gross receipts taxes, consists of the non-competitive related delivery revenue increase of $28,570,000 and the competitive service revenue requirement portion of the delivery revenue decrease of $1,232,000. The resulting proposed overall increase for RY1, inclusive of the increase in rates and charges of $517,000, for revenue taxes, amounts to $30,319,000.

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-1), 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.

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.

ORANGE AND ROCKLAND UTILITIES, INC.

Electric Infrastructure and Operations

TABLE OF CONTENTS

I. <u>Introduction</u>

Q. Would the members of the Electric Infrastructure and Operations Panel ("Panel") please state your names and business addresses?

A. Wayne A. Banker, Keith Brideweser, John F. Coffey, Angelo M. Regan, and Roberta J. Scerbo, all of whose business address is 390 West Route 59, Spring Valley, New York, 10977. Aseem Kapur, whose business address is 4 Irving Place, New York, New York 10003. Eugene L. Shlatz, whose business address is 77 South Bedford Drive, Burlington, Massachusetts.

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

A. **(Banker)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R" or the "Company") as Chief Engineer of Distribution Engineering.

(Brideweser) I am employed by Orange and Rockland as Section Manager for Systems Engineering.

(Coffey) I am employed by Orange and Rockland as Chief Engineer of Transmission and Substation Engineering.

(Regan) I am employed by Orange and Rockland as Director of Electrical Engineering.

(Scerbo) I am employed by Orange and Rockland as Director of the Utility of the Future ("UotF") organization.

(Kapur) I am employed by Orange and Rockland's affiliate, Consolidated Edison Company of New York, Inc. ("Con Edison") as Director of Information Technology.

(Shlatz) I am employed by Navigant Consulting Inc. ("Navigant") as a Director in its Energy Practice.

Q. Please describe your educational backgrounds.

A. **(Banker)** I received a Bachelor of Science degree in Electrical Engineering in 1991 from Clarkson University in Potsdam, New York and a Master of Business Administration degree in 2000 from the Hagan School of Business at Iona College in New Rochelle, New York. I am a licensed Professional Engineer in the State of New York.

(Brideweser) I received a Bachelor of Science degree in Psychology from Gordon College in 1987 and a Master of Science degree in Computer Science from New York University in 2014.

(Coffey) I received a Bachelor of Science degree in Electrical Engineering in 1988 from Manhattan College in Riverdale, New York. I am a licensed Professional Engineer in the State of New York.

(Regan) I received a Bachelor of Science degree in Electrical Engineering in 1985, and a Master of Science degree in Industrial Engineering Management Science in 1987, both from Fairleigh Dickinson University, in Teaneck, New Jersey. I am a licensed Professional Engineer in the State of New York.

(Scerbo) I hold a Bachelor of Arts degree in Political Science from Moravian College.

(Kapur) I hold a Bachelor of Science degree in Mechanical Engineering from Rutgers, the State University of New Jersey.

(**Shlatz)** I hold a Bachelor of Science degree and a Master of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute. I am a registered Professional Engineer in the State of Vermont.

Q. Please describe your work experiences.

A. **(Banker)** I joined Orange and Rockland in 1990, and have held positions for the Company as an underground Distribution and Transmission Engineer, as Divisional Field Engineer for the Electrical Operations Department, and my present position, which I assumed in 2005, as Chief Engineer of Distribution Engineering.

(Brideweser) I joined Orange and Rockland in 1993 and have held various positions in Systems Operations, Distribution Engineering, and Systems Engineering. My experience at the Company includes engineering support for the Energy Management System, designing and developing the Outage

Management System (“OMS”), and designing and integrating the Geographic Information System (“GIS”).

(Coffey) I worked for one year at Burns and Roe Group, Inc. in Oradell, New Jersey as an Electrical Engineer prior to my arrival at Orange and Rockland in 1989. I have held various engineering positions involved in Substation, Relay, Supervisory Control and Data Acquisition (“SCADA”), and Major Equipment engineering. I have served in my current position as Chief Engineer of Transmission and Substation Engineering since 2010.

(Regan) I was employed by Central Hudson Gas and Electric Corporation as an overhead distribution systems engineer from 1985 to 1987. Since then, I have worked for Orange and Rockland for over 30 years as an overhead and underground Systems Engineer, as Manager of the Distribution Engineering Department, and then as Chief Distribution Engineer, prior to assuming my present position and responsibilities as Director of Electrical Engineering.

(Scerbo) I joined the Company in 1989 serving in several positions in both the Gas and Fuel Resources organizations. I have also held the roles of Director -Retail Access, and Director – Customer Assistance overseeing the Company’s Call Centers, Business Offices and Customer Accounting department before assuming my current position as Director – Utility of the Future.

(Kapur) I joined Con Edison in June 2003 as a management intern and have held various positions in Distribution Engineering, the Smart Grid Implementation Group, and as a Section Manager in Manhattan Electric Operations. I transitioned to my current role of Director, Information Technology in July 2016.

(**Shlatz)** I have more than 30 years' experience in electric utility operations, engineering, and electric pricing. At Navigant, I am responsible for managing studies of electric utility system reliability, renewable energy, and advanced energy systems. I have been responsible for numerous technical and economic studies of electric supply and reliability for municipal, cooperative, and investor-owned electric utilities throughout North America. My experience includes evaluation of conventional and renewable energy sources, and the impact of these sources on electric reliability and cost of supply.

I have testified before state utility commissions on electric reliability, distributed energy resources, and siting of energy delivery facilities on behalf of municipal, cooperative, and investor-owned utilities, including rate cases involving review of capital projects proposed for inclusion in rates. My qualifications and previous appearances before regulatory agencies are set forth in Exhibit EIOP-1.

I previously was employed by Green Mountain Power between 1985 and 1994 in various positions of increasing responsibility, including Director of Engineering and Operations, where I was responsible for the planning, design, and operation of the Company’s generation, transmission and distribution system.

Q. Do you belong to any professional organizations?

A. **(Banker)** I am a member of the Institute of Electrical and Electronics Engineers (“IEEE”).

(Brideweser) No.

(Coffey) I am a member of IEEE.

(Regan) I am a senior member of IEEE.

(Scerbo) No.

(Kapur) No.

(**Shlatz)** I am a member of IEEE.

Q. Please generally describe your current responsibilities.

A. **(Banker)** As Chief Engineer of Distribution Engineering, I oversee the planning, engineering and design for the distribution system and distribution projects, as well as all underground engineering projects, both transmission and distribution, that are included in the Company's capital improvement budget.

(Brideweser) In my current position, I manage the Systems Engineering section, which is responsible for the high value network for the distribution supervisory control and data acquisition ("DSCADA") system, distribution system modelling, cyber-security, and historical database systems.

(Coffey) In my current position, I oversee the planning, engineering and design of transmission and substation projects included in the Company's capital improvement budget.

(Regan) In my current position, I oversee the planning, engineering and design for the electric delivery system from the bulk power system through to the customer, including all transmission, substation and distribution projects, advanced systems and technology related projects and programs, and system reliability and performance engineering.

(Scerbo) As Director of UotF, I oversee the team that collaborates with internal and external organizations, third parties, the New York Joint Utilities,[1] and customers

[1] The New York Joint Utilities are Central Hudson Gas & Electric Corporation, Con Edison, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and

in developing a future utility business model, as envisioned in New York's Reforming the Energy Vision ("REV") proceeding. My team works to enable the regulatory, policy, and operational requirements necessary to encourage the integration of increased levels of distributed energy resources ("DER") to facilitate the Company's transition to the role as the Distributed System Platform ("DSP").

(Kapur) In my current role, I am responsible for development and delivery of software applications utilized to design, construct and operate the electric distribution grid at Con Edison and Orange and Rockland. The Business System Delivery team facilitates change of business practices and processes through the use of cutting edge technologies, information and applications software.

(**Shlatz)** At Navigant, I am responsible for managing studies of electric utility system reliability, renewable energy, and advanced energy systems.

Q. Have you previously testified before the New York Public Service Commission ("Commission") or other regulatory bodies on energy matters?

A. **(Banker)** Yes. I submitted testimony in the Company's last electric base rate case, Case 14-E-0493.

Rockland, and Rochester Gas and Electric Corporation (collectively, the "JUs").

(Brideweser) No.

(Coffey) Yes. I submitted testimony in the Company's last electric base rate case, Case 14-E-0493.

(Regan) Yes. I have submitted testimony in a number of the Company's previous electric base rate cases, including Case 14-E-0493, Case 11-E-0408, Case 10-E-0362, and Case 07-E-0949.

(Scerbo) No.

(Kapur) No.

(Shlatz) Yes, I have provided testimony on behalf of Con Edison in two Commission proceedings. The first was for Con Edison's Competitive Opportunities filing in Case 96-E-0897. The second is an appearance before the Commission in Case 07-E-0523, where the Commission directed Con Edison to conduct a Targeted T&D Demand-Side Management study.[2]

Q. What is the purpose of the Panel's testimony in this proceeding?

A. The purpose of the Panel's direct testimony is to present and support the Company's electric transmission and distribution ("T&D") capital budget and major plant additions that were identified through the Company's planning process, which will be placed into plant in

[2] Case 07-E-0523, Order Establishing Rates For Electric Service, at 158 (March 25, 2008).

service during the period January 1, 2019 through December 31, 2019 (“Rate Year” or “RY1”). The Panel also will address the Company’s operation and maintenance (“O&M”) requirements during the Rate Year. As explained more fully in the direct testimony of the Company’s Accounting Panel, the Company is not proposing a multiyear rate plan in this electric base rate filing. However, in addition to providing projections for the Rate Year, the Company has included forecasted financial information for the two annual calendar years beyond the Rate Year (*i.e.*, 2020 and 2021), which we will refer to as “RY2” and “RY3”, respectively, for ease of reference.

The Panel also discusses the Company’s activities and initiatives necessary to facilitate its continued evolution and progression to integrate and advance DERs and become the DSP provider, including organizational and process changes, new programs, demonstration projects, and foundational investments in information technology (“IT”) systems and communications infrastructure.

The Panel’s testimony describes the process that the Company and Navigant applied to evaluate Non Wire Alternatives (“NWAs”) as potential alternatives to Orange and Rockland’s Port Jervis, Little Tor, Lovett 345kV Station and L702A UG traditional capital investment projects. The Panel presents the results of Navigant’s analysis, which includes a determination as to whether any of the above-mentioned projects meet Orange and Rockland’s Suitability Criteria, and if so, how many years each traditional T&D project could potentially be deferred. Finally, the Panel describes a proposed modification to the Company’s major storm cost reserve.

Q. Please describe how the remainder of this testimony is organized.

A. Section II describes the Company’s distribution system planning process, and explains how the Company identifies planned T&D projects and programs. It addresses the suitability criteria used to evaluate projects and provides an overview of how NWA projects are considered as potential deferral or replacement options for traditional investments. Section III describes the Company’s planned T&D programs and projects during RY1, RY2, and RY3. Section IV describes the Company’s initiatives to support DERs and DSP implementation, including an overview of the UotF organization, a discussion of the Company’s current and potential NWA and REV Demonstration Projects, and the Company’s planned Electric Vehicle (“EV”) program. Section V describes the key investments the Company is making in grid modernization technologies and operations. Finally, Section VI discusses a proposed modification to the Company's major storm cost reserve.

II. **Electric Delivery System Planning Process**

Q. Please describe the purpose of the Company's Electric Delivery System Planning Process.

A. The purpose of the Company's electric delivery system planning process is to maintain and enhance the safety and reliability of the T&D system while maintaining system performance within defined and acceptable design and operating risk tolerances.

Q. What are the primary deliverables and high level steps of the Company's planning process?

A. The Company's planning process evaluates the electric delivery system over a specified future forecast period and identifies system needs and solutions. Historically, the Company has performed a forecast and contingency analysis for the upcoming summer period, a two-year forecast for its distribution circuits, and a five-year forecast for its substation banks/transmission feeders. The Company then conducts operating reviews of its assets through that forecast period and applies its design standards and risk-assessment methodology to the results to identify current and future operating risks and potential corrective solutions. The Company also investigates if major capital infrastructure investments can be substantially deferred, reprioritized, or even eliminated by alternative and less costly traditional infrastructure investments, targeted non-traditional measures and alternative solutions, such as DER, DG, DR, EE, or a combination thereof. Alternative traditional solutions could include: (1) constructing lower cost distribution projects to defer major upgrades or new builds, (2) using new technologies and/or distribution automation/smart grid asset deployment for improved asset utilization, and (3) reprioritizing and accelerating the construction of lower cost distribution and substation investments. As further described later in this testimony, the Company is exploring ways to better facilitate consideration of alternatives as part of its planning and capital budgeting process. The Company also reassesses previously identified needs and project solutions that have not yet been initiated to confirm the need and timing of the solution. As part of this reassessment, the Company reviews available data such as: updated load forecasts, load modifier forecasts (which include DERs), asset condition, system reliability, and the system’s load serving capability under normal and specific contingency conditions.

Q. When did the Company most recently complete its planning process?

A. In the spring of 2017.

Q. Did the Company evaluate alternatives to traditional infrastructure solutions as part of this process?

A. Yes. In developing the capital plan requirements detailed in Exhibit AP-E5, Schedules 1 and 2, the Company evaluated all of the alternatives to traditional infrastructure just mentioned, as well as all non-traditional alternative solutions.

Q. Please describe Orange and Rockland’s current load forecasting and risk assessment processes.

A. Each year, the Company forecasts overall system load and the projected summer peak loads for each transmission facility, individual substation and station transformer bank, and distribution circuit. The Company also projects the peak loads for each transmission line, substation, and station transformer bank as part of its five-year forecast. Substations are grouped into specific load regions based on geographic proximity and available switching capabilities among adjacent stations and circuits. Mathematical regression models consider and incorporate historical peak loads for each region, along with other relevant variables, to forecast weather-normalized loads for the summer peak and for a future forecast period for each region. The Company considers the impact of load modifiers, which include photovoltaics (“PV”), EVs, DERs, distributed generation (“DG”), and other demand-side management (“DSM”) measures, such as energy efficiency (“EE”) programs and voluntary or Company-administered load reduction programs. The Company then uses the forecasted loads to perform operating reviews on each of its major assets. These reviews cover transmission lines and banks down through their distribution circuits, for both normal and contingency operating conditions. The results of the contingency analysis are then evaluated against the Company’s design standards to assess if the electric facilities are, or will be, operating outside of acceptable design and/or risk tolerances. If any of the assets do not operate within their respective design standards either currently, or at some point during the future forecast period, the Company identifies a need, determines a solution, and develops a schedule to implement the solution consistent with its priority, as part of its capital budget development process. This process includes evaluating traditional solutions and NWAs. The Company employs additional screening tests to determine if or where targeted load reduction may be used as a potential solution.

Q. Please describe the role the Company’s design standards play in the distribution system planning process.

A. The Company’s electric system planning design standards provide guidance in assessing operating risk, identifying system needs, and prioritizing electrical infrastructure projects. The design standards balance the costs of infrastructure investment against the benefits of mitigating the risk of significant outage events as described by the magnitude of the outage and duration of the event. The electric design standards provide criteria to evaluate whether electric facilities are, or will be, operating outside of acceptable tolerances for equipment loading, operating parameters, and customer outage exposure. For the Company, acceptability is measured by meeting Company criteria for both the amount of load or number of customers impacted, and the reliability impact based on anticipated customer hours of outage duration. These standards are foundational to the capital planning process, and key for both short-term and long-term planning, as they provide a process by which future risk mitigation investments are identified and prioritized.

Q. Is the Company considering changes to its planning process?

A. Yes. The Company is considering refinements that will allow the planning process to evolve to reflect the growth of DERs and the Company’s commitment to considering NWAs while still adhering to basic planning principles, such as addressing appropriate operating risk and maintaining safety and reliability.

Q. How is the Company modifying its planning process to facilitate consideration of potential alternative solutions and NWA opportunities?

A. Commencing with the 2017-18 planning process, the Company is now expanding its planning horizon to include a ten-year outlook in addition to the traditional five-year outlook. The expanded ten-year planning horizon will facilitate consideration of NWA opportunities and other alternative solutions by providing the Company additional time to identify and analyze potential solutions. The Company will also be able to implement solutions far enough in advance to mitigate associated operating risk prior to critical need timeframes and other potential commitment dates.

Q. Is the Company exploring other modifications to its planning process?

A. Yes. The Company is exploring modifications to its planning process to account for the growth of DER and other load modifiers. Traditionally, the Company’s load forecasts with respect to load modifiers have relied on top-down, deterministic methods to provide projections for peak load levels across the electric delivery system. However, because of the increased penetration of DER and other load modifiers, the Company is implementing new methods and approaches that provide more granular and location-based information about how load and load modifiers will evolve and impact local system reliability and system investment requirements. Such information will also assist the Company in developing DSP capabilities and integrating DERs on its system.

Q. Please provide an example of the new methods you are discussing.

A. Historically, the Company has evaluated the impact of DERs at a system level. The Company incorporated DERs into its system forecasts by applying load modifiers that were determined at the overall system level and subtracted from gross load. Over time, the Company expanded the list of DERs it considered from EE and demand response (“DR”) to include PVs (starting in the 2016 forecast) and EVs (starting with the 2017 forecast).

Starting with the 2018 forecast, the Company’s DER forecasts will become more granular. In addition to considering DER impacts at a system level, the forecasts for each substation, bank, and circuit will reflect the impact of DERs on that particular element of the system. This newly developed forecasting methodology will add granular detail for the electric delivery system within specific geographic/operating regions to provide improved study and solution development for projected system needs. The Company expects to continue to enhance and refine its processes for projecting load growth and for modifying the net load to account for all load modifiers appropriately.

