New York Public Service Commission

Electric Case ______________

Orange and Rockland Utilities, Inc.

Volume 2

Testimony

ORANGE AND ROCKLAND UTILITIES, INC.

INDEX OF WITNESSES – 18-E-______

ORANGE AND ROCKLAND UTILITIES, INC.

Other Electric Initiatives – ELECTRIC

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Introduction

Q. Would the members of the Other Electric Initiatives Panel ("Panel") please state your name and business address.

A. Gabriel Cano, Scott Dunwoody, and Michele Hanebuth. Our business address is 390 West Route 59, Spring Valley, New York, 10977.

John V. Murphy. My business address is 500 Route 208, Monroe, NY, 10940.

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

A. (**Cano)** I am the Program Manager for Information Technology Business Services Delivery.

(Dunwoody) I am the Section Manager for the Energy Control Center Support Services group in the Company's Control Center Operations.

(Hanebuth) I am the Director for the Control Center and Substation Operations.

(Murphy) I am the Section Manager of the Transmission and Distribution Maintenance Department in Electric Operations.

Q. Please describe your educational backgrounds.

A. **(Cano)** I earned a Bachelor of Science degree in Business Management from Manhattan College and an M.B.A in Information Systems from Hagan Business School of Iona College.

(Dunwoody) I earned a Bachelor of Science Degree in Engineering (Electrical Emphasis) from Dordt College and a Master of Engineering Degree in Electric Power Engineering from Rensselaer Polytechnic Institute.

(Hanebuth) I earned a Bachelor of Engineering Degree in Electrical Engineering from Manhattan College in 1989 and a Master of Science Degree in Management Science from Pace University in 1995.

(Murphy) I earned a Bachelor of Business Administration Degree in Finance from St. Bonaventure University.

Q. Please describe your work experiences.

A. **(Cano)** I have been employed by Orange and Rockland for approximately 15 years. I have held a variety of Information Technology ("IT") Management positions during that time including Senior System Analyst, Lead

Analyst, and Project Specialist. I have been in my current position since February 2015.

(Dunwoody) I have been employed by Orange and Rockland for approximately ten years. I have held a variety of engineering and management positions during that time, including Systems Protection Engineer in Transmission and Substations Engineering, Engineer and Systems Specialist in Control Center Operations, and Section Manager in North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") and Energy Management System ("EMS") Support Services in Control Center Operations. I have been in my current position since July 2017. Prior to my current position, I was the CIP Section Manager for approximately three years.

(Hanebuth) I was previously employed by Consolidated Edison Company of New York, Inc. ("Con Edison") for approximately 25 years. I held a variety of engineering and management positions throughout Electric Operations during that time including Watch Engineer, Bronx Area Manager for Substation Operations, Senior System Operator, and Associate

Chief System Operator. I have been in my current position at Orange and Rockland since May 2014.

(Murphy) I have 21 years of increasing responsibilities in utility finance and operations. I spent 12 years in Finance where my responsibilities included assisting in the coordination and preparation of rate case filings and related analyses and proposals for Orange and Rockland and its wholly-owned New Jersey utility subsidiary, Rockland Electric Company. In 2008, I was promoted to Manager-Electric Operations and over the last nine years have worked in various capacities including Section Manager-Electric Operations, where I was responsible for the Electric Overhead and Underground Line Groups, including the Equipment Technician Group. I have been in my current position since July 2017.

Q. Please generally describe your current responsibilities.

A. **(Cano)** I am responsible for the availability and reliability of the Outage Management Systems (“OMS”), Geographic Information Systems (“GIS”), as well as the associated downstream reporting and analytics systems.

(Dunwoody) My primary responsibility is managing the EMS Support Services Group in Control Center Operations. The EMS Support Services Group maintains the reliable operation of the Company’s electric transmission Supervisory Control and Data Acquisition (“SCADA”) system. I also currently manage the NERC CIP group in Control Center Operations. Responsibilities for the NERC CIP group include maintaining NERC CIP compliance for the Company and setting cybersecurity policy for the Control Center and Substation Operations.

(Hanebuth) I am responsible for the safe, reliable, and compliant operation of the electric transmission and distribution system. I am also responsible for the safe, reliable, and compliant maintenance and operation of the Company’s Substations. In addition, I am responsible for the oversite of the Company’s NERC Compliance program, the Company’s CIP Compliance, and the Support Services area, which supports the needs of the Energy Control Center (“ECC”).

(Murphy)I am responsible for providing overall leadership and direction for the safe, timely, reliable, and efficient coordination of both a Company workforce and contractors that perform vegetation management, stray voltage testing and inspection, capital construction projects, pole inspection, ancillary contract services for use by Electric Overhead Construction, and associated maintenance on the distribution and transmission system.

Q. Have you previously testified before the New York Public Service Commission ("Commission")?

A. **(Cano)** No.

(Dunwoody) No.

(Hanebuth) Yes. I previously submitted testimony in the Company's last electric rate case, Case 14-E-0493.

(Murphy) No.

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

A. The purpose of the Panel's direct testimony is to discuss various program changes required by the Company to support compliance efforts, maintain security, manage expanding work volume, and improve system reliability.

Q. Please describe how the remainder of this testimony is organized.

A. The remainder of this testimony is broken down by department in the following order: Substation Operations, Control Center Operations, Electric Operations, Electric Engineering, and Information Technology. This testimony supports the Company’s proposals to add the following nine full time equivalents (“FTEs”): two Relay Technicians, four Equipment Technicians, a Smart Grid Operating Supervisor, an Underground Engineer, and a Firewall Administrator. This testimony also discusses the need for consulting resources for NERC Compliance, maintenance for the Tipping Point software, a new Ash Tree Mitigation program, and OMS enhancements. The Panel’s direct testimony is supported by white papers that provide additional details about each program and FTE request. The white papers are part of Exhibit OEI-1.

Q. What time period does this direct testimony cover?

A. The Panel will present the projects and programs planned for the 12 month period ending December 31, 2019 ("Rate Year" or "RY1"). As discussed by the Company's Accounting Panel, while the Company is not proposing a multi-year rate plan in this filing, the Company is interested in pursuing, through settlement discussions with Staff and interested parties, a multi-year rate plan. To facilitate settlement discussions, we also address capital plant additions and other programs and initiatives for the two years following the Rate Year. For convenience, we will refer to the 12 month periods ending December 31, 2020 and December 31, 2021 as "RY2" and "RY3," respectively.

Other Operations Initiatives

Substation Operations

Q. Please describe the additional resources requested for the Substation Operations team.

A. The Substation Operations team is requesting funding to hire two additional FTEs in the relay group. The Substation Operations department is responsible for approximately 90 substation facilities throughout the Company's service territory. Responsibilities include transmission and distribution equipment real time operation and maintenance, maintaining system reliability, and physical site/security maintenance. During the past seven years, the Company’s total asset inventory has increased due to the Company’s construction of eleven new substations and the addition of new equipment at four existing substations. As set forth in Tables 1 and 2 below, these projects placed additional facilities, substation equipment, and associated ancillary systems into service, which has increased the department’s workload. This equipment requires regularly scheduled routine and periodic maintenance.

Table 1: New/Upgraded Station Facilities

	Station Name	Trans-formers	Transmission Bkrs	Dist. Bkrs	Ckt. Swtchrs	Capacitors
1	Corporate Dr	3	5	15		
2	Snake Hill Rd	3	6	17		1
3	Hartley Rd	2	6	13		2
4	Sugarloaf 110		8			
5	Sugarloaf 112	1	1			
6	Dean	1		4	1	
7	Blue Lake	1	2	3		
8	Darlington	2	3	11	2	
9	Mac Arthur 1&2		4			
10	Summit Ave	2	3	13	2	
11	Sterling Forest	1	1			
12	New Hempstead*	1	4	13	2	2
13	Monroe*	1		13	1	
14	South Mahwah*	1	2	13	1	
15	Wisner*		1			1
	Totals	**19**	**46**	**115**	**9**	**6**
Total New Devices: 19 + 46 + 115 + 9 + 6 = 195						

*Upgraded Facility (new equipment was installed)

Table 2: Yearly Labor Hours

		Task Hours	Crew Size	Required Hours
Periodic Maintenance Items (Done on a 6 year Frequency)				
	# of New Devices			
Trip Test – 8 hrs./ea.	195	1560	2	3120
Relay Maint. – 16 hrs/ea.	195	3120	2	6240
			Total	9360
	Average/year (Total/6 year freq.)			**1560**
Real Time Response Items				
	Events per year			
Station Priority Alarms (4 hrs/ea.)	180*	**720**	2	**1440**
Line & Equip. Trip Outs (6 hrs/ea.)	15*	**90**	2	**180**
	Total Yearly Labor Hours Required			**3180**

Available Labor Hours/Person:

[(52 wks x 40 hrs) – vacation, training, holidays, sick] = 1800 hrs

Headcount Needed: 3180/1800 = 2

* Based on 60 priority alarms/year/station x 15 new or upgraded stations, assuming 20% of these require relay group response.

**Based on an average of 1 trip out/station/year.

The Substation Operations department is also responsible for addressing real time issues that arise at these facilities and for investigating and responding to equipment issues as they occur. The Company’s response, maintenance, and testing requirements are driven by certain compliance and regulatory requirements (*e.g.*, NERC, Northeast Power Coordinating Council (“NPCC”) and/or the need to maintain the Company’s transmission and distribution system in a safe, efficient, and reliable condition for the workforce and customers.

Using a contractor work force in energized substation facilities requires the Company to provide a safety person to oversee the contractors. This safety requirement increases the expense of performing the work. Also, the Substation Operations relay group’s maintenance backlog has grown over the same period. The growth in work requirements has diverted the existing manpower to assist in the construction of the new substations and existing substation additions described above. The increased work load from these additional assets is contributing to the growth of a maintenance backlog that could compromise the performance of the system.

Q. What is this proposed start date and cost of the request?

A. The proposed start date is January 1, 2019 and the projected O&M expenditure for these positions is $165,920 annually ($82,960 for each FTE), starting in RY1.

Control Center Operations

Q. Please describe the Company's request to add a Firewall Administrator position?

A. The Company is requesting to add an ECC Firewall Administrator. Cyber threats to Bulk Electric System ("BES") (High Value) SCADA Systems are an increasing risk in the utility industry. Examples of this increasing risk are the 2015 and 2016 Ukraine cyber attacks which compromised SCADA infrastructure and caused widespread blackouts. In addition, recent malware specifically targeting SCADA systems, such as BlackEnergy and Dragos CRASHOVERRIDE, demonstrate that

SCADA systems have become a prime target for hackers. Protecting and securing the Company’s High Value SCADA Systems is a top priority for Orange and Rockland. The Company has implemented various security improvements to its High Value SCADA networks in recent years, including additional network segmentation and an isolated testing bed that mirrors production. These security improvements include additional firewall assets, networking assets, network administration, and firewall administration. While the administrative tasks and responsibilities relating to these security improvements have increased, the supporting group responsible for these tasks and responsibilities has remained static. Moreover, firewall administration is currently the responsibility of corporate firewall/network administrators who work on all of the Company’s, as well as Con Edison’s, corporate assets. The preferred approach is to have a dedicated, on site administrator whose primary focus and responsibility is the assets within the ECC. A dedicated ECC firewall administrator would manage the additional firewall, network, and cyber security technologies within the

ECC, maintain compliance with existing NERC CIP standards, and prepare for upcoming changes to these standards.

Q. What is the proposed start date and cost of a dedicated Firewall Administrator?

A. The proposed start date is January 1, 2019 and the projected O&M expenditure for this position is $85,220 annually, starting in RY1.

Q. Please discuss the Company's need to recover the software license and maintenance costs associated with the Tipping Point software program.

A. The Company installed Tipping Point, an Intrusion Prevention System ("IPS"), in 2017 within the ECC to identify and prevent potentially malicious activity from occurring on the High Value SCADA Networks. The Company's BES SCADA Systems are currently secured in High Value Networks behind firewalls that block all traffic not required for normal/emergency operation. Tipping Point provides an additional layer of security to these High Value Networks by performing deep packet inspection on network traffic entering and leaving the High Value Networks and blocking the network traffic based on known threats. The known threats exist in a database that Hewlett-Packard maintains with malicious IP addresses and DNS entries. Tipping Point also has Digital Vaccine services which block known harmful traffic such as botnets, malware, worms, and Distributed Denial of Service attacks.

Q. What is the cost of maintaining this software program?

A. The licenses and maintenance for Tipping Point software program are projected to cost $16,590 in RY1 and $17,350 each in RY2 and RY3.

Q. Please discuss the Company’s need to secure funding for consulting services to support NERC Compliance.

A. The NERC compliance model continues to mature in the Standards Development and the Compliance Monitoring and Enforcement arenas. It also continues to migrate to a Risk-Based compliance model whereby NERC regions now conduct Internal Risk Assessments and Internal Controls Evaluations of Registered Entities. These activities assist the regions in determining the potential Monitoring and Enforcement scope and depth for Registered Entities, so that Registered Entities have the appropriate levels of controls in place to mitigate risk and facilitate compliance.

Orange and Rockland must continue to develop and implement effective controls to sustain compliance and meet all emerging regulatory and physical/cyber security risks. This includes the Company’s further development of robust internal controls to meet the transition of the NERC enforcement model to a risk-based approach.

Orange and Rockland is requesting funding to engage consultants to address areas where in-house subject expertise may be limited and/or a more agile, rapid, or accelerated response is required to meet emerging regulatory or risk mitigation needs. This also allows for third party review and incorporation of other industry best practices of which the Company may be unaware. The services include:

<u>Internal Controls Development& Assessments</u>: These services will assist the Company’s subject matter experts (“SMEs”) in developing and implementing strong internal controls to facilitate compliance with regulatory requirements. Activities will include

identifying risk mitigation strategies, developing internal control objectives, and developing and implementing preventative, detective, and corrective controls. This will assist in facilitating Orange and Rockland’s compliance and potentially reducing regulatory risk through reduced audit scope with NPCC’s Compliance Monitoring Enforcement Program (“CMEP”) activities.

Gap Analysis & Audit Prep*:* These services directly assist the Company’s SMEs in identifying any potential or actual gaps in compliance, and provide technical recommendations to facilitate compliance. Services may also include assistance in preparing for an audit by NPCC through third party review and mock audit exercises.

Awareness and Capability Consulting/Training*:* These services include working with Company SMEs to increase their awareness and technical understanding of the NERC Standard Requirements, and to implement compliance strategies. Awareness may include increased focus on the annually identified Risk Elements and Areas of Focus by NERC.

These services will allow Orange and Rockland to address any potential technical gaps, and develop and implement strategies to address emerging regulatory and reliability risks as they relate to NERC.

Q. What will these consulting services cost?

A. These services are estimated to cost $75,420 per year starting in RY1.

Electric Operations

Q. Is the Company planning to add any other positions in its Electric Operations department?

A. Yes. The Company is planning the addition of one Smart Grid Operating Supervisor and four Equipment Technicians.

Q. Please describe the need for the Smart Grid Operating Supervisor?

A. With the evolution of grid modernization and renewed focus on, and integration of, distributed energy and customer sited technologies, Orange and Rockland will need an Operating Supervisor to manage construction needs necessary to support its distribution automation /smart grid programs and the interface on new technologies with the electric delivery system. Orange and Rockland has been implementing distribution automation programs since the early 1990's on its electric distribution system. Orange and Rockland has committed to making system upgrades with the implementation of its distribution automation/smart grid design throughout its service territory. The Company is deploying this program to approximately 20 circuits annually in its New York service territory, resulting in the installation of approximately 125 SCADA enabled devices each year.

This amount of expanding workload requires the engagement of a dedicated Operating Supervisor to supervise and manage outside line construction crew(s). This position will be responsible for the supervision and assignment of work to crews for all activities associated with construction, installation, maintenance, removal, repairs, operation, and inspection of distribution technologies, equipment, and Intelligent Electric Devices ("IEDs") in support of the continued expansion of enhanced distribution technologies and automation systems across the

Company’s service territory. Furthermore, this Supervisor will be required to respond to system emergencies and be assigned accordingly to support safety and restoration efforts during major storms and system events.

Q. What is the proposed start date and cost of this FTE?

A. The proposed start date for this FTE is January 1, 2019. The annual cost for this FTE ($125,000) will be allocated 65% Capital and 35% O&M. This request is for the O&M portion of the position, which will be $43,750 starting in RY1.

Q. Please describe the need for the four Equipment Technicians.

A. The Electric Overhead Operations group is responsible for the operation and maintenance of IEDs such as switched capacitor banks, automated motor operated air break switches (“MOABs”), reclosers, and all associated field monitoring and communications equipment. This includes the installation, testing, repairs and annual maintenance of the IEDs. As described above, the Company has been and will continue to significantly increase installation of these devices over the next 10+ years. In addition to maintaining this equipment, the Electric Overhead Operations group will be tasked with maintaining/replacing batteries in the network communication devices that are being installed for AMI.

The four additional Equipment Technicians will perform work necessary to support these increasing electric distribution automation and resiliency efforts. Equipment Technician duties include but are not limited to performing any work required for the operation and maintenance of all field installed reclosers, MOABs, regulators, sophisticated (smart) capacitor bank controller, supervisory controls, communication systems (SCADA, SMART GRID), sectionalizers, load loggers/recorders, and other meters associated with engineering studies in the overhead and underground system. They also record, analyze, and interpret the results of power quality studies on field or customer equipment.

Q. What is the proposed start date and cost of these additional FTEs?

A. The proposed start date for each of these four positions is January 1, 2019. The annual cost for these positions ($302,200) will be allocated 20% Capital and 80% O&M. This request is for the O&M portion of the position, which will be a cost of $241,760 starting in RY1.

Q. Please describe the Company's Ash Tree Mitigation Program.

A. The Emerald Ash Borer ("EAB") is a non-native beetle whose larvae kill ash trees by burrowing in the inner bark and disrupting the flow of water and vital nutrients. The EAB beetle, first found in New York State in 2009, is expected to increase its presence and the damage it inflicts to ash trees throughout New York and other states. An Urban Tree Health Study completed in 2013 identified that ash trees make up about 10%, or 77,500 trees, of the total tree population along the overhead electric facilities within 10 feet of the conductors. As these trees become affected by the EAB, they dry out quickly and die due to lack of moisture. This makes the trees brittle and contributes to limb, trunk, and root failure causing them to fall and come into contact with energized facilities, causing damage and disruptions. The Ash Tree Mitigation project will identify and remove ash trees damaged by the EAB beetle limiting potential damage to Orange and Rockland’s overhead infrastructure and minimizing impacts to electric reliability.

Q. What additional resources are required to support this program?

A. The Company is planning to hire contractors to complete the necessary work. The resources required to complete the program will include a dedicated investigator/supervisor to complete the survey and coordinate the work, as well as two vegetation management crews to complete the actual tree removal work. The estimated cost of the program is $750,000 annually, starting in RY1.

Electric Engineering

Q. Please describe the need for an Underground Engineer.

A. Increasing focus on resiliency has led to more underground projects, both transmission and distribution related, within the Company’s service territory. From the distribution perspective, a growing number of projects are being designed to place portions of existing overhead circuits underground to minimize exposure to outage sources such as high winds or falling tree limbs that could affect multiple circuits simultaneously. In addition, underground distribution circuit substation outlets are significantly increasing in length to provide path diversity for circuits and to reduce exposure to outage sources in order to improve system reliability. These circuit outlets have gone from under a 1000 feet of total length to lengths of over one mile. The underground systems have become more complex due to waterway, railroad, and major roadway crossings now installed underground verses overhead. These require directional borings with advance environmental permitting. From the transmission perspective, the Company is finding increased community and regulatory resistance to constructing new overhead transmission facilities. Even upgrading existing overhead transmission corridors with overhead design construction methods is facing substantial opposition, requiring the Company to pursue underground construction designs. The current Company's five year budget will double the total installed footage in the ground on the transmission system that was previously installed over the last 45 years.

These factors have substantially increased the workload of the current staff in the Company's Distribution Engineering Department. In addition, these new designs have significant environmental and field permitting requirements attendant with them, construction limitations, and safety requirements. This greatly increases the complexity and design man-hours required for each project.

The factors and issues described above necessitate the addition of an Underground Engineer. Specifically, this new engineer would be responsible for the design, approval requirements, and construction oversight for various project installations on the distribution and transmission electric systems, with dedicated focus on underground projects.

Q. What is the proposed start date and cost of this Underground Engineer?

A. The proposed start date for this FTE is January 1, 2019. The annual cost for this FTE ($71,400) will be allocated 70% Capital and 30% O&M. This request is for the O&M portion of this FTE, which will be $21,420 starting in RY1.

Information Technology

Q. Please provide an overview of the Oracle Outage Management System ("OMS") project.

A. The Company decided to deploy the Oracle OMS because the future integration with AMI requires siginifcant integration and new functionalities, and incorporating a new system now which is also synergistic with Con Edison's system makes it cost effective and better for long term stability.

Q. What are the benefits of the new Oracle OMS?

A. The new Oracle OMS has improved stability, streamlined integration to AMI, and leveraged existing business and IT expertise.

Q. Are there any ongoing costs related to the OMS?

A. Yes. There is an annual product maintenance fee from Oracle that covers software updates, security patches, and ongoing maintenance and support. The maintenance of the OMS is estimated to cost $103,370, $105,430, and $107,540 in RY1, RY2, and RY3, respectively.

Q. Please describe the Company's plan for OMS enhancements during the rate period.

A. The Company plans to perform major enhancements to its OMS over four years. In 2017, the Company implemented new Interruptions applications, developed a new OMS dashboard to interface into the Oracle OMS, and retired OMS Web. In 2018, Orange and Rockland will design and implement an Oracle Mobile solution for Damage Assessment. The Company will also make enhancements to service packs, the dashboard, and the training simulator. In 2019, the Company plans to implement the OUA Business Intelligence platform for Outage Management. In 2020, Orange and Rockland will implement a stand-alone Oracle OMS environment with new server hardware and integrate ADMS with the Oracle OMS. This work is being pursued in conjunction with Con Edison. The standardization of the platform will allow both companies to leverage lessons and resources and implement industry best practices.