Q. Does Orange and Rockland have a formalized process to prioritize its projects?

A. Yes. There is a two-step process for prioritizing major projects in the Company’s overall electric capital investment plan. The first step is a prioritization conducted by the Electrical Engineering organization within the planning process. The second step is prioritization against other Company projects through a corporate-wide optimization process and methodology.

In the first step, Electrical Engineering prioritizes projects based on multiple drivers that have 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 needs, and construction window availability. Other drivers, such as operating conditions, safety, system losses, and voltage improvements are also considered. The total weight awarded a project establishes its priority relative to other projects for the entire forecasted planning period. These results are used in the development of the Company's five–year budget.

In the second step, the Company considers and prioritizes the overall capital budget for a one-year future-looking forecast period. The Company then analyzes its corporate portfolio using its strategic alignment optimization methodology and process. During this optimization process capital projects seeking funds for the upcoming budget year are ranked after they are reviewed using a series of Corporate key drivers. Projects are ranked relative to each other based on their attributes with consideration towards the following objectives (in no particular order):

- Improve Public and Employee Safety;
- Reduce Cost to Customers;
- Provide Reliable Service;
- Improve Customer Experience;
- Enhance External Relationships;
- Reduce and Manage Risk;

- Strengthen and Develop Employees;
- Strengthen Company Processes; and
- Sustain Environmental Excellence.

The initial portfolio prioritization is selected by a team comprised of department managers and directors from all areas of the Company. The overall capital portfolio is then reviewed and any necessary adjustments are made. A final portfolio is then approved by the O&R Capital Governance Committee.

Q. Has the Company changed how it screens for whether a project can be deferred or replaced by an NWA or other non-traditional alternative?

A. Yes.

Q. Please explain the previous process.

A. Previously, the Company employed a three-step process. First, the Company used a technical screening process similar to the current NWA suitability matrix discussed later in this testimony. Second, when the Company determined that an NWA or other non-traditional alternative was a viable technical option, it determined a present value for deferring the project. The present value was determined by dividing the present value savings (in terms of revenue requirement) by the load reduction required to defer the traditional project. The result was a value in dollars per kW. The Company used a hurdle rate of $150/kW, which was based on the Commission’s previously adopted value for system-wide energy efficiency programs, as the standard to determine whether it would perform more detailed studies. Third, for projects that overcame the hurdle rate, the Company performed studies that reviewed the type and number of customers affected, and the load profiles attendant for the circuits in the geographic area of the project. These studies also included an analysis of whether enough capacity reductions could be achieved and, if so, a cost-benefit analysis of the alternative as compared to the traditional investment.

Q. Does this three-step process affect the Company’s submission in this rate case?

A. Yes. The current capital program reflects the use of this previous process, which was most recently implemented in the Company’s 2016-2017 planning cycle. The 2016-2017 planning cycle drives the Company’s current electric system budgets and those projects represented in Exhibit AP-E5, Schedules 1 and 2.

Q. What is the Company’s new process?

A. The Company continues to use a three-step process but with different criteria. First, the Company uses a Company-specific version of the NWA suitability matrix developed by the JUs as part of the ongoing REV/DSP implementation process. The JUs developed the NWA suitability matrix to be a common framework to identify projects that are most suitable for NWA consideration. The Company's specific NWA suitability matrix is provided below. Second, the Company will develop and evaluate a portfolio of potential NWA solutions. Third, the Company will conduct a Benefit Cost Analysis ("BCA").

<table>
<tr><th>Criteria</th><th colspan="2">Potential Elements Addressed</th></tr>
<tr><td>Project Type Suitability</td><td colspan="2">• Project types include Load Relief or Load Relief in combination with Reliability. Other categories have minimal suitability and will be periodically reviewed for potential modifications due to State policy or technological changes.</td></tr>
<tr><td rowspan="2">Timeline Suitability</td><td>Large Project
(Projects that are on a major circuit or substation and above)</td><td>• 36 to 60 months</td></tr>
<tr><td>Small Project
(Projects that are feeder level and below)</td><td>• 18 to 24 months</td></tr>
<tr><td rowspan="2">Cost Suitability</td><td>Large Project
(Projects that are on a major circuit or substation and above)</td><td>• No cost floor</td></tr>
<tr><td>Small Project
(Projects that are feeder level and below)</td><td>• Greater than or equal to $450k</td></tr>
</table>

Q. How does the Company use its NWA suitability matrix?

A. The Company uses the criteria in the NWA suitability matrix to make an initial assessment of whether an NWA should be considered as an alternative to a traditional infrastructure project. This screening process determines if a proposed traditional project is a candidate from a technical and timing perspective to be cost-effectively deferred or replaced by implementing an NWA, which could include DG, DER, DR, EE, DSM, or a portfolio thereof.

Q. What are the benefits of using a NWA suitability matrix?

A. The NWA suitability matrix provides greater clarity, certainty, and long-term visibility to the market. It promotes an efficient allocation of time and resources for both developers and utilities. The NWA suitability matrix focuses on three criteria: project type, timeline, and cost. These criteria identify projects that are best suited for competitive procurement of an NWA, giving developers the greatest opportunity to compete, and providing the greatest opportunity for the success of the process.

Q. What type of projects is best suited for replacement or deferral by an NWA?

A. The nature and characteristics of electric delivery system needs are a primary influence on whether a given project is viable and suitable for NWA consideration. As part of the project evaluation with respect to the suitability matrix criteria, the Company considers numerous factors when determining whether a proposed solution, or portfolio of solutions, has the characteristics that would effectively satisfy the system need. These factors include the lead time with respect to the system need date, the economics of the project, and any additional positive reliability impacts of the traditional project beyond the identified planning need. Based on an assessment of these three criteria, load relief or capacity projects, as well as some types of reliability projects, are expected to be the best candidates for NWAs in the near term.

Q. What do you mean by a Load Relief or capacity project?

A. Load Relief or capacity projects are projects where additional T&D capacity will be needed at some forecasted future period to meet Orange and Rockland's planning design standards resulting from projected increases in load; typically, during hours of peak demand.

Q. Why are such projects best suited for replacement or deferral by an NWA?

A. There are several reasons why. First, the grid services provided by installed DER are more likely to align with traditional load relief and reliability solutions. Second, these types of projects will be required to be identified far enough in advance to provide sufficient lead time for an NWA solicitation. Finally, the scale of investment for the project can influence the likelihood of a NWA being cost-effective.[3]

Q. Please describe the Timeline Suitability Criterion.

A. Timeline Suitability addresses whether there is sufficient time to conduct an NWA solicitation and successfully implement the chosen solution before the required trigger date to commit significant funds and resources towards meeting the required traditional T&D project in-service date. Timelines vary depending on factors such as project size, complexity, and customer demographics. Similarly, the traditional utility project required in-service date greatly influences whether there is sufficient time to conduct and implement an NWA solicitation.

Q. Please describe the Cost Suitability criterion.

A. Cost Suitability assesses the potential for an NWA solution to be more cost-effective at meeting customers' needs than a traditional solution. Cost suitability criteria sets a threshold above which NWA solutions are more likely to be cost-competitive with traditional solutions. Orange and Rockland established a cost floor for small projects at

[3] See Case 16-M-0411, *In the Matter of Distributed System Implementation Plans*, Joint Utilities' Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices, filed May 8, 2017.

$450K based on historical averages of previously completed capital projects. For large projects, no cost floor is assigned.

Q. Are the considerations and factors discussed above part of the Company’s NWA suitability matrix?

A. Yes. They will be incorporated in the Company’s NWA suitability matrix moving forward.

Q. What type of projects are generally not suitable candidates for replacement or deferral by an NWA?

A. Typically, projects that are driven by new customer demand, typically driven by new or expanding customer load, involve high-risk circumstances, address regulatory compliance requirements (such as those imposed by the North American Electric Reliability Corporation (“NERC”), Federal Energy Regulatory Commission (“FERC”), or New York Independent System Operator (“NYISO”)), address safety or operational issues, or are required to replace aging or obsolete equipment are not good candidates for replacement or deferral by an NWA.

Q. Please describe the second and third steps of the Company’s new process.

A. If a project passes the NWA suitability matrix, the Company will prepare hypothetical portfolios of NWA solutions to determine whether it can obtain enough capacity to satisfy the project need. If it determines that it can, the Company will conduct a BCA and other economic evaluations to determine the cost-effectiveness of the portfolio, as well as associated potential customer rate and bill impacts. If the Company decides to go forward with an NWA or non-traditional alternative, it will issue a request for proposal (“RFP”), in order to assess actual market solutions.

Q. Is the Company working to develop any toolsets that will enable improved study capability for NWA solutions and BCA?

A. Yes. The Company is developing a software ‘toolkit’ that is expected to facilitate the analysis for each of the key steps in the Company’s updated NWA planning and review process. This project includes the required data collection and the development of a software tool that will allow the Company to assess the potential for a broad range of DER technologies within the Company’s service territory (such as EE, DR, customer-sited generation, and storage) by the third quarter of 2018. It will also be used to help the Company determine whether it should proceed with an RFP for an NWA in an area. The new planning tools will also handle the BCA for the Company in order to determine if NWA alternatives are cost effective as compared to specific traditional solutions.

Q. How is the Company developing this toolkit?

A. The Company plans to develop customized software tools and processes based on detailed surveys and studies that will provide statistically significant analysis and highly accurate results concerning the load modifier potentials that exist in the Company’s service territory.

Q. How will the BCAs be implemented or change moving forward?

A. The JUs have collaboratively developed a BCA methodology to comply with the Commission’s Order Establishing the Benefit-Cost Analysis Framework.[4] That methodology and the associated templates have been combined with Company-specific data to develop Orange and Rockland’s BCA Handbook. The BCA Handbook, filed in conjunction with the Company’s initial DSIP in June 2016,[5] is being incorporated into the integrated planning process, as well as the forecasting and modeling tools described above. The BCA Handbook illustrates the Company’s support for the evaluation and deployment of NWAs, where appropriate. It also serves as an integrated part of the Company’s updated electric delivery system planning process, from forecasting

[4] Case 14-M-0101 - *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Establishing the Benefit Cost Analysis Framework (issued, January 21, 2016). (“BCA Order”)

[5] Case 16-M-0412, Benefit Cost Analysis Handbook, Revised Benefit Cost Analysis Handbook (filed August 22, 2016) (“BCA Handbook”).

to implementation of DER as potential solutions and deferrals for traditional solutions, in a manner that best serves the Company's customers, manages risk, and maintains the safety and reliability of the grid.

Q. Please describe the results of the Company's most recent electric planning cycle with respect to the identification of potential NWAs.

A. The Company identified six potential NWA projects, which are described in more detail below in the DSP Implementation section of this testimony.

Q. Did the Company screen all projects that are shown in Exhibit AP-E5, Schedules 1 and 2, that meet the criteria for NWA suitability review?

A. Yes. The Company screened all projects that met the suitability criteria for NWA consideration. Projects that were not suitable for NWA consideration and must be constructed as traditional infrastructure solutions are included and discussed in detail in Section III below.

III. T&D Programs and Projects

A. Plant Additions and Capital Budget

Q. Are you familiar with, and were you involved in the preparation of, Exhibit AP-E5, Schedules 1 and 2?

A. Yes. Exhibit AP-E5, Schedules 1 and 2, reflect the capital expenditures and capital plant additions, respectively, for the Company’s T&D programs and projects forecasted for the period January 1, 2019 through December 31, 2021. These schedules also include anticipated project expenditures and plant additions that will occur during the period October 1, 2017 to December 31, 2018 (“Linking Period”). Our testimony will focus on the plant additions by rate year, as set forth in Exhibit AP-E5, Schedule 2. Exhibit AP-E5, Schedule 2, includes spending totals for electric blankets and smaller capital projects under $1 million for which general details are provided below. This schedule also sets forth spending totals for major capital projects over $1 million, along with their projected in-service dates.

With respect to how the Company describes and budgets its projects within specific driver categories, projects are classified as follows: (1) Risk Reduction Projects, (2) New Business Projects, (3) System Expansion Projects, (4) Replacement Projects, and (5) Resiliency Projects. The capital plant additions discussed in more detail below all fall into one of these categories. Additional information is also provided for projects that are forecasted to have significant spending during a potential three-year rate period, but would be completed and added to plant in-service after such a rate period. The forecasted in-service dates are estimated and may change, based on actual finalized project approval time frames and subsequent construction and installation schedules. The forecasted costs have been quantified based on an analysis of recent spending for material, equipment, and labor for similar projects that are in progress or have recently been completed by the Company.

Q. How were the projects included in Exhibit AP-E5 identified?

A. The projects included in Exhibit AP-E5 were identified and prioritized through the Company’s electric delivery system planning process, as described previously.

Q. What types of projects is the Company seeking to fund as a part of this rate case?

A. The Company has several programs and projects in its capital plan that are necessary to maintain system reliability and reduce the risk of equipment and system failures. As noted above, the Company groups these capital expenditures and plant additions into the following budget categories:

- *Risk Reduction:* Risk reduction projects and programs mitigate high risk outcomes for normal or contingency scenarios that exist for facilities that do not meet the Company’s current design standards, as well as programmatic maintenance, repair, and replacement of components to address risks related to equipment, component or unit failure. These projects and programs are designed to increase reliability or reduce/mitigate a risk that is currently present, or may be associated with a facility utilizing proactive replacement strategies.

- *New Business:* Projects that are undertaken to accommodate the connection of new customer load or expansion of existing customer load.
- *System Expansion:* System expansion includes planned system capacity upgrades necessitated by growth in customer demand to reduce risks related to facilities that are forecasted to not meet design standards during some future operating state under normal and/or system contingency operating scenarios. These projects or programs typically include new substations, feeder cable, and transformer load relief.
- *Replacement:* Projects or programs to replace failed assets such as transformers, circuit breakers, and relays; or replacement of equipment that has not yet failed but is performing poorly, has become obsolete and difficult or costly to maintain, or is approaching the end of its useful life.

- *Resiliency:* Projects or programs that make physical changes to reduce susceptibility to storm conditions such as high winds, flooding, or flying debris. Resiliency projects or programs improve the durability and stability of the Company's infrastructure allowing the system to better withstand the impacts of severe weather events with less damage and/or provide for the recovery of the system and customer load more quickly. The Company has been implementing resiliency projects since 2013 and plans to complete projects described more specifically as storm-hardening by 2020.

Additional information regarding the Company's T&D capital projects forecasted for some of the costs in the Linking Period, and for all of the projects in RY1, RY2 and RY3, as summarized in Exhibit AP-E5, Schedules 1 and 2, is provided below.

Q. How does the Company develop its project cost estimates for major projects?

A. The Company has defined three levels of progression for project cost estimates exceeding $5 million: the Budgetary (Planning) Estimate, the Appropriation Estimate, and the Current Working Construction Estimate ("CWE"). 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 typically contains higher amounts of contingency, approximately in the 20 percent to 30 percent range, due to the high 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 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 actual construction that have already been approved by the Company's Board of Directors. It includes all direct and indirect costs of the project such as: labor, equipment, material, corporate

overheads, escalation, contingency, and retirement costs. The Appropriation Estimate will typically contain contingencies and unknowns in the range of 10 to 20 percent. This is to account for certain risk factors that still exist and need to be accounted for in this stage, particularly with respect to final approvals, equipment, labor procurement, and unknown construction factors.

3) The CWE is typically the 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 construction. This estimate is then 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 addressed 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 period during the project timeline. It is important to note that estimates are not changed often, and will only be updated or modified based on actual available project information and updates to that information along the project implementation timeline.

Q. Please describe what the estimates in Exhibit AP-E5, Schedules 1 and 2, represent and how they may differ from the budgetary and CWE estimates.

A. The estimates in Exhibit AP-E5, Schedules 1 and 2, are Plant Additions estimates. A Plant Additions estimate is derived from the total current actual spending plus projections in the capital budget based on the estimated date in service. 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 Schedule 2 is representative of the Company's spending on a project to date and 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 reference the Plant Additions estimate.

Q. Is the Company making any requests related to the Commission’s AC Transmission Proceedings (Case Nos. 12-T-0502, 13-E-0488, et al.)?

A. Yes.

Q. Please explain.

A. In its December 17, 2015 Order in the AC Transmission Proceedings, the Commission stated that the Developer chosen to build Segment B would be required to upgrade the existing double circuit 69 kV line from the Shoemaker to Sugarloaf substations in Orange County. The Commission further stated that Orange and Rockland should perform the work necessary to complete this upgrade.

Q. Is the Company seeking funds to perform that work in this rate case?

A. No. The Company has not included in its electric revenue requirement in this filing any costs associated with or contemplated by the upgrade to the Shoemaker to Sugarloaf line required by the December 17, 2015 Order. The Company reserves the right to seek the Commission’s authorization to recover any such costs by surcharge, by increase in base rates, or by other means, as determined by the Commission.

Q. Is the Company making any requests related to the Indian Point Contingency Proceeding (Case 12-E-0503)?

A. The Company has not included in its electric revenue requirement in this filing any costs associated with or contemplated by the Commission's November 4, 2013 Order in Case 12-E-0503 (Indian Point Contingency Plan Order), or subsequent orders issued in that proceeding. However, the Company reserves the right to seek the Commission's authorization to recover any such costs by surcharge, by increase in base rates, or by other means, as determined by the Commission.

i. *Electric Blankets & Regular Projects Under $1 Million*

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 safe and reliable electric service. Blankets are an accounting convention, long accepted by the Commission and Department of Public Service Staff ("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.

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 covers overhead or underground system improvement electrical projects required for the connection of new customers to the distribution system.
- *Streetlights* - This blanket covers the installation of new streetlights on the Company’s system associated with new business projects and new customer requirements.
- *Road Widening* - This blanket covers the relocation of existing Company facilities that interfere with municipal, state or federal road widening projects.
- *Telephone Interference Work* - This blanket covers expenditures required when 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 covers installations or upgrades to existing facilities to address customer voltage complaints. This type of work may include adding new transformers, upgrading existing transformer capacity and/or upgrading secondary systems to improve operating conditions.
- *System Integrity* - This blanket covers 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.*, system for handling non-emergency customer trouble calls).
- *Resiliency* – This blanket covers projects that make physical changes to reduce susceptibility to storm damage, including high winds, flooding, or flying debris. Resiliency projects improve the durability and stability of the Company’s infrastructure allowing the system to withstand the impacts of severe weather events with minimal damage and/or provide for the recovery of the system and customer load more quickly.