Q. What is the justification for these enhancements?

A. In anticipation of changes in the industry, such as increased integration for AMI, REV, and ADMS capabilities, the Company expects to implement a major Oracle OMS enhancement (new functionality) every two years and a major hardware upgrade every five years. The Company also plans to replace the existing operating hardware because it was acquired in 2014, is on a five-year replacement cycle, and will soon be obsolete. This new system has a high availability environment which offers different approaches with regard to redundancy, full tolerance, and quick disaster recovery.

The enhancements previously mentioned will have important operational benefits. For example, the Company can pursue enhanced visibility into outage data by way of business intelligence analytics which will be fed downstream by the operational OMS. With the planned near real time data collection expected from AMI to the OMS systems, it is critical that the

Company provide the same near real time data to its OMS Dashboards and Business Intelligence Analytics Platforms to facilitate efficient restoration activities. With no enhancements, the older technology will be difficult to maintain and vendor support will become unavailable to support existing products and system. Orange and Rockland wants to use the most cutting-edge technology as it relates to new enhancements and features that are consistent with industry needs/drivers.

Q. What is the estimated Plant Additions for this project?

A. The Electric Plant Additions estimate for this project is $843,100 in RY1 and $1,850,200 in RY2.

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
EARNING ADJUSTMENT MECHANISMS PANEL – ELECTRIC

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INTRODUCTION

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

A. (**Cigliano**) My name is Charmaine Cigliano. My business address is, One Blue Hill Plaza, Pearl River, New York 10965.

(**Barone**) My name is Kristen M. Barone. My business address is 390 West Route 59, Spring Valley, New York 10977.

(**McGuire**) My name is Michael McGuire. My 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," "O&R" or the "Company")?

A. (**Cigliano**) I am Section Manager – Customer Energy Services.

(**Barone**) I am Section Manager of the Utility of the Future ("UotF") organization.

(**McGuire**) I am Principal Engineer of the Technology Engineering organization.

Q. Please describe your educational backgrounds.

A. (**Cigliano**) I received a Bachelor of Science degree from the Binghamton University in 1988 with a double major in Mathematics and Computer Science.

(**Barone**) I received a Bachelor of Science degree in Mechanical Engineering in 2006 from Manhattan College and a Master of Business Administration degree in 2011 from the Hagan School of Business at Iona College.

(**McGuire**) I received a Bachelor of Science degree in Electrical Engineering Technology in 1988 from Rochester Institute of Technology.

Q. Please describe your work experiences.

A. (**Cigliano**) My first employment after graduation was with O&R as an Analyst with the Economic Research Department where I held positions of increasing responsibility. In 1998, as a result of the merger between Consolidated Edison Company of New York, Inc. (“Con Edison”) and O&R, I was offered and accepted the position as a Senior Planning Analyst in Con Edison’s Electric Forecasting Department. In 1999, I accepted a

Senior Planning Analyst position in Con Edison’s Rate Engineering Department. In 2000, I returned to O&R as the Customer Information Management System Billing Team Lead and in 2004 I was promoted to the Manager of Retail Access. In 2008, I was promoted to my current position as Section Manager - Customer Energy Services.

(**Barone**) I joined Orange and Rockland in 2012, and have held positions with the Company as a Program Administrator for Commercial Energy Efficiency programs, as a Major Accounts Engineer in New Business Services, an Engineer and Project Specialist in the UotF organization, and my present position as Section Manager in the UotF organization. Prior to my employment with Orange and Rockland, I was a Program Engineer of energy efficiency projects at the New York Power Authority in White Plains, New York.

(**McGuire**) I joined Orange and Rockland in 1988 and have held several roles in Performance Engineering, Systems Operations, Distribution Planning and Technology Engineering. My most recent positions include Principal Engineer for Distribution Planning and my present position as Principal Engineer in Technology Engineering.

Q. Do you belong to any professional organizations?

A. (**Cigliano**) I am a member of the Board of Directors for the Association for Energy Services Professionals (“AESP”). AESP is a dynamic community of energy efficiency professionals dedicated to advancing the industry through professional development, networking and advocating for a resilient, sustainable energy future in North America.

(**Barone**) I am currently a member of the Association of Energy Engineers.

(**McGuire**) I am currently a member of the Smart Electric Power Alliance.

Q. Please generally describe your current responsibilities.

A. (**Cigliano**) I am responsible for the design, implementation and evaluation of O&R’s portfolio of energy efficiency (“EE”), demand response (“DR”), renewable and low-income programs.

(**Barone**) As Section Manager of UotF, I collaborate with internal and external organizations, third parties, the Joint Utilities,[1] and customers in developing a future utility business model as envisioned in New York Public Service Commission's ("Commission") Reforming the Energy Vision ("REV") proceeding. I also oversee a team that works to enable the regulatory and policy 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").

(**McGuire**) As Principal Engineer of Technology Engineering, I evaluate the Company's electric system for beneficial locations to install microgrids, work with Distribution Planning to enable the regulatory and policy requirements necessary to encourage the integration of increased levels of DER, and collaborate with internal and external organizations,

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[1] The New York Joint Utilities are Central Hudson Gas and Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid (collectively "National Grid"), Con Edison, National Fuel Gas Distribution Corporation, New York State Electric & Gas Corporation, Orange and Rockland, and Rochester Gas and Electric Corporation (collectively the "JUs").

including the JUs, in developing future utility business models as envisioned in the REV proceeding.

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

A. (**Cigliano**) Yes, I testified before the Commission in Cases 11-E-0408, 14-E-0493, and 14-G-0494.

(**Barone**) No.

(**McGuire**) No.

PURPOSE OF TESTIMONY

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

A. The purpose of the Panel's direct testimony is to present the Company's proposal for Earning Adjustment Mechanisms ("EAMs") in accordance with the Commission's Order Adopting a Ratemaking and Utility Revenue Model Policy Framework in Case 14-M-0101.[2] The

[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding"), Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) ("REV Track Two Order").

Company proposes to implement four EAMs[3] that are directly tied to achievement of REV objectives and associated customer benefits. The proposed EAMs are: (1) System Efficiency ("SE EAM"); (2) Energy Efficiency ("EE EAM"); (3) Interconnection ("IEAM"); and (4) Advanced Metering Infrastructure ("AMI")Customer Engagement ("AMI EAM").

Q. Has the Company previously submitted an EAM proposal to the Commission?

A. Yes. The Company submitted an EAM proposal in February 2017 in Case 16-M-0429.[4] The Company's proposed EAMs in this proceeding supercede and replace those contained in its February 2017 proposal.

SUMMARY OF EAM PROPOSAL

Q. Please summarize the Company's proposed EAMs.

[3] For the purpose of this testimony, "EAM" is defined as the broad area of focus representing earning opportunities. The EAMs consist of individual elements defined as "metrics" that are designed to achieve different objectives within the area of focus. For example, the EE EAM is focused on the broad objective of energy efficiency and consists of two metrics, *i.e.*, MWh reduction and energy intensity.

[4] Case 16-M-0429, *In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision*, Petition of Orange and Rockland Utilities, Inc. for Earning Adjustment Mechanisms, (filed Feburary 13, 2017).

A. The Company proposes to implement the following four EAMs.

- The SE EAM measures the improvement in system efficiency while promoting the growth of DER. The SE EAM consists of three metrics: MW Peak Load Reduction, Circuit Peak Load Reduction, and DER Utilization.
- The EE EAM measures the improvement in EE in reducing customer usage, which results in lower costs for customers and reduced carbon emissions. The Company established the EE EAM targets to help achieve the State Energy Plan and the Clean Energy Standard ("CES").[5] The EE EAM consists of two metrics: MWh Reduction and Energy Intensity.
- The IEAM measures the Company's efforts to expedite and facilitate the Distributed Generation ("DG") interconnection process and support the key REV objective of DER market development. The IEAM consists of a single

[5] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* (issued August 1, 2016).

metric: Applicant Satisfaction. This metric is consistent with the Commission’s order regarding the JU IEAM proposal,[6] and the subsequent JU filing.[7]

- The AMI EAM measures the improvement in customer engagement and use of AMI technology, features and benefits. The AMI EAM consists of three outcome-based metrics: Customer Awareness, Weekly AMI report email enrollment, and High Bill Alert (“HBA”) text message enrollment.

Q. Please describe the Company’s proposal regarding EAM earnings opportunities.

A. The Company proposes positive earning adjustments, calculated as return on equity basis points, for each of the four EAMs. The proposed EAM earnings opportunities are a maximum of 100 basis points each year. The allocation of these earnings opportunities

[6] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Directing Modifications to the Joint Utilities' Proposed Interconnection Earning Adjustment Mechanism Framework (issued March 3, 2017).
[7] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Modified Interconnection Survey Process and Proposed Earning Adjustment Mechanism of the Joint Utilities (filed May 8, 2017).

is summarized in Table 1 below, and is discussed in detail later in the testimony.

Table 1: EAM Maximum Earnings Opportunities Basis Points

EAMs and Associated Metrics	2019	2020	2021
System Efficiency			
MW Peak Load Reduction	22.0	22.0	22.0
Circuit Peak Load Reduction	2.0	2.0	2.0
DER Utilization	26.0	26.0	26.0
Energy Efficiency			
MWh Reduction	26.0	26.0	26.0
Energy Intensity (Residential)	4.5	4.5	4.5
Energy Intensity (Commercial)	4.5	4.5	4.5
Interconnection			
Applicant Satisfaction	5.0	5.0	5.0
AMI Customer Engagement			
Customer Awareness	5.0	5.0	0.0
Weekly AMI Report Email Enrollment	2.5	2.5	5.0
HBA text message enrollment	2.5	2.5	5.0
Total	100.0	100.0	100.0

While the proposed earnings opportunities in Table 1 are expressed as basis points, the Company recommends that the values be converted to dollars once the Company’s capital structure and rate base are determined in this proceeding. The dollar amounts will change from year to year with changes in rate base.

Q. Why has the Company proposed earnings opportunities up to a maximum of 100 basis points?

A. The Company's proposal is consistent with the Commission's guidance in the REV Track Two Order (p. 68). The Company agrees with the Commission's statement that: "Incentive opportunities should be financially meaningful and structured such that they encourage enterprisewide attention at the utility and encourage strategic, portfolio-level approaches beyond narrow programs."[8] The Company believes that earnings opportunities of up to 100 basis points is financially meaningful and provides the Company with sufficient incentive to pursue expansive initiatives that will result in achievement of REV objectives and significant customer benefits.

[8] REV Track Two Order, p. 68.

Q. What is the effective time period for the EAMs?

A. The Company proposes that the EAMs be effective for Rate Years 1 through 3 (*i.e.*, January 1, 2019 through December 31, 2021), if agreement is reached on a three year rate plan and the Commission adopts the plan. The proposed EAM targets measure the Company's calendar year performance. The Panel would note that, as discussed in the direct testimony of the Company's Accounting Panel, the Company is not proposing a multi-year rate plan. However, in addition to providing projections for the Rate Year (*i.e.*, calendar year ending December 31, 2019), the Panel does address projected expenditures in the two years following the Rate Year in this proceeding (*i.e.*, calendar years ending December 31, 2020 and 2021, respectively).

Q. Please describe the development of Company's EAM proposal.

A. The Company developed its proposed EAMs with the goal of achieving the REV objectives and customer benefits discussed by the Commission in REV Track Two Order (pp. 53-93), while also reflecting the unique characteristics of the Company's customers, its service area, and its operational capabilities and constraints.

Q. Please describe how the Company's EAM proposal aligns with Commission's guidance in the REV Track Two Order.

A. The Company's proposed EAMs follow the Commission's guidelines in the following ways:

1) *Outcome-based*: The Company has proposed EAMs that are based on outcomes that achieve broad policy objectives.
2) *Avoidance of Counterfactuals*: The proposed EAMs have fixed performance targets which make them easier to administer and more outcome-oriented.
3) *Symmetry*: The proposed EAMs are positive-only, and have symmetrical minimum and maximum performance targets.
4) *Size of EAM*: The proposed EAMs have a total maximum earning opportunity of 100 basis points. The size of each EAM varies based on the underlying programs, anticipated costs, and customer benefits.

5) *Shape of the Line*: The proposed EAMs are a function of target achievement such that increasing awards are linked to increasing performance.

6) *Timeframe for Achievement*: The proposed EAMs are for three years, providing sufficient time for the realization of outcome-based achievements. We would note that if the Commission approves only a one-year rate plan in this proceeding, because there would be less opportunity for the achievement of outcome based EAMs, the proposed EAM targets would need to be revised to place more emphasis on the programmatic EAMs.

Q. Please describe the customer benefits resulting from the Company's EAM proposal, as outlined by the Commission in the REV proceeding.

A. In the REV Track Two Order (pp. 53-93), the Commission identified multiple customer benefits that can be achieved from utility actions taken to implement the new policy objectives of the REV Proceeding and which form the justification for EAMs. These include lower customer costs through improved efficiency in capital investments, better use of existing assets, and lower energy usage through EE. The initiatives that form the basis for the proposed EAMs are undertaken to support these REV goals, including increased capabilities of customers to participate in markets, reduced carbon emissions, and market development of DER.

Q. Please describe the proposed process and timeline for the Company's EAM proposal.

A. The Company recognizes that development of the proposed EAMs constitutes an ongoing effort requiring discussion and collaboration among Staff of the Department of Public Service ("Staff") and various stakeholders that are parties to this proceeding. Accordingly, the Company proposes to conduct two technical forums related to the proposed EAMs with Staff and interested parties to this proceeding. The purpose of these forums would be to start a dialogue regarding the proposed EAMs and to identify areas of agreement.

SYSTEM EFFICIENCY EAM

Q. Please describe the metrics related to the Company's proposed SE EAM.

A. As noted above, the Company proposes three SE EAM metrics: (1) MW Peak Load Reduction; (2) Distribution Circuit Peak Load Reduction; and (3) DER Utilization.

MW Peak Load Reduction

Q. Please describe the Company's proposed MW Peak Load Reduction metric.

A. The MW Peak Load Reduction measures the reduction in O&R's system peak. The Company considers this metric a hybrid of program-achievement and outcome-based metrics.[9] The Company plans to reduce its system peak through various initiatives, including its Energy Efficiency Transition Implementation Plan ("ETIP") and expanded EE based measures. In addition, the Company plans to reduce its system peak through DR, solar photovoltaic ("PV") and other DG.

Q. Did the Company consider an alternative approach for measuring peak load reduction?

[9] As discussed in REV Track Two Order (p. 61), outcome-based incentives align with policy objectives while program-based incentives are based on specific utility inputs or attainment of specific program targets.

A. Yes. The Company considered an outcome based metric based on reductions in the system peak load. However, the Company concluded that this approach was unsuitable because the historical system peak loads (normalized for weather) do not provide a reasonable basis for measuring the Company's contributions to reduce peak load.

Q. Please describe the Company's initiatives to produce and measure peak load reduction.

A. The Company's plan to implement various EE programs is discussed in the Company's EE Panel's direct testimony. The EE programs' contribution to peak demand reduction will be calculated using the New York Independent System Operator's ("NYISO") coincident peak for each EE measure, as outlined in the New York State Technical Resource Manual ("TRM").[10] The Company will encourage MW demand reduction performance through its DR programs including, but not limited to, Commercial System Relief Program ("CSRP") and Direct

[10] New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-Family, and Commercial/Industrial Measures Version 4, effective January 1, 2017. NYS DPS Matter #15-01319.

Load Control (“DLC”). DR performance will be calculated as the average MW of demand reduction received from all DR events, including tests, for the year. The Company will also encourage solar PV and other DG interconnections and take into account the annual incremental impact on the system peak demand based upon internally utilized peak coincident factors.

Q. Please describe the Company’s proposal for MW Peak Load Reduction targets.

A. The Company’s proposed maximum targets for O&R peak reduction are 25.3 MW, 20.8 MW, and 22.8 MW for 2019, 2020, and 2021, respectively. For details on the MW Peak Load Reduction targets, please refer to attached Exhibit ___ (EAMP-1).

Q. Please describe how the Company developed the MW Peak Load Reduction targets.

A. The Company developed the MW Peak Load Reduction targets based on planned contributions from its ETIP, expanded EE and DR programs, as well as solar PV and other DG installations.

Q. Please describe how the Company developed the MW Peak Load Reduction targets from the Company's EE and DR programs.

A. The Company developed EE program contributions to peak demand reduction targets based on the historical ratio of program KW to KWH applied to planned EE savings. The DR program contributions were developed based on program enrollment and historical performance data.

Q. Please describe how the Company developed peak reduction targets from solar PV.

A. The peak reduction targets from solar PV were developed based on the Company's solar PV forecast. The Company's peak reduction target setting methodology is provided in Exhibit ___ (EAMP-1).

Q. Did the Company consider an alternative forecasting methodology for peak reduction resulting from solar PV?

A. Yes. The Company considered second order polynomial regression analysis utilizing historical solar PV data. However, the Company rejected this approach because the historical data did not provide a reasonable basis for measuring the Company’s efforts to increase solar PV.

Q. Please describe how the Company developed peak reduction targets from other DG.

A. The peak reduction targets from other DG were based on the Company’s plans to install and operate other DG, including Combined Heat and Power (“CHP”).

Circuit Peak Load Reduction

Q. Please describe the Company’s proposed Circuit Peak Load Reduction metric.

A. The Circuit Peak Load Reduction metric measures the improvement in the load factor of six distribution circuits where such improvement results in system and customer benefits. The metric measures the annual peak load reductions on six distribution circuits compared to their historical peak load. The peak load reductions are based on reductions needed to improve the load factor of the six distribution circuits to match the overall O&R system load factor.

Q. How did the Company select the six distribution circuits?

A. The Company identified six circuits serving load in the Blooming Grove and Warwick areas, where improving load factor would result in maximum customer benefits. Peak reduction or shift of customer usage patterns to off peak usage on these circuits may reduce risk under contingency conditions, and improve operating conditions and potentially result in reliability improvements for these circuits.

Q. Please describe the Company’s plans to implement peak load reduction initiatives in the selected circuits.

A. To achieve the circuit peak load reductions, the Company plans to evaluate implementation of targeted EE and DR programs in the specified circuit areas. Implementation measures may also include battery storage, cooling storage, and DR enablement.

Q. Please describe the Company’s proposed targets for the circuit peak load reductions.

A. The Company proposes to reduce circuit peak load by a maximum of 0.25 MW, 0.92 MW, and 2.43 MW by 2019, 2020, and 2021, respectively. Exhibit ___ (EAMP-1) sets forth the details on the Circuit Peak Load Reduction targets.

Q. Please describe the development of Company's proposed Circuit Peak Load Reduction targets.

A. The Company developed the Circuit Peak Load Reduction targets based on moving the aggregate circuit load factor towards the system load factor. The Company developed its proposed maximum target such that the aggregate circuit load factor becomes equal to the system load factor by 2021. To achieve such load factor improvement, the Company needs to reduce the summer peak load for these circuits by 2.43 MW, which is set as the 2021 target, as discussed above.

<u>DER Utilization</u>

Q. Please describe the Company's proposed DER Utilization metric.

A. The Company's proposed DER Utilization metric measures newly added DER in the Company's service territory. The metric considers all MWhs produced, consumed, discharged, or reduced by DER, including solar PV, battery storage, electric vehicles ("EVs"), and other technologies. The metric measures MWh generated from DER[11] and the MWh consumed for beneficial uses.[12]

Q. Please describe the Company's proposed targets for the DER Utilization metric.

A. The Company proposes a maximum target of 44.3 GWh, 30.3 GWh, and 36.9 GWh of DER utilization in 2019, 2020, and 2021, respectively. The targets will be measured annually at the end of the measurement period. For details on DER Utilization targets, please refer to attached Exhibit ___ (EAMP-1).

Q. Please describe how the Company developed the DER Utilization targets.

A. The Company's proposed DER Utilization targets are based on the projected increase in the DER technologies mentioned above.

Q. How were the DER Utilization targets for solar PV developed?

A. Similar to the peak reduction solar PV targets discussed earlier, the Company developed the DER

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[11] DER MW deployment conversion to MWh: DER (MWh) = [end-of-year MW_{DER}] x 8760 x Capacity Factor (applicable to solar PV, CHP, and Fuel Cells)

[12] DER technologies providing beneficial usage include battery storage, EVs, and thermal storage.

targets for solar PV based on the Company's electric forecasts. The Company's DER Utilization target setting methodology is provided in Exhibit ___ (EAMP-1).

Q. Did the Company consider an alternative forecasting methodology for solar PV?

A. Yes. The Company considered a second order polynomial regression analysis using historical solar PV data. However, the Company rejected this approach because the historical data did not provide a reasonable basis for measuring the Company's efforts to increase solar PV.

Q. How were the DER Utilization targets for EVs developed?

A. The EV DER targets were developed based on the Company's forecast. The Company's DER Utilization target setting methodology is provided in Exhibit ___ (EAMP-1).

Q. Please describe the overall benefits of Company's proposed SE EAM.

A. The Company has developed the SE EAM consistent with the benefits discussed in the REV Track Two Order (pp.

72-73). These include reduction of the need for electric infrastructure investments, achievement of renewable goals, and reduction of carbon emissions. Furthermore, improving load factor of distribution circuits can lead to improved asset use, lower peak hour energy costs, lower peak electric generator emissions, and improved reliability of the distribution system. In the long-term, this could lead to deferral of transmission and distribution ("T&D") infrastructure investment. The DER Utilization metric encourages the Company to work with DER providers and expand the use of DER in its service territory.

Q. Did the Company attempt to quantify the benefits of the SE EAM?

A. Yes. The Company conducted a Benefit-Cost Analysis ("BCA") which generally follows the framework approved by the Commission,[13] and quantified the avoided capacity cost benefits of MW system peak reduction, and distribution circuit peak reduction, as well as

[13] 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").

the wholesale market and carbon emission benefits of the MWH generated from DER. The BCA is discussed in detail later in this testimony.