- *Reinforcement/Replacement* – This blanket includes the replacement or reinforcement of transmission structures and possibly the replacement of shield wires and/or conductors determined to be structurally deficient.

Also included in the overall blankets category are: (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.

Q. What is included in the category of Regular Projects under $1 million set forth Exhibit AP-E5, Schedule 2?

A. These expenditures consist of 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 used and shared with other assets, to improve reliability on the distribution system. These costs also reflect some smaller transmission and substation system projects and upgrades.

Q. How are the larger capital projects with forecasted spending of more than $1 million presented in the Panel's testimony?

A. The identification of the major capital projects within each of the rate years fall into the Risk Reduction and Replacement categories as shown and listed in the table below, and are discussed further in the testimony to follow. Capital project white papers with more detailed information about each of these projects are included in Exhibit EIOP-2.

In Service Date	**Project**
Risk Reduction	
RY1	West Shore Rail Line Structures 30, 110, 145
RY2	Port Jervis Substation 2-35 MVA Bank, Circuit Exits & 69kV Intrastation Tie
RY2	Little Tor Substation, Transmission Tap and UG Circuit Exits
RY2	West Shore Rail Line Structures 190, 197, 211
RY3	Lovett 345kV Station, Remote Relaying and Transmission
RY3	Install OPGW on T/L 702
RY3	West Nyack Capacitor Bank II
Replacement	

RY1	Ramapo Banks 2300 Replacement
RY1	Line 67 Relay Replacements at West Haverstraw
RY3	Burns Breaker Replacements

ii. <u>Risk Reduction Projects</u>

Q. Please describe the risk reduction projects that will have an addition to plant in excess of $1 million and will be in service during Rate Year One.

A. The Company is planning for the following risk reduction projects to go into service during Rate Year One: (1) West Shoreline structures 30, 110, and 145 (December 2019).

Q. Please provide an overview of the West Shoreline Structures 30, 110, and 145 project.

A. This project involves the replacement of three double-circuit two-pole wood structures located on Lines 55/56 (Structure 30) and 551/561 (Structures 110 & 145) with double-circuit galvanized steel poles.

Q. What is the justification for this project?

A. Originally constructed with mainly wood pole structures in the 1960's, some of the poles on Lines 55/56 and 551/561 have prematurely deteriorated, thereby raising structural integrity concerns. An extended outage on these lines could lead to system voltage violations under certain system contingencies. Replacement with galvanized steel structures will greatly reduce the potential for outages during severe weather events and will comply with current code requirements.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The West Shoreline Structures 30, 110, 145 project's current in-service date is December 2019. The Electric Plant Additions estimate for this project is $1,459,300.

Q. Has the NWA suitability criteria been applied to and performed for the West Shoreline Structures 30, 110, 145 project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the West Shoreline Structures 30, 110, 145 project was not a suitable project for an NWA solution. The project is driven by the age, condition and obsolescence of the assets which are not viable, the project is not suitable for NWA solutions to address.

Q. Please describe the risk reduction projects that will have an addition to plant in excess of $1 million and will be in service during RY2.

A. The Company is planning the following risk reduction projects to be in service during RY2: (1) Port Jervis Substation 2-35MVA Banks, Circuit Exits & 69kV Intrastation Tie (June 2020), (2) Little Tor Substation, Transmission Tap and Underground Circuit Exits (December 2020) and (3) West Shoreline Structures 190, 197, 211 (December 2020).

Q. Please provide an overview of the Port Jervis Substation 2-35MVA Banks, Circuit Exits & 69kV Intrastation Tie project.

A. The Port Jervis projects are necessary to provide a complete rebuild of the existing substation located there. Due to the topography, available land, and other building/construction constraints, the new substation will be constructed with separate upper and lower yards. The upper yard will be a transmission yard containing the 69kV busses, breakers, and switches with take-off structures for the two 69kV underground feeds to supply the lower yard. The lower yard will consist of two - 69/13.2kV, 35 MVA substation power transformers with load tap changers (“LTCs”) and the switchgear/control house. The LTCs will improve area voltage and operating conditions. The two transformers will supply switchgear capable of feeding eight distribution circuits. A mobile transformer and temporary transformer will be needed to completely de-load the existing Port Jervis Substation during construction.

Q. What is the justification for this project?

A. The existing Port Jervis Substation is a single bank station with no tap changer control. Port Jervis is located at the northwestern edge of the Company’s service territory, and its few distribution ties have limited capacity. The Port Jervis Substation does not meet the

Company’s distribution design standards. The existing bank also does not phase in with the other circuits in the area, which forces a break before make condition, which prevents closed transition ties for electrical system interfaces, resulting in outages to customers before they can be tied to other sources. There are operating and safety issues associated with forced and unforced outages to station equipment. The obsolescence of the existing equipment and the other operating and safety issues in the station mentioned above, in addition to the design standards issues warrant the upgrade of the Port Jervis Substation.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The Port Jervis Substation 2-35MVA Bank, Circuit Exits & 69kV Intrastation Tie project’s current in-service date is June 2020. The Electric Plant Additions estimate for this project is $28,276,900.

Q. Has the NWA suitability criteria been applied to and performed for the Port Jervis project?

A. Yes. The Company applied the NWA suitability criteria matrix and determined that Port Jervis was not a suitable project for an NWA solution. These facilities do not presently meet the Company’s design standards. That is, the need is now and not a future forecasted need that could allow the Company to possibly plan for and implement potential cost-beneficial alternative solutions. The obsolescence, operating, and safety problems are issues that are not viable for NWA solutions to address.

Q. Did the Company also have a third party review the project and determine if there were any suitable NWAs for this project?

A. Yes, the Company also used a third party consultant – Navigant -- to perform a NWA suitability and alternative potential/BCA study using the Company's NWA suitability criteria matrix for this project. Testimony set forth below will provide a summary of Navigant's study results for the Port Jervis project. They also performed similar analysis for the Little Tor Substation, Lovett 345kV Substation, and Line 702A Underground Projects, which are also discussed below.

Q. Please provide an overview of the Little Tor Substation project.

A. The Company plans to install a new Little Tor Substation in New City, New York. The 138kV transmission source will 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. The new substation will include two

138/13.2kV, 50MVA substation power transformers with LTCs and provisions for eight – 13.2kV distribution circuits. One of the distribution circuits will exit the station and travel east along South Mountain Road. This will support local customers in the area and be used to re-feed the existing Tilcon rock quarry and other customers, improving reliability for Tilcon and reducing momentary outages for customers.

Q. What is the justification for this project?

A. The New City area is located between the Company's New Hempstead, Congers, and West Haverstraw Substations. These three substations and the temporary mobile transformer, which is presently installed and operating at the future Little Tor Substation site, serve a combined total of approximately 36,700 customers and 185 MVA of load at peak. Approximately 46 percent of this load is supplied from the New Hempstead Substation and the Little Tor mobile transformer. The Little Tor Substation will assume the load temporarily being served by the mobile transformer and provide relief to the circuits for the New Hempstead substation. It will also provide relief to the 22-1-13 and 22-4-13 circuits in the Congers Substation. The distribution circuits operating in this area do not presently meet the Company’s current distribution design standards.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The Little Tor Substation project’s current in-service date is December 2020. The Electric Plant Additions estimate for this project is $24,488,200.

Q. Has the NWA suitability criteria been applied to and performed for the Little Tor Substation project?

A. Yes. The Company applied the NWA suitability criteria matrix and determined that the Little Tor Substation was not a suitable project for an NWA solution. The area’s electric delivery system does not presently meet the Company’s design standards; that is, the need is now and not a future forecasted need that could allow the Company to possibly plan for and implement potential cost-beneficial alternative solutions. There are operating problems for local area circuits under contingency conditions, particularly without the mobile transformer operating. The long-term application of the mobile transformer to maintain local area operating requirements is neither practical nor appropriate for its intended use. In addition the proposed Little Tor Substation is an ‘in-flight’ project for which the Company has already expended significant time and resources. It has completed the design, and is now approaching the end of a long and difficult permitting process. The Company has committed to and obtained major equipment, with construction anticipated to commence in RY1. Testimony later in this panel will summarize Navigant's study results for the Little Tor project.

Q. Please provide an overview of the West Shoreline Structures 190, 197, 211 project.

A. This project involves the replacement of three double-circuit, two-pole wood structures located on Lines 551/561 (Structures 190, 197 & 211) with double-circuit galvanized steel poles.

Q. What is the justification for the project?

A. This project has the same justification as the West Shoreline Structures 30, 110, 145 project discussed earlier in this testimony.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The West Shoreline Structures 190, 197, 211 project's current in-service date is December 2020. The Electric Plant Additions estimate for this project is $4,392,900.

Q. Has the NWA suitability criteria been applied to and performed for the West Shoreline Structures 190, 197, 211 project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the West Shoreline Structures 190, 197, 211 project was not a suitable project for an NWA solution. The project is driven by the age, condition and obsolescence of the assets, which are not viable, and the project is not suitable for NWA solutions to address.

Q. Please describe the risk reduction projects that will have an addition to plant in excess of $1 million and will be in service during RY3.

A. The Company is planning the following risk reduction projects to be in service during RY3: (1) Lovett 345kV Substation, Remote Relaying, and Transmission, (2) Install OPGW on T/L 702, and (3) West Nyack Capacitor Bank II.

Q. Please provide an overview of the Lovett 345kV Substation Remote Relaying, and Transmission project.

A. The Company plans to install the new Lovett 345 kV Substation, including a 448MVA - 345/138 kV transformer bank to be electrically connected to existing 345 kV Line Y88. The Lovett 345kV Substation will provide a third source into the Eastern Load Pocket (“ELP”), mitigating the impact of the retirement of the Lovett Generating Station.

Q. What is the justification for this project?

A. The proposed 345/138kV substation will provide an additional interface into the Company's Eastern Division. The project has also been identified as a required system reinforcement need by the NYISO as a result of the latest Reliability Needs Assessment after the review of common tower contingencies to 345kV Lines 67/68. The installation of the new Lovett Substation will prevent the overload of several transmission lines during these contingencies, as well as the load shedding of approximately 50,000 customers in the ELP.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The Lovett 345kV Station, Remote Relaying, and Transmission project's current in-service date is December 2021. The Electric Plant Additions estimate for this project is $32,717,100.

Q. Has the NWA suitability criteria been applied to and performed for the Lovett 345kV Station project?

A. Yes. The Company applied the NWA suitability criteria matrix and determined that Lovett 345kV Station project was not a suitable project for an NWA solution. The electric delivery system in the area does not meet the Company's design standards presently; that is, the need is now and not a future forecasted need that could allow the Company to possibly plan for and implement potential cost-beneficial alternative solutions. In addition, the substantial amount of capacity deficit to address contingency and operating problems that both the Company and the NYISO have identified are issues that are not practical for NWA solutions to address. Testimony set forth below will summarize Navigant’s study results for the Lovett 345kV Station project.

Q. Please provide an overview of the Install OPGW on T/L 702 project.

A. This project proposes to replace one of the existing conventional shield wires on the overhead portion of Line 702 (West Nyack to Corporate Drive) and Line 703 (Corporate Drive to Harings Corner) with a new fiber optic ground wire (“OPGW”) between the West Nyack Substation, the Orangeburg Transition Structure, and Harings Corner Substation, a distance of approximately 4.9 miles.

Q. What is the justification for this project?

A. Having a continuous fiber link between these three substations will allow for state of the art relay protection and accommodate other necessary communication requirements between them, such as expanded bandwidth necessary to accommodate grid modernization and future DSP functionality. In addition, an OPGW is required for the high speed relay tripping and video surveillance systems, which the Company has installed in all three substations.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The Install OPGW on T/L 702 project's current in-service date is December 2021. The Electric Plant Additions estimate for this project is $2,744,900.

Q. Has the NWA suitability criteria been applied to and performed for the Install OPGW on T/L 702 project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the Install OPGW on T/L 702 project was not a suitable project for an NWA solution. This project is an asset replacement project that provides upgraded technology and functionality, and is not a viable and suitable project for an NWA solution.

Q. Please provide an overview of the West Nyack Capacitor Bank II project.

A. This project calls for the installation of one 16 MVAR capacitor bank at the West Nyack Station in 2021. This project is part of the larger project to construct underground Line 702 starting from the Burns Substation and terminating at a second 138/69 kV auto-transformer bank at the West Nyack Substation.

Q. What is the justification for this project?

A. Recent power flow studies indicate that the loss of either Line 561 or Line 702 will result in voltage violations at various 138 kV busses in southern Rockland County, with the worst observed at the West Nyack station. This voltage violation will only be exacerbated as proposed and expected block load growth is added in the Orangeburg area, as there are various projected load additions in 2020 and beyond.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The West Nyack Capacitor Bank II project's current in-service date is December 2021. The Electric Plant Additions estimate for this project is $1,701,200.

Q. Has the NWA suitability criteria been applied to and performed for the West Nyack Capacitor Bank II project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the West Nyack Capacitor Bank II project was not a suitable project for an NWA solution. This project solves for system voltage operational issues at the transmission system level under current system contingency conditions, and is not a viable and suitable project for an NWA solution.

iii. *Replacement/Upgrade Projects*

Q. Please describe the replacement/upgrade projects that will have an addition to plant in excess of $1 million and will be in service during Rate Year One.

A. The Company is planning the following replacement projects to be in service during Rate Year One: (1) Ramapo Banks 2300 Replacement and (2) Line 67 Relay Replacements at West Haverstraw.

Q. Please provide an overview of the Ramapo Banks 2300 Replacement project.

A. This project is the replacement of existing Ramapo Bank 2300, comprised of three single-phase units, each rated 133 MVA, 345/138kV. After reviewing planning studies considering contingency analysis and growth, the findings indicate that the existing transformer should be replaced with a single unit, three-phase 525 MVA transformer.

Q. What is the justification for this project?

A. This transformer is at the end of its useful life and has become an operational and environmental liability. Transformer Bank 2300 has been in service for over 40 years. The unit has experienced repeated leaks over its’ life that have required repairs and necessitated environmental cleanup. In addition, should one of the single-phase units fail, there are no single-phase spare units available as this current design is obsolete.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The Ramapo Banks 2300 Replacement project's current in-service date is May 2019. The Electric Plant Additions estimate for this project is $9,364,800.

Q. Has the NWA suitability criteria been applied to and performed for the Ramapo Banks 2300 Replacement project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the Ramapo Banks 2300 Replacement project was not a suitable project for an NWA solution. The project is driven by the age, condition and obsolescence of the assets, which are not viable, and this project is not suitable for NWA solutions to address.

Q. Please provide a description of the Line 67 Relay Replacements at West Haverstraw project.

A. This project will upgrade protection systems for 345kV Line 67 at the Ladentown, Bowline, and West Haverstraw terminals (the Company will only be responsible for costs at the West Haverstraw terminal). The upgraded design will require two separate systems of protection, as well as breaker failure protection and auto-reclosing relays.

Q. What is the justification for this project?

A. The existing solid-state devices have malfunctioned several times in recent years, causing transmission line outages. Due to their age, the electro-mechanical relays are 'drifting', or not operating properly within the manufacturer's original specifications and tolerances. In addition, they are no longer supported with spare parts and technical assistance by the equipment manufacturers. This compromises the accuracy and reliability of the protection systems, making them obsolete.

Q. What are the estimated Plant Additions and projected in-service date for this project?

A. The Line 67 Relay Replacements at West Haverstraw project's current in-service date is May 2019. The Electric Plant Additions estimate for this project is $1,030,200.

Q. Has the NWA suitability criteria been applied to and performed for the Line 67 Relay Replacements at West Haverstraw project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the Line 67 Relay Replacements at West Haverstraw project was not a suitable project for an NWA solution. The project is driven by the age, condition, and obsolescence of the assets, which are not viable, and the project is not suitable for NWA solutions to address.

Q. Please describe the replacement project that will have an addition to plant in excess of $1 million and will be in service during RY3.

A. The Company is planning the Burns Breaker Replacements project to be in service during RY3.

Q. Please provide an overview of the Burns Breaker Replacements project.

A. The purpose of this project is to replace the six 138kV and the three 69kV OCBs with SF^6 gas insulated circuit breakers (“GCBs”), also known as “puffer” breakers, along with the associated control cables for each breaker.

Q. What is the justification for the project?

A. Based on the condition and failure of similar breakers of the same vintage in Orange and Rockland’s service territory, the Company has determined that all the oil breakers in the Burns Substation are nearing the end of their useful lives. Proactively replacing them before failure will reduce risk to the system and the potential for future customer outages. In addition, GCBs minimize fire and explosion hazards and this project will remove approximately 20,700 gallons of oil from the system. This will improve safety for Company personnel working within the substation environment and limit the Company’s environmental liability from potential spills and leaks.

Q. What are the estimated Plant Additions and the projected in-service date?

A. The Burns Breaker Replacements project's current in-service date is December 2021. The Electric Plant Additions estimate for this project is $1,986,600.

Q. Has the NWA suitability criteria been applied to and performed for the Burns Breaker Replacements project?

A. Yes. The Company applied its NWA suitability criteria matrix and determined that the Burns Breaker Replacements project was not a suitable project for an NWA solution. The project is driven by the age, condition and obsolescence of the assets, which are not viable, and the project is not suitable for NWA solutions to address.

B. Projects In-Service after December 31, 2021

Q. Does the Company have any major electric capital projects that would have significant expenditures during a three-year rate period, but be added to plant in service after RY3?