ENERGY EFFICIENCY EAM

Q. Please describe the metrics related to the Company's proposed EE EAM.

A. The Company proposes two metrics for its EE EAM:(1) MWH Reduction; and (2) Energy Intensity.

MWH Reduction Metric

Q. Please describe the Company's proposed MWH Reduction metric.

A. The MWh Reduction metric is a program-based metric that provides EAM opportunities based on achievement of energy savings (MWh) from the Company's EE programs. The energy savings would be measured using TRM calculations and custom analysis using available site specific data in combination with industry standards. The MWh Reduction metric is consistent with the REV Track Two Order.

Q. Please describe the Company's plans to achieve the MWH Reduction metric.

A. The Company plans to achieve the MWH Reduction Metric through its ETIP program, as well as the proposed expansion of the EE program to assist in meeting the CES and State Energy Plan.

The Company's programs are discussed in detail in the direct testimony of the Company's EE Panel.

Q. Please describe the Company's proposed targets for the MWH Reduction metric.

A. The proposed targets are designed consistent with the objectives of the CES and the State Energy Plan. The proposed target for 2019 of 24.5 GWh is based on the Company's existing ETIP goals, with resulting increases in MWh from new initiatives. The measurement will be based on the energy reduction projects installed during the calendar year. The Company proposes to expand its energy savings over three years to 37.4 GWh in 2021. For further details on the MWh Reduction targets please refer to Exhibit ___ (EAMP-1).

Energy Intensity

Q. Please describe the Company’s proposed Energy Intensity metric.

A. The Company is proposing Energy Intensity as an outcome-based metric that measures energy savings from all initiatives, including those offered by the Company, New York State Energy Research and Development (“NYSERDA”), and third-party market participants, as well as other customer initiatives. This metric measures the effectiveness of O&R’s EE behavioral programs in steering its customers towards a culture of energy conservation, which would result in a “market transformation” outcome as envisioned by the Commission’s REV Track Two Order.[14]

Q. Is the Company proposing separate energy intensity metrics for different customer segments?

[14] As the Commission discussed in the REV Track Two Order (p. 79), “Efficiency incentives should serve our strategic goals of phasing down surcharge-funded resource acquisition programs and increasing market transformation achievements, including both targeted efficiency that is enabled by newly monetized value streams and transactional platforms, and also efficiency implemented by customers and third-party market participants with a reduced need for direct utility support.”

A. Yes. Because the Company's EE programs are tailored towards different customer segments, *i.e*. residential and commercial, the Company is proposing separate energy intensity metrics for these customer segments.[15] The residential energy intensity will measure reductions in residential kWh per customer. The commercial energy intensity metric will measure reduction in commercial kWh per employee.[16]

Q. Please describe the calculation of Residential Energy Intensity.

A. Residential Energy Intensity is calculated as: Weather- and Billing Days-Normalized[17] billed usage for the Residential Class (Service Classification ("SC") No 1) divided by the number of Residential customers. Billed usage will be adjusted for Community DG and

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[15] Residential customers include all residential SC No. 1; and commercial SC No. 2 customers include all private non-manufacturing employees.

[16] Employment data used is Private Non-Manufacturing ("PNM") Employment. PNM data is developed using Bureau of Labor Statistics data and Moody's Analytics forecasts for Orange and Rockland Counties.

[17] For the calculation of energy intensity each year, weather normalized ("WN") annual energy usage data will be used. The Normalization model is based on fixed coefficients for independent variables. Normal weather is the 10-year normal HDDs and CDDs for the year ended 2016. Coefficients were developed using econometric time series regression with modeling period from the first quarter of 1990 to the third quarter of 2017.

beneficial uses for EVs, battery storage, thermal storage, and heat pumps.

Q. Please describe the calculation of Commercial Energy Intensity.

A. Commercial Energy Intensity is calculated as: Weather- and Billing Days- Normalized (calculated in the same manner as for Residential Energy Intensity) billed usage for the Commercial Class (SC No. 2) divided by the number of employees in Orange and Rockland counties. Billed usage will be adjusted for Community DG and beneficial uses for EVs, battery storage, thermal storage, and heat pumps.

Q. Please describe the Company’s proposed targets for the Energy Intensity metric.

A. The Energy Intensity targets are set as a percentage decrease in energy usage per customer and per employee for the residential and commercial classes, respectively. For residential, the Company proposes a maximum target based on a year-over-year reduction in Energy Intensity of 0.83 percent in 2019, increasing to 1.31 percent in 2021. For commercial, the Company proposes a maximum target based on a year-over-year reduction in Energy Intensity of 0.79 percent in 2019, increasing to 1.27 percent in 2021.

Q. Please describe the development of the Company's proposed energy intensity targets.

A. The Company established the Energy Intensity targets in three steps.

First, the Company determined an appropriate trend line based on the Company's experience. The Company determined the trend line based on a quarterly rolling average of the Company's forecasted energy usage data from 2019 to 2021.

Second, the Company calculated the standard error of the historical and forecast data.

Third, the Company established performance targets such that at the *minimum level*, the energy intensity is equal to the trend, at the *target level*, the energy intensity is below the trend by 0.25 standard error, and at the *maximum level*, the energy intensity is below the trend by 0.50 standard error. The targets also consider the energy savings related to the expanded EE programs. The Company's target setting methodology is detailed in Exhibit ___ (EAMP-1).

Q. Please describe the benefits of Company’s proposed EE EAM.

A. The REV Track Two Order (pp. 79-83) identified EE EAM as critical to achieving the objectives of REV. Incremental energy savings help reduce customer bills, both through reduced energy usage costs for customers, as well as reduced potential capacity costs related to peak demand periods. The expansion of EE programs also raises customer awareness of the benefits to be derived from the efficient use of energy. Moreover, reduced energy usage provides broad environmental benefits including reduced carbon emissions and greenhouse gases. The Energy Intensity metric encourages the Company to work with third parties and customers to promote a culture of energy conservation.

Q. Did the Company attempt to quantify the benefits of the EE EAM?

A. Yes. The Company quantified the benefits achieved through the programs associated with the EE EAM. As discussed earlier, the Company conducted a BCA that quantified the wholesale market and carbon emission benefits of MWH savings achieved from the programs designed to achieve the two EE EAM metrics. The BCA is discussed in detail later in this testimony.

INTERCONNECTION EAM

Q. Please describe the metrics related to the Company's proposed IEAM.

A. The Company proposes Applicant Satisfaction as the metric for the IEAM. Consistent with the Commission's order,[18] and the subsequent JU Filing,[19] the Company proposes that the SIR Timeliness be considered a 'threshold condition' to qualify for the IEAM earning opportunity. The timeliness threshold would be linked to three key steps during the SIR process: (1) the 10-business day requirement to review and determine application completeness; (2) the 15-business day requirement to complete the preliminary screening; and

[18] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Directing Modifications to the Joint Utilities' Proposed Interconnection Earning Adjustment Mechanism Framework (issued March 3, 2017).

[19] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Modified Interconnection Survey Process and Proposed Earning Adjustment Mechanism of the Joint Utilities (filed May 8, 2017)("JU Filing").

(3) the 60- or 80-business day requirement to complete the Coordinated Electric System Interconnection Review ("CESIR"). The Company also proposes, consistent with the JU Filing, that the timeliness threshold metric have a 100 percent compliance requirement subject to adjustment for events that are beyond utility control (*e.g.*, major storms or applicant-driven delays). The Company proposes to track SIR Timeliness as a scorecard metric, as discussed later in this testimony.

Applicant Satisfaction

Q. Please describe the Company's proposed Applicant Satisfaction metric.

A. The Applicant Satisfaction metric will be based on the survey results at two points during the interconnection process: the mid-point survey upon applicant's receipt of the utility preliminary review and the completion survey upon energization of the project. The Company also notes that, consistent with the JU Filing, the survey questionnaires will contain a core set of questions that are applicable to all the JUs and are the basis for the earnings opportunity.

The satisfaction survey was developed by the JUs, with the assistance of a stakeholder collaborative, and filed with the Commission.[20] Survey questions that are measured and included in the metric allow for a maximum satisfaction score of 100.

Q. Please describe the Company's proposed Applicant Satisfaction targets.

A. The Company proposes that the baseline for the Applicant Satisfaction metric be set by using the results of the JUs' initial survey process, which is currently underway. The performance targets would be set through a collaborative process with stakeholder parties.

Q. Please describe the benefits of having an Interconnection EAM.

A. The Company's efforts in achieving the IEAM will result in improvement in the DG interconnection process that is integral to the expansion and market development of DER, and achievement of REV objectives.

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[20] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Joint Utilities Supplemental IEAM Survey Instrument (filed August 28, 2017).

The IEAM will allow the Company to further align its interests with those of DER stakeholders in an increasingly effective manner.

AMI CUSTOMER ENGAGEMENT EAM

Q. Please describe Company's proposed AMI Customer Engagement EAM.

A. The Company proposes three outcome-based metrics for the AMI Customer Engagement EAM: (1) Customer Awareness; (2) Weekly AMI ("WAMI") report email enrollment; and (3) HBA text message enrollment.

Q. Please provide some background on the Company's AMI EAM proposal.

A. An important component of the Company's AMI initiative is engagement with customers and third parties to help educate and take advantage of the benefits of the Company's AMI program.

As required by the Commission's AMI Order, O&R with its affiliate Con Edison (collectively, "the Companies"), jointly prepared and submitted their AMI Customer Engagement Plan to the Commission in July

2016. This Plan reflects a customer-centric, collaborative strategy resulting from the Companies' research, customer surveys, benchmarking with peer utilities, and collaboration with third-party stakeholders. The Companies developed an engagement platform so that customers receive messages consistent with their preferences, and third parties receive messages that enable them to participate in animating the DSP market. In executing this Plan, the Companies will encourage adoption of AMI and provide customers with resources to better manage their energy usage and costs. During and beyond the AMI rollout, the Companies will continue to identify opportunities to engage customers and third parties, and to improve customer and community relations.

Customer education provides the foundation to prepare customers for AMI meter installation and to take advantage of immediate AMI-enabled benefits and future benefits as new market opportunities are introduced. In order to track the Company's success in AMI customer engagement, the Company proposes an AMI EAM that measures the improvement in customer awareness of AMI features, benefits, and technology.

Customer Awareness

Q. Please describe the Customer Awareness metric of the AMI EAM.

A. The Customer Awareness metric is focused on measuring the Company's efforts to promote customer awareness of AMI technology, features and benefits.

Q. How will the Company measure the customer awareness of AMI?

A. The Company's performance in promoting AMI customer awareness will be based on surveys of customers in two deployment areas (Rockland County and Orange/Sullivan Counties). The Company conducted an initial survey in September 2016, prior to the deployment of AMI, to establish a baseline of customer awareness related to AMI. Based on the initial survey results, 67 percent of respondents were not aware of AMI or Smart Meters.

Accordingly, the Company established a baseline of 33 percent customer awareness.[21]

During the roll-out of AMI enabled meters, the Company will conduct one survey in each deployment area. This mid-deployment survey will be conducted in Rockland County in 2018, and in Orange and Sullivan Counties in 2019. These surveys will include only customers that have had AMI meters installed. In these surveys, the Company will measure the AMI awareness of customers based on the customer's general familiarity with Smart Meters and their functionality.

In June 2020, the Company will conduct a post-deployment survey in each of the two deployment areas. The survey will include only customers that have had AMI meters installed and were not contacted in the first survey. The post-deployment survey will measure customer awareness of AMI benefits.

All surveys will be conducted by an independent third-party and will consist of at least 200 phone surveys

[21] When asked, 'How familiar are you with Smart Meters?' 33 percent of surveyed customers responded with either "I have heard of Smart Meters, and I am familiar with their function" or "I have heard of Smart Meters, but I am not very familiar with their function."

and 200 online surveys. The Company will provide the results of the surveys as part of its AMI scorecard metrics reporting.

Q. What are the Company's proposed targets for the AMI Customer Awareness Metric?

A. The AMI Customer Awareness targets were set based on the results of Company's recent AMI surveys and industry experience. The Company proposes to increase the customer awareness from 33 percent in 2016, to a maximum of 68 percent in the mid-deployment surveys of 2018 and 2019. The Company proposes to maintain the targets at 68 percent in 2020 since industry experience shows declining AMI customer awareness post deployment. The proposed target is applicable to each of the two deployment areas. For details on AMI customer awareness targets, please refer to Exhibit ___ (EAMP-1).

<u>WAMI and HBA Enrollment</u>

Q. Please describe the WAMI report email, and the HBA text message enrollment metrics as part of AMI EAM.

A. The two additional outcome-based metrics are proposed to measure the Company’s efforts to influence customers to take better control of their monthly bills and energy usage. These enrollment metrics will measure the percentage of AMI customers that opt-in to receive the WAMI email and HBA text messaging in a given rate year as compared to industry benchmarks.

Q. What is the Company’s proposal on the targets for the WAMI report email and the HBA text message enrollment metrics?

A. The proposed targets are set based on the percentage of total AMI customer installations in the twelve months prior to July 1 in a given year, that decide to enroll in these AMI services. The Company set a baseline for the two metrics based on vendor experience of 1.0 percent participation for opt-in AMI programs.[22] The Company proposes targets of 1.0 percent, 2.0 percent, and 3.0 percent for minimum, target, and maximum levels, respectively each year

[22] The benchmark was set in collaboration with Company’s AMI engagement vendor, Opower.

from 2019 to 2021. For details on AMI EAM targets, please refer to Exhibit ___ (EAMP-1).

Q. What are the benefits associated with the AMI EAM?

A. AMI helps enable the Company to fulfill the REV objectives of providing products, technology, and incentives that allow customers to participate actively in energy markets and take control of their monthly bills. With the appropriate data systems and web presentment in place, customers will have the opportunity to leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions.

BENEFIT-COST ANALYSIS

Q. Please describe the results of the BCA performed by Company for its EAM proposal.

A. The Company's BCA shows that the EAMs provide significant customer benefits[23]. Specifically, if the Company achieves the maximum targets associated with

[23] The BCA benefits calculation does not include the benefits associated with Interconnection or AMI metrics.

its above-described EAM proposal, the net benefits would be $116.0 million with a Benefit-Cost ratio of 1.9. If the Company achieves the mid-point targets, the net benefits would be $99.5 million with a Benefit-Cost ratio of 1.8. If the Company achieves the minimum targets, the net benefits would be $82.2 million with a Benefit-Cost ratio of 1.7. The detailed results for the BCA are included in Exhibit ___ (EAMP-2).

Q. Please describe the Company's methodology for conducting the BCA for its EAMs.

A. The Company's BCA is generally consistent with the BCA Order and the BCA Handbook filed by the Company.[24] The analysis captures the major societal benefits gained through system peak reduction, addition of DER, and energy savings. The analysis also considers the costs to achieve the benefits including the program administration costs, and DER participant costs.

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[24] Case 16-M-0412, *In the Matter of Benefit Cost Analysis Handbooks*, Orange & Rockland Benefit Cost Analysis Handbook, Revised August 22, 2016.

Q. Please discuss in more detail the benefits considered in Company's BCA.

A. The Company considered key benefits in the BCA, including avoided generation costs, avoided T&D costs, avoided energy costs, and avoided carbon emissions. Avoided generation and avoided T&D benefits result from MW peak load reductions that the Company achieves through its peak load reduction and circuit peak load reduction targets. Avoided generation capacity costs ("AGCC") are based on the forecast of capacity prices for the wholesale market provided by Staff,[25] while avoided T&D benefits are based on the Company's most recent marginal cost of service study that estimates the marginal T&D investments needed to serve one kW of system peak load.[26]

Avoided energy and avoided carbon emissions benefits result from the reduction in MWH energy usage through Company's EE and DER initiatives. The avoided energy benefit is based on the NYISO forecast of annual

[25] Case 14-M-0101, BCA Att A 2017 (filed August 15, 2017).
[26] As discussed in the direct testimony of the Company's Demand Analysis and Cost of Service Panel.

Locational Based Marginal Price ("LBMP"),[27] and the avoided carbon emissions benefit is based on the NYSERDA Tier 1 Renewable Energy Credit ("REC") procurement price of $24.24 per MWh. The benefits considered in the BCA are provided in Exhibit ___ (EAMP-2).

Q. Please discuss the costs considered in the Company's BCA.

A. The two major costs considered in the BCA are program administration costs and DER participant costs. Program administration costs include the Company's ETIP budget, the incremental EE budget proposed in this rate case proceeding,[28] the Company's annual DR program costs, and battery installation costs. DER participant costs include solar PV and CHP capital investment and O&M costs. The costs considered in the BCA are provided in Exhibit ___ (EAMP-2).

Q. Please describe how the targets were considered for calculation of benefits in the Company's BCA.

[27] NYISO 2016 CARIS 2 Average LBMPs report.
[28] As discussed in the direct testimony of the Company's EE Panel.

A. The Company calculated the benefits for the BCA so as not to double count the benefits for the outcome-based metrics. Specifically, the Company removed the circuit peak load reduction targets from the total system peak load reduction targets, so that they are not counted twice. Similarly to avoid a double count, the Company removed the Company’s new EE programs’ MWH savings from the energy intensity targets, and only considered the incremental savings from energy intensity initiatives.

EAM ALLOCATION STRUCTURE

Q. Please describe how the Company proposes to allocate the earnings opportunities across its proposed EAMs.

A. As discussed earlier, the Company proposes earnings opportunities of up to 100 basis points each year tied directly to the achievement of predefined EAM metrics. As set forth in Table 1 above, the 100 basis points are assigned to individual EAM metrics. For each EAM metric, the Company can achieve different earnings opportunities for minimum, target, and maximum achievement levels.

Q. What was the Company’s approach to assigning earnings opportunities to the proposed EAMs?

A. The Company’s approach to assigning earnings opportunities to the proposed EAMs generally followed the results of the BCA.

Q. Please describe how the BCA results were used to develop the proposed earnings opportunities at minimum, target, and maximum achievement levels.

A. The proposed earnings opportunities at minimum, target, and maximum achievement levels were based on the net benefits at each achievement level. As discussed earlier, the Company’s BCA resulted in net benefits of $82.2 million at minimum, $99.5 million at target, and $116.0 million at maximum achievement levels. Thus, the proposed basis points at minimum, target and maximum achievement were 70.0, 85.0 and 100.0 basis points, respectively. The proposed earnings opportunities on a net present value basis are approximately 13.0 percent of net benefits at each target achievement level.

Q. Please describe how the BCA results were used to develop the earnings opportunities for each EAM metric.

A. The proposed earnings opportunities for each EAM metric were based on the relative benefit of each EAM metric. The first step was to assign specific earnings opportunities at each achievement level for Interconnection of 0.5, 3.0 and 5.0 basis points and for AMI Customer Engagement of 2.5, 5.0 and 10.0 basis points at the minimum, target and maximum achievement levels, respectively. The remaining earnings opportunities at the minimum, target and maximum achievement level were then generally assigned based on the relative benefit of each EAM metric at each achievement level. The earning opportunity proposal is included in Exhibit ___ (EAMP-3).

REPORTING AND EVALUATION

Q. How does the Company propose to report performance regarding its EAM targets?

A. The Company proposes to measure and report EAMs on a calendar year basis. On March 31 of 2020, 2021, and 2022, the Company will submit a report to the Commission on its previous calendar year's performance in relation to the targets. These reports will include a discussion of its earned EAMs, if applicable.

Q. Is the Company proposing any evaluation and review of EAMs through the rate period?

A. Yes. The Company proposes to perform an evaluation and review by June 1, 2020 to determine if any changes or modifications to the EAMs may be warranted. The Company will submit a report of such review and evaluation to the Commission.

COST RECOVERY

Q. How does the Company propose to recover the earned EAMs?

A. The Company proposes to collect earned EAMs through the Company's Energy Cost Adjustment mechanism in the following 12-month period. Such collection will commence on June 1 following the Company's filing of its EAM performance report, if the Commission takes no action by June 1st. The EAMs may be subject to adjustment if the Commission determines that the Company’s calculations should be revised. For further discussion regarding EAM recovery, please refer to the direct testimony of the Company’s Electric Rate Panel.

SCORECARD

Q. Is the Company proposing any Scorecard metrics?

A. The Company proposes to use the technical forum discussed earlier in this testimony, to initiate discussion on the Scorecard metrics with a goal of reaching consensus with Staff and interested stakeholders on the data sources and targets for the metrics. As an initial proposal, the Company recommends establishing the following Scorecard metrics:

- Voluntary time-of-use rate participation;
- Electric vehicle rate participation; and
- SIR timeliness.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.

ENERGY EFFICIENCY PANEL – ELECTRIC/GAS

Table of Contents

Introduction

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

A. **(Kennedy)** My name is Donald Kennedy and my business address is One Blue Hill Plaza, Pearl River, New York 10965.

(Cigliano) My name is Charmaine Cigliano and my business address is One Blue Hill Plaza, Pearl River, New York 10965.

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

A. **(Kennedy)** I am the Director of Customer Energy Services.

(Cigliano) I am the Section Manager of Customer Energy Services.

Q. Please describe your educational backgrounds.

A. **(Kennedy)** In 1998, I graduated from the State University of New York, Rockland Community College with an Associate Degree in Math and Science. In 2002, I graduated from the State University of New York with a Bachelor of Science in Business Administration. In 2010, I graduated from Walden University with a Masters of Business Administration.

(Cigliano) I received a Bachelor of Science degree from Binghamton University in 1988 with a double major in Mathematics and Computer Science.

Q. Please describe your work experiences.

A. **(Kennedy)** I joined the Company in 1981 as a Meter Reader. I have since held the positions of Supervisor - Meter Reading, Senior Supervisor – Customer Accounting, Manager – Customer Accounting, Manager - Customer Assistance, Director of Customer Assistance, and Director of New Construction Services prior to my present position.

(Cigliano) My first employment after completing my education was with Orange and Rockland as an Analyst with the Economic Research Department where I held positions of increasing responsibility. In 1998, as a result of the merger between Con Edison and O&R, I was offered a position as a Senior Planning Analyst in Con Edison’s Electric Forecasting Department. In 1999, I accepted a Senior Planning Analyst position in Con

Edison’s Rate Engineering Department. In 2000, I returned to O&R as the Customer Information Management System Billing Team Lead. In 2004 I was promoted to Manager of Retail Access. In 2008, I was promoted to Section Manager - Customer Energy Services.