A. Yes. The Company has one such project: the Line 702A Underground ("UG").

Q. Please provide an overview of the Line 702A UG project.

A. The Company plans to construct a 138 kV UG line originating from the Burns Substation and terminating at the West Nyack

Substation, which will operate electrically in parallel to the current overhead Line 702 transmission feeder. This UG line will connect into a second 138/69 kV auto-transformer bank at the West Nyack Substation, providing a parallel feed into Southern Rockland County, solving for the Line 561 contingency, and improving source reliability and capacity.

The project scope also includes the installation of an OPGW on the overhead sections from the West Nyack Substation to the Harings Corner Substation in New Jersey. The new UG line from Burns to West Nyack will include fiber optic cable in the underground conduit system as well.

Q. What is the justification for the project?

A. The N-1 conditions resulting from the loss of Line 561 will load Line 702 and Line 652 above their long-term emergency ratings by 2020. Absent the completion of the L702A Underground project, both Line 702 and Line 652 will require significant conductor upgrades to improve thermal ratings to meet the transmission design standards. Voltage violations will also worsen with the increased loading, requiring capacitor bank installations.

The completion of the UG Line 702A will greatly improve the transmission source capacity and reliability of the Company’s transmission system in the area.

Q. What are the estimated expenditures within the potential three-year rate period commencing in 2019, and the estimated Plant Additions and projected in-service date after the three-year rate period?

A. The Line 702A UG project's anticipated in-service date is December 2022. The Electric Capital Expenditures estimated within the potential three-year rate period for all associated Line 702 UG projects (New Line 702A Underground, Burns Terminal, and West Nyack 2nd Autobank) is $22,697,900. The total cost estimate for this project is $39,200,000.

Q. Has the Company applied the NWA suitability criteria to the Line 702A UG project?

A. Yes. The Company applied the NWA suitability criteria matrix and determined that the Line 702A UG project was not a suitable project for an NWA solution. The electric delivery system in the area does not meet the Company's design standards presently; that is, the need is now and not a future forecasted need that could allow the Company to possibly plan for and implement potential cost-beneficial alternative solutions. The substantial amount of capacity deficit to address contingency and operating problems that the Company has identified are issues that are not practical for NWA solutions to address. Testimony set forth below will summarize Navigant's study results for the Line 702A UG project.

Q. With respect to the major capital projects discussed above, please describe the process and procedures used to monitor and evaluate actual project milestones and cost objectives against 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. It is responsible for the development and tracking of project schedules, estimates, and contract documentation for all large capital projects. The Project Controls Group and individual project teams employ standardized project schedules to track performance and milestone achievement. The Company's cost analysts and project managers use Oracle Business Intelligence software to track actual costs and expenditure details.

Q. Has the Company been keeping Staff and other interested parties informed of the status and progress of its electric T&D capital infrastructure spending?

A. Yes. The Company has kept Staff and the other parties informed of any schedule changes, project scope modifications, concerns, and increased spending, particularly regarding projects identified in the Company's current electric rate plan, as well as those upcoming projects that are included and discussed in this Panel's testimony. Pursuant to the Company's current electric rate plan, Orange and Rockland has been providing quarterly and annual reports to Staff and other interested parties regarding the Company's T&D capital expenditures. In addition, 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 proposes to continue this project status review and update process as part of any new electric rate plan.

C. NWA Suitability Study Results

Q. Why did the Company have Navigant review the potential suitability of NWA solutions for the Port Jervis, Little Tor, Lovett 345kV Substation, and L702A UG projects ("Major Projects")?

A. Each of the Major Projects would involve more than $20 million in traditional infrastructure investment. Moreover, the Company had not previously applied its NWA suitability criteria matrix to projects of such substantial scope. Therefore, the Company concluded that, for the first time the matrix was used, an independent review of the suitability of the Major Projects to NWA solutions would provide valuable information and feedback. The Panel would note that Navigant's review was based on the descriptions of the Major Projects set forth in this testimony and associated whitepapers.

Q. Please summarize the results of Navigant's review.

A. Navigant confirmed Orange and Rockland's determination that none of the Major Projects are suitable candidates for an NWA solution. Each project fails two of Orange and Rockland's NWA suitability criteria as outlined below.

(1) Project Type – The Company's NWA Suitability Criteria identifies Load Relief projects and projects that combine Load Relief and Reliability as suitable candidates for an NWA solution. None of the Major Projects fit these categories. Each Major Project addresses reliability or operating risks that currently exist, and therefore is designated as a Risk Reduction/High Exposure Reliability project.

(2) Project Timeline – The Company's NWA Suitability Criteria states that for Large Projects, such as the Major Projects, an NWA solution may be suitable for projects needed between 36 and 60 months. Each Major Project is needed sooner than this timeframe. There is not enough time for the Company to pursue and implement an NWA solution and

evaluate its success before the need to commit to and implement the traditional solution.

(3) Project Cost - Each Major Project meets this criterion. The Company's NWA suitability criteria state that there is no cost cap for Large Projects.

Q. Please elaborate on why the Major Projects fail the Project Type criterion.

A. The Lovett and L702A UG projects address conditions that do not currently meet Orange and Rockland's design standards. Accordingly, Navigant has designated each project as a Risk Reduction/High Reliability Exposure project rather than a Load Relief project. Although the Company expects future load growth in the areas served by the Lovett and L702A UG projects, its forecast does not alter the fact that these Major Projects are needed today to satisfy the Company's design standards.

Similarly, although the Company forecasts that the Little Tor and Port Jervis substations will experience capacity deficiencies in 2019 and 2020, respectively, both projects address needs that exist today. With respect to the Little Tor project, the Company has already installed and has had a mobile substation in-service for the past four years to partially alleviate distribution circuit deficiencies that do not meet the Company's design standards. Mobile substations, however, are not intended to provide continual capacity support. Typically, they are installed as a temporary measure to provide back-up support when a substation transformer fails or for maintenance or construction activities. Because the reliability risk already exists, Navigant has designated Little Tor as a Risk Reduction/High Exposure Reliability project.

The Port Jervis project also addresses existing reliability and operating deficiencies that under current conditions do not meet the Company’s distribution design standards, as well as having minimum approach distance (“MAD”) safety issues. These deficiencies include inadequate substation bus voltage regulation due to the absence of regulating devices (the transformer does not have load tap changing capability),[6] and absence of instrument transformers needed for SCADA control. The small substation footprint and older design configuration require that the substation be de-energized for crews to perform maintenance or emergency repairs in order to avoid MAD working clearance violations and associated safety hazards. Because these risks exist today and are independent of load served, Navigant has

[6] Bus voltage regulation is provided by 34.5kV transmission sources from adjacent substations, which provide substandard regulation compared to conventional load tap changing devices.

designated the Port Jervis project as a Risk Reduction/High Exposure Reliability project.

Q Please elaborate on Navigant's conclusions regarding Orange and Rockland's Timeline Suitability Criterion.

A. Navigant analyzed the minimum lead time required to implement and confirm the viability of an NWA solution for each of the Major Projects in light of the deadline faced by the Company for making a "Go/No Go" commitment. Navigant concluded that evaluating an NWA solution requires four steps that are typically implemented over a period of two to three years to determine if there is sufficient firm DER capacity to enable deferral of the traditional project. The four steps and associated timelines are summarized below, and explained in greater detail in the reports attached in Exhibit EIOP-3.[7]

(1) Write, Release and Award NWA RFP: 3 Months, +/- 3 months;
(2) Vendor Recruits and Confirms Customers: 6 Months, +/- 3 months
(3) First Year Geo-targeted NWA Project: 9 Months, +/- 3 months

[7] The Navigant reports included in Exhibit EIOP-3 include project assessments for both NWA Suitability and BCA Analysis.

(4) Measurement and Verifications of First Year Results: 3 Months, +/- 3 months

As outlined in Navigant's report for each Major Project, there is insufficient time to complete this process before the Go/No Go decision deadline. Timeliness is particularly critical at this juncture as the Company embarks on the implementation of the NWA process. Each traditional major capital project fails the project timeline criteria as there is insufficient lead time to pursue and implement an NWA solution to relieve the existing reliability and operational risks associated with each of the four projects, while leaving enough time to execute and implement a traditional solution by the required in-service date if the execution of an NWA were unsuccessful.

IV. DSP Implementation

A. Background

Q. How does the Company's approach to electric operations align with the Commission's REV goals and objectives and the enablement of the DSP?

A. The Company's continuing efforts to modernize the grid, strengthen the electric delivery system, integrate DERs and provide customers with the information and opportunities to take more control of their own energy usage is consistent with the Commission's REV initiatives. The Company remains committed to modernizing its infrastructure to support additional efficiency and resiliency, and to maintain and enhance reliability. Many of the projects the Company is pursuing will incorporate new and evolving technologies, several of which are designed to enhance the Company's ability to facilitate, integrate, and use DER. The installation of advanced new or replacement infrastructure and Company systems is also needed to build the foundation for the DSP, enable future DSP functionality, and maintain reliable service for customers. These infrastructure projects and new systems will help to integrate new energy solutions and DER with the electric delivery system, facilitate DSP markets, enable increased monitoring and more granular control of system resources, including increased automation and communications, and provide enhanced analytics. These benefits will facilitate both long-term system planning and daily operations through proactive response to changing system conditions.

Q. What steps is the Company taking towards becoming a DSP provider?

A. The Company is laying the groundwork to assume the role of DSP provider while also maintaining high levels of reliability by: (1) making necessary changes to processes and organization structure, (2) making key investments in advanced systems and technologies to modernize the grid, and (3) establishing new programs and demonstration projects to enable DER integration and future market development.

As detailed in the Distribution System Planning section of this testimony, the Company is actively engaged in identifying system needs that can potentially be solved with NWAs. The Company is also adapting the way that it operates the grid to incorporate and address both the opportunities and challenges associated with increased DER penetration. This includes enhancing monitoring of the system to view the impact of DER in real-time when facing contingencies and other forms of system stress, and potentially facilitating the employment of DER solutions to address such situations. The Company continues to enhance its DER interconnection process to implement a more streamlined and transparent process for both individual customers and DER providers, while also better integrating information on interconnections into the forecasting and planning process. Finally, the Company is continuing to expand its ability to collect and analyze both system and customer data through improved field sensors and Advanced Metering Infrastructure (“AMI”). The information gained from the analysis of this data will provide the Company with the insight to more effectively manage the electric delivery system and develop markets more dynamically so that customers, the Company, and DER providers can reap the benefits that DER provide. The information will also furnish customers and DER providers with improved insight to effectively manage their energy usage and production. These actions will establish the functionalities necessary for the Company to evolve its role as the DSP.

Q. Are investments in new systems and technologies required to support these underlying process changes?

A. Yes. The Company is making foundational investments in grid capabilities needed to enable a more reliable, resilient, flexible, and efficient electric delivery system. Broadly, these enhancements include model and tool enhancements to better analyze the impact of DER on forecasting and to integrate improved DER analysis capabilities for potential alternative solutions into the Company's planning process. With respect to grid operations, an Advanced Distribution Management System ("ADMS") will serve as a platform to organize and manage the functionality required to provide near real-time visibility and control of grid assets and DER on the system. The collection of additional system data will facilitate the Company's forecasting and planning processes and real time operational awareness of system parameters. This data will be provided via the expansion of various equipment, sensors, and communications that report back through a DSCADA and other means, such as AMI when more fully deployed. It will provide DER providers with information about locations where DER can deliver the most benefit to the distribution system. The Company also plans to enhance its Volt/VAR Optimization ("VVO") capabilities to maintain acceptable voltage levels and power factor efficiencies throughout the distribution system under a broader range of operating conditions. Each of these initiatives is described in more detail later in this testimony.

Some organizational changes are also needed to support this DSP evolution, and these are described in more detail in the following section of this testimony.

B. Utility of the Future ("UotF") Organization

Q. Please describe the purpose and responsibilities of the Company's UotF organization.

A. The Company established the UotF organization in June 2015 to organize and align the Company's overall approach to REV, facilitate the Company's transition to the DSP, and expedite DER integration within the evolving energy distribution markets in New York. This new department has day-to-day REV initiative oversight and is responsible for framing the structure and developing the approach to advancing the DSP at Orange and Rockland. This involves coordinating REV and DSP related activities across various groups within the Company. This requires particularly close coordination with Orange and Rockland's Electrical Engineering, Energy Services, and Rate Engineering groups, as well as with Con Edison's UotF Team, and the JUs. The UotF organization led the development of the DSIP filed in June 2016. The initial DSIP effort included defining and interpreting the requirements outlined by the Commission; formulating strategic positions; supporting the development of content; overseeing stakeholder engagement; coordinating content with Con Edison; packaging the final filing; and responding to any comments and additional requirements post-filing. The UotF organization oversaw Orange and Rockland's contribution to the development of the JUs' Supplemental DSIP ("SDSIP"). Going forward the UotF organization will continue to manage all aspects of DSIP development for each biennial filing.

In addition, the UotF organization oversees regulatory compliance and policy matters pertaining to REV, as well as the development and administration of the Company's current and future NWA programs and demonstration projects.

Q. How is the UotF organization currently structured?

A. The UotF organization currently consists of two functional groups - DSP Implementation: Markets and Regulatory Policy and DSP Implementation: DER Integration.

The Markets and Regulatory Policy group is primarily responsible for coordinating the Company’s response to various New York rate reform and regulatory initiatives. These include the Value of DER proceeding, the Company’s proposed Earnings Adjustment Mechanisms (“EAMs”), and establishment of Platform Service Revenues (“PSRs”). The DER Integration team is primarily responsible for operational matters and Company programs and processes aimed at increasing DER adoption on the distribution system. This includes the oversight of NWAs, demonstration projects, and the Company’s proposed EV program.

Q. Please describe the responsibilities of the DSP Implementation: Markets and Regulatory Policy group in more detail.

A. The Markets and Regulatory Policy group is charged with providing support for monitoring and assessing regulatory developments, particularly as they pertain to rate and regulatory reform driving DSP implementation at the Company. The group is responsible for developing Company positions and responses to REV proceedings by coordinating with Company subject matter experts ("SMEs") and the JUs, engaging various stakeholder groups, and aligning policy with Con Edison. The group is also responsible for the establishment of processes, coordination and facilitation of functionalities, and project management for systems required to implement the plans laid out in the Company's DSIP and SDSIP. The group is also responsible for the development and implementation of subsequent DSIP filings. The group provides oversight and coordination among various internal organizations that are developing the Company's DSP capabilities, while facilitating alignment with the overall DER integration strategy.

The group guides the Company's development of future utility business models and tariffs. This includes working with SMEs across the Company to identify and develop EAMs. The Company's EAMs proposal is described in detail by the EAM Panel.

In addition, the group participates in various other Staff and JUs initiatives. These include the Commission and New York State Energy Research and Development Authority ("NYSERDA")-led Clean Energy Advisory Council ("CEAC"); multiple working groups pertaining to the Value of DER ("VDER") effort; and Staff, JUs, and NYISO DSP Roadmap efforts. The group supports the Company in the development of distribution-level market design.

The group also evaluates alternative ratemaking approaches for the future DSP as envisioned in the REV Track Two Order - where price signals that "indicate real-time value" guide investments to the "best locations." This includes the group's management of projects such as the Company's Smart Home Rate ("SHR") demonstration, and the implementation of the VDER proceeding, both of which are described later in this testimony.

Q. Please describe the responsibilities of the DSP Implementation: DER Integration group in more detail.

A. The DER Integration group is responsible for coordinating the Company's evolving approach to distribution planning and grid operations. This includes providing oversight of the Company's NWA programs, administering REV demonstration projects, and developing and implementing its EV program.

The DER Integration group oversees activities for the planning, development, and administration of current and future NWAs at the Company. The group is responsible for coordinating with the Distribution Engineering organization to identify potential NWAs and determine the DER solution portfolio, manage the individual projects, and continuously assess and refine them. Specific responsibilities of the group include:

- Identifying potential NWA opportunities in coordination with Distribution Engineering;
- Participating in the BCA applied to potential NWA solutions, to determine the most beneficial solution for the investment need;
- Complying with the Company’s NWA Operating and General Accounting Procedures, including developing Commission filings that request approval, recovery mechanisms, and incentives for NWA projects;
- Executing the procurement process, including developing RFPs and/or Requests for Information (“RFI”);
- Administrating and participating in the selection of DER solutions and providers, which includes reviewing various solutions and proposals from a potentially wide-range of third party partners or vendors, as well as participating in contract negotiation and execution;
- Managing individual projects including oversight of the development, implementation, and/or fielding of

discrete DER solutions that are part of a broader solution; and

- Continually assessing any remaining project need based on fielded DER and latest system requirements; and
- Refining the DER solution portfolio for additional procurement, with support from Electrical Engineering.

The DER Integration group also oversees the development and administration of REV demonstration projects, which includes identifying specific focus areas for future demonstration projects and prioritizing REV-related concepts to be tested. Once these focus areas are identified, the group administers the process to select third-party partners to support demonstration projects when appropriate. The DER Integration group also supports the development of proposals, implementation plans, and other regulatory filings associated with the demonstration projects. The ongoing administration of the Company's REV demonstration projects is either handled directly by the UotF organization, or is assigned to an appropriate group within the Company, with ongoing oversight by the UotF organization.

The DER Integration group is also responsible for developing programs and processes within the Company to encourage the adoption of EV within the Company’s service territory.

Additional detail on current and planned NWAs, demonstration projects and EV programs will be provided later in this testimony.

Q. Please describe the current staffing of the UotF organization.

A. The UotF organization currently consists of a Director, one Section Manager for each of the two groups discussed above, and six Project Managers/Project Specialists. With its relatively small size, the group leverages SMEs from various organizations across the Company to assist in addressing the many regulatory requirements, opportunities, and challenges presented by the changing energy landscape in New York.