Q. Do you belong to any professional organizations?

A. **(Kennedy)** I am a member of the Association for Energy Services Professionals (“AESP”). AESP is a dynamic community of energy efficiency professionals dedicated to advancing the industry through professional development, networking and advocating for a resilient, sustainable energy future in North America.

(Cigliano) I am a member of the Board of Directors for AESP.

Q. Please generally describe your current responsibilities.

A. **(Kennedy)** I am responsible for the oversight of energy efficiency, demand response, and Solar Renewable Energy Credit programs in New Jersey, retail choice, and low income programs for the Company and its utility subsidiary, Rockland Electric Company. I am also responsible for administration of the Customer

Engagement and Marketplace Platform ("CEMP") Reforming the Energy Vison ("REV") Demonstration project.

(Cigliano) I am responsible for the design, implementation and evaluation of O&R's portfolio of energy efficiency, demand response, targeted demand-side management ("DSM"), renewables (New Jersey) and low-income programs. I have been a member of the Implementation Advisory Group, the Evaluation Advisory Group and the E2 Advisory Group. I am currently a member of the Clean Energy Implementation and Coordination Group.

Q. Have you previously testified before the New York Public Service Commission ("Commission") or other regulatory bodies on energy matters?

A. **(Kennedy)** Yes, I submitted testimony in the Company's last electric base rate case, Case 14-E-0493. I also submitted testimony on behalf of the Company's New Jersey affiliate, Rockland Electric Company, in NJBPU Docket Nos. ER13060535 and ER17080869.

(Cigliano) Yes, I have submitted testimony in Cases 11-E-0408 and 14-E-0493.

Purpose

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

A. The purpose of the Panel’s testimony is to describe the Company’s existing energy efficiency programs that are offered via its Energy Efficiency Transition Implementation Plan (“ETIP”), as well as its proposed new program offerings. The Panel will describe how these new program offerings will build upon the foundation of the Company’s existing ETIP programs.

Expansion of Energy Efficiency Programs

Q. Please discuss the Company’s proposal to expand its portfolio of energy efficiency programs.

A. The Company is proposing to expand the portfolio of energy efficiency programs it offers to electric and gas customers. The expansion of the electric programs supports the goals of the Commission’s Clean Energy Standard Order.[1] The Commission adopted the State Energy Plan (“SEP”) goal that 50% of New York’s

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[1] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Order Adopting a Clean Energy Standard (issued August 1, 2016) (“Clean Energy Standard Order”). Expansion of the gas energy efficiency programs is also consistent with the State Energy Plan and Clean Energy Standard goals of reducing greenhouse gas emissions.

electricity is to be generated by renewable sources by 2030 as part of the strategy to reduce statewide greenhouse gas emissions by 40% by 2030. The Commission also adopted a Clean Energy Standard ("CES") consistent with the SEP goal. The Company's goal is to expand its existing ETIP energy efficiency offerings and to introduce new programs that would increase the adoption of new energy efficiency and related technologies.

More specifically, the expanded energy efficiency programs will support initiatives outlined in the SEP such as:

- 40% reduction in greenhouse gas emissions from 1990 levels;
- 50% of energy generation from renewable energy sources; and
- 600 trillion BTU increase in statewide energy efficiency.

To meet the state policy goals of (1) generating 50% of New York's electric supply by renewable sources by 2030, and (2) reducing statewide greenhouse gas emissions by 40% by 2030, statewide energy use must decline by 2,227 GWh annually. As such, utility ETIP programs would need to reduce approximately 1.2% of sales for the period of 2017-2020, 1.4% of sales from 2021-2025, and the 2.0% of sales from 2026-2030 to meet the annual reduction target of 2,227 GWh. The Company's current annual ETIP program represents approximately 0.5% of 2015 energy sales, therefore efforts will need to increase by 240% to achieve these goals.

In order to support the SEP and REV initiatives, the Company proposes to expand the energy efficiency programs currently implemented in the Company's ETIP by providing new program offerings. As discussed in the direct testimony of the Company's Accounting Panel, the Company proposes to recover the costs of its existing ETIP programs, as well as the costs of its proposed expanded ETIP programs, through base rates.

Current ETIP Portfolio

Q. Please describe the Company's current ETIP portfolio.

A. The Company's current ETIP portfolio consists of three electric programs and one gas program targeting MWh and Dth reductions, respectively. The Company’s ETIP portfolio has programs targeting both residential and commercial and industrial (“C&I”) customers. The ETIP portfolio includes the following four programs:

1. Residential Efficient Products Program;
2. Small Business Direct Install Program;
3. C&I Electric Rebate Program; and
4. Residential Gas Rebate Program.

The 2012 – 2016 annual electric portfolio budget of $6.3 million has an associated target of 19,302 MWh of savings, at an overall cost of $326/MWh. For the 2012-2015 program period, once all projects currently underway are installed, the Company will exceed 100% of the electric portfolio goals on an achieved and committed project basis while spending $19.4 million, at an overall cost of $251/MWh.

The annual gas portfolio budget of $537,000 has an associated target of 14,691 Dth of savings, at an overall cost of $37/Dth. For the 2012-2015 program period, the Company has achieved 103% of its gas target while spending $2.0 million, at an overall cost of $34/Dth.

Q. Please describe the Company's Residential Efficient Products Program.

A. This program provides rebates for residential customers that purchase ENERGY STAR® appliances upgrades, as well as arranging for the recycling of replaced and secondary refrigerators, freezers and room air conditioners. This program supports the promotion and sale of high efficiency appliances by providing cash incentives for products with efficiency levels that meet or exceed ENERGY STAR® specifications. Product incentives are offered directly to customers as a rebate and local contractors are informed of eligible appliances at regular update meetings and through other periodic communications. The Company has begun to integrate energy efficiency and demand response initiatives to provide for a more streamlined customer experience, particularly for those customers using the Company's Online Marketplace (which is described in greater detail by the Customer Service Panel). By offering products from the Company's Efficient Products Program though O&R's Marketplace, customers are able to apply for instant rebates at checkout, as opposed to filling out a rebate application and waiting 4-6 weeks for a rebate check.

Q. Please describe the Small Business Direct Install Program.

A. This program provides businesses with energy efficiency solutions in the hard-to-reach small business market segment. This program provides a turn-key streamlined customer experience to business customers with an average monthly peak demand of less than 110 kW. After the completion of a free on-site audit performed by the Company’s contractor, an easy to understand audit report is provided that contains recommendations specific to that customer’s needs and a simple payback timeline for the recommended investment. This program covers up to 70% of the installed cost of a measure and targets lighting, refrigeration, and cooling end-uses. Customers may apply for short-term, no-interest financing offered by the vendor for the remaining 30% of the installed cost of a measure so that their revenue stream is net positive upon installation as a result of their bill savings. The Company continues to integrate its energy efficiency message across the portfolio of electric programs and across market demand response initiatives to business customers.

Q. Please describe the C&I Electric Rebate Program.

A. This program provides prescriptive and custom rebates to encourage C&I customers to identify energy saving opportunities, develop a building performance improvement plan, and implement cost-effective retrofit upgrade projects. The program includes rebates for high efficiency lighting and controls, HVAC measures and variable speed drives, along with rebates for custom efficiency projects. The custom portion of the program provides rebates for projects that do not fall into the prescriptive category but provide significant savings for industrial processes, building management systems, and other technologies beyond traditional lighting and HVAC upgrades. Energy efficiency messaging is tailored to cross-market demand response initiatives to C&I customers.

Q. Please describe the Residential Gas Rebate Program.

A. This program provides incentives to customers who purchase energy efficient natural gas space and/or water heating equipment for their residences. The Company engages with the HVAC contractor community to assist in promoting the benefits of upgrading to high efficiency space and/or water heating equipment and supports the stocking of high efficiency equipment. Similar to the Residential Efficient Products Program described above, these gas rebates are coordinated with the MY ORU Store (which is described in greater detail by the Company’s Customer Service Panel), to engage customers to also purchase low flow devices at rebated pricing.

Q. Please describe how the Company currently recovers the costs of its existing ETIP programs.

A. Currently, the funding for the ETIP electric portfolio is $6.3 million and $537,000 for the ETIP gas portfolio. The Company recovers the cost of its electric programs through the Energy Cost Adjustment (“ECA”) and the costs for its gas program through the Monthly Gas Adjustment (“MGA”) surcharge. Program costs include administration, marketing, incentives and rebates, implementation, and evaluation.

Q. Is the Company proposing any modifications to how it recovers the cost of its existing ETIP programs?

A. Yes, the Company proposes to transfer these program costs, as well as the costs of the proposed new ETIP programs described below, into base rates. The Company would recover these costs, including its approved rate of return on these costs, over a three-year period, as described in the Accounting Panel’s testimony. The payroll costs for 8.0 positions, in the amount of $718,000 annually, to administer the programs were incorporated into base rates in the Company’s last electric base rate case (Case 14-E-0493). At that time, the payroll associated with an additional 2.5 positions continued to be recovered through the ECA surcharge. In this electric base rate filing, the Company proposes to transfer the payroll costs of the remaining 2.5 positions, in the amount of $225,000 annually, from the ECA surcharge into base rates.

Proposed New ETIP Program Offerings

Residential

Q. Please discuss the Company's proposed new residential energy efficiency initiatives.

A. The Company is proposing to introduce the following four new energy efficiency programs for residential customers:

1. Residential Marketplace Enhancement Program;
2. Residential Behavioral Software and Education Program;
3. Residential New Construction Program & Home Performance; and
4. Residential Upstream Lighting Program.

Q. Please describe the Company's proposed Residential Marketplace Enhancement Program.

A. The Company proposes to expand its existing Residential Efficient Products and Gas Rebate Programs to better integrate them into the MY ORU STORE. This integration will allow the Company to promote energy efficiency upgrades and establish a one-stop shopping experience, including instant rebates, which will make purchasing energy efficient equipment quick and seamless. Use of the MY ORU STORE will eliminate the market barriers of higher upfront purchase costs and provide customers with instant rebates, access to product information, and various manufacturer product services and offerings. Instant rebates will be expanded to include larger appliances such as central air conditioning, heat pumps, mini splits, pool pumps, dishwashers, washing machines, furnaces, boilers, water heaters, and refrigerators.

Behavioral software analytics will also be integrated into the MY ORU STORE messaging to provide customers with a web-based platform that analyzes customer-specific energy data and demographics to help customers better manage their energy use. For example, recommendations for no cost or low cost upgrades will be provided along with suggestions for potential longer-term energy upgrade investments. Customers can then compare payback scenarios for investing in different types of energy efficient products or upgrades. Customers will also be able to compare bill and/or energy savings and better understand the value proposition of investing in products and services that may have a higher upfront cost and may provide for bill savings over a longer period of time. Examples of this type of equipment include, but are not limited to, products and services that integrate renewable energy products with energy storage backup systems and HVAC upgrades. Customers will also be provided instant rebates to install products and have the ability to select an installer that best meets their needs via the MY ORU STORE. The Company will explore new and innovative ways that customers can more readily participate in programs and pay for energy upgrades through a combination of low interest financing and bill savings. DER service providers will be encouraged to offer energy efficiency upgrades to customers through a pay-for-performance or financing arrangement, where the upgrades are paid for using actual bill savings over time. Such an arrangement will reduce or eliminate upfront costs to customers.

Q. Please describe the Company’s proposed Residential Behavioral Software and Education Program.

A. The Company proposes to leverage MY ORU STORE as the platform to implement a residential behavioral program to further engage all residential customers to manage their energy use. The Company also proposes to employ gamification (*i.e.,* the application of elements of game playing – such as accumulating reward points and competing with others online - to encourage engagement with a product or service) to further encourage energy efficient and demand response behaviors. All residential customers will have the ability to enroll in this behavioral platform and receive messaging via mobile device and/or computer to participate in overall energy reduction or peak system events. The behavioral messaging will target both electric and gas energy behaviors, as the majority of the Company's customers are dual fuel electric/gas customers. Engaging more customers on a personalized level reinforces the energy savings impact by modifying energy behaviors and provides customers with the ability to better manage their overall energy use. Customers will also be more informed about their ability to realize additional energy savings by shifting load to off peak hours through time-of-use rates. The behavioral platform will be integrated with the other energy efficiency and demand response programs to increase participation and customer satisfaction by validating energy savings over time, and after specific measures are installed.

The Company will also collaborate with the local water utility, SUEZ, to promote both energy and water conservation via school programs that engage students from kindergarten to high school through classroom instruction. The Company will provide take home energy savings kits to students who can engage with parents to install the kits and begin saving energy. To further enhance the energy savings messaging, as part of their curriculum, students will be encouraged to enroll in the behavioral software platform so that the students can monitor how they use energy and track their savings over time.

Q. Please describe the Company’s proposed Residential New Construction Home Performance Program.

A. In partnership with the New York State Energy Research and Development Authority’s (“NYSERDA”) existing lowrise new construction program, the Company will identify and promote new construction and home performance energy efficiency opportunities in the residential market. By offering new construction and home performance incentives, the program will capture otherwise lost opportunities as it encourages energy efficiency from building inception and renovations. Incentives will be coordinated with NYSERDA and be offered to builders and customers to encourage building to the New York ENERGY STAR® Certified Homes standard and beyond to achieve maximum economic efficiency.

Demand response and energy efficiency can be incorporated into the home, such as efficient lighting and smart thermostats, which will make it easier for the resident(s) in these homes to respond to price signals and better manage energy use. With education and increased awareness, residential builders and customers may begin to realize the long-term energy savings value of an ENERGY STAR® Certified Home and be willing to pay a higher purchase price for that home. The Company will coordinate with local municipalities to drive new construction building requirements beyond existing levels and employ incentives to offset the higher cost of construction. In addition, to assist with the Company's carbon reduction initiative, builders will be incentivized to install ground source and air source heat pumps in areas that do not have access to natural gas facilities to provide for efficient heating and cooling. The Company will pay incentives directly to builders to offset some of the added cost associated with building to a higher energy standard (also renovations). O&R will also coordinate with NYSERDA for additional construction incentives.

Q. Please describe the Company's plans to implement a Residential Upstream Lighting Program.

A. The Company will increase its efforts to partner with NYSERDA, trade allies, retailers, distributors and other utilities to implement an upstream lighting initiative for residential customers. Market transformation through a managed upstream approach will develop and enhance relationships with trade allies, distributors, contractors, and retailers through cooperative marketing and outreach efforts.

This program will provide point of sale rebates for light-emitting diode ("LED") bulbs at the retail level. Distributors, retailers and the Company will engage in co-branding efforts to promote efficient LED lighting and introduce incentives to buy down the cost of LED lighting at the point of purchase. By providing upstream rebates to electric distributors to buy down the cost of energy efficient measures, the Company will begin to transform the market so that the energy efficient products on retailor shelves are at an affordable price point. Program incentives are provided directly to the distributor or retailor so that these measures become the recommended solution as opposed to a less efficient, less costly measure.

Commercial and Industrial

Q. Is the Company proposing to implement any new C&I efficiency initiatives?

A. Yes, the Company is proposing to implement a number of new programs targeting C&I customers including:

1. Commercial Software Data Analytics and Education Program;
2. Commercial Midstream Lighting Program;

3. Commercial Demand Reduction Program;
4. Commercial New Construction Program; and
5. Energy Efficiency Provider Solicitation Program.

Q. Please describe the proposed Commercial Software Data Analytics and Education Program.

A. Through this program the Company will use monthly and hourly usage data and software analytics to deliver energy saving insights to C&I customers that are on a real-time pricing rate. These insights will accelerate and expand the adoption of energy efficient upgrades, optimize energy efficiency and demand response programs, and boost customer engagement and satisfaction. In addition, the integration of software data analytics, which are specifically designed to analyze individual customer facilities to determine cost and savings associated with energy efficiency improvements, will provide a customer platform that supports the utility's role as a trusted energy advisor. Internal program staff will use hourly meter data and software analytics to target C&I customers and provide a detailed view of their energy usage as well as insights and personalized energy efficiency recommendations to drive efficiency. These customized reports will help C&I customers identify equipment that could potentially be upgraded if the savings from lower cost efficiency measures are used to offset the cost of more expensive energy savings measures. This more holistic and analytical approach will generate deeper savings beyond lighting, as customers will have the information they need to develop long-term plans to implement cost effective energy savings.

Customers with robust paybacks will be targeted initially and on-site visits will be scheduled with facility managers to encourage participation in existing programs. Program Administrators will use these analytical tools to demonstrate how energy efficient measures can be implemented and funded through direct bill savings. They will then engage C&I customers to develop an energy plan to address all facility end-uses where the potential for energy savings exists.

Informed customers are engaged customers, and engaged customers represent an opportunity to enlist partners in achieving energy savings goals and managing peak demand through the communication of data, analytics, and load management programs. The Company will also facilitate the potential of pairing customers with low-interest financing options available through NYSERDA’s Green Bank, the New York Power Authority (“NYPA”), or other financial institutions. Low cost financing will accelerate the installation of all cost effective energy savings and should increase energy savings by enabling customers to move beyond lighting and invest in more sophisticated equipment to obtain more significant energy savings.

Q. Does the Company propose to offer incentives for advanced energy efficiency and other technologies in the C&I sector?

A. Yes. The Company plans to offer incentives for advanced and emerging technologies that have the potential to save energy, reduce peak demand, or shift demand to off peak periods (*e.g.*, energy storage, cooling storage, building management systems) in the C&I sector. For example, as hourly usage is analyzed, the Company can make recommendations on the effectiveness of building management systems, energy storage or cooling storage to reduce load based on price signals or shift load to off peak periods. The Company will offer increased rebates for these higher cost technologies to encourage the adoption of these emerging and advanced technologies. In doing so, the Company will develop processes so that programs deployed to encourage adoption of technologies designed to reduce or shift load are implemented so that they work in coordination with other Company initiatives such as Non Wires Alternatives (“NWAs”), demand response programs, and locational based pricing offered through the Value of DER tariff.

Q. Please describe the Company’s proposed Commercial Midstream Lighting Program.

A. This program will provide point of sale rebates for LEDs at the wholesale and/or retail level for C&I customers. Distributors, retailers and the Company will engage in co-branding efforts to promote efficient LED lighting and introduce incentives to buy down the cost of LED lighting. By providing midstream rebates to electric distributors to buy down the cost of energy efficient measures, the Company will begin to transform the market so that the energy efficient products offered by retailors are at an affordable price point. For example, O&R may partner with distributors to offer contractors and/or commercial lighting customers discounted pricing on LED lamps and select types of LED fixtures for commercial applications. Program incentives will be provided directly to the distributor so that these measures become the recommended solution, as opposed to a less efficient and less costly measure. To broaden the scope and improve the effectiveness of this program, the Company plans to explore a partnership with Con Edison, NYSERDA, and other New York utilities.

Q. Please describe the Company’s proposed Commercial Demand Reduction Program.

A. This initiative will provide enhanced rebates that target demand savings and load curtailment which will coincide with the system peak demand. The Company will offer incremental rebates to incentivize the installation of measures that will reduce distribution load constraints. For example, for locations that peak during evening hours, energy efficient outdoor lighting may be incentivized through a higher rebate to reduce the evening peak. For locations with daytime peaks, office lighting and HVAC improvements may be rebated at higher levels to encourage the upgrade of equipment and the permanent reduction of peak demand. On-site audits will be conducted at no cost to the customer so that potential equipment replacements and/or upgrades can be identified and customized rebates offered based on the existing equipment at the facility. Areas identified as NWAs will be addressed primarily through an NWA solicitation and coordinated with the Commercial Demand Reduction Program.

Q. Please describe the Company’s Commercial New Construction Program.

A. In partnership with NYSERDA’s existing new construction program, the Company will promote an initiative to identify new construction opportunities to eliminate lost energy saving opportunities in new and renovated commercial buildings. By offering new construction and remodeling incentives, this integrated approach captures otherwise lost opportunities as it encourages energy efficiency from the buildings inception. In addition, the incorporation of building management systems at the time of construction is less costly than installing in an existing building. Demand response and energy conservation can be incorporated into building design so that the individual(s) responsible for managing new buildings can respond to price signals and better manage energy use. The Company will coordinate with local municipalities to drive new construction building requirements for commercial building beyond existing levels and establish incentives to offset the higher costs of construction.

Q. Please describe the Company's proposed Energy Efficiency Provider Solicitation Program.

A. This program involves inviting third parties to provide the Company with energy savings similar to a standard offer solicitation to deliver energy savings in a specific customer market segment or for specific advanced energy efficiency technologies. A standard offer or Request for Proposal ("RFP") process would set a price for the energy savings delivered and third parties would submit proposals outlining how they intend to provide the required level of savings. The Company may also use reverse auctions to set the price that would be paid for energy savings in a specific market or for a specific advanced technology. RFPs will be issued to engage third parties in meeting specific energy reductions in targeted customer segments. For example, hospitals may be a targeted market segment for energy savings and a specific $/kWh may be offered to third parties for energy reductions at hospitals.

Funding Request

Q. Please discuss the funding request associated with the Company's proposed expanded energy efficiency programs.

A. As discussed above, the annual electric component of the Company's current ETIP portfolio budget is $6.3 million and generates 19,302 MWh of annual savings, at an overall cost of $326/MWh. The Company exceeded 100% of the electric portfolio goals on an achieved and committed project basis, while spending $19.4 million, at an overall cost of $251/MWh. The Company was able to obtain MWh savings at a lower cost than that budgeted because a significant amount of the savings was the result of C&I customers installing low-cost lighting solutions.

Moving forward, the Company expects that the budgeted electric portfolio design spend of $326/MWh will decrease minimally to $325/MWh in 2019 with new residential programs below the design spend at $244/MWh and new C&I programs at $601/MWh. This overall decrease is attributable to the addition of residential behavioral savings that are less expensive to implement. This C&I increase can be attributed to the fact that a lot of the "low hanging fruit" in terms of energy savings (*i.e.,* lighting upgrades described above) have already been achieved. Therefore the Company must rely more heavily on non-lighting related energy savings in the C&I sector, which are more expensive to promote, rebate, and ultimately deploy. In addition, as the Company engages third-party vendors to provide energy savings beyond lighting through an RFP or auction process, the cost per MWh saved will increase.