Q. Is the Company seeking to add positions in the UotF organization?

A. Yes, the Company is proposing to add one full-time position, *i.e.*, a Financial Analyst, to support the DER Integration group. The Company will fill this new position in RY1.

Q. What duties will the DER Integration Financial Analyst perform?

A. The DER Integration Financial Analyst will support the DER Integration team by performing BCAs to better understand a project's or program's impact using the tests prescribed by the Commission. These include the societal cost test ("SCT"), the utility cost test ("UCT"), and rate-payers impact method cost test ("RIM"), as outlined in the Company's BCA handbook. The Financial Analyst will also assist in developing other internal financial analysis such as customer bill impacts, in order to identify various DER technologies in a portfolio that could satisfy identified system needs, while maintaining the lowest cost possible. The Financial Analyst will also provide support for RFP and RFI development, as well as the regulatory reporting associated with NWA and demonstration projects. The detailed reporting for future NWA projects is described in more detail in the NWA testimony below. The Financial Analyst will be essential in implementing the Commission's REV goals to develop and administer NWAs and demonstration projects.

The Financial Analyst's responsibilities will also include assisting in the development of Company strategies, policies, and operational procedures to address emerging new business solutions and revenue models; preparing quarterly reports and supporting materials for Staff meetings; preparing submissions for the Commission; and coordinating aspects of DSP facilitation with the JUs and other stakeholders.

The incremental O&M cost associated with the Financial Analyst is $67,880 annually, starting in RY1. Please see Exhibit EIOP-4 for additional supporting detail.

C. Non-Wires Alternatives

Q. Has the Company identified any NWA opportunities that could potentially defer and/or eliminate capital expenditures for traditional electric infrastructure in its current planning cycle?

A. Yes. The Company has identified potential NWA opportunities for projects in the chart below.

Project	Project Type	Required Load Relief	NWA Need-by-Date
Monsey	Load Relief/ Reliability	2.5 – 3 MW	2021
West Haverstraw	Load Relief/ Reliability	5 MW	2021
Blooming Grove	Load Relief/ Reliability	15.5 MW	2021
Sterling Forest (Tuxedo Park)	Load Relief/ Reliability	746 kV	2021
West Warwick	Load Relief/ Reliability	7 MW	2022
Mountain Lodge Park	Load Relief/ Reliability	280 kW	2022

The Monsey project is the furthest along in the planning, development and cost estimation process. As such, the

Company proposes to include the Monsey NWA costs in the proposed base rates.

Q. Please provide a brief description of the Monsey NWA project.

A. The Monsey Substation is located in the hamlet of Monsey, in the town of Ramapo, in Rockland County. The area is experiencing significant area residential and business growth that has led to highly loaded circuits and substation transformer banks. As a result, Orange and Rockland expects non-compliance with its distribution design standards under normal and contingency conditions in the near future. The Company's traditional solution is the construction of a new substation with increased capacity. This would consist of two 50 MVA transformer banks and additional circuits to serve the growing load, provide for contingency needs, and meet design standards. In order to defer or eliminate construction of the new substation, NWA load reductions will be needed starting in 2020. Approximately 2.5 to 3.0 MW of load reduction will be needed by 2021, depending on actual future load growth. The Company issued an RFP in August 2017 for qualified and experienced NWA providers with the capability to deliver innovative NWA solutions. These NWA solutions could potentially provide capacity alternatives in the Monsey substation area with the distinct goals of: (1) reducing peak electric load within the area served by the Monsey Substation and Banks 144 and 244 for bank contingency purposes; and (2) reducing peak electric load on Monsey distribution circuits 44-2-13, 44-3-13, 44-6-13 and associated distribution circuit ties for single distribution circuit contingency purposes.

In October 2017, the Company received proposals from ten vendors. The proposals included a variety of NWA solutions including: DR, energy storage, EE, and DG. The Company is reviewing these proposals for technical feasibility, with the intent of identifying and selecting a technically sufficient portfolio that will meet the required demand reduction needs. The Company then will perform a BCA on the portfolio using the methodology outlined in the Company's BCA Handbook. The Company will ultimately decide whether to proceed with the NWA solution(s), after considering the BCA SCT, UCT and RIM tests, as well as potential additional internal cost and bill impact evaluations that will be reviewed with Staff.

Q. Is the Company seeking cost recovery for the Monsey NWA project in this electric rate case?

A. Yes. The Company proposes to recover in base electric rates the estimated costs associated with implementing the Monsey

NWA. The projected costs are $50,000 in RY1, $3,518,000 in RY2, and $2,888,000 in RY3. The direct testimony of the Accounting Panel discusses how the Company proposes to recover such costs.

Q. Please provide a brief description of the Company's other potential NWA opportunities.

A. West Haverstraw: The Company evaluated an NWA to reduce loading on three area circuits to improve transfer capability during contingency scenarios. To defer the traditional utility project, the Company will need to reduce load by approximately 5.0 MW by the summer of 2021. The Company expects to issue an RFP for potential NWAs in the second quarter of 2018.

Blooming Grove: The area distribution circuits in the Blooming Grove Substation are approaching the point of not meeting design standards. In order to defer the traditional utility solution of constructing a new substation, the Company is considering alternative solutions to reduce load in the area by 15.5 MW by 2021. As part of the Company's annual planning cycle, it will monitor station needs and adjust capacity requirements based on actual growth, block load additions, and other factors, as necessary. The Company expects to issue an RFP for potential NWAs in the fourth quarter of 2018.

Sterling Forest (Tuxedo Park): Due to reliability concerns related to meeting peak demand in this area, the Company is considering an NWA to reduce peak load in this area by 746 kW. The Company expects to issue an RFP for this potential NWA project in the first quarter of 2019.

West Warwick: The Wisner Substation has multiple operating limitations that historically would have been addressed by constructing a new substation. Instead, the Company has identified an NWA opportunity to reduce load by 7.0 MW by the summer of 2022. The Company conducts an annual planning cycle to monitor local area needs and will adjust capacity requirements based on actual growth, block load additions and other factors as necessary. The Company expects to issue an RFP for this potential NWA in third quarter of 2019.

Mountain Lodge Park (Blooming Grove): The Company estimates that by 2022, there will be significant strain on the amount of backup available on the distribution system in this area. Due to the costs of the potential traditional solutions, the Company is considering an NWA to reduce the load in Mountain Lodge Park by approximately 280 kW at peak. The Company expects to issue an RFP for this potential NWA in the fourth quarter of 2019.

For additional detail on these potential NWA projects, please refer to the JUs' Supplemental Information on the NWA Identification and Sourcing Process and Notification Practices filing (Case 16-M-0411 and Case 14-M-0101) that the JUs submitted to the Commission on May 8, 2017.

Q. What is the Company's plan for implementing future NWA projects?

A. Consistent with the Commission's recent Order on the Company's Program Advancement Petition,[8] when the Company has reasonable certainty as to the cost of an NWA portfolio, it will make a filing with Staff. The Company will then, in consultation with Staff, perform a BCA in accordance with the BCA Handbook and the Commission's BCA Framework Order.[9] The Company will also develop a final BCA using actual NWA costs and quantities after the completion of the NWA.

Q. If an NWA is approved, how will the Company communicate its progress?

A. The Company will submit an implementation plan for all NWA projects that includes, at a minimum, detailed measurement

[8]Case 17-M-0178, *Petition of Orange and Rockland Utilities, Inc. for Authorization of a Program Advancement Proposal*, Order Granting Petition in Part (issued November 16, 2017)("PAP Order").
[9]Case 14-M-0101, *supra*, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) ("BCA Framework Order").

and verification (“M&V”) procedures, the portfolio of projects to be completed, estimated NWA program expenditures, estimated traditional project costs displaced by the NWA projects and the associated impact on the Net Plant Reconciliation mechanism, and a customer and community outreach plan. The Company will file updates to each implementation plan annually by January 31st of each year, or more frequently as necessary. The Company will also submit quarterly reports for each NWA project detailing the expenditures and program activities, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits.

In the event a change in the MWs provided by a NWA portfolio is warranted, the Company will file an updated implementation plan and BCA for that NWA project. The Company will also update its implementation plan and BCA in the event the length of the deferral period for the traditional infrastructure investment related to the NWA project is modified, which would most likely occur as a result of changing forecasts and load projections.

Q. Is the Company proposing a cost recovery mechanism for NWA projects not included in the proposed revenue requirement?

A. Yes. The Company's proposal for the recovery of such costs is described in the direct testimony of the Accounting and Electric Rate Panels.

Q. Is the Company proposing a financial incentive structure for its NWA projects?

A. Yes. The Company proposes to establish a financial incentive structure applicable to all its future NWA projects, consistent with that approved by the Commission for Con Edison.[10] The Company proposes a multi-step process for determining the incentive it would receive for implementing NWA projects that is based on the Company retaining 30 percent of the Net Benefits ("Initial Incentive"). Net Benefits are defined as the difference between the present value of net costs and benefits of the proposed NWA project and the present value of the net costs and benefits of the traditional utility project. The remaining 70 percent of the Net Benefits would be deferred for the benefit of customers. The present value will be calculated using the Company's after-tax weighted average cost of capital ("WACC") as the discount rate.

[10] Case 15-E-0229, *Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision*, Order Approving Shareholder Incentives (issued January 25, 2017) ("Con Edison Shareholder Incentive Order").

To provide an incentive for the Company to manage the costs associated with a NWA project, the Company proposes to adjust the incentive, as necessary, throughout the NWA project implementation to reflect the difference between actual and estimated costs. To determine the Final Incentive, the Company proposes to share the difference between the total utility cost assumed in the Initial Net Benefits calculation and the actual total utility cost of the NWA project on a 50/50 basis with customers. Therefore, the Company’s Final Incentive would equal the sum of the Initial Incentive, and 50 percent of the cost overruns or underruns of the NWA project. The Company proposes that the Final Incentive be subject to both a floor and a cap, such that the Final Incentive shall neither be less than $0, nor greater than 50 percent of the Initial Net Benefits. This proposal is consistent with the Con Edison Shareholder Incentive Order.

Q. Will the proposed incentive mechanisms be the same for Large and Small NWA projects?

A. In general, when compared to Small NWA projects, Large NWA projects require greater quantities of load relief, longer lead times to implement, and defer higher cost T&D infrastructure. In contrast, Small NWA projects will often require the Company to react to shorter project lead times and implement solutions more quickly. Given this inherent difference in project type, the Company proposes separate incentive mechanisms for Large and Small NWA projects, with a more streamlined incentive calculation for Small NWA projects.

Q. What is the proposed incentive mechanism for Large NWA projects?

A. For Large NWA projects, the Company proposes to establish an Initial Incentive based on a 70/30 share of the Net Benefits between customers and shareholders at the time when the Company has either entered into contracts with DER providers for the entire NWA portfolio, or when the Company and Staff agree that there is reasonable certainty regarding the price of the portfolio of DER.

The Company proposes to begin collecting the Final Incentive from customers once 70 percent of the MW DER need has become operational. The Company defines “operational” as the point at which DERs have been installed and verified through the Company’s M&V procedures.

Q. What is the proposed incentive mechanism for Small NWA projects?

A. For Small NWA projects, the Company proposes a similar 70/30 sharing of the Net Benefits between customers and shareholders. However, the Small NWA projects incentive will be calculated on a per MW basis ("Initial Unit Incentive"). The Initial Unit Incentive will be determined by dividing the Company's proposed 30 percent share of the Initial Net Benefits by the number of MWs to be procured for the NWA project. For Small NWA projects greater than 1 MW, incentives will be recorded as each MW becomes operational. For Small NWA projects less than 1 MW, the Company will record the final incentive once the entire NWA portfolio is implemented.

Q. How does the Company propose to recover any financial incentives it may earn from implementing an NWA project?

A. The Company proposes that the financial incentive, for both Large and Small NWA projects, be recovered from customers through its Energy Cost Adjustment ("ECA") mechanism in the same manner as other NWA program costs. The Company proposes to amortize the Final Incentive, for both Large and Small NWA projects, over the course of the remaining deferral period for the traditional T&D project, inclusive of carrying costs on the unamortized balance at the Company's Commission-approved WACC.

Q. Are there any circumstances under which the financial incentive mechanism would be modified?

A. Yes. The Company also proposes to modify its incentive in the event that the number of MWs required to execute a NWA project changes in response to the Company's annual reliability needs assessments. In the event the reliability assessment results in the determination that additional DER MWs are needed to achieve the intended deferral of traditional infrastructure, the Company will notify Staff, and increase the DER MWs accordingly. If it is feasible to increase the DER MWs to continue implementing the NWA project, the Company proposes to receive cost recovery of the expenditures incurred in obtaining the additional DER MWs, including carrying charges at its effective WACC, on these deferred costs until recovered from customers. The Company, however, would forego earning any additional incentives related to obtaining the additional DER MWs. The Company proposes that expenditures related to these additional MWs would not be considered in the calculation of the difference in utility DER costs for calculating the Final Incentive. This process would be the same for both Large and Small NWA projects.

Q. What would happen if the reliability assessment results in the determination that fewer DER MWs are needed to achieve the intended deferral of traditional infrastructure?

A. The Company will notify Staff, and decrease the DER MWs accordingly, to the extent contractually feasible. For Large NWA projects, the Company will plan to reduce DER MWs only when the reliability needs assessment demonstrates a consistent downward trend in the amount of MWs needed for load relief. That downward trend must be sustained over a period of at least three years, and result in a material reduction of 30 percent or more of the DER MWs which were initially determined to be necessary to effectuate deferral of the traditional infrastructure. For Small NWA projects, the Company will consider each annual assessment, as opposed to requiring a consistent downward trend over the course of three years. However, the Company will only reduce the amount of DER MWs for Small NWA projects when the reliability needs assessment results in a 30 percent decrease in DER necessary to effectuate deferral. The Company will consult with Staff before effectuating any reductions in DER MWs, and will continue to procure the original amount of DER MWs if directed to do so by the Commission.

Q. If the amount of MWs required declines, is the Company proposing any modifications to the financial incentive?

A. Yes. For both Large and Small NWA projects, the Company proposes to true-up the incentive earned in the event of a reduction in required DER MWs. The Company would true-up the incentive by converting the Initial Incentive into an Initial Unit Incentive, as previously described for Small

NWA projects. The Company would then calculate the difference in utility DER cost on a per-MW basis ("Unit Difference in Utility DER Cost"). The Final Incentive would be calculated as the sum of the Initial Unit Incentive plus or minus the Unit Difference in Utility DER Cost, multiplied by the reduced amount of DER MWs determined to be necessary. The Company proposes the Final Incentive determined using this mechanism would be subject to the same cap and floor provisions of 50 percent of Initial Net Benefits, and $0, respectively.

Q. Would the Company's proposed incentive mechanism be modified if a NWA project is ultimately unable to defer or eliminate the original traditional infrastructure project?

A. Yes. If at any time the Company determines that continuing an NWA project is operationally or technically infeasible, the Company will immediately halt the recovery of any incentive, without providing a refund of any incentive amounts collected to that date.

<u>Pomona</u>

Q. Please describe the Company's Pomona Distributed Energy Resources Program ("Pomona DER Program").

A. The Commission approved the Pomona DER Program as part of the Company's last electric rate case.[11] It is intended to defer construction of the Pomona Substation and associated facilities by implementing a portfolio of DER solutions that would provide up to 6.0 MW of peak load reduction. The Commission capped the Company's total spending on the Pomona DER Program at $9.5 million in 2014 dollars, which equates to $11.5 million in future escalated dollars, and authorized a ten-year recovery period.

Q. Please provide a status update on the Pomona DER Program.

A. The Company is proceeding in accordance with its Implementation Plan that was submitted to the Commission on December 15, 2015 and updated annually since. The latest implementation plan was issued on December 29, 2017. The Company provides quarterly updates to the Commission where it details progress achieved on the Program. The Company continuously encourages customer participation in its EE programs: Small Business Direct Install and Commercial and Industrial Existing Building Programs and a total of 0.7 MW reduction in the load pocket has been achieved, or committed to be installed by the end of the year toward the

[11] Case 14-E-0493, *Proceeding on Motion of the Commission as to the Rates Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.*

targeted 1 MW goal. The Company has selected a vendor for a new residential DR program that will be deployed in the Pomona area in early 2018.

As part of the progress on the portfolio of DER solutions, the Company evaluated various DER solutions received as part of the RFI responses and developed a prioritized list of deployment options. One of the chosen portfolio solutions was battery - based energy storage. Orange and Rockland issued an RFP on December 6, 2017 seeking proposals for Distributed Energy Storage Systems that could provide load relief in the Pomona area.

In addition, as part of its education and outreach efforts in Pomona, the Company is continuing to identify opportunities to educate customers and municipal officials on the programs and the Pomona program initiatives as well as the Company's Residential Customer Engagement Marketplace Platform.

Q. What is the Company's proposed spending for the Pomona DER Program in RY1, RY2 and RY3?

A. The Company proposes to spend $3,017,030 in RY1, $778,000 in RY2, and $353,000 in RY3 on the Pomona project. These costs are primarily related to installation of the battery, DG projects, and internal labor. The direct testimony of the Accounting Panel details the Company's cost recovery for the Pomona DER Program.

D. Demonstration Projects

Q. Please describe the Company's ongoing REV demonstration projects.

A. In July 2015, the Company, consistent with the REV Track One Order, proposed its first demonstration project known as the Residential Customer Engagement and Marketplace Platform ("CEMP"). This demonstration project was designed to build partnerships with a network of third-party product and service providers to educate customers and increase their awareness of energy consumption, motivate them to participate in Company programs, increase distribution and adoption of DER, and develop new revenue streams for the Company and its partners. The Company filed the implementation plan for the CEMP in November 2015, and launched the project in January 2016. The three-year demonstration project period for the CEMP will end on December 31, 2018. Details of and lessons learned from the CEMP are further discussed in the direct testimony of the Customer Services Panel.

Q. Is the Company developing future REV demonstration projects?

A. Yes, the Company filed a proposal with the Commission for an Optimal Export Demonstration Project on October 23, 2017. By letter dated December 19, 2017, Staff informed the Company that Staff had determined that the proposed Optimal Export Demonstration Project complies with the objectives set forth in the Commission's Order Adopting Regulatory Policy Framework and Implementation Plan, issued February 27, 2015, in Case 14-M-0101.

Orange and Rockland plans to file a proposal for an Innovative Storage Business Models Demonstration Project in early 2018. The Company also filed a Smart Home Rate Demonstration Project concept in February 2017 and is in the early stages of working with Con Edison to further develop that proposal.

Q. Please describe the Optimal Export Demonstration Project in more detail.

A. Increasing hosting capacity to accommodate greater numbers of DER is an essential component of the evolving utility business model. The Commission’s DSIP Order states that utilities “shall propose individual demonstration projects that provide them the opportunity to use alternate approaches to increasing hosting capacity and facilitate greater DER penetration on their networks.”

In response to this guidance, on October 23, 2017, the Company filed with the Commission its proposal for the Optimal Export Demonstration Project. The proposed project seeks to implement alternate interconnection schemes for applicants facing significant system upgrade costs associated with interconnection. Rather than an expensive conversion of the Company's local distribution system to accommodate these interconnection requests, the Company is proposing to work with customers, developers and third-parties to use inverter functionality coupled with supporting technology to maximize the proposed DG project's ability to export back to the grid while also mitigating any impacts the interconnected DG would have on the system. This project seeks to demonstrate alternatives to high interconnection costs, encourage higher DG penetration on select constrained circuits, and allow the Company to gain valuable experience with advanced inverter and DER system control technologies and their impacts on the electric delivery system. As Orange and Rockland gains experience with the performance of advanced inverter functionality paired with supporting technology, as well as with additional affordable energy storage technology on the system, similar solutions could be offered and implemented as alternatives to significant infrastructure upgrades for applicable customers. These solutions would likely contain eligibility criteria and requirements developed through experience gained from this demonstration project. Lessons learned throughout the industry regarding these technologies’ ability to increase hosting capacity on circuits will also contribute to the development of these offerings.

The Company proposed that this project will commence in 2018 and will run for approximately three years.

Q. Please describe the Innovative Storage Business Models Demonstration Project in more detail.

A. On February 5, 2016, Con Edison and the Company jointly released an RFI soliciting responses from third parties on delivering innovative energy storage solutions that provide value for key stakeholders, including customers, shareholders, and project partners. In response to the RFI, the Company has entered into collaboration with Tesla, Inc. to test different business models to determine how to take full advantage of the benefits provided by energy storage assets, with a particular focus on enabling the wide-scale deployment of energy storage in the future. The project involves deploying a 4MW/8MWh portfolio of aggregated batteries located either behind-the-meter of commercial and industrial customers or co-located with distribution-connected remote solar projects located within the Company’s service territory. Though all battery installations will be developed, designed, installed, operated, and maintained by Tesla, the two companies will work together to test the hypothesis that batteries can provide a range of services across multiple use cases with a portfolio of value streams by maximizing storage utilization to benefit multiple stakeholders. The focus of the project is the development of battery operation across customers, distribution, and wholesale services in order to maximize the value of battery systems, while maintaining their availability to distribution system operators during critical need periods. This business model strives to enable storage to realize its full potential as a flexible and capable grid asset, while reducing the cost of grid storage services. It also endeavors to increase the value of solar and provide significant benefits to project participants and other customers. Furthermore, this project seeks to develop and test the mitigation of storage implementation barriers, in order to support the acceleration of wide-spread storage deployment in New York.

Q. Please describe the SHR Concept in more detail.

A. As part of the Commission’s Track Two Order, electric utilities in the state were directed to propose SHR

Demonstration Projects. These projects are intended to test and observe the impact new rate designs have on the behavior of "prosumers", which are defined as technically savvy customers that are adopting new technologies to proactively manage energy use. As standard volumetric rate designs provide little to no incentive to fully leverage the benefits of new technologies, the SHR is intended to determine whether alternative rate structures will provide sufficient information and price signals to allow prosumers to leverage technology to respond to prices that could ultimately provide benefits to the consumer as well as the utility.

On February 1, 2017, the Company, along with Con Edison, filed their proposed SHR Concept Demonstration Project. Similar to other REV demonstration projects, the two companies filed together, which will enable the sharing of resources to reduce implementation costs and also expand the applicability of lessons learned. The Companies are in the process of developing a pilot program that will test how different rate structures, when combined with data provided through smart meters, impact customer energy behaviors, overall energy consumption, and bill amounts. Additional information regarding this proposed demonstration project can be found in the Companies' REV

Demonstration Project SHR Concept that was filed with the Commission on February 1, 2017.

Q. What is the Company’s actual and planned spending on the demonstration projects?

A. The Company projects that unrecovered costs of demonstration projects through December 31, 2018 will be \$4.1 million. Total spend during the rate period will be \$1.6 million, \$1.3 million, and \$0.3 million in RY1, RY2, and RY3, respectively.

Q. How does the Company propose to recover demonstration project costs?

A. Currently, demonstration project costs are recovered over ten years through the ECA surcharge. As discussed in detail in the direct testimony of the Company’s Accounting Panel, the Company is proposing to recover all planned demonstration project costs in base rates.

Q. Does the Company anticipate that the revenue requirements associated with the planned costs of future demonstration projects could exceed the cap established in the Track One Order?

A. At this time, the Company does not anticipate that the revenue requirement associated with the planned costs of future demonstration projects will exceed the cap. As the future demonstration projects and costs become better defined, the Company will evaluate whether it will require additional funding beyond the cap. In the event that additional funding is needed, the Company plans to propose an increase to its cap during an ECA proceeding.

E. Platform Service Revenues

Q. Is the Company proposing any PSRs?

A. Yes. As described in the Customer Services Panel’s direct testimony, the Company intends to transition its’ MY ORU Store into base rates beginning January 1, 2019, which is the conclusion of the three-year CEMP Demonstration Project period. The Company expects to continue to grow it into a robust marketplace where customers can purchase DER and EE products and services. The Company proposes that revenue generated from the sale of products and services, as well as advertising and other program income, be treated as a PSR.

Q. Please describe the product or services provided by the MY ORU Store in more detail.

A. O&R, in partnership with Simple Energy, has developed the CEMP. This demonstration project was designed to build partnerships with third-party providers to help increase customer awareness and education of energy consumption, facilitate customer participation in O&R programs, increase distribution and adoption of DER and develop new revenue streams for O&R and its partners. The synergistic combination of the My ORU Advisor and the My ORU Store has enhanced O&R’s engagement with customers by providing tools and information needed to make informed energy choices, as well as promote the purchase of energy efficient products and services through its online store. Customer data and behavioral analytics are used to target and motivate customers to take action on both the engagement and marketplace platforms.

O&R reinforces its commitment to its customers as their trusted energy advisor by not only providing energy education and awareness, but also by making efficient products and services available, and affordable, through instant rebates at the point of purchase.

Q. How do the products or services above meet the criteria for approval of a PSR as outlined in the Track Two Order?

A. The MY ORU Store meets the criteria for approval of a PSR because it provides a service that is not effectively provided by non-utility providers. Due to its close relationship with its customers, O&R is uniquely positioned to attract customers to its website (and MY ORU Store) to gain access to information about their energy consumption and ways to reduce their energy bill. Non-utility providers would not have similar access to this information, nor would they have the Company's brand identity as a trusted energy provider.

Q. Please describe the method to be employed to price the product or service.

A. The marketplace (My ORU Store) offers a variety of products and services for purchase by O&R customers. The products that are part of the online assortment are sourced directly from manufacturers by Simple Energy and retail pricing is agreed upon by both Simple Energy and O&R. Simple Energy is also responsible for identifying and managing shipping providers so that products are shipped in a timely manner at the lowest cost possible. With regard to services, the fixed pricing was mutually agreed upon by O&R and the third-party supplier installers, based on current market rates of the specific services.

Net revenue is generally split between Simple Energy and O&R for products and services sold. There are some exceptions on water-savings products that are co-rebated by Suez Water New York, Inc. O&R's share is higher for services as these third-party relationships were brought in solely by O&R contacts.

Q. How does the Company propose to allocate PSR revenues between ratepayers and shareholders?

A. The Company proposes that 80% of its share of the net revenues generated by the MY ORU Store be returned to customers and 20% be retained by the Company.

Q. Why does the Company believe an 80/20 allocation is appropriate for this PSR?

A. The Company believes that an 80/20 sharing allocation is appropriate because: (1) it is consistent with the Commission's guidance in the Track Two Order, (2) it provides sufficient incentive to the Company to continue to grow the MY ORU Store into a robust marketplace, while also providing substantial savings to customers, and (3) it is generally consistent with the Company's existing incentive for off-system gas pipeline capacity sales, which the Commission identified in the Track Two Order as a comparable revenue-sharing mechanism.

Q. What does the Company propose in terms of deferral accounting until rates are reset?

A. The Company proposes to defer 80% of revenues associated with this PSR for customer benefit until base rates are reset and retain 20%. Please refer to the Accounting Panel's direct testimony for additional detail.

Q. Has the Company identified any other potential PSRs?

A. Yes. The Company has identified two other opportunities, which it is evaluating as potential PSRs.

As discussed by the Customer Services Panel, the Company is working with Con Edison to identify opportunities to use excess capacity from its communications infrastructure from AMI to serve other needs. At this point, this opportunity is conceptual. Should the Company identify a PSR related to this opportunity that meets the criteria for approval, it will propose it in a future filing.

The second opportunity is related to the Company's planned Innovative Storage Business Model demonstration project described above. As part of its proposed partnership with Tesla in this demonstration project, the Company will perform the role of scheduling coordinator for Tesla assets into wholesale markets, for which it will receive a nominal fee. This opportunity will be described in more detail in the Company's proposal, which will be filed in early 2018. Based on the experience of the demonstration project, should the Company identify a PSR that meets the criteria for approval, it will propose it in a future filing.

F. Value of DER Implementation

Q. Please describe the compensation methodologies currently available to customers with DG.

A. The Commission established a new compensation methodology for customers with DG in its *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy*

Resources, and Related Matters.[12] This order "represent[s] the first steps in the necessary evolution of compensation for DER from the mechanisms of the past to the accurate models needed to develop the modern electric system envisioned by REV through the development of VDER tariffs."[13] The VDER Order sets forth the new compensation methodologies that include Phase One NEM and the Value Stack. Net metering projects existing at the time of the VDER Order were grandfathered and could retain their existing method of compensation. The Company must develop processes and procedures to maintain the ability to bill customers on the appropriate methodology. Whether a project qualifies for grandfathered net metering treatment, Phase One Net Energy Metering, or the Value Stack depends on the time of application, contract execution, and/or payment of a deposit; and the type of customer and/or project.

Q. Please describe the Value Stack in more detail.

A. The Value Stack is comprised of six different components designed to capture the true value of energy exported by DGs to the distribution system. Each component has its own inputs, rate, and calculation formula. The methodology applies to various DG project types, including on-site

[12] Case 15-E-0751 (issued March 9, 2017) ("VDER Order").
[13] Id at p.1.

generation projects, Remote Net Metering, and Community Distributed Generation ("CDG").[14] The Value Stack compensation methodology became effective on November 1, 2017. Existing net metering customers, or those customers that are not required to receive compensation under the Value Stack tariff, can choose to remain in their current methodology or make a one-time irrevocable election to be served under the Value Stack tariff.

Q. Please describe the CDG program.

A. The CDG program allows a CDG Host that owns or operates electric generating equipment eligible for net metering or the Value Stack tariff to distribute credits calculated on the net energy produced by the project to be applied to the accounts of other electric customers ("CDG Satellites") with which it has a contractual arrangement related to the disposition of net metering credits. The CDG project must have at least ten subscribers and distribute the net metering credits from a CDG facility to subscribers on a monthly basis in accordance with a CDG project sponsor's

[14]The Commission required that the Company establish its CDG program by October 26, 2015 in Case 15-E-0082, *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program*, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015). ("CDG Order")

instructions, with the ability to update the allocation percentages each month.

Q. What is the Company doing to comply with the VDER Order and the CDG Order?

A. To establish its CDG program, the Company filed tariff amendments and documentation of CDG procedural requirements. The Company filed additional tariff amendments to implement the VDER Order and the Phase One NEM and Value Stack compensation methodologies. As part of its business process development efforts for the CDG program and the new compensation methodologies, the Company analyzed the requirements of the program and the orders to determine if there is an existing Company system or process capable of performing Value Stack credit calculations. These include CDG credit calculations, and other program administration functions consistent with Commission requirements. The Company’s analysis indicated that implementation of the Value Stack tariff will involve new account management processes and complex credit calculations. Manual processing and billing of accounts served under the Value Stack tariff would be highly inefficient and time consuming due to the complexity of the process, the fluidity of the data, and the sheer volume of work that would be needed to manage the program via spreadsheets and manual data entry. Manual processing would increase the risk of human error, increasing the potential for inaccurate bills and decreased customer satisfaction. Given this analysis, the Company recognizes that due to the complexities of calculating and applying the Value Stack credits, maintenance of existing grandfathered NEM rules, and the potentially large volume of participating customers – in particular for CDG – full automation is necessary. Such automation will include the integration of a large amount of new data types into the customer information management system ("CIMS"), the integration of several secondary systems, and the management of new customer relationships.

Please refer to the direct testimony of the Customer Services Panel for additional detail, including cost estimates, of the Company's proposed new billing solution and enhancements to CIMS.

Q. Does the Company anticipate any other costs related to CDG and VDER implementation?

A. Yes. The VDER Order directed that a second phase should be commenced as soon as practical to evaluate potential improvements that could be made to enhance the effectiveness of the Value of DER in promoting the integration of DER and providing a post-NEM compensation mechanism for DERs.

The refinement of the Value Stack in Phase Two is expected to require additional changes to the system the Company is implementing as part of Phase One. Inclusion of new technologies into the Value Stack, expansion of the Value Stack to include more value components and modification to existing components will require the Company to update and revise the calculation, crediting and billing processes for the Company's Value Stack customers. In addition, as a stated goal of Phase Two is to transition all mass market (residential and small commercial non-demand billed) customers to the Value Stack from net metering, the Company's billing and accounting systems will require modification to accommodate this transition.

The Company also expects that further system changes may be required to implement consolidated billing. On September 14, 2017, the Commission issued the *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters*, which requested that utilities provide a timeline and cost estimate for implementing consolidated billing for CDG within twelve months. Consolidated billing for CDG, as well as the potential use of vendor, third-parties, and/or a statewide system for consolidated billing, are being discussed by the JUs. The Company will continue to work with Staff and other interested parties through relevant working groups as part of the VDER proceeding. In order to comply with the Commission order, the Company expects that there could be costs related to CDG consolidated billing implementation during the Rate Year, but is not seeking recovery at this time.

Should the Company incur incremental costs related to either VDER Phase II or consolidated billing during the Rate Year, it will propose cost recovery mechanisms, as part of future compliance filings.

G. Electric Vehicles Program

Q. Please describe the evolving market and regulatory environment for EVs within New York State.

A. New York has taken a number of steps recently to encourage adoption of EVs within the state, including: the ChargeNY program, which aims to put 30,000 to 40,000 EVs on the road and install 2,500 additional public and workplace charging stations by 2018; the Multi-State Zero-Emission Vehicles (“ZEV”) Action Plan, which sets a collective goal for 3.3 million ZEVs by 2025, including 800,000 ZEVs on the road in New York; and a $70 million NYSERDA initiative to provide rebates for the purchase of EVs of up to $2,000 per vehicle, to install new charging stations throughout the state, and for consumer education awareness.

While New York has taken aggressive steps to encourage EVs, adoption in the state remains relatively low. Recent data indicate that there are less than 1,000 EVs within the Company's service territory. To meet the targets of the State's ZEV Action Plan, the Company estimates that there would need to be over 48,000 EVs in its territory by 2027.

Q. What efforts has the Company taken to date related to EVs?

A. The Company is participating in the development of a joint EV Readiness Framework with the JUs, which was outlined in the Supplemental DSIP filing on November 1, 2016. In general, the JUs seek to "prudently invest utility customer funds in opportunities where the expected benefits resulting from increased sales outweigh the capital revenue requirements."[15] While the JUs acknowledged that EV deployment will be unique to each utility's service territory, certain principles will apply to the collective JUs' efforts, including leveraging core business functions and extant business relationships, near-term focus on pilots and demonstration projects, close collaboration among all market participants, and participation in local,

[15] Case 16-M-0411, In the Matter of Distributed System Implementation Plans (issued November 1, 2016), p.111

regional, and state-wide EV market development activities. The JUs have held multiple stakeholder sessions to collect feedback on the framework and will publish the final EV Readiness Framework in early 2018.

The Company is supportive of New York State's efforts to increase EV adoption and, along with the other JUs, is committed to developing the appropriate tools, processes, and capabilities to be prepared for EV market growth.

Q. Is the Company engaged in any other EV readiness initiatives?

A. Yes. In addition to the JUs' EV Readiness Framework described above, the Company is a founding member of the ChargEVC coalition whose mission is to serve as a trusted resource for research and a singular voice for advocacy, leading to advanced EV market development programs and policies. The coalition works with local legislative leaders to expand EV programs in response to local conditions on a state-by-state basis, starting with New Jersey. ChargEVC has completed a detailed market study for the state, including consideration of current market conditions, economic impacts of EV adoption, environmental benefits, and utility implications. The Coalition has also issued a Market Development Roadmap for New Jersey and developed educational awareness collateral. The Company expects that lessons learned from this initiative will be applicable to its EV efforts in New York.