Currently, residential programs account for 12% of the 19,302 MWh in the ETIP portfolio goal, funded at $365/MWh. According to the Company's most recent potential study (performed in 2008), residential customers represent 36% of the economic potential while representing approximately 44% of total energy sales. Commercial customers represent 55% of the economic potential and 46% of total energy sales. The remaining economic potential (8%) and energy sales (9%) were attributable to industrial customers.

At the same time, the Company can no longer depend on low cost lighting savings from the C&I segments, but must engage customers to move beyond lighting to more expensive energy savings including new technologies, albeit at a higher cost.

To illustrate the increased costs of this program, it is helpful to examine the recent experience in the state of Massachusetts. In that state, 2016 electric energy efficiency programs were funded at $398/MWh, but increased to $463/MWh for the 2017 program year. Similarly, C&I direct install programs in Massachusetts are currently funded in excess of

$600/MWh, significantly higher than the $302/MWh currently budgeted in the direct install program in the Company's ETIP.

For the Company to achieve savings beyond lighting, the funding of the Company's direct install program must increase to provide deeper energy saving programs to all end-uses. While the Company's direct install program has been funded at a level that is significantly less than those in Massachusetts, it has also under-performed in the last Energy Efficiency Portfolio Standard ("EEPS") and ETIP program periods. In response to this, the Company has transitioned to a pay-for-performance contract, where the vendor is only paid for MWh installed based on the engineering algorithms found in the New York Technical Resource Manual. This approach has worked well in 2016 and 2017. If the program underperforms, then the remaining funding can be shifted to other higher performing programs.

Q. Please describe the Company's proposal to increase spending on its portfolio of electric energy efficiency programs.

A. The Company is proposing to spend an additional $1.7 million in RY1, $3.2 million in RY2, and $5.7 million in RY3 over its current annual ETIP spend of $6.3 million. This increase in spending is projected to produce savings of $325/MWh in RY1, $299/MWh in RY2 and $322/MWh in RY3. The Company projects that this proposal will generate program energy savings of 188% of the current ETIP goal in Year 3, for a total savings of 37,393 MWh (an additional savings of 18,091 MWh). The table below outlines the proposed funding levels and projected savings.

	RY1	RY2	RY3	RY1	RY2	RY3	RY1	RY2	RY3
ETIP	**19,302**	**19,302**	**19,302**	**$327**	**$327**	**$327**	**$6,302,164**	**$6,302,164**	**$6,302,164**
New Res	4,050	8,900	10,640	$244	$163	$169	$990,000	$1,449,418	$1,798,378
New C&I	1,113	3,476	7,451	$601	$496	$527	$668,290	$1,724,080	$3,923,160
Total New	**5,163**	**12,376**	**18,091**	**$321**	**$256**	**$316**	**$1,658,290**	**$3,173,498**	**$5,721,538**
Total	**24,465**	**31,678**	**37,393**	**$325**	**$299**	**$322**	**$7,960,454**	**$9,475,662**	**$12,023,702**

Q. Does the Company propose to add any personnel to manage its expanded programs?

A. Yes. The Company proposes to add one additional FTE to manage the upstream lighting program and increased workload in the C&I sector related to the Energy Efficiency Provider Solicitation Program. As the expected start date for this position is June 2019, the projected O&M expenditure for this additional position in RY1 is $54,100. Beginning in RY2, this amount will increase to $92,700 (*i.e.,* annualized expenditure). For additional information on this request, please see the white paper in Exhibit EE-1.

Q. How does the Company propose to recover costs associated with the Energy Efficiency Programs?

A. The Company has unspent Energy Efficiency funds collected from customers for the purpose of operating the Energy Efficiency Portfolio Standard (“EEPS”) 1, EEPs 2, and ETIP programs, during the period of 2009-2016. The Company proposes to use these unencumbered Energy Efficiency funds, estimated at $6 million, to offset the expense of the additional $10.6 million program spending level. Please see the direct testimony of the Company’s Accounting Panel for more information on how the additional Energy Efficiency costs will be recovered.

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
Customer Service Panel – ELECTRIC/GAS

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Introduction

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

A. **(Kennedy)** My name is Donald Kennedy and my business address is One Blue Hill Plaza, Pearl River, New York 10965.

(**Melvin)** Robert Melvin and my business address is 390 West Route 59, Spring Valley, New York 10977.

(Scerbo) Keith C. Scerbo and my business address is 390 West Route 59 Spring Valley, New York 10977.

(Sullivan) Karin Sullivan and my 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", "O&R", or the "Company")?

A. **(Kennedy)** I am the Director of Customer Energy Services.

(**Melvin)** I am the Director of the Customer Information Management System ("CIMS").

(Scerbo) I am the Director of Advanced Metering Infrastructure ("AMI").

(Sullivan) I am the Director of Customer Assistance.

Q. Please describe your educational backgrounds.

A. **(Kennedy)** In 1998, I graduated from the State University of New York, Rockland Community College with an Associate Degree in Math and Science. In 2002, I graduated from the State University of New York with a Bachelor of Science in Business Administration. In 2010, I graduated from Walden University with a Masters of Business Administration.

(**Melvin)** I graduated from Hobart College in 1990 with the degree of Bachelor of Arts in Economics. In 1995, I graduated from Iona College with a Masters of Business Administration degree in Financial Economics.

(Scerbo) In 1991, I graduated from the Juniata College with a Bachelor's Degree in Business Management.

(Sullivan) I earned an Associate's degree in Business Administration from the Westchester Business Institute in 1997. In 2001, I graduated from St. Thomas Aquinas College with a Bachelor's of Science Degree in Business Administration.

Q. Please describe your work experiences.

A. **(Kennedy)** I joined the Company in 1981 as a Meter Reader. I have since held the positions of Supervisor - Meter Reading, Senior Supervisor – Customer Accounting, Manager – Customer Accounting, Manager - Customer Assistance, Director of Customer Assistance, and Director of New Construction Services prior to my present position.

(Melvin) I was employed by the Company from 1990 through 1995 in the Economics Research Department where I developed sales and load forecasts. From 1995 through 2008, I was employed by International Business Machines Corporation ("IBM") in various financial management and operations positions within IBM Global Services. In 2008, I returned to the Company as a Specialist in Customer Energy Services and have also served as the Retail Access Manager. In 2014, I assumed management responsibility for the CIMS team.

(Scerbo) I joined the Company in 1991 as a Customer Accounting Representative. I have since held the positions of Customer Systems Analyst – Customer Accounting, Business Analyst - CIMS, Lead Business Analyst - CIMS, Sr. Specialist - CIMS, Section Manager

– CIMS, and Director of New Business Services, prior to my present position.

(Sullivan) I began my career at Orange and Rockland in 1980 as a Clerk in the Credit and Collections department. In 1982, I accepted a position as a Credit and Collections Clerk assisting customers with termination notices and customers that were locked for non-payment. In 1983, I accepted a Meter Reading position and in 1986 was promoted to Supervisor - Meter Reading. In 1991, I assumed supervisory responsibility for nine individuals in the Collections department where I managed the Company's shared meter investigations so that they complied with state law and New York Public Service Commission ("Commission") regulations. In 2001, I was promoted to Sr. Supervisor of the Customer Assistance department and promoted again in 2002 to Manager of Customer Assistance. In 2015, I was promoted to my current position.

Q. Please generally describe your current responsibilities.

A. **(Kennedy)** I am responsible for the oversight of energy efficiency, demand response, and Solar Renewable

Energy Credit programs in New Jersey, retail choice, and low income programs for the Company and its utility subsidiary, Rockland Electric Company. I am also responsible for administration of the Customer Engagement and Marketplace Platform ("CEMP") Reforming the Energy Vison ("REV") demonstration project.

(Melvin) My primary responsibility is to oversee and manage the proper operation of CIMS. In this role, I supervise a team that processes electric and gas bills, and operates and maintains the Company's billing system in order to comply with evolving customer needs and regulatory requirements. I also manage several ancillary systems at Orange and Rockland that interact with the billing system.

(Scerbo) I am responsible for projects and processes associated with the Company's implementation of AMI.

(Sullivan) As the Director of Customer Assistance, I am responsible for the Call Center and the Customer Accounting departments. In this role, I oversee: the accuracy of customer bills and cash flows to corporate bank accounts; the Company's interactive voice response ("IVR") and telephone equipment, and the

Company's responses to customer inquiries. I also participate in the Company's storm response efforts as the Chief Customer Operations Officer.

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

A. **(Kennedy)** Yes, I submitted testimony in the Company's last electric base rate case, Case 14-E-0493. I also submitted testimony on behalf of the Company's New Jersey affiliate, Rockland Electric Company, in NJBPU Docket Nos. ER13060535 and ER17080869.

(**Melvin)** Yes, I submitted testimony to the Commission in Cases 14-E-0493 and 14-G-0494.

(Scerbo) Yes, I submitted testimony to the Commission in Case 14-G-0494.

(Sullivan) No, I have not.

Purpose

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

A. The purpose of the Panel's testimony is to describe the investments the Company has made and will continue to make to provide service to its electric and gas customers. These investments can be classified into the following three categories:

1. *Enhancements to Customer Facing Applications*: Investments in platforms and programs that are used by the Company to interact and communicate directly with its customers (*e.g.*, Digital Customer Experience, product/service offerings).
2. *Upgrades to Underlying Foundational Technologies and Systems:* Investments in the technologies and systems used by the Company to serve the needs of its customers (*e.g.*, customer billing system, data storage systems, and AMI).
3. *Programmatic Modifications:* Modifications to existing operations/processes to improve the efficiency and convenience of the services/programs offered to customers (*e.g.*, payment methods, programs to make it easier for customer to convert to natural gas, implementation of Value of Distributed Energy Resources ("VDER")).

Though separate, these three categories are interrelated. As described in greater detail in our testimony below, many of the Company’s investments in one category (*e.g.*, data storage) are necessary to leverage fully the capabilities of an investment in another category (*e.g.*, updated website).

Q. Will the Panel be presenting and sponsoring any exhibits as a part of their testimony?

A. Yes. The Panel is presenting the following exhibits. All of these exhibits were prepared under our supervision and direction.

- Exhibit (CSP-1), which provides white papers for capital projects that are included as part of our testimony;
- Exhibit (CSP-2), which provides white papers for capital projects that are included as part of our testimony;
- Exhibit (CSP-3), which provides Customer Engagement Marketplace Platform metrics; and

Enhancements to Customer Facing Applications

Digital Customer Experience

Q. Please explain the Company’s Digital Customer Experience (“DCX”) program.

A. The DCX program is a joint project between Orange and Rockland and its affiliate, Consolidated Edison Company of New York, Inc. (“Con Edison”), which began in 2015 in order to improve continuously the customers’ digital experience. This effort includes redesigning all of the Company’s customer facing digital platforms, including its external website (www.oru.com), mobile website, “My Account” portal, and mobile application (“app”) to make them easier for customers to navigate and access information. Though this effort is underway, ongoing investments in the DCX will enhance the Company’s digital platforms (particularly as to ease of use/navigation), and facilitate access to and consistency of information posted across platforms.

Q. Why is the Company investing in its digital platforms?

A. The Company views its ongoing investment in the DCX as a foundational investment that will enable Orange and Rockland to better serve the changing needs and expectations of its diverse and increasingly digitally-connected customer base. Customers' interactions with companies outside of the energy industry, (*e.g.*, Amazon, American Express, and Uber), are resetting their base level service expectations. As a result, Orange and Rockland's customers expect simplicity in navigating the Company's websites and other digital platforms, the ability to access content and perform transactions via mobile devices, personalization of products and services, and real-time tracking and notifications.

To meet evolving customer expectations, as well as state policy goals of improving the level of engagement between utilities and their customers, the Company must continually make investments to improve and enhance the platforms it uses to communicate and interact with its customers. In addition to the improvements in the customer experience, ongoing investment in the DCX program supports and complements other Company efforts, including the AMI initiative. Such investment will assist in the Company's ability to implement the policy goals of the Commission's Reforming the Energy Vision ("REV") proceeding, and help facilitate the Company's transition to the role as the Distributed System Platform provider ("DSP").

Q. What are the overall goals and objectives of the Company's DCX program?

A. The goals and objectives of the DCX program are as follows:

- Improve customer satisfaction by effectively meeting expectations of a diverse customer base in an increasingly digital world;
- Provide customers with a more consistent, simple, and personalized experience that is intuitive and engaging across all of the Company's digital touch platforms (*e.g.*, website, mobile, apps);
- Deepen engagement with customers through improved access to online customer usage data and supporting analytical/engagement tools;

- Provide customers more options to communicate with the Company via their preferred channel and on their own terms;
- Enable the expansion of energy efficiency, demand response, and Distributed Energy Resource (“DER”) supplier offerings;
- Improve the Company’s ability to communicate in near real-time with customers (*e.g.*, providing updates on storm response efforts, outages);
- Implement a robust, adaptable technology solution capable of supporting the future needs of the Company’s customers;
- Maintain customer data security across all device platforms by using industry best practices and complying with all Consolidated Edison, Inc. policies related to cyber security and data protection, including protecting Personally Identifiable Information (“PII”) guidelines; and
- Provide customers with the ability to communicate/interact with the Company via lower-cost channels while maintaining operational

excellence through the development and optimization of self-service functionality across all platforms (*e.g.*, pay bill, start/stop service, enter meter readings).

Q. What new functionality does the DCX program provide to customers?

A. In addition to a re-design of existing content and services, the Company is providing a number of new services and functions aimed at advancing the level of customer service. These include, but are not limited to:

- Usage analysis tools, including graphics that will provide customers a graphical representation of their energy usage, the ability to compare their usage to other customers, and the ability to overlay weather and price information on usage graphs;
- The option of receiving high bill alerts and customized energy savings tips;
- The option for Live Chat with a Customer Service Representative ("CSR");

- A “Preference Center,” which allows customers to identify their preferred communications channel (*e.g.*, email, call, text) for interactions with Company on issues such as bill alerts, outages, and energy efficiency communications;
- Personalized content for each customer class, so that the most relevant content is provided to customers based on their classification and available programs; and
- Data sharing tools related to Green Button Connect (“GBC”) will be made available to customers to provide them the option to allow the Company to share their usage data with authorized vendors (the GBC platform is described in greater detail later in this testimony).

Q. Please describe the investments the Company has made as part of its DCX program.

A. In 2016, the Company launched its redesigned public facing website that provides customers an updated and engaging experience, with more intuitive navigation, and social media integration. As part of this effort, the Company deployed an industry leading Web Experience Management (“WEM”) platform that has improved functionality, including content management tools, web usage analytics, and the ability to target and personalize messages and test multiple versions of content on the website to measure effectiveness. In 2017, the Company successfully re-designed and re-platformed all authenticated web pages that are part of My Account, as well as the mobile web and mobile app experience. This included deploying an Identity Access Management (“IAM”) product that enables a more secure and streamlined customer authentication (*e.g.*, log in, set password) process and establishing a single sign-on for all services, which allows customers to access third-party service vendors without an additional login. These updates all comply with the Company’s cyber security and PII guidelines. In addition, the Company has introduced several new streamlined self-service offerings to make it easier for customers to pay their bills and start/stop service. The Company has also redesigned its web services related to energy efficiency/Demand Side Management (“DSM”) program enrollment and administration, implement personalized content for customer segments, and extended the functionality of its mobile app.

Q. Will the Company’s DCX program extend beyond 2017?

A. Yes. In 2018, the Company plans on optimizing the customers My Account experience to assist customers in finding information and incentives that relate to them individually and empower the customer to make more energy efficient choices. We are also planning on expanding the DCX platform with features that will deliver value to commercial customers to help them better manage and understand their billing and usage. In 2019, the Company plans to upgrade the underlying technology of its WEM platform; evaluate deploying a “Click to Call” functionality that will provide customers the option to use their mobile/web-connected device to request that a Company representative contact the customer via phone to discuss a specific issue; deploy a co-browse functionality that will make it easier for a customer contact representative to guide a customer through the Company’s website; and implement a virtual assistant for “Live Chat” services that will provide a lower cost alternative to addressing customer inquiries.

Beyond 2019, the Company is committed to investing in its DCX program so that the digital experience provided to customers meets their needs and expectations and can be accessed via the latest technologies and follow industry trends.

Q. What is the Company’s allocated share of the estimated capital costs associated with the DCX program?

A. As the DCX program is a joint effort between Con Edison and Orange and Rockland, Orange and Rockland is allocated seven percent of the costs associated with the DCX program. Specifically, the estimated capital costs allocated to the Company for the DCX program are $565,5000 in the Rate Year (*i.e.*, the twelve months ending December 31, 2019) (“Rate Year” or “RY1”); and $419,200 in the twelve months ending December 31, 2020 (“RY2”); and $430,000 in the twelve months ending December 31, 2021 (“RY3”). As explained more fully in the direct testimony of the Company’s Accounting Panel, the Company is not proposing a multi-year rate plan in its electric and gas rate filings. However, in addition to providing projections for the Rate Year, the Company has included forecasted financial information for RY2 and RY3, respectively.

Q. What is the Company's allocated share of the estimated operation and maintenance ("O&M") expenses associated with the DCX program?

A. As with the capital costs of the DCX program, Orange and Rockland is allocated seven percent of the O&M expenses associated with the DCX program. Specifically, the estimated total O&M expenses allocated to the Company for the DCX program is $538,000 in RY1; and, if applicable, $538,000 in RY2 and $538,000 in RY3. The Company incurred O&M expenses of $329,000 during the test year. Therefore, the O&M amount being requested is $209,000 in each of the three rate years.

Additional information on the DCX program is contained in Exhibit CSP–2.

Green Button Connect ("GBC")

Q. Please describe the Company's GBC tool.

A. The Company's GBC tool provides all customers the ability to download their energy usage data in an

Extensible Markup Language (“XML”) standard format file. Providing usage data in XML format makes it easier for customers to download and analyze their data because the XML format is a default file type for Microsoft programs (*i.e.*, Word, PowerPoint, and Excel).

The GBC tool also provides customers the ability to authorize the Company to share their usage data directly to designated third parties in a machine-readable format. Once registered with the Company, designated third parties will then be able to use this information to design new products, services, and pricing programs with the goal of helping customers save money and meet the growing interest for more choice and personalized energy services.

Q. Does the GBC tool provide for the transfer of PII?

A. No. The tool only processes customer usage data. It does not include any PII. In addition, the transfer process is secure and customer-driven, which eliminates the need for customers to share their user names and login information in order for designated third parties to receive regular access to customer data. Moreover, registered third parties will be required to agree to Con Edison's and Orange and Rockland's vendor agreements and data security protocols.

Q. What are the projected O&M expenditures for the GBC program?

A. The deployment of the GBC tool is a joint effort between Orange and Rockland and Con Edison. The tool became operational on December 31, 2017 and the Company will incur an O&M cost going forward not incurred in the test year. The projected O&M expenditures for the ongoing maintenance of the GBC program are $68,500 in RY1, $68,500 in RY2, and $68,500 in RY3. As GBC is a joint effort between Con Edison and Orange and Rockland, the expenditures outlined above reflect the Company's allocated share, which is seven percent, of total program costs. Additional information on the GBC tool is contained in Exhibit CSP–2.

Customer Engagement Marketplace Platform ("CEMP")

Q. Please describe the Company's REV demonstration project, the CEMP.

A. On July 1, 2015, the Company submitted its plan to implement a demonstration project, the CEMP, in compliance with the Commission Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015 in Case 14-M-0101)("February 2015 Order"). On August 3, 2015 Department of Public Service Staff ("Staff") informed the Company that the CEMP project complied with the objectives set forth in the February 2015 Order.

Q. Please explain the various components of the Company's CEMP project.

A. The Company's CEMP project is comprised of two components. The first component is the Marketplace, known as MY ORU Store. The Marketplace is an online environment where customers can purchase EE and DER products and services. To drive awareness and interest, customers receive weekly emails about new product and service offerings, special offers, and messaging on how to reduce energy consumption and save money.

The second component is MY ORU Advisor, which is an interactive, behavior-based portal which provides tips and energy usage insights. This portal also includes a virtual home tour explaining how energy is typically consumed within each room and by each appliance within a typical home. Customers are encouraged to explore energy tips, view and analyze their energy consumption data, share information and interact with others to earn points and rewards for taking energy savings actions. Customers are also provided with home energy reports ("HERs") on a monthly basis. These reports provide customers with individual monthly electric usage information and an individual energy comparison rating that is based on how the customers' energy usage compares to a similar home as well as an energy efficient home.

Q. Please explain the goals of the CEMP?

A. The CEMP was designed to build partnerships with a network of third-party product and service providers to increase customer awareness and understanding of energy consumption, motivate customers to participate in Company programs, increase the distribution and adoption of EE and DER products and services, and develop new revenue streams for the Company and its partners.

Q. Please describe the Company’s 2016 and 2017 activities related to the CEMP.

A. In the first quarter of 2016, the Company and its business partner, Simple Energy, launched the Marketplace (My ORU Store) component of the CEMP for residential customers, with limited product offering(s). By the end of the first quarter, a variety of products were introduced on the Marketplace including programmable thermostats, LED lighting, advanced power strips, and water saving products. During the second quarter of 2016, additional products, such as an air conditioning modlet, which is used to control window air conditioning units remotely, and a variety of connected home lighting devices were introduced. At the same time, home energy assessments and fixed priced services, including air conditioning tune-ups provided by local third party service providers (“TPS”), were also added to the Marketplace.

In the third quarter of 2016, the products available via the Marketplace were further expanded to include additional lighting products, an expanded line of low-flow shower heads, and faucet aerators. The services offered via the Marketplace were also expanded to include heating system tune-ups, a limited time offer to encourage demand response enrollment, and in-home inspections. During the third quarter, the Company also launched its MY ORU Advisor portal and accompanying HERs. The HERs are now distributed in both paper and electronic form via email to approximately 80,000 customers. As previously described, these HERs provide customers with information on the amount of energy they consume, along with data to allow them to compare their usage with other customers. The HERs also include information on appliance usage and describe the potential to achieve greater energy savings through Energy Star® appliance upgrades. The MY ORU Advisor portal also features an interactive home profile that gives customers the information to evaluate the energy consumed by each room and appliance in a typical home.

Customers also now have the ability to view and analyze their energy usage, receive energy savings tips, share individual achievements with other participants, and earn rewards/points by reducing energy usage through energy savings actions. During 2017, the Company expanded the Marketplace to include water conservation measures and insights in conjunction with Suez Water, who pays a hosting fee to be on the Marketplace. Products were further expanded to include connected home devices, Wi-Fi controlled lighting, indoor/outdoor security cameras, carbon monoxide smoke detectors, outdoor lighting and clothes washers. In addition, the suite of programmable thermostats was expanded to include additional manufacturer products.

Q. What has been the Company’s experience with the CEMP to date?

A. Thus far, experience with the various components of the CEMP, including the MY ORU Store, has proven to be successful. Product purchases fluctuate on a monthly basis, but overall they remain strong. Customers have responded positively to promotional advertisements and periodic messaging, as demonstrated by the combination of repeat visitors and the increasing number of new user visits to the site as referenced in Exhibit CSP-3. Although the roll-out of new products and services has taken longer than expected, the Company believes the My ORU Store and its expanding product line, coupled with TPS offerings and the ability for customers to apply instant energy efficiency rebates will continue to attract the interest of customers. The MY ORU Advisor plays an equally important role in the O&R suite of programs available to educate and engage customers about energy efficiency. Through the use of customized messaging and user friendly interactive tools, learning how to conserve energy can be scaled to meet the needs of customers at various income levels with specific energy savings goals in mind.

Q. What are the Company’s long range expectations for the CEMP?

A. Looking forward over the next four years, the Company anticipates that the MY ORU Store component of the project will continue to transition into a robust marketplace where customers can purchase DER and EE products and services. The Company also believes the MY ORU Store will become a resource that will be more frequently used by customers that are interested in evaluating and selecting a service provider to install EE solutions and/or DER equipment or perform periodic maintenance/repairs on existing equipment such as heating and air conditioning systems. The Company also expects that offerings available via the MY ORU Store will continue to expand to include additional energy efficient and water conservation products including water heaters, in-home battery storage systems, home security devices, in-home energy controls, and expanded line of lighting products and controls for both residential and commercial customers. In addition, the Company expects that the ORU Store will expand the service offerings to include solar installations and additional TPS installation services. Advertising sponsors on the MY ORU Store will expand to include product manufacturers, energy efficiency and gas conversion programs offered by the Company and the addition of TPS advertising for both fixed and variable fee services. Given the interconnectedness between water and electricity, the Company expects to continue its partnership with Suez well into the future.

Q. Please explain how the CEMP will further evolve to benefit the Company and its customers and develop into a long term sustainable solution?

A. To achieve a more long term, cost effective, and sustainable solution, the Company proposes to further separate the two components of the CEMP. The MY ORU Store will continue to function as a marketplace for customers to purchase EE and DER products and services. The Company will explore the potential of expanding or replacing the MY ORU Advisor with a similar product that can easily be integrated with AMI and the DCX to further enhance customer data presentment and provide customers with more granular information to help them make better informed energy decisions.

Q. What are the projected incremental O&M costs associated with each of the components of the CEMP?

A. The estimated incremental O&M costs for the CEMP are $200,000 beginning in RY1. This includes Software as a Service ("SAS") fees, as well as funding for added enhancements to the program and marketing and advertising expenses. At the end of each rate year, program spending will be reconciled to net profits earned from the sale of products and services, as well as advertising and other program income. Net profits from the MY ORU Store will be shared between customers and the Company on an 80 percent customers / 20 percent Company basis. This allocation of profits is discussed in greater detail in the Platform Service Revenue section of the direct testimony of the Electric Infrastructure and Operations Panel.

Q. How does the Company propose to fund the CEMP moving forward?

A. The Company proposes to include the funding of the MY ORU Store in base rates, commencing January 1, 2019, and fund the program through year end 2021. This includes transferring the cost of two employees that are currently funded via the Energy Cost Adjustment ("ECA") surcharge into base rates.

The estimated cost for the MY Advisor, $800K per Rate Year will also be recovered through base rates as part of the proposed energy efficiency program enhancements that are described in the testimony of the Energy Efficiency Panel. Prior to 2019, the Company collected the costs for this REV demonstration project through its ECA surcharge.

Automated Outage Communication

Q. Please describe the Company’s proposed Automated Outage Communication Project.

A. Though the Company has access to customer phone numbers that customers have provided to the Company (which are stored in CIMS), it does not currently have the capability to provide targeted communications to specific customers or a specific area of customers about service interruptions and outages. This project involves reprograming the Company’s Interactive Voice Response (“IVR”) phone system to allow Orange and Rockland to use the phone numbers in CIMS to make automated phone calls to customers to notify them of service interruptions, system outages, or other important information about their electric and/or gas service. By proactively communicating via automated phone calls, the Company will be keeping customers better informed, which will make it easier for them to plan for scheduled service interruptions and/or respond to outages. At the same time, the volume of incoming calls during service interruptions is expected to decline as customers will be more informed regarding the interruptions in service.

Q. What is the proposed addition to plant for this project?

A. The proposed addition to plant for this project is $900,000 in RY3. For additional information on this project, please see Exhibit CSP–1.

Upgrades to Underlying Foundational Technologies and Systems

Enterprise Data Analytics Platform

Q. Please describe the Company’s Enterprise Data Analytics Platform (“EDAP”).

A. EDAP is a joint Orange and Rockland and Con Edison data warehouse and analytics tool that went live in 2017. This tool supports the overall master data management for various data intensive initiatives and projects. This platform makes it easier for the Company to store and retrieve data for various reporting and data analytics purposes. More specifically, EDAP is the storage repository which provides the capability for the Company's DCX and GBC initiatives and will also support the Company's AMI initiative.

Q. What is the projected O&M expenditure for the ongoing operations of EDAP?

A. The projected O&M expenditures for the ongoing O&M of EDAP are $118,000 in RY1, $118,000 in RY2, and $118,000 in RY3. As EDAP is a joint Con Edison and Orange and Rockland platform, the expenditures outlined above reflect the Company's allocated share, *i.e.*, seven percent, of total program costs. Additional information on EDAP is contained in Exhibit CSP–2.

Customer Information System

Q. Is the Company exploring the replacement of CIMS, its existing Customer Information System ("CIS")?

A. Yes. The Company is currently exploring its options relating to replacing CIMS with a more modern CIS. CIMS is an Accenture customer service product ("Customer/1") that is currently 19 years old. The Company's initial investment in CIMS was $32 million, which investment was fully depreciated after 15 years in 2013. While the system has adequate functionality in terms of today´s operational needs, it may not be able to meet the Commission's goals and objectives outlined in REV and the future business needs associated with advanced billing, including the potential for bill rebates, new billing items, and innovative rate designs.

The Company will likely need to transition to a new CIS. This transition is consistent with trends observed within the utility industry, where of the original 31 utility companies using Accenture's Customer/1 billing system, currently only 20 companies are still using this CIS. Of these 20, ten are looking to replace their Customer/1 systems and three are currently transitioning to a different CIS.

This trend is not surprising given that a new system will provide substantially better capabilities for utilities to meet their expanding business needs. In addition, as companies migrate away from the Customer/1 product, Accenture may be expected to reduce the level of vendor support that it offers, thereby negatively affecting system performance and reliability.

Q. Please explain the actions the Company has taken to date to evaluate its options for replacing CIMS.

A. Given the potential size of this effort, the Company is working in conjunction with Con Edison to evaluate their options for a new CIS. The Joint Proposal adopted by the Commission in Con Edison's last electric base rate case (Case 16-E-0060) provides that Con Edison must begin to implement its plan to replace its existing Customer Service System ("CSS") commencing in mid-2018. This replacement CSS will contain a suite of systems to better support customer service and billing. Given Con Edison's plans to replace its CSS, and the age of Orange and Rockland's CIMS, Con Edison and Orange and Rockland (collectively, the

"Companies") agreed to explore the potential synergies, cost savings, and operational benefits of jointly developing a new CIS that would be used by both Companies.

In October 2017, the Companies hired a consultant to develop a business case for a joint CIS. As part of this business case, the Companies will perform detailed analyses to quantify projected cost savings, outline a project timeline, and identify other potential future synergies and efficiencies that could be achieved if the Companies were to jointly develop and operate a single new CIS billing platform. This business case will also identify and explore unique business processes used across the Companies and recommend alignment solutions where possible.

The Companies currently expect to complete this business case in the spring of 2018. Once the Companies complete this business case, they will share the results with Staff for their review and feedback and Orange and Rockland will provide appropriate information in its update filing.

Q. Does the Company plan on exploring any other CIS options?

A. Yes. The Company believes it is appropriate to identify and evaluate all options relating to its customer billing system taking into account synergies, life cycle cost savings, functionality and the need to address growing business demands and regulatory mandates. The Company will also evaluate other options including, but not limited to, remaining on CIMS and routinely upgrading when necessary or developing a new CIS system that would be separate from Con Edison.

Q. Is the Company including any costs of this CIS effort in this rate case filing?

A. The Company is in the process of developing a business case jointly with Con Edison and will share the findings of its business case with Staff once completed. As noted by the Company's Accounting Panel, consistent with normal accounting practices, the initial development costs for this capital project will be considered part of CWIP and accrue all appropriate carrying charges. The Company currently forecasts capital expenditures of $5 million in RY1,

$14 million in RY2, and $16 million in RY3 as a placeholder for replacing CIMS with a joint CIS. These costs, which are not included in the revenue requirement because the new system is not expected to be operational until after RY3, reflect the estimated cost of retaining a System Integrator, performing data cleansing, commencing the design and build of the new CIS, and developing testing and training plans. Once the business case is completed, the cost estimates and savings will be updated and more detail on the spending will be available.

Priority Customer Repository – NUCON Enhancement

Q. Please describe the Company’s existing New Business Management system (“NUCON”).

A. NUCON is a flexible technology platform that the Company developed internally in 2007. The original purpose of this project management platform was to aid the Company’s New Business Group (“NBG”) in facilitating and completing gas and electric service requests and in maintaining a single database that would contain key information for all active NBG projects (*e.g.,* key contacts and phone numbers, account information like specific regulatory or rate class requirements, details on the project and any part projects that had been completed, customer circuit data). Housing all of this information in a single database increased Company efficiency when processing customer requests through the lifecycle of the project.

Q. Are there are any limitations to the current NUCON system?

A. Yes. The primary limitation is that the NUCON system does not allow the Company to store any of this information collected from the customer during the project in the system. Instead, the Company must employ manual inter-departmental processes to integrate NUCON data with other systems like CIMS, Work Management System ("WMS",) the Electric Information Management System ("EIMS"), and the Company's NRG mapping software. This manual process has caused inefficiencies and data entry errors as the information cannot be extracted from one system but must be manually extracted from individual Company systems. At the same time, anytime a customer contacts the NBG with an inquiry not related to an active project, the NBG must contact other departments that have stored customer data on their system(s) to search for, retrieve, and review the requested data, or manually review paper files to obtain the information needed to respond to the inquiry.

Q. Please describe the Company's proposed Priority Customer Repository.

A. To address the aforementioned concerns, the Company is proposing enhancements to NUCON that would establish customer profiles for all large power customers and critical power customers (*e.g.,* hospitals, data centers and three-shift manufacturing facilities) that currently have access to 24/7 support from the Company. These customer profiles would contain information including key contacts and their information (including email addresses), a list of current and historic projects, circuit-level data, service classifications and rate classification information, electric and gas premises information (*e.g.,* how the customer is serviced from the distribution system) and any special regulatory or service class requirements (*e.g.,* interruptible gas customers, elevated pressure, demand response program, emergency response protocols) that will be linked to other system platforms (*e.g*., CIMS and NRG). By storing this information in NUCON and linking it to other systems, the Company will be able to streamline existing work practices, provide an automated solution to existing manual processes, increase efficiencies in current processes, improve the accuracy of its data, and be more responsive to customer inquiries. It will also provide transparency and accessibility to customer data to internal organizations. Depending on the efficiencies achieved via this enhancement, the Company may explore further enhancements that would apply to other customers.

Q. What are the projected additions to plant for this enhancement?

A. The Company is projecting additions to plant of $775,000 in RY1. For additional information on this request, please refer to the white paper in Exhibit CSP–1.

Appointment Scheduling System Software

Q. Please describe the Company’s current appointment scheduling process.

A. The Company does not have a single system to manage its appointments (*e.g.,* service set-up, meter drops). Instead, each department, including Customer Service, Electric Operations, Energy Services, Customer Meter Operations, and Gas Operations, schedules appointments independent of one another. For example, Gas Operations may schedule an appointment with a customer that involves visiting the customer’s residence at a certain time. Customer Service, who also needs to visit the customer’s residence, would be unaware that Gas Operations was already there. Because there is not a single enterprise system in use across the Company that contains customer appointment information, the Company cannot coordinate service calls or share important customer information across departments. As a result, the Company has an opportunity to be more efficient and combine appointments where it makes operational sense.

Q. Please describe the Company's request to update its scheduling system software.

A. The Company will conduct a preliminary feasibility study to analyze how to implement efficiently and expeditiously a new centralized appointment scheduling system software solution, in order to improve scheduling and planning functionality across all of its Customer Service departments. As part of this study, a team comprised of key business users from across the Company will review all of the Customer Service organizations' business processes relating to appointment scheduling, identify and analyze opportunities to streamline business processes as appropriate, and develop a future technology strategy for processing appointments in a single system across the entire Customer Service organization.

Q. What are the expected benefits of a new appointment scheduling system?

A. The primary benefit will be to establish an enterprise system that will contain a customer appointments centralized repository of information that will enable groups throughout the Company to better coordinate and communicate with one another regarding customer appointments. This will result in increased operational efficiencies and transparency as multiple organizations within the Company will have enhanced awareness regarding customer appointments. Another expected benefit is improved customer service as customers will be able to resolve their inquiry through one phone call or contact rather than being required to reach out to separate departments to schedule appointments or obtain information about a particular appointment.

Q. Please describe the projected additions to plant associated with this project?

A. The Company projects an addition to plant of $527,500 in RY2. For additional information on this request, please refer to Exhibit CSP-1.

Off-Cycle Enrollment Software

Q. Please describe off-cycle enrollments and how they are currently processed by the Company.

A. Retail access enrollment is the process the Company uses to switch a customer’s commodity service (1) from Orange and Rockland to an Energy Service Company

(“ESCO”), (2) from an ESCO to Orange and Rockland, or (3) between ESCOs. An off-cycle enrollment occurs when a customer enrolls in the program on a date that is different than the customer’s scheduled meter read date for electric, or at a date other than the first of the month for gas.

According to the current Uniform Business Practices (“UBP”), an off-cycle change to ESCO commodity service is allowed no later than five business days before the date requested for the change for electric and ten business days before, if a new ESCO or the customer arranges for a special meter reading or agrees to accept an interim date for estimating consumption. Any change based upon an interim estimate of consumption or a special meter reading is effective on the date of the interim estimate or special meter reading. Off-cycle changes of gas service providers are allowed if the incumbent and new ESCO agree on an effective date no later than 15 calendar days following the request.

Q. Please describe why the Company’s current off-cycle enrollment process may not be sufficient in the future.

A. In 2015, the Commission issued an order in Case 12-M-0476 changing the timeline for on-cycle switching of electric providers from 15 calendar days to five business days, and natural gas providers from 15 calendar days to ten business days. Although the Order did not modify off-cycle switching for either gas or electric commodity service, the Company anticipates that the Commission will reconsider off-cycle switching once the Company deploys AMI to a majority of customers in its service territory. As the Company is in the process of deploying AMI across its service territory, it expects the Commission to implement similar requirements for off-cycle enrollments that it has for on-cycle enrollments. The July 20, 2015 Draft Report on Accelerated Switching Collaborative indicated that:

Based on the discussion of issues explored during the Collaborative, it is recommended that off-cycle switching not be implemented for electric enrollments at this time. The consensus of the Collaborative is that off-cycle switching be addressed in a subsequent collaborative at such

> *time that AMI has been deployed to a majority of New York electric customers in any Utility service territory.*

Q. Please describe the Company’s request relating to the development of off-cycle enrollment software.

A. To provide off-cycle enrollments (and de-enrollments) in a timely manner (*i.e.,* according to the timeline for on-cycle enrollments), the Company must modify CIMS, the Company’s system used to communicate and process customer enrollments, drops, rescinds, price changes and other customer/marketer information, as well as develop new transactions. These programing changes would be performed by the Company’s and Con Edison’s Information Resource personnel, as well as external consultants.

Q. What is the projected addition to capital plant for this software?

A. The projected addition to capital plant for these upgrades is $1.634 million in RY1.

Innovative Time of Use Pricing Software Enhancements

Q. Please describe the Company’s need for Innovative Time of Use Pricing Software enhancements.

A. As part of this rate filing, the Company is proposing several new programs that will require new and unique rate structures. These programs include, but are not limited to, the Company's Smart Home and Electric Vehicle Charging programs that are described in greater detail in the DSP Implementation section of the Electric Infrastructure and Operations Panel's direct testimony.

In order for the Company to implement these programs, particularly the required rate structures, the Company will need to make several modifications and enhancements to its software systems, particularly CIMS. The enhancements will allow the Company to implement accurately the sophisticated rate structures associated with the aforementioned programs.

Q. What are the projected additions to plant for these enhancements?

A. The Company is projecting additions to plant of approximately $750,000 in RY1. For additional information on this request, please refer to the white paper in Exhibit CSP–1.

Advanced Metering Infrastructure ("AMI")

Q. Please provide an overview of the Company's AMI program.

A. The Company is continuing the implementation of its AMI smart meter initiative in order to empower customers with control, choice, and convenience. This project, which is being implemented across the Company's service territory, includes the installation of approximately 229,000 advanced electric meters and 134,000 advanced gas modules. The Company's AMI project is hardware intensive and involves the replacement of electric meters and installation of gas modules at every endpoint. The Company's deployment plan includes the purchase and installation of the hardware and software required to operate the system, including AMI-enabled electric meters and gas modules, a communications network, and the "headend" system that monitors and controls communications with and among all installed meters.

The AMI project requires coordination across several departments within the Company and represents a fundamental change to the Company's business operations, field operations, customer service and associated staffing levels. It is expected to deliver significant customer, societal and business benefits, as detailed in Case 17-M-0178.

Q. Has the Commission taken any action recently regarding the Company’s AMI efforts?

A. Yes, on November 16, 2017 in Case 17-M-0178, the Commission issued an Order approving Orange and Rockland’s proposal to deploy AMI across its entire New York service territory. The Commission also approved the Company’s Customer Engagement Plan that outlined how it will engage customers and third parties to better understand and take advantage of the benefits of AMI.

Q. What is the estimated capital spending for the Company’s AMI Program during the rate years?

A. The estimated addition to plant for the Company’s AMI program is $22.3 million in Rate Year 1 and $9.8 million in Rate Year 2.

Q. Please describe the Company’s AMI customer engagement strategy.

A. As required by Ordering Clause 2 of the Commission’s AMI Business Plan Order,[1] on July 29, 2016 the Companies jointly filed with the Commission their AMI Customer Engagement Plan, a copy of which can be accessed via the Commission’s website.

Q. What are the additional projected O&M expenditures associated with the Company’s AMI Customer Engagement efforts?

A. The additional projected O&M expenditures are $115,000 in Rate Year 1, $51,000 in Rate Year 2, and $110,000 in Rate Year 3.

Q. Is the Company proposing any performance metrics for its AMI program?

A. Yes. The Company is proposing the following three outcome based metrics for AMI related Earnings Adjustment Mechanism (“EAM”) incentives:

1) Customer Awareness;
2) Weekly AMI (“WAMI”) Report Email Enrollment, and;

[1] Case 15-E-0050, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions, (issued March 17, 2016)(“AMI Business Plan Order”).

3) High Bill Alert ("HBA") Text Message Enrollment

For further description of these proposed EAMs, please see the direct testimony of the Company's EAM Panel.

Q Is the Company proposing any Platform Service Revenues ("PSRs") for its AMI program?

A. Not at this time. However, if the Company identifies an opportunity to generate PSRs from its AMI system during the rate plan(s) that are established during this proceeding, it will propose it in a future filing.

Programmatic Modifications

"No-Fee" Debit/Credit Card Transactions

Q. Please describe the Company's current policy regarding residential customers that pay their electric and/or gas bills using a credit and/or debit card (collectively "CC/DC").

A. Under current practices, residential customers can pay their electric and/or gas bill using a CC/DC (accepted cards include MasterCard, Visa, and Discover). Though a CC/DC is accepted, residential customers are subject to a transaction fee of $3.95 each time they pay their bill using a CC/DC. These transaction fees are charged by the Company’s third-party credit card processing vendor (“CC/DC Vendor”). The CC/DC Vendor assesses and collects these fees directly from customers. These fees have no impact on the Company’s revenues.

Q. Is the Company proposing any changes to its policy regarding CC/DC payments for its residential customers?

A. Yes. The Company is proposing to shift to a “no-fee model” where the per-transaction CC/DC fee will be eliminated. Instead, the Company will incur the aggregate costs of processing CC/DC payments and will include the estimated annual transaction fees charged by the vendor into base rates charged to residential customers.

Q. Is the Company proposing this change for its commercial customers?

A. No. The transition to the “no-fee model” will only apply to residential customers. Commercial customers will continue to be charged a transaction fee of 2.6 percent of their bill if they pay their bill using a CC/DC.

Q. Please explain the Company’s rationale for this proposal.

A. As the use of a CC/DC for transactions continues to increase, customers have an expectation that the Company will provide billing and payment options that are on par with those available when conducting other day-to-day transactions, like paying for groceries, a cell phone bill, or a medical bill. Though there are exceptions, it is becoming less common for companies to charge a separate fee for customers that use a CC/DC. Instead, any transaction costs associated with the use of a CC/DC are embedded in the price of the good/service and spread across all customers.