Q. What is the Company proposing to do to increase EV adoption within its New York service territory?

A. The Company plans to encourage EV adoption in its service territory through: (1) installation of Electric Vehicle Supply Equipment ("EVSE"), (2) a new EV education and outreach initiative, and (3) new rate designs, including expanded Time of Use ("TOU") rates and the PEV Quick Charging Station Program.

The Company is proposing an EVSE program to own, operate and deploy a combination of Level 2 plug-in electric vehicle ("PEV") chargers and DC Fast chargers to be used in the non-residential marketplace. The program will also offer rebates for Level 2 chargers to prospective residential PEV buyers. The rebates will be similar to those offered by other utilities around the country, which have been shown to drive EV adoption in those states.

The education and outreach program will seek to inform consumers about key EV topics – including ownership costs, environmental benefits, charging options, and available incentives – through various channels such as bill inserts, social media, e-mail blasts, and a dedicated EV page on the Company's website. The program will also include engagement with local and municipal governments and Drive-and-Ride events.

Capital costs associated with the EVSE investment will be $336,000 per year for RY1, RY2, and RY3. The cost of rebates for residential chargers and the outreach and education programs will be $150,000 in RY1, $125,000 in RY2, and $100,000 in RY3. Please refer to Exhibit EIOP-4 for additional detail on this request.

Finally, as discussed by the Company's Electric Rates Panel, the Company will leverage its existing residential voluntary TOU rate to encourage PEV adoption, as well as deploy two separate rate provisions to further facilitate PEV adoption. The Company also plans to encourage third-party EVSE installation through the PEV Quick Charging Station, which offers a delivery rate discount for EV charging stations installed at publicly-accessible locations.

V. <u>Grid Modernization</u>

Q. Please describe how the Company defines Grid Modernization.

A. The Company's definition is set forth below. The Panel would note that the term "Grid Modernization" is one of several commonly used and non-mutually exclusive terms related to utility investments that the JUs continue to address in a collaborative effort.

Grid Modernization: Investments, some of which may be considered foundational and/or DSP-enabling, that improve the reliability, resiliency, efficiency, and automation of the T&D system. Such investments can include the sensors, data, and communications networks that enable enhanced visibility and understanding of the behavior of the network; technologies and equipment that facilitate greater customer engagement regarding energy usage and alternatives; and the underlying systems, data management and analytics that facilitate situational awareness, asset management, contingency and risk analysis, outage management and restoration. These necessary core investments underpin the required focus on grid reliability and resiliency. They provide the basis for increased operational flexibility, can enable efforts toward achieving state policy goals, including the integration of various types of DER, and are beneficial for any resource mix.

Further definition and clarification are provided for some of the terms included in the grid modernization definition that define and support the goals these investments and systems seek to achieve, as follows:

Foundational: Enabling grid capabilities that provide and/or support applications that increase reliability, resiliency, safety, and enhanced situational awareness and operational flexibility through advanced technology and equipment including robust sensing and measurement, information management, data management and analytics and communications networking capabilities. Foundational investments are “no regrets actions” that can support both current applications and future applications, such as integration and utilization of DER, in a modular fashion;

Reliability: The ability of the electric system to receive and deliver the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and unscheduled outages of system components, while maintaining the ability to withstand sudden disturbances or unanticipated loss of system components within accepted and defined risk tolerances and goals;

Resiliency: Preparation for, and adaption to, changing conditions and the ability to withstand or rapidly recover from system disruptions. Disruptions can be caused by deliberate attacks, accidents, or naturally occurring threats or incidents;

Safety: Operation of the distribution grid in a manner that ensures public and workforce welfare, operational risk management, and appropriate fail safe modes; and,

Operational Flexibility: The ability to operate physically connected generation, transmission, and distribution facilities in a manner which accommodates dynamic grid conditions and changing demand, type of generation and resource availability. This also includes the efficiency of utility operations.

The Company defines these as terms for beneficial outcomes achieved through investments that promote these functions and attributes, which may be distinctly separate or may be complementary with (or foundational to) investments made for the express purpose of DER integration or value capture.

The Company envisions and determines that the investments and initiatives discussed and described further in this Grid Modernization section of the testimony embody the functionality, attributes and critical elements described in the term definitions above, and are necessary for the Company to realize its requirements and capabilities as a DSP provider.

Q. What additional systems, communications, and process capabilities is the Company investing in to support its continued evolution as a DSP provider that provide foundational elements for grid modernization, enable future market capabilities, and allow the Company to build on its existing accomplishments, investments and capabilities?

A. The Company plans to make foundational investments that will provide operational flexibility and reliable operations, as well as enable the functionality envisioned for advanced grid modernization and future market enablement. The key initiatives proposed by the Company during the rate period that are needed to support the Company’s continued evolution as a DSP Provider are grouped into the following areas:

- ADMS and Distributed Energy Resource Management Systems (“DERMS”);
- Data Analytics;
- Communications Infrastructure;
- Planning and Forecasting; and
- Hosting Capacity and Interconnection.

The proposed systems, initiatives and/or projects in each of these areas are described in more detail in the testimony below.

Q. How does the increase in DER impact the Company’s need to monitor and control its grid assets?

A. As the penetration of DER increases across the Company's service territory, the requirements, opportunities, impacts, and challenges generated by DER will expand. There will be an increased and ongoing need for situational awareness and control which will require systems and applications to acquire data and produce actionable information in a near real-time environment. Establishing the appropriate level of visibility, monitoring, and control will be critical to realizing the most value to customers and the system from system assets and interconnected DER, while maintaining a safe and reliable grid.

Further, near-real time monitoring of DER will be essential for the Company to track DER performance and capabilities, both to make same day operational decisions and for near-term forecasts and scenario planning. As the amount of information gathered grows, the need for a system that will aggregate, analyze, validate, and display the information to the operator will become a necessity. Information will have to move among systems on a common information model as it becomes increasingly integrated with data sources, historical measurements, and advanced applications.

Q. Describe the Company's current ability to monitor and control DER.

A. Existing system infrastructure will only partially meet the monitoring and control needs of the system as DER penetration increases. Alarm index and events tagging are currently done in SCADA at the substation circuit source. Current and voltage measurements are available through Orange and Rockland's SCADA system, which covers 98% of the Company's substations. However, there is no power quality or frequency monitoring at the circuit level. A DSCADA system monitors and controls Distribution Automation equipment, including re-closers, motor operated air break switches, capacitors, and regulators. Coverage at this sub-circuit level is presently less than 20% of the entire system.

The Company's ability to monitor and control large DG is limited to interrupting larger PV sources only, with re-closers at the point of interconnect. Switching plans and real-time contingency analyses are conducted by distribution planners and system operators, though the process is entirely manual. There is presently no centralized logic or technical capability for automating Fault Location, Isolation, and Service Restoration ("FLISR") control. Some existing DR and EE customers have advanced metering, but there is presently no automation of aggregation or program integration in this area, although the Company's AMI deployment will advance data availability and functionality towards these ends. All DR notifications are currently done via phone calls or email.

Additional system data collection will be required relating to the DER nodal generation. Devices, meters, communications, and SCADA costs will be incurred to monitor and provide visibility into the interaction of the additional DER contributions with respect to maintaining appropriate operating conditions, including real and reactive power, voltage and power quality. The availability of this system data with advanced analytical capabilities will be the basis for evaluating system impacts on the overall circuit and within local load pockets. Aggregating all this information, visibility, and control within a core system that can be modularly expanded to facilitate future enhancements, and tie to other critical systems and sources of information, is essential to achieving this type of foundational functionality. Systems such as this are being installed and used at numerous utilities throughout the country, and they are known as ADMS.

A. ADMS and DERMS

Q. Please provide an overview of ADMS.

A. An ADMS is a foundational platform that is developed and integrated with other systems and near real-time data sources to enhance electric distribution system situational awareness, analysis, monitoring and control to improve reliability, resiliency, and efficiency. These systems and sources of data will likely include and/or integrate with the following: an Energy Management System (“EMS”), a GIS, a CIMS, a DSCADA system, an OMS, Distribution Automation devices, substation equipment, AMI, customer data, customer equipment, and DG/DER data and/or equipment.

An ADMS is fundamental to hosting and integrating many advanced applications that will facilitate functionality needed to implement advanced grid modernization, enhanced system reliability and efficiency, and greater DER penetration and future market functionality. Some of these advanced applications will include FLISR, monitoring of DG to provide robust historical databases, integrated transmission and distribution state estimation, near-real time reliability and contingency analysis, VVO, and integration with DERMS functionality. While DERMS are presently in early development stages, functionality envisioned from these systems will provide the necessary interfaces to customer DG and DER to allow for proper monitoring of the interface to that equipment, and control of that equipment over a broad range of devices to allow for proper operating conditions throughout the system and load cycle.

Q. Why is an ADMS important to facilitate advanced Grid Modernization and market functionality?

A. An ADMS extends the planning model of the system into real-time operations. Coordinating through integrated systems and the external interfaces as described above, an ADMS will act in near real-time to modify both Company and customer equipment appropriately, to achieve system states that maintain appropriate and efficient operating conditions. It will also provide the platform to realize VVO and FLISR functionality that have the capability to substantially improve system efficiency and reliability through expansive implementation. ADMS will do this through its dynamic model of the electric delivery system and near real-time operations through SCADA feedback and control. It will have a near real-time reference to the current state electrical system, which will be the basis for analyzing and executing on appropriate future system states for switching plans and contingency situations. An ADMS will be able to identify, monitor, and record data from abnormal system conditions resulting from planned and unplanned events that modify the design configuration of the electrical system.

Initial planning for the appropriate incorporation of DER must be integrated with a sophisticated, near real-time ADMS. The ADMS must provide monitoring, control, and analysis for normal states, anticipated alternatives, unusual or abnormal states, and data collection with advanced analysis capabilities. This will allow operators or the ADMS system to automatically reconfigure the system in near real-time to plan for and affect changes necessary to operate a safe, reliable, and economically efficient system.

Q. Is it the Company’s position that it presently has the appropriate building blocks and initiatives in place or in progress to implement a successful ADMS solution?

A. Yes. The Company has all the necessary components in place or in progress for the implementation and systems integration required to realize a successful and robust ADMS solution as described below:

- A foundational, accurate, and complete GIS with customer and asset connectivity, which updates an engineering analysis system model daily containing all customer load data, system data, DER, and device configurations;
- SCADA data that is available for 98% of the Company’s substations, and an increasing number of sub-circuit

device, monitoring and control (currently at 19% of the Company’s distribution circuits and increasing at a rate of approximately 8 percent of the circuits annually);

- An expanding and comprehensive distribution automation/smart grid program that has more than 450 devices deployed and will build out at a rate of approximately nine circuit pairs per year (within the New York portion of the Company’s service territory) with monitoring and control functionality;
- A robust radio frequency and communication infrastructure which can support distribution automation and facilitate ADMS command and control throughout the territory in the near-term. The Company is also investigating the potential to leverage its AMI communications network for certain last mile grid automation functionality and data transfer; and
- The deployment of an AMI program which will provide for extensive and granular sensing and measurements that will be used as a robust feedback loop to refine and improve the calculated values in the state estimation and power flow results in near-real time.

Q. What are the main drivers for the Company to implement an ADMS at this time and what is the implementation strategy?

A. Technology investments such as ADMS and DERMS are able to modularly expand, as well as incorporate and improve future functionality. As such, they are necessary to maintain the appropriate pace of the Company's DSP evolution to provide the foundational investments necessary to realize advanced grid modernization and future market capabilities. The Company's initial technology investments will focus on building the necessary interfaces to engage customers, increase the volume and granularity of data, enable greater DER penetration, and improve system reliability and operating conditions. In order to execute on this in a measured and effective way, the Company will implement ADMS functionality in stages. The initial stage will include the replacement of the Company's existing DSCADA system with a significantly more robust DSCADA application that can accommodate the breadth and scope of the envisioned future state. The Company's existing DSCADA system is near the end of its useful life. It does not have the functionality or capability to accommodate the type and number of interface points that the Company is building out in the near-term, let alone what is ultimately envisioned. During this initial stage, the Company will develop the foundational system platform with the selected vendor, integrate critical systems and data, and apply advanced model monitoring and control over the portions of its system that have been readied for Smart Grid operation. This will allow the Company to identify and resolve initial implementation issues before expansion to a greater portion of the service territory. Later stages will include additional and expanded system improvements or module integration (such as DERMS capability) as required to enable enhanced operational capabilities or market functionality, as well as expanded operation of the system onto portions of the electric delivery system as they become smart grid ready through Orange and Rockland's continued expansion of advanced equipment and applications with automation control. The Company will also be installing an Operator Training Simulator, which will provide control center personnel the capability to simulate, test, and evaluate FLISR, VVO, and DER interface applications within a powerful simulation and training environment.

Q. When will the ADMS functionality described above be in-service and what is the anticipated cost for this initial ADMS functionality?

A. The initial stage functionality described above is expected to be in-service toward the end of RY3. The total estimated capital expenditures associated with this initial ADMS functionality implementation in RY1 is estimated to be $1,290,100, $1,290,900 in RY2 and $1,290,800 in RY3. Please see Exhibit EIOP-4 for additional supporting details.

Q. What is the current state of the Company’s VVO implementation and systems?

A. The Company implements voltage control to maintain certain levels of efficiency, primarily through conservation voltage reduction implementation at the substation bus, and by operating the system through automated local controller set points on its substation LTCs, distribution capacitors, and distribution regulators. Watt and VAR readings for the majority of the Company’s substation banks are available through the SCADA system. However, the Watt and VAR readings are not being obtained for the Company’s distribution circuits at the substation or the sub-circuit level. These measurements are required for VVO applications to make accurate near real-time system adjustments. In addition, the tap changer controls on those substation transformers that have them do not all allow for access and control through remote interface.

Monitoring and voltage support infrastructure on existing equipment is limited. Voltage, power quality, and reliability data are currently not available at the circuit level. Although LTCs are connected back to the EMS and thus can see voltage changes, only newly-built substations may have the required monitoring and voltage support equipment. Currently, there are 79 substation transformer banks feeding the Company’s electric distribution system. The Company retains five years of transformer bank data, which consists of the following data points: amp readings for 12 banks, voltage readings for 66 banks, and MW/VAR readings for 74 banks. There are 220 circuits serving New York customers on the Company electric distribution system. The Company currently records amp readings for 207 circuits via the SCADA network. In addition, the Company receives MW/VAR readings for just two circuits based on the advanced RTUs and relays operating within those substation environments. Over time, the vast majority of these assets will need upgrades to obtain the correct operating system data parameters necessary to implement a robust VVO solution.

Q. Please describe the Company’s approach to upgrading its VVO capabilities.

A. The Company envisions a phased approach to implement more advanced VVO capability and realize results through the deployment of various supporting equipment, the incorporation of AMI, and the implementation and development of an ADMS. In the near term, VVO will likely be limited based on ADMS implementation timelines and the availability of infrastructure. As such, VVO capabilities are to be implemented at new substations first, where sufficient distribution automation and smart grid equipment is being deployed.

As these equipment upgrades and advanced technologies proliferate across the system, the Company ultimately envisions a near real-time integrated Volt/VAR Control System employing SCADA control through an ADMS. The system will use the Integrated System Model ("ISM") and advanced applications to achieve system wide VVO throughout the load cycle. This will be done to the extent systems are determined to be practical and cost beneficial. In the long-term, third-party DER contributions to VVO solutions may be considered as part of the VVO control schemes once the technology is developed and successful pilot programs have been completed and evaluated to show proven capabilities.

Q. What is required to achieve the goals of the VVO system?

A. Implementing VVO to achieve system-wide efficiencies requires monitoring and communications equipment to be deployed on the entire system, along with operable devices that can adjust voltage and VARS. An analysis tool with appropriate algorithms to manage and control the Volt/VAR supporting equipment also will be needed. The preferred near-term solution is to implement elements of VVO along with automated local controller set points on substation LTCs, distribution capacitors, and distribution regulators with the availability of remote manual LTC control. In the long term, the Company envisions deployment of the necessary monitoring and communications to enable automated VVO, controlled and adequately adjusted and maintained through an ADMS.

Q. Is the Company anticipating any staffing additions to support the ADMS program?

A. Yes. The Company plans to add a SCADA/ADMS engineer during RY1. This SCADA/ADMS engineer will support the implementation of the ADMS platform development with the selected vendor, support additional RTU deployment, and provide DSCADA commissioning, control, and alarm documents for the field technicians and Distribution Operators. This SCADA/ADMS engineer will also develop and maintain data maps, alarms, and events for new and existing equipment such as VVO controls, electric grid sensors, and DG interconnections.

Q. What is the proposed start date and cost of this SCADA/ADMS engineer?

A. Cost for this SCADA/ADMS engineer will be allocated 80% Capital and 20% O&M. The annual O&M cost of the position will be $16,220 starting in RY1. Please refer to Exhibit EIOP-4 for additional detail on this request.

Q. Are there any additional projects supporting ADMS and VVO which will be implemented during the period 2018-2020?

A. There are two additional projects that the Company will implement in the 2018-2020 timeframe. First, the Company will upgrade regulators to make them SCADA ready. There are 104 voltage regulators presently operating on the Company’s system that are not SCADA ready at this time. The Company anticipates upgrading 33% of the Company’s regulators to be SCADA capable in next three to four years. Second, there are a small number of distribution LTCs and breaker relays that will be upgraded to test VVO functionality requirements.

Q. What are the costs associated with these two additional projects?

A. The total cost for the two projects is estimated to be approximately $2 million over the next three year period. The total cost covers SCADA Regulators and Distribution LTCs/Breaker Relays.

Q. Please describe the purpose of a DERMS.

A. The purpose of a DERMS is to understand and manage the unique status and capabilities of diverse DERs to present these capabilities to other supporting applications for enhanced monitoring, control, and operation of the electric delivery system. The tool will be used in response to system operational events, environmental/weather and equipment conditions, and eventually market conditions. It will also be used to track and report on the growth of DERs in the Company’s service territory. A DER Management System will provide visibility and control of a diverse portfolio of resources to address local constraints while flexibly addressing system-wide concerns. This system can be a standalone solution exchanging information with ADMS or integrated directly into the suite of programs included in an ADMS. The system will visualize, predict, and optimize DR and DG at the circuit, feeder, or segment level, presented in a dashboard suitable for operational use. In the long term, the Company envisions a single, comprehensive DER data repository (DER Management System or module). It will be fully integrated with the operating and planning systems described above as a platform to work with ADMS functionality and a defined operating user interface environment.

Q. Please describe the Company’s efforts to date to evaluate potential DERMS solutions.

A. To date, the Company has conducted research on the DERMS marketplace and facilitated vendor showcases. This has provided a better understanding of existing system and vendor capabilities, to explore industry and utility specific challenges, and obtain third-party recommendations for responding to DER effects on the power grid and the potential energy marketplace. The Company, in conjunction with Con Edison, will use the findings from these industry reviews and demonstrations to develop an achievable DERMS Project. This project will be part of its overall Grid Modernization Roadmap that will be integrated with, or be an integrated functional module of, an ADMS platform.

Q. Is the Company seeking any funding related to a DERMS solution?

A. Not at this time. The Company will continue to work with Con Edison to determine the best path forward on a potential joint DERMS solution and will provide updates on cost estimates and the timing of such investments when available. As mentioned above, there is also the potential for the selected ADMS vendor to have or develop a robust DERMS solution as part of their integrated solution.

B. MOAB Upgrade Program

Q. Please provide an overview of the MOAB Upgrade Program.

A. The Company will implement a program that will replace approximately 75 gang operated air-break (“GOAB”) switches annually with motor operated air-break (“MOAB”) switches. Removed GOAB switches in good working order will be salvaged as replacements for other new (for those areas of the system that will not receive MOAB switches) or damaged GOAB installations as necessary. A motorized switch has key advantages over one that can only be operated manually. Because they are SCADA enabled, MOAB switches provide functionality to either be operated or tagged via direct operator control at the Company’s energy control center (“ECC”) or, eventually, via ADMS control.

Q. What is the justification for the project?

A. The key attributes of this upgrade program will seek to identify and prioritize existing GOAB switch locations that have a high frequency of operation, have high strategic value, and/or are located in distant or hard to reach locations. The GOABs to be identified for replacement are anticipated to be optimum candidate devices whose upgrade will result in improved outage restoration times and reduced maintenance requirements. MOAB installations will also have the added benefit of being able to identify and send fault information back to the ECC, and eventually the ADMS. This will identify outage cause locations more quickly and granularly, and improve FLISR operation in an ADMS operating environment, thereby reducing restoration time and customer outage hours of exposure.

The Company proposes to implement this program to upgrade an additional 25 units annually during the potential three-year rate period and envisions a program that continues this pace for a total of approximately five to seven years to address prioritized MOAB locations as described above. This incremental number of replacement units represents approximately 1.5% annually of the total GOAB population. The implementation of this program will serve to accelerate the pace of Grid Modernization, improve operational capabilities, and enhance the customer experience.

Q. How much will this program cost?

A. The Electric Plant Additions estimate for the MOAB Upgrade Program is $1,199,400 in RY1, $1,200,600 in RY2, and $1,199,700 in RY3.

C. Data Analytics

Q. Please provide a description of the Enterprise Data Analytics (“EDA”) Operation program.

A. In the SDSIP, the JUs identified enhanced data analytics as one of several key investments for the DSP evolution and to enable enhanced DER integration. As such, the Company is establishing an organization focused on providing data analytics tools and resources to business areas, in conjunction with Con Edison Analytics Center of Excellence. This program is expected to improve operational excellence and cost management by allowing business areas to leverage analytical models and data generated by other departments and corporate systems, increasing integration prediction, simulation, and projection into business processes. The vast amount of data that will be generated from the advancement of automation and grid modernization, including AMI, will provide significant opportunities to improve how the Company operates and how customers manage their energy usage.

The EDA operating model is a hybrid approach that uses existing analytics expertise embedded in business areas plus the addition of centralized resources to leverage across the Company. Information governance, enterprise architecture and a Center of Excellence will reside at the enterprise level to allow for proper start-up and ongoing oversight for building out the analytics capabilities and managing user adoption. The business areas will manage projects and maintain business-specific solutions according to the skills and maturation of analytics in their area.

Q. What are the costs associated with the EDA Operation program?

A. This program will be a joint Con Edison and Orange and Rockland effort and capital and O&M costs will be split 93%/7% respectively. The Company anticipates that Orange and Rockland’s portion of capital costs will be between $1 million and $2 million over the next three-year period and that there will be ongoing maintenance costs that will be absorbed within the Company’s shared services budget. This program is presently anticipated to be funded from Orange and Rockland’s base capital and O&M budgets, so no incremental funding is being requested at this time.

D. Communications Infrastructure

Q. Please provide a description of the Company’s Communications Infrastructure Expansion program.

A. This project will cover engineering design requirements and the physical expansion of the Company’s fiber optic infrastructure. The Company will develop a plan for the expansion of corporate fiber optic infrastructure to several of its electric substations and radio tower facilities. The design will address major bandwidth constraints and allow for the reliable communications needed to support the increased data communications demands that will result from the Company’s field automation efforts. The fiber optic infrastructure expansion will offer increased reliability, network capacity and cybersecurity controls at all fiber and data communication facilities under this plan. Once upgraded, these facilities will act as high-capacity data networking access points and will become part of the Corporate Communications Transmission Network (“CCTN”). CCTN is comprised of the Company’s fiber optic and microwave systems and is the Company’s data communications backbone for high-capacity connectivity to all data centers and server farms. As the Company expands its automation programs, the CCTN will play a major support role.

Q. What is the justification for this project?

A. This project plays a crucial role in supporting the Company’s grid modernization and other automation initiatives planned over the next several years. The current network, while reliable, does not have the bandwidth capacity to support expanded data requirements envisioned for advanced grid modernization and future market enablement. The Company’s CCTN will support and secure sensitive data for several critical systems and functional applications, including Smart Grid, AMI, ADMS, and EMS applications.

This project will also support critical “last mile” communications efforts, as it will offer increased access by extending the CCTN further out to the distribution networks and within customer neighborhoods. The Company will look to incorporate and secure wireless “last mile” data at the new CCTN facilities. The fiber optic expansion project will allow the Company to look at alternate Radio Frequency (“RF”) solutions, including the potential to leverage the existing RF infrastructure used for AMI. Access to expanded high-speed data facilities will become more achievable for multiple RF applications and devices used for DSCADA, AMI, and security surveillance.

Q. What is the expected project cost and in-service date?

A. The Communications Expansion project will have various in-service dates over the rate period. The Electric Plant Additions proposed for this project is $928,300 in RY1 and $904,000 in RY2.

Q. Are there any O&M requests associated with this program?

A. Yes. The Company will require two additional CCTN Operations and Support FTEs in order to support the ongoing bandwidth expansion and maintenance of its communications infrastructure. The fiber and data expansion will take place within highly restricted and secured areas where only qualified and vetted employees are permitted access. The

Company’s Telecommunications group will be responsible for providing these services, along with emergency response services across the entire CCTN.

The Company is also requesting one additional Information Technology Planning (“ITP”) FTE for developing the design criteria for the fiber expansion requirements. This FTE will be the sole optical design employee for the Company and will team up with the dedicated microwave, radio, and substation communications FTE, on all fiber optic expansion projects within Company substations and radio tower facilities. The new ITP employee is also necessary for optical equipment and circuit design. This aspect of the position includes establishing the necessary bandwidth, redundancy, security controls, and disaster recovery specifications across the network.

Q. What are the proposed start dates and costs of these new employees?

A. The proposed start date for the CCTN Operations and Support positions is June 1, 2018. Annual cost for these positions will be allocated 93 percent to Con Edison and 7 percent to Orange and Rockland. This O&M request is for the Orange and Rockland portion, which will be $9,870 starting in RY1.

The proposed start date for the Information Technology Planning position is January 1, 2019. The annual O&M cost for this position will be allocated 93 percent to Con Edison and 7 percent to Orange and Rockland. This O&M request is for the Orange and Rockland portion, which will be $6,760 starting in RY1.

E. Hosting Capacity and Interconnection

Q. What is the Company’s vision for sharing and displaying hosting capacity as it relates to developing a DSP?

A. The Company has taken a three-stage approach to enhancing its DG interconnection maps. In Stage 1, in February 2016, the Company made available a “red zone” map[16] for distribution circuits. In Stage 2, the Company used the Electric Power Research Institute’s (“EPRI”) Distribution Resource Integration and Value Estimation (“DRIVE”) tool to complete a hosting capacity analysis for all circuits 12 kV and above, which represents approximately 98% of its circuits. This was done in conjunction with the Supplemental DSIP filed in November 2016 in collaboration with the JUs. The hosting capacity map, accessible from the Company website, displays this analysis. As required by the Commission’s DSIP Order, the Company submitted its filing documenting the completion of the hosting capacity analysis for all circuits at and above 12 kV on October 2, 2017.

[16] The indicator map is available on the Company’s DG website (www.oru.com/solar).

For the Stage 2 displays, the Company determined each circuit’s hosting capacity by evaluating the potential power system criteria violations as a result of large PV solar systems with an AC nameplate rating starting at, and gradually increasing from, 300 kW interconnecting to three phase distribution lines. The analyses represented the overall feeder level hosting capacity only, and did not account for all factors that could impact interconnection costs (including substation constraints). It is noted that issues related to circuit protection require further analysis to make a definitive determination of hosting capacity, and the data is provided for informational purposes only and is not intended to be a substitute for the established interconnection application process.

Additional displays with tabulated data are included in the form of data pop-up displays to indicate that the hosting capacity may be lower at any given location. Existing DER were not considered in this stage of the hosting capacity analysis, and the data pop-ups were intended to provide additional context to the displays. For these reasons, the Company included and updates the installed and queued DG values in the data pop-ups on a monthly basis.

The Company will complete Stage 2, with an analysis of the full system and the complete maps, by June 30, 2018. This stage of the hosting capacity roadmap will fulfill the requirement in the DSIP Guidance Order calling for substation level hosting capacity data and will provide this information at a greater level of granularity with distribution feeder-level specificity.

For Stage 2.1, data pop-ups for each feeder will provide the following information in tabular format: voltage level of the feeder and other data shown in the Stage 1 indicator maps; current and queued solar PV (MW); and range of gross three-phase feeder level hosting capacity (MW) bounded by the least and greatest minimum hosting capacity values of any three-phase section on that feeder.

For Stage 3, per the SDSIP, the JUs are building on this advanced hosting capacity analysis, and they expect to continue to add advanced capabilities to the hosting capacity analysis. Stage 3 elements will include:

- Sub-feeder level hosting capacity;
- Substation level hosting capacity; and
- Reflect existing DG in the analysis (excluding storage).

Q. What systems are used to support the interconnection of DER today?

A. As outlined in EPRI's September 2016 Interconnection Online Application Portal ("IOAP") Functional Specifications document,[17] the Company is deploying a phased approach to implementing the IOAP.

In April 2016, the Company enhanced its online portal to facilitate timely DER interconnection by purchasing Clean Power Research's ("CPR") PowerClerk Interconnect software for accepting and processing applications. PowerClerk Interconnect is built upon the PowerClerk Incentives platform, the industry-leading software platform for renewable energy incentive processing. A hosted, web-based application, PowerClerk Interconnect is used today to process approximately 70 percent of the solar PV incentive applications (by volume) in the United States. The portal allows customers to log in, enter application information, attach supporting documents, and electronically submit their applications. All applications received by Orange and Rockland since April 29, 2016 were received through this portal. The Company converted all legacy applications to PowerClerk in January 2017.

[17] http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf

Q. What other IOAP investments need to be made in order to meet these requirements for interconnection?

A. Orange and Rockland was awarded a grant from NYSERDA to work with Electrical Distribution Design ("EDD") and CPR on a project to build a seamless DER Interconnection Assessment Application consisting of the CPR PowerClerk front-end integrated to the Distribution Engineering Workstation/Integrated System Model ("DEW/ISM") back-end. The proposed solution is to integrate existing industry-recognized software solutions for streamlined DER interconnections and distribution circuit analysis by CPR and EDD. The result will be a seamless end-to-end process for queuing/tracking/managing DER interconnection requests; for quickly analyzing and responding to those requests; and for integrating the DER resources into the engineering and operating models at the Company.

Phase 1 of the IOAP Functional Specifications entailed the automation of the application process. It automated applications and proceeded towards integrating the site availability and installation readiness validations (systems requirements checks and sizing compatibilities) into existing utility interconnection application processing database and systems (for all Applications 0-5 MW). The NYSERDA grant covered the cost of the majority of the requirements listed in Phase 1. Phase 2 involves automation of the SIR Technical Screening process and will automate the SIR technical screening requirements with links to both utility technical and customer databases (Applications >50kW). Phase 3 will fully automate all application and portal processes, integrating the application processing for larger systems with distribution planning, hosting capacity results and feeder analysis. The grant from NYSERDA will assist in the Company meeting the phased requirements outlined in the EPRI IOAP Functional Specifications.

Q. Discuss how this integrated system and IOAP implementation will improve the Interconnection application process?

A. The proposed solution integrates existing industry-recognized software solutions for streamlined DER interconnections and distribution circuit analysis by CPR and EDD, resulting in a seamless end-to-end process for queueing/tracking/managing DER interconnection requests. Today, customers/solar providers input DER Interconnection Requests into the PowerClerk software, which manages the queue and related workflow. With the proposed solution, upon receipt of a request from PowerClerk, the DEW/ISM will automatically run interconnection screens based on Orange and Rockland acceptance criteria. When a criteria violation occurs, the request will be forwarded to the appropriate engineer to review the violations and plan corrective actions using DEW software which houses Orange and Rockland's ISM. The ISM will integrate data from GIS, CAD, and transmission system models together into the single analysis model, relating customer load, customer load research statistics, SCADA measurements, EMS measurements, weather (historical and forecast) measurements, outage data, solar generation, and other data to appropriate equipment modeled in the ISM. All DERs in the queue, regardless of approval state will be available in the DEW/ISM model, enabling engineers and operators to have a complete view of DER on the system.

While the IOAP implementation will save time by automating the interconnection process and reducing errors in data collection and review, there will still be a need for human interaction to manually review criteria violations and system operating concerns, drawings, certifications and other pertinent documents for interconnection approval.

Q. Does the Company's enhancement of the PowerClerk software support the New York State SIR?

A. Yes. The New York State SIR was established to provide a framework for processing applications to interconnect DG systems to the State's investor-owned utilities' electric distribution systems. The SIR serves as the process guideline for interconnection of DG systems up to 5MW, with any requests to interconnect to the transmission system handled by the NYISO through the FERC interconnection process. The SIR lays out a six-step procedure for DG systems 50 kW or less and an eleven-step procedure for DG systems from 50kW to 5MW of aggregate nameplate capacity which includes a more detailed impact study, known as the Coordinated Electric System Interconnection Review. In addition, the Commission has established a state DG Ombudsman council, with representation from each utility to further coordinate on interconnection issues. The Company's integrated PowerClerk/DEW/ISM solution, and vision/plan for its evolution, is consistent with these standards and best practices.

Q. Are there any additional incurred costs associated with developing and maintaining these system investments?

A. Yes. The annual incremental maintenance costs for PowerClerk related to the IOAP functional requirements and the ESRI DRIVE Tool is estimated to be $113,130, ($98,046 for PowerClerk and $15,084 for the ESRI DRIVE hosting capacity tool).

VI. Major Storm Cost Reserve

Q. Does the Company's current electric rate plan include a major storm cost reserve?

A. Yes. Subject to various terms and conditions, the current rate plan provides for the Company to charge costs to the reserve if they meet the definition of a "major storm."[18] The Company proposes that the major storm cost reserve be continued, with one modification.

Q. What modification to the major storm cost reserve does the Company propose?

A. As discussed in the Accounting Panel's direct testimony, the Company proposes that it be allowed to charge to the major storm cost reserve for costs the Company incurs to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a Major Storm will affect its electric operations, but which ultimately does not do so, either at all or to the extent forecasted.

Q. Explain when this type of charge to the major storm cost reserve would apply.

[18] A "major storm" is defined in the current rate plan as a period of adverse weather during which service interruptions affect at least ten percent 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 costs. ("Major Storm").

A. In order to expedite restoration efforts when a Major Storm is forecast, the Company's Electric Emergency Response Plan may call for the pre-staging of contractors and/or mutual assistance crews, taking into consideration the forecasted regional weather impact and pre-determined minimum staffing requirements. However, weather forecasting is not an exact science, and storms that the Company reasonably expects to require contractors and mutual aid may turn out to be less severe than predicted, or not materialize at all. Because such contractor and mutual aid mobilization costs are reasonably incurred, the Company is proposing to charge the costs associated with pre-staging contractors and/or mutual assistance crews to the major storm cost reserve when these costs exceed $100,000 per storm.

Q. Has the Commission authorized these types of pre-staging costs to be charged to the major storm cost reserve for any other New York State electric utility?

A. Yes. The Commission has approved costs incurred in reasonable anticipation that a storm will significantly affect a utility's electric operations, but which ultimately does not do so to be charged to the major storm cost reserve in a number of electric utility rate plans. These include the most recent electric rate plans approved by the Commission for Con Edison (Case 16-E-0060), New York

State Gas and Electric and Rochester Gas and Electric Corporation (15-E-0283) and Central Hudson Gas and Electric Corporation (14-E-0318).

Q. Does this conclude your testimony?

A. Yes. It does.