Over the past several years the Company has seen a 38 percent increase in residential customers that pay for their electric and/or gas bill by means of a CC/DC. In the five years ended December 31, 2016, customers paid $1,124,335 in CC/DC transaction fees; money that could have been used to pay for their utility bills. By moving to the no-fee model, Orange and Rockland will become more aligned with other companies in increasing the convenience of using CC/DCs to conduct transactions. Based on conversations with the CC/DC Vendor, the Company believes that transitioning to this model could reduce the aggregate per-transaction fee by nearly 50 percent. This transition will enhance the customer experience and allow customers to choose the payment option that best meets their needs. The Company also expects that the number of customers using the CC/DC payment option will increase as a result of this program, which will likely result in operational benefits such as a reduction in returned payments and faster same-day payments.

Q. Do the terms of the Company’s current contract with the CC/DC Vendor allow for the immediate implementation of the proposed transition to the no-fee model?

A. No. The Company, along with Con Edison, is currently under contract with the CC/DC Vendor to charge residential customers a per-transaction fee through mid-2019. Though under contract until mid-2019, the Company will engage its current CC/DC Vendor as to how it would implement the no-fee model starting in mid-2018.

Q. What are the Company's estimated total annual O&M costs of transitioning to the no-fee model?

A. Based on preliminary discussions with the CC/DC Vendor, the Company estimates that the annual incremental O&M costs will be $180,000 in RY1, $230,000 in RY2, and $325,000 in RY3. These cost estimates are based on the Company's projections as to the acceptance rate for customers that will pay their electric and/or gas bill via CC/DC in the future, as well as preliminary cost estimates of moving to the no-fee model provided by the CC/DC Vendor. For additional detail, please see the white paper in Exhibit CSP-2.

Q. Does the Company propose any mechanism to address possible under or over-collection of credit/debit card fees?

A. Yes. The Company recognizes the estimated fees are based on projected acceptance rates and costs under the no-fee model. Therefore, the Company is proposing a reconciliation of its estimated fees, as explained in the Accounting Panel testimony.

Natural Gas Conversion Programs

Q. Is the Company proposing any programs to enhance the use of its existing natural gas system and strategically expand natural gas service to underserved areas?

A. Yes. The Company recognizes the importance of leveraging its existing asset base as a platform to make natural gas available to either current electric customers that do not currently use natural gas in their home or business, as well as to new commercial and residential customers. In order to provide customers with more information and more options related to their energy needs, the Company is committed to educating customers on the many benefits of natural gas and our gas conversion process.

To achieve these goals, the Company is proposing the following three new programs: (1) Non-Residential Entitlements, (2) Customer Excavation Entitlements, and (3) a Neighborhood Expansion Program.

Q. Are the Company's proposed initiatives to enhance the use of its existing gas system and expand service in underserved areas consistent with the Company's proposals (discussed in the direct testimony of the Company's Gas Infrastructure and Operations Panel ("GIOP")) to explore non-pipes solutions ("NPSs")?

A. Yes, they are. The Company's overarching goal is to provide customers with more and better options to meet their energy needs. As explained in the direct testimony of the GIOP, the Company is committed to exploring the viability of various NPSs. However, as a practical matter, NPSs that involve moving to an alternate source of heating are not an economic option for many of our customers. Accordingly, expansion of natural gas service should still be an option made available to provide customers a cleaner and more environmentally friendly energy alternative.

Q. Please describe the Company's proposed initiatives.

A. Each of the Company's proposed initiatives is described in more detail, below.

Non-Residential Entitlements

Q. Is the Company proposing any changes to non-residential entitlements?

A. Yes. In an effort to minimize the upfront cost of converting to natural gas, the Company proposes to modify its entitlements to provide up to 100 feet of main or service to non-residential customers. Under current tariffs, non-residential customers are entitled to 100 feet of natural gas main at no additional charge, but are not entitled to any natural gas service extension. In other words, if only a service extension is required to access natural gas, the non-residential customer would be responsible for the full length of the extension at a cost of $20 per foot (the cost of additional main extension is determined on a case by case basis and is typically approximately $90 per foot). The additional cost of paying for a service extension can be cost prohibitive for some customers, particularly if customers incur the expense of purchasing or upgrading a furnace and/or removing or remediating oil storage facilities. The Company anticipates that by providing non-residential customers the option of using the 100 foot entitlement for either mains or service extensions, more potential customers will be encouraged to consider converting to natural gas service. The Company anticipates that providing this additional flexibility around entitlements should prompt some non-residential customers to consider gas conversion. The cost of the additional natural gas conversions that are expected via this effort will be absorbed in the new business blanket that is described in the direct testimony of the Gas Infrastructure and Operations Panel. This proposed modification will not impact entitlements for residential customers.

Customer Excavation Entitlement

Q. Please describe the Company's proposal relating to customer excavation entitlement modifications.

A. The Company is requesting modifications to its customer entitlements for customers that perform the excavation work on their property required to install pipe to connect to the Company's natural gas system. More specifically, the Company is requesting that an additional service footage allowance, beyond that which is already authorized for each individual service class, be provided to customers that excavate their own trench. Any additional footage allowances would be limited to the Company's avoided cost of excavation. For example, if the Company's estimated cost of excavating a trench on a customer’s property is $1,000 and the customer excavates a trench that meets the Company’s requirements, the customer would be entitled to the additional footage allowance that is equivalent to $1,000 of gas service pipe and installation. These additional entitlement allowances will provide customers with the ability to reduce the cost of connecting to the Company’s natural gas system.

Q. Please describe how this modification is different than the Company’s current practice.

A. Currently, if a customer is interested in obtaining natural gas service from the Company, the customer has the option to either dig its own trench or have the Company dig the trench. If the customer digs its own trench, the customer is still limited, pursuant to the Company’s gas tariff, to the same footage entitlement as a customer that had the Company dig the trench. With this modification, the customer would be entitled to an additional footage allowance, because the Company has avoided the cost associated with digging the trench (*e.g.,* if the cost to provide natural gas to a new customer is $1,000 to dig a trench, and $2,000 for labor and materials, the customer would only be charged $2,000), but is still limited to the service entitlements applicable to its service class.

Q. Please describe why the Company is seeking this tariff modification.

A. The primary reason for this request is to provide customers that are interested in connecting to the Company's natural gas system with a potential option to reduce the excavation component of costs. By providing these additional entitlement allowances to customers that perform the excavation, those customers that choose to do so may be able to access natural gas at a reduced cost.

Q. Will this proposed modification result in any additional costs for the Company?

A. No. The Company will cap the additional service entitlements available to customers at its avoided cost for excavating the trench. The cost of any services beyond avoided cost would still be the responsibility of the customer.

Neighborhood Expansion Program

Q. Please describe the proposed Neighborhood Expansion Pilot Program.

A. Under this proposed program, the Company would have the ability to extend natural gas mains into existing neighborhoods that do not have access to natural gas once the Company is able to cover its costs through a combination of actual subscriptions (*i.e.,* customers signing up for natural gas service) and projected future subscriptions based on historical conversion experience for similar areas.

Q. How does this program differ from current Company practices for extending natural gas service into existing neighborhoods that do not have access to natural gas?

A. Currently, the Company must obtain enough customer subscriptions to cover the cost of the extension before it breaks ground on the project. Each customer that subscribes to natural gas service reduces the cost for all customers participating in the project. For example, if, beyond customer entitlements, the Company incurs costs of $5,000 to extend a main and ten customers subscribe, they each would pay $500. If 20 customers subscribe, the cost for each customer would be $250. However, if customers cancel their subscription, the costs for the remaining customers would increase. If there are enough customers that cancel their subscriptions, the cost for each remaining subscriber increases, which leads to more cancelations, culminating in insufficient demand to install the main extension. For example, over the past several years, the Company has had six instances where residents in a particular area had shown interest in converting to natural gas, but there were not a sufficient number of subscriptions to make the project economically viable.

That being said, historical experience has shown that within five years of a main extension being placed into service, there is a significant increase in the number of customers that had not previously subscribed to the project converting to natural gas. In other words, customers are more willing to convert to natural gas once the Company has placed the required infrastructure into service.

Q. How will this program address the issue of the Company not being able to pursue potential expansion due to inadequate subscriptions?

A. Knowing that customers are more willing to convert to natural gas once infrastructure is in place, the Company believes that this post-construction conversion rate should be considered when the Company is initially considering whether to install the main extension. Under this program, the Company will perform targeted analysis of neighborhoods in its franchise territory that could potentially be candidates for natural gas conversion. Once neighborhoods have been identified, the Company will then determine the total entitlements required to justify expansion under the Company's current entitlements for both residential and non-residential customer classes. The Company will then contact the residents in these neighborhoods to determine interest in becoming a natural gas customer. At the same time, the Company will make a projection as to the number of residents that will likely convert to natural gas once the extension has been constructed. This projection will be based on natural gas conversion rates of similar neighborhoods considering factors like population density, housing stock, distance between residences, and soil type. If the combination of known subscriptions and projected future conversions is sufficient, the Company will move forward on constructing the extension.

Q. What is the expected cost of this program?

A. The cost of the additional natural gas conversions that are expected via this effort will be absorbed within the new business blanket that is described in the direct testimony of the Gas Infrastructure and Operations Panel.

Value of DER Implementation

Q. Please describe the Company’s proposed new billing solution related to the Value of DER implementation.

A. As described in the testimony of the Electric Infrastructure and Operations Panel, in order to comply with the recent VDER Order and CDG Order, the Company is moving forward with a solution to automate account management processes and credit calculations associated with the Value Stack tariff. The Company is developing both an interim and long-term billing solution. In the interim, the Company contracted with a vendor to build an application to calculate and manage the Value Stack credits for customers based on specific criteria related to the Commission’s orders. Once the credits are calculated, manual bills will be produced for each customer that will reflect the appropriate credit and credit carryover. In the long-term, the Company intends to contract with a vendor to configure, build and test a billing module, which would expand CIMS and automate billing to all Phase One NEM and Value Stack customers.

Specifically, O&R must capture and manage customer election data from distributed generation customers when they either interconnect new systems under or opt-in to the Value Stack. CDG Hosts also will need to transmit satellite information and allocation percentages to O&R. As a result, the Company will need to design and build interfaces to automate the transfer of this information into CIMS. Similarly, other necessary values for calculating Value Stack credits (*e.g.*, a project’s coincident export during the New York Control Area peak, O&R’s top ten system peak hours, NYSERDA’s Tier 1 Renewable Energy Credit auction prices) will need to be imported into CIMS. Additional interfaces between CIMS and various other systems will be required to import such data. Automating the transfer of this data is essential for reducing the time required to calculate and apply Value Stack credits to customers’ bills and to minimize the possibility of error associated with manual data entry.

The Company must develop methods for linking either the CDG or remote net metering (“RNM”) Host and corresponding satellite accounts, using rules established for credit allocation per project type (*i.e.,* by percentage for CDG). Currently, these relationships are managed manually outside of the billing system. No mechanism exists within CIMS to identify and manage the CDG Host and satellite account relationship, including the allocation of credits earned on one account and distributed to a variety of others.

The Company must develop the ability to permit CDG Hosts to “bank” excess credits. Tracking of banked credits and the allocation of credits outside of the CDG Host’s regular, monthly satellite allocations requires the development of separate rules. To facilitate credit banking, the Company must establish methods within CIMS to allow for the banking and distribution of unallocated credits, subject to the rules governing both the carryover of excess CDG credits and the forfeiture of appropriate credits. The Company must develop and incorporate into CIMS a method to move these specific allocations from the bank and apply the monetary credit to a chosen satellite’s monthly bill. In addition, CDG Host banks will require a tracking method within CIMS so that the forfeiture rules are applied appropriately.

In addition, the ability of CIMS to accept both import (relating to energy received by the customer) and export (relating to energy exported by the customer onto the grid) interval meter data is a new process that must be developed, as well as the ability to bill on multiple meter data channels (*i.e.*, charge the customer for imported energy while separately calculating the customer’s Value Stack credit for exported energy). This represents a significant and fundamental system design change.

Q. What benefits will the Company’s planned billing solution provide?

A. Building the interim solution (which is a manual process) and then modifying CIMS (which will automate the interim process) will allow the Company to efficiently and effectively implement and administer the net metering tariffs, and in particular the Value Stack programs, by calculating and applying the appropriate credits to customers’ bills, tracking production credits, providing billing support and reporting capabilities as well as customer support for all DG facilities being served under the Company’s net metering tariff. Due to the significant changes required to implement the Value Stack, it is not feasible for the Company to implement immediately full automation of the Value Stack and the Company’s billing system. To meet the billing requirements of the Value Stack Tariff, the Company developed a two-phase approach. The Company will employ a manual interim process until CIMS can be modified to automate the Value Stack billing process. Full automation will allow the Company to deliver program administration and allocation of credits to customers’ utility accounts faster, more accurately, and more efficiently than through a manual process. The Company recognizes that full automation is necessary due to the complexities of calculating and applying the Value Stack credits, and the potentially large volume of participating customers (particularly for Community Distributed Generation).

Q. How much will this project cost and what is the project’s in-service date?

A. The current in-service date for the Automate Community Net Metering project is December 2019. The Common Plant Additions estimate for this project is $1.7 million. Though the additions to plant are $1.7 million, the Company’s total estimated capital expenditures for these upgrades are $4.5 million, with the majority ($4.0 million) occurring prior to RY1. For additional information on this project, please refer to the white paper in CSP-1.

Additional Personnel Requests

Q. Please explain the Company’s proposal to add six new Technical Programmers to the Customer Systems department.

A. When initially established, the primary responsibility of the Customer Systems department was to develop, implement, and maintain CIMS. However, over the past several years, the department’s responsibilities have expanded significantly and now include developing and implementing new systems, and maintaining numerous others (*e.g.*, field order routing and design system and associated wireless applications, daily meter reading applications, a new construction project management system). The department is also responsible for customer systems related disaster recovery preparation, PII protections and cyber security planning.

The combination of the Company's ongoing effort to implement new technologies and automate processes and the effort required to comply with regulatory directives and state policy goals has and will continue to place additional strain on the Customer Systems department.

Q. Please describe the specific responsibilities of the additional six System Specialists, relating to the Customer Systems department.

A. These System Specialists will have a knowledge and expertise in technical programming and will serve as additional resources to code and test system enhancements.

Q. What is the projected O&M expenditure of these six positions?

A. The costs of these positions are governed by the shared service common allocation methodology (*i.e.*, 93 percent Con Edison/seven percent Orange and Rockland). Employing this allocation, the Company's expected O&M expenditure is $46,200 in each of RY1, RY2, and RY3. For additional information on this request, please see the accompanying white paper in Exhibit CSP–2.

Q. Please describe the Company’s request for one additional New Business Services (“NBS”) Engineer.

A. The Company is requesting one additional full-time NBS Engineer that will be responsible for supporting the process of interconnecting and energizing DERs, specifically, DG, photovoltaic, and EV charging installations. The responsibility of this engineer will be to provide technical expertise, from inception to completion, for all major account customer project requests, as required.

Q. Please describe the need for this additional position?

A. Over the last three years, the number of DG installations has steadily increased and it is not uncommon to have several dozen projects in the queue. For example, as of December 2017, there were 76 DG projects in the pending queue. This trend is expected to continue and the Company projects an increase in DG application requests. Currently, there are four Engineers in the NBS department that manage between 40-60 projects, as well as support multiple department initiates and Commission regulated programs. The addition of the 76 DG projects to the existing

Engineers workload would negatively impact customer satisfaction and NBS department’s ability to meet all current NYS Electric Tariff and the Standardized Interconnection Requirements (“SIR”) time frame requirements. In addition, as the Commission has further refined the SIR timeline project milestones, a focused-dedicated effort is required to necessitate compliance. The requested additional position is essential not only to handle the current level of customer requests, but also to meet anticipated growth projections.

In addition, the demand for additional services has increased, while the staffing levels have remained constant. The increase in DG customer requests along with the projected New Business related construction trends and favorable economic climate, necessitates the need for the additional position.

Q. What is the projected O&M expenditure of this position?

A. The projected O&M expenditure for this position is $97,752, commencing in RY1. For detailed support for this request, please see the accompanying white paper in Exhibit CSP–2.

Q. Is the Company projecting any future reductions in Customer Service personnel?

A. Yes. The Company is projecting a reduction of twelve FTEs in 2019, primarily meter readers. This reduction is the result of projected efficiencies associated with the Company’s AMI program. This reduction is reflected in Accounting Panel Exhibits AP-E3 and AP-G3, Schedule 6, line 15.

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.

Low Income Panel – ELECTRIC/GAS

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Introduction

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

A. **(Kennedy)** My name is Donald Kennedy and my business address is One Blue Hill Plaza, Pearl River, New York 10965.

(Cigliano) My name is Charmaine Cigliano and my business address is One Blue Hill Plaza, Pearl River, New York 10965.

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

A. **(Kennedy)** I am the Director of Customer Energy Services.

(Cigliano) I am the Section Manager of Customer Energy Services.

Q. Please describe your educational backgrounds.

A. **(Kennedy)** In 1998, I graduated from the State University of New York, Rockland Community College with an Associate Degree in Math and Science. In 2002, I graduated from the State University of New York with a Bachelor of Science in Business Administration. In

2010, I graduated from Walden University with a Masters of Business Administration.

(Cigliano) I received a Bachelor of Science degree from Binghamton University in 1988 with a double major in Mathematics and Computer Science.

Q. Please describe your work experiences.

A. **(Kennedy)** I joined the Company in 1981 as a Meter Reader. I have since held the positions of Supervisor - Meter Reading, Senior Supervisor – Customer Accounting, Manager – Customer Accounting, Manager - Customer Assistance, Director of Customer Assistance, and Director of New Construction Services prior to my present position.

(Cigliano) My first employment after completing my education was with Orange and Rockland as an Analyst with the Economic Research Department where I held positions of increasing responsibility. In 1998, as a result of the merger between Con Edison and O&R, I was offered a position as a Senior Planning Analyst in Con Edison's Electric Forecasting Department. In 1999, I accepted a Senior Planning Analyst position in Con Edison's Rate Engineering Department. In 2000, I returned to O&R as the Customer Information Management System Billing Team Lead. In 2004 I was promoted to Manager of Retail Access. In 2008, I was promoted to Section Manager - Customer Energy Services.

Q. Do you belong to any professional organizations?

A. **(Kennedy)** I am a member of the Association for Energy Services Professionals ("AESP"). AESP is a dynamic community of energy efficiency professionals dedicated to advancing the industry through professional development, networking and advocating for a resilient, sustainable energy future in North America.

(Cigliano) I am a member of the Board of Directors for AESP.

Q. Please generally describe your current responsibilities.

A. **(Kennedy)** I am responsible for the oversight of energy efficiency, demand response, and Solar Renewable Energy Credit programs in New Jersey, retail choice, and low income programs for the Company and its utility subsidiary, Rockland Electric Company. I am also responsible for administration of the Customer Engagement and Marketplace Platform ("CEMP") the

Reforming the Energy Vison (“REV”) Demonstration project.

(Cigliano) I am responsible for the design, implementation and evaluation of O&R’s portfolio of energy efficiency, demand response, targeted demand-side management (“DSM”), renewables (New Jersey) and low-income programs. I have been a member of the Implementation Advisory Group, the Evaluation Advisory Group and the E2 Advisory Group. I am currently a member of the Clean Energy Implementation and Coordination Group.

Q. Have you previously testified before the New York Public Service Commission (“Commission”) or other regulatory bodies on energy matters?

A. **(Kennedy)** Yes, I submitted testimony in the Company’s last electric base rate case, Case 14-E-0493. I also submitted testimony on behalf of the Company’s New Jersey affiliate, Rockland Electric Company, in NJBPU Docket Nos. ER13060535 and ER17080869.

(Cigliano) Yes, I have submitted testimony in Cases 11-E-0408 and 14-E-0493.

Purpose

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

A. The Panel will describe the Company’s efforts to comply with the Orders issued by the Commission in Case 14-M-0565 (“Low Income Proceeding”). In particular, the Panel will discuss its proposed New Low Income Program (“New Low Income Program”). The Panel will also describe the Company’s new Low Income Bill Discount Program, summarize the continuation of the Reconnection Waiver Program, and address the Company’s proposal to continue the reconciliation and deferral of New Low Income Program costs.

Q. Is the Panel sponsoring any exhibits in support of its testimony?

A. No

Proposed New Low Income Program

Q. Has the Commission taken any action recently regarding utility low income programs?

A. Yes. The Commission instituted the Low Income Proceeding in January 2015 to address certain low income customer related concerns. On May 20, 2016, the Commission issued its Order Adopting Low Income Program Modifications and Directing Utility Filings in the Low Income Proceeding ("May 2016 Order"). The May 2016 Order established a standard framework for the low-income programs to be offered by all New York State utilities. In particular, the Commission adopted a framework for statewide utility low income programs to set low income discounts to achieve a target energy burden (*i.e.*, the percentage of a household's income that is spent on energy) of 6% of monthly household income. To implement this policy, the Commission established a four-tiered discount structure and a formula to establish a discount level for each tier. The Commission directed utilities to submit implementation plans detailing how they would comply with the May 2016 Order.

In compliance with the May 2016 Order, on September 16, 2016, the Company submitted its Implementation Plan, which outlined its proposed New Low Income Program. The New Low Income Program included a New Low Income Bill Discount Program ("New Bill Discount Program"). The Company proposed to increase electric low income credits from $2.6 million to $8.7 million, and gas low income credits from $1.9 million to $3.0 million, in order to meet the 6% low income customer energy burden guideline.

Q. Did the Commission approve the Company’s New Bill Discount Program?

A. No, it did not. On February 17, 2017 the Commission issued its Order Approving Implementation Plans with Modifications in Case 14-M-0565 (“February 2017 Order”).

In the February 2017 Order, the Commission directed the Company to increase the budget of its New Bill Discount Program to $14.6 million. The Company’s revised New Bill Discount Program became effective on January 1, 2018, coincident with the start of the 2017/2018 Home Energy Assistance Program (“HEAP”) season. All customers currently receiving HEAP assistance for their Orange and Rockland electric and/or gas services, or other fuel services (*e.g.*, oil, propane, or wood), are now eligible for the New Bill Discount Program and will be enrolled by the

Company in the same manner customers traditionally have been enrolled.

Q. Please describe any other new components of the New Low Income Program that the Company established to comply with the requirements of the May 2016 and February 2017 Orders.

A. In compliance with the May 2016 and February 2017 Orders, in addition to tiered bill discounts, the Company's New Low Income Program will include automatic enrollment in budget billing with an opt-out option, and reconnection fee waivers. Under the New Low Income Program, customers, once qualified, will be entitled to 12 monthly bill discounts. The Company plans to have all components of its New Low Income Program fully implemented by year end 2018, consistent with the February 2017 Order.

Q. What are the amounts of the monthly low income bill discounts that will be provided under the New Low Income Program?

A. Consistent with the February 2017 Order, the amounts of the new monthly low income bill discounts are shown in Table 1 below.

Table 1: New Monthly Low Income Bill Discounts – Tiered Benefit Levels

Income Level	Electric Heating	Electric Non-Heat	Gas Heating	Gas Non-Heat
Tier 1	$35	$35	$7	$3
Tier 2	$55	$55	$23	$3
Tier 3	$76	$76	$39	$3
Tier 4	$57	$57	$25	$3

Q. What is the forecasted participation level once the New Low Income Program has reached full enrollment?

A. The May 2017 Order assumes a total participation level of approximately 13,000 customers, as compared to approximately 10,500 low income participants currently enrolled in the program. This estimated participation level was also used to establish the cost forecasts.

Q. What are the forecasted costs of the Low Income Bill Credit component for the New Low Income Program?

A. The forecasted costs of the electric and gas bill discount component of the New Low Income Program are outlined below.

Table 2: Projected Cost of Bill Discounts (millions)

Period	Costs	Electric	Gas
January 2019 – December 2019	$13.4	$9.9	$3.5
January 2020 – December 2020	$13.7	$10.0	$3.7
January 2021 – December 2021	$13.9	$10.2	$3.7

These projected costs are based on the assumption that there will be a participation level of 100% (*i.e.*, approximately 13,000 participants) in each of the periods noted in Table 2 above. The funding levels used to estimate the program bill credits in Table 2 above are based upon the Company's review of customers income levels (and corresponding tiered benefit levels) as reflected by their HEAP bill credits from the previous year. The Panel provided these projections to the Company's Accounting Panel.

Q. Please address how the funding limits established in the May 2016 Order may impact budgets and costs associated with the New Low Income Program.

A. The May 2016 Order established a funding limit where the total low income program budget may not exceed 2% of a utility's total electric and gas revenues for sales to end-use customers. If the estimated budget exceeds the funding limit, the target energy burden will be increased (with a corresponding decrease to bill discounts) until the funding limit is met. The May 2016 Order directed utilities to update their Implementation Plans annually, at which time adjustments would be made so that program budgets remain within the Commission's prescribed funding levels. The Company's current total budget established in the February 2017 Order is $14.6 million, which represents 1.61% of the Company's 2014 revenues. Consistent with the February 2017 Order, the Company will continue to monitor the low income credits on a monthly basis and make adjustments as necessary to avoid exceeding the funding limit.

Q. Please discuss the other programs or services the Company offers beyond bill credits to low income customers to assist them in lowering their energy bills.

A. The Company offers various services, through its website to all customers, regardless of income, that are designed to assist customers in reducing their energy burden. These services, which are described in greater detail by the Company’s Customer Service Panel, include energy savings tips, rebates for energy efficient appliances, and the recycling of older appliances that have been replaced with ENERGY STAR® products. In addition, the Company will continue to refer customers to the New York State Energy Research and Development Authority (“NYSERDA”) for energy efficiency programs.

Reconnection Fee Waiver Program

Q. Please describe the Reconnection Fee Waiver Program offered by the Company.

A. The Company offers a Reconnection Fee Waiver Program that provides a one-time waiver of the reconnection fee (which can range from $27 to $104) for low income customers (defined as customers who have received assistance via HEAP in the last twelve months) who have had their service terminated for non-payment. The Company will continue to provide its Reconnection Fee Waiver program under the New Low Income Program. Table 3 below sets forth the reconnection fees waived by the Company during 2017.

Table 3: Waived Reconnect Fees in 2017

	Jan-Mar (Q1)	Apr-Jun (Q2)	Jul-Sep (Q3)	Oct -Dec (Q4)	Total
Electric Reconnects					
Heating	$189	$378	$311	$162	$1,040
Non-Heating	$3,524	$9,872	$8,872	$5,105	$27,373
Total	$3,713	$10,250	$9,183	$5,267	$28,413
Gas Reconnects					
Heating	$276	$345	$587	$207	$1,415
Non-Heating	$0	$0	$69	$0	$69
Total	$276	$345	$656	$207	$1,484

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name, title, employer, and business address.

A. My name is Joseph Briscese. I am Section Manager – Electricity and Gas Hedging for Consolidated Edison Company of New York, Inc. ("Con Edison"). My office is located at 111 Broadway, New York, New York 10006.

Q. Please describe your responsibilities in that position.

A. I am responsible for developing and implementing electric and gas hedging programs for Con Edison and its affiliate, Orange and Rockland Utilities, Inc. ("O&R" or the "Company"); procuring new supply to replace expiring legacy contracts; strategically evaluating and participating in Regional Greenhouse Gas Initiative auctions; and evaluating and procuring renewable energy certificates.

Q. Please describe your professional background.

A. I have been in my current position since March 2009. From 1998 to 2009, I was involved in Risk Management for various companies, including Deloitte and Touche, Constellation Energy, and Public Service Company of New Mexico. From 1986 to 1997, I was employed by

Jersey Central Power & Light Company in various engineering positions of increasing responsibility. I received a Bachelor of Science in Electrical Engineering and Bachelor of Arts in Economics from Rutgers University in May 1986 and a Master of Science in Electrical Engineering from Rutgers University in May 1991. I also have a Professional Engineering License.

Q. Have you previously testified before the New York Public Service Commission ("Commission")?

A. Yes. I previously submitted testimony in the 2011 O&R electric base rate case (*i.e.*, Case 11-E-0408) and the 2014 O&R electric base rate case (*i.e.*, Case 14-E-0493).

PURPOSE OF TESTIMONY

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

A. The purpose of my direct testimony is to describe O&R's historical and projected wholesale electricity supply purchases for the Company's full service customers. Historical supply purchases cover calendar years 2014 through 2016 and projected supply purchases cover calendar years 2017 through 2021, which includes the twelve months ending October 31, 2019 (“Rate Year”).

HISTORICAL SUPPLY COSTS

Q. What are the Company’s objectives when purchasing electricity supply for its full service customers?

A. The Company seeks the lowest reasonable electricity supply purchase costs for its customers, subject to reliability and contractual constraints. As part of this objective, the Company also seeks to mitigate price volatility.

Q. In what ways does the Company accomplish these objectives?

A. The Company pursues structural and tariff changes in the New York Independent System Operator’s (“NYISO”) wholesale electricity markets that are beneficial to the Company’s customers through active participation in the NYISO governance process and through filings with the Federal Energy Regulatory Commission (“FERC”). Where appropriate, the Company pursues certain matters before FERC through the use of litigation, mediation, and settlement.

Q. Please describe, in general terms, how O&R procures electricity supply for its full service customers.

A. Electric energy and capacity are procured from the NYISO’s energy, capacity, and ancillary services markets. The Company also uses physical and financial hedges to mitigate price volatility for its customers. In addition, since 2015, the Company has procured a portion of its energy and capacity supply for its full service customers through annual requests for proposals (“RFPs”) that procure supply up to three years in advance.

Q. I show you a one-page document entitled, “ORANGE AND ROCKLAND UTILITIES, INC. - WHOLESALE ELECTRICITY SUPPLY COSTS – CALENDAR YEARS 2014 THROUGH 2016,” and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (ES-1)

Q. What does Exhibit ___ (ES-1) show?

A. Exhibit ___ (ES-1) illustrates the allocated and invoiced costs, from January 1, 2014 through December 31, 2016, for energy, capacity, and other services acquired on behalf of the Company’s full service customers. I note that this exhibit shows the historic decline in the volume of the Company’s spot market purchases has ebbed and we see a reversal of that decline, which is primarily due to customers migrating from retail access to full service.

Exhibit ___ (ES-1) also identifies the net impact of the Company’s financial hedging in each of the last three years, including the cost of those hedges. The exhibit shows that the Company’s hedging costs have increased, as a result of decreasing energy prices.

Q. Please describe the Company’s spot purchases for O&R’s electric commodity customers.

A. Spot energy purchases are made from the NYISO, primarily in its day-ahead market, but also from its real-time market. The NYISO prices energy in each of those markets at 11 different load zones. O&R customers’ consumption is in NYISO’s Zone G, the Hudson Valley load zone.

The Company also makes spot capacity purchases from the NYISO’s capacity markets. The NYISO administers four capacity market areas: one for NYC, one for Long

Island, one for Lower Hudson Valley, and one for rest-of-state (“ROS”). O&R’s capacity obligation is primarily in NYISO’s Lower Hudson Valley market; however, prior to May 2014, O&R’s entire capacity obligation was in NYISO’s ROS market. The NYISO conducts auctions that allow load serving entities (“LSEs”), like O&R, to purchase capacity for a one-month period or for periods of up to six months. In general, any LSE that has not previously met all of its capacity obligations through one of these auctions, or through these auctions combined with its non-NYISO purchases, must purchase capacity from the monthly NYISO spot auctions. Prices in the spot auctions are set according to a demand curve approved by FERC. One aspect of the spot auction is that all supply offers in the NYISO’s spot auction receive a single market clearing price that is set at the intersection of the administrative demand curve and the total aggregate supply offered, so that more supply than required will continue to be available for future reliability. Such excess capacity is purchased by the NYISO on behalf of the LSEs, which are obligated by the NYISO tariff to purchase such "excess capacity."

Q. Please describe the Company's RFPs for new supply to serve O&R's electric commodity customers.

A. Beginning in 2015, the Company started to issue annual RFPs for new energy and capacity. The RFPs seek to procure new supply in yearly tranches through a forward auction. Rather than purchase all of its supply for a given year ("Delivery Year") through the NYISO markets, the Company sets aside a certain amount for purchase through the RFPs ("RFP Supply"). And rather than purchase all the RFP Supply for a Delivery Year in a single RFP, the Company's goal is to procure approximately one-third of it in each of the three years proceeding the Delivery Year. For example, if the Company reserves 600 MW of capacity supply as RFP Supply for a given Delivery Year, then it will seek to procure 200 MW of capacity supply in each of the auctions that occur in the three years that precede the Delivery Year.

Q. What kind of products does the Company seek to procure in the RFPs?

A. The Company seeks to procure either financial or physical supply. For capacity, the Company seeks to procure supply at a fixed price. For energy, the Company seeks to procure supply at either a fixed or index-based price.

Q. How are the tranches defined?

A. Energy tranches are established for the calendar year, while capacity tranches are established according to the NYISO-defined capability periods (from May 1st, the start of the summer capability period until April 30th, the end of the following winter capability period).

Q. How are RFPs conducted?

A. RFPs are conducted using a reverse blind auction to select the lowest bidders. In a reverse blind auction the names of the suppliers are masked or hidden from the utility and offers are made at decreasingly lower prices. The platform currently used for the auction is supplied by EnerNoc, which is an energy software and service provider, and discussed in detail below.

Q. Why did the Company start issuing RFPs and how do they benefit customers?

A. The Company started to issue RFPs to diversify its supply options. RFPs also have the effect of acting as a hedge.

Q. How do RFPs act as a hedge?

A. When the Company procures fixed price supply through an RFP, whether physical or financial, it acts as a hedge against price fluctuations in the NYISO markets. Index based supply aquired through an RFP does not have that same effect, however, such purchases may themseleves be hedged like spot purchases.

Q. What have been the RFP results thus far?

A. To date, all of the energy supply procured through the RFPs has been financial. The capacity procured through the RFPs has been a mix of financial and physical supply.

Q. Does the Company plan to continue conducting annual RFPs for new supply up to three years forward?

A. Yes.

Q. Please describe the Company’s financial hedging practices.

A. The Company uses financial hedge products to mitigate the volatility of its spot purchases. These products include, for example, fixed-for-floating price swaps, also known as contracts for differences (“CFDs”), and call options. CFDs are typically traded on a peak or “5x16” basis, meaning their value is computed over the 16 peak hours (*i.e.*, 7:00 AM to 11:00 PM, prevailing time) on non-North American Electric Reliability Corporation (“NERC”)-holiday weekdays. For example, a buyer of a CFD will negotiate to give the seller of a commodity at settlement a fixed price per unit of the commodity in exchange for the seller giving the buyer the market price per unit. CFDs may also be traded on an “around the clock” basis, priced at the arithmetic average of all 24 hours in a day, or on an “off-peak” basis, meaning their value is computed over eight off-peak hours (11:00 PM to 7:00 AM) during weekdays, and all weekend and NERC holiday hours. CFDs may be procured bi-laterally with a supplier or through an RFP. Call options typically provide a financial benefit to the option holder when the contracted parameters, such as spot price exceed prior agreed-upon thresholds or strike price. The premiums or purchase costs of such options are related to the volatility of the underlying product, the length of time prior to delivery and the agreed-upon strike price.

Q. Are there any other financial hedge products the Company uses to mitigate the volatility of its spot purchases?

A. Yes. As mentioned above, through an RFP, the Company procures capacity hedges for the Lower Hudson Valley to mitigate capacity price volatility. The capacity hedges for Lower Hudson Valley are not liquid and, as a result, are not ideal for procuring bi-laterally with a supplier. Capacity hedges are similar to the CFDs described above, whereby a buyer of the capacity hedge or swap (in this case O&R through an RFP), will pay a fixed price per unit to the seller at settlement in exchange for the seller giving the buyer the market price per unit at settlement. The market price at settlement is based on the Unforced Capacity (“UCAP”) Spot Market Auction Results as published by the NYISO. Capacity hedges may be financial (cash settled) or physical whereby capacity supply procured is used to offset the Company obligation.

PROJECTED SUPPLY COSTS

Q. Have you prepared a projection of wholesale energy costs?

A. Yes.

Q. I show you a one-page document entitled "ORANGE AND ROCKLAND UTILITIES, INC. - PROJECTION OF WHOLESALE ELECTRICITY SUPPLY COSTS – 2017 through 2021" and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (ES-2)

Q. What does Exhibit ___ (ES-2) show?

A. Exhibit ___ (ES-2) sets forth my projections of electricity supply costs through 2021, based upon the forecast of full service sendout provided to me by the Company's Electric Forecasting Panel.

Q. Please describe the methodology used to develop these projections.

A. As noted earlier, physical capacity and energy are supplied predominantly from spot purchases from the NYISO, with some of the physical capacity supply from the RFPs. Spot capacity purchase costs are based on a projection of capacity supply margins in the Lower Hudson Valley region as provided by the NYISO, the application of these margins to expected demand curve parameters to project prices, and then the application of these prices to the Company's expected spot capacity requirements, net of any physical capacity purchases from the RFPs, in the Lower Hudson Valley region. The costs of excess capacity, as described earlier, and ROS capacity purchases are also included in these cost projections. Spot capacity purchase costs consist of the above-mentioned cost projections and the costs of any physical capacity purchases from the RFPs.

Spot energy costs are based on market values as of September 18, 2017. These price projections were then applied to the forecast of full service volumetric requirements as provided to me by the Company's Electric Forecasting Panel.

Q. Has the net impact of financial hedges been included in these projections?

A. Financial hedges have been assumed to be "at the money," meaning that hedges will settle without a gain or a loss, thereby not affecting customers' prices for the purposes of these cost projections. However, hedges may command premiums for reducing buyers' price volatility risks and so may be expected to increase costs marginally over the long-term.

It should be noted that the Company currently hedges only for those customers with demands less than 300 kW. I would further note that in its February 26, 2008 Order in Case 06-M-1017, the Commission reiterated that utilities are responsible for taking steps to mitigate wholesale price volatility for their residential and small commercial customers. As a result of that Order, O&R and the other New York utilities publish on their Internet websites quarterly volatility reports that compare actual supply rates charged to full service customers to a hypothetical unhedged market index based on load-shaped spot market prices.

AUCTION PLATFORM

Q. What auction platform does the Company currently use?

A. As mentioned above, the Company uses EnerNoc as its current auction platform for new supply.

Q. What benefits does EnerNoc offer over other alternative auction platforms to procure energy and capacity supply?

A. Unlike most other alternatives, EnerNoc is a complete supply procurement solution because it provides the auction platform and manages every aspect of the procurement process. In other words, EnerNoc also project manages the auction.

Q. How much does EnerNoc cost?

A. EnerNOC charges suppliers that participate in the RFP auction 6.9 cents for every MWh of energy awarded and $35.80 for every MW-month of capacity awarded. In prior auctions this has added up to approximately $2.4 million dollars in annual fees collected from Con Edison and O&R suppliers, of which $200,000 was paid by O&R suppliers. These fees can be reflected in the price suppliers offer, and therefore are passed on to customers.

Q. Is the Company investigating whether there are more cost effective solutions than EnerNOC?

A. Yes. O&R is exploring using an in-house (Oracle based) solution for an upcoming auction to be conducted by Rockland Electric Company (O&R's New Jersey utility subsidiary) to hedge supply for its electric customers. In addition, there are other third-party vendor solutions available at a reduced cost compared to the EnerNoc auction platform, but they are not complete end-to-end solution packages like EnerNoc and will require auction platform customization for a fee and incremental internal labor costs to support the RFP. O&R is investigating these options.

Q. Is the Company proposing any tariff revisions which clarify that costs associated with on-line auction platforms are recoverable as a supply cost?

A. Yes. As noted above, all of EnerNOC's costs currently are passed on to customers in the supply cost. If the Company decides to pursue either an in-house or third-party alternative to EnerNOC, some costs may become disaggregated from the supply costs. The Company is proposing clarifying tariff language that allows the Company to continue to recover costs associated with using an on-line auction platform as a supply cost. These tariff revisions are also addressed in the Electric Rate Panel testimony.

Q. Has the Company decided which alternative (in-house or third-party vendor) it will pursue?

A. No. The Company has not yet made a final decision and is still exploring these two different options.

Q. Will there be capital and O&M expenses associated with either an in-house or third party auction platform for the RFP?

A. Most likely. As explained above, neither option will provide the same “end-to-end” service currently provided by EnerNOC. Therefore, the Company expects that incremental internal labor hours will be needed to support either alternative for functions that include, but are not limited to: project management, reporting, and auction administration. There may also be capital dollars needed for the purchase of a third party auction platform or enhancements to the in-house solution.

Q. Does the Company have an estimate of what such costs might be?

A. Because the Company has not yet decided which option to pursue, it does not have an estimate for capital and O&M expenses at this time. The Company expects that it will have more information relating to cost estimates for this initiative during the update phase of this proceeding.

SYSTEM ENHANCEMENTS

Q. Are there any planned Con Edison System Enhancements that will also benefit O&R?

A. Yes, there are.

Q. Please describe these initiatives.

A. Con Edison plans to undertake in 2018 the following three System Enhancements: (1) nMarket Upgrade/Replacement Project, (2) Transmission Owners Data Reporting System (“TODRS”) Next Generation Project, and (3) MetrixIDR Upgrade. For the reasons described below, it is expected that these enhancements will also provide benefits to O&R. In order to take advantage of potential synergies presented by these System Enhancements, O&R will pay its allocated portion of the capital costs associated with these enhancements, as described by the Company's Accounting Panel.

Q. Are there projected O&M expenses associated with these System Enhancements?

A. Any additional maintenance and support fees will be allocated according to the method prescribed by the Company's Accounting Panel.

Q. What is the nMarket Upgrade/Replacement Project?

A. The nMarket Upgrade/Replacement Project will upgrade or replace the existing nMarket System in order to support Electricity Supply's Physical Wholesale business requirements in implementing New York State's Reforming the Energy Vision ("REV") Initiative. These business requirements consist of the following:

- Electric supply and distributed energy resource ("DER") purchase, scheduling, and invoicing;

- Regulatory and SOX compliance; and
- Interfacing with other internal systems.

Q. Please describe why the nMarket Upgrade/Replacement Project is necessary?

A. The implementation of the REV Initiative will expand the participation of DERs in the wholesale energy markets, as well as extend the electricity markets down to the network and distribution levels. This will add complexity to Electricity Supply’s Physical Wholesale business requirements, resulting in the need to upgrade or replace the existing nMarket System.

Q. Please describe the TODRS.

A. TODRS is a program that reconciles certain costs between the NYISO and Energy Service Companies (“ESCOs”).

TODRS performs the Transmission Owner Energy Reconciliation and Load Forecast Tag reporting (“ICAP Tag”) functions required by the NYISO. Energy Reconciliation is the process by which the Transmission Owner determines the hourly contribution of each customer to actual metered zonal load recorded by the NYISO. ICAP Tag reporting determines the contribution of each customer to the forecasted annual electric peak. TODRS retrieves customer energy consumption data and supporting information from a number of sources, such as NYISO posted zonal load, the Customer Information System, the Retail Access database, the Recharge New York database, the Load Profile Display Program, and Meter Data Management database. TODRS then distributes consumption data through each hour during a month based on the customer's meter type, service class, and consumption patterns. The hourly data is then used to calculate monthly reconciled energy consumption and ICAP tags that are reported to the NYISO.

Q. Please describe the proposed upgrade to TODRS.

A. "TODRS Next Generation" will include a web interface where ESCOs and customers can view and download their hourly energy usage and capacity tag information online. This upgrade will enhance the users experience by helping them find data quickly and effectively. It will also establish an automated interface reporting process for other systems, such as MetrixIDR (described below), to extract daily data. Finally, the proposed upgrade will assist the Company in implementing expected business requirements resulting from REV and Advanced Metering Infrastructure ("AMI") implementation projects.

Q. Please describe MetrixIDR.

A. MetrixIDR is a calculation engine that forecasts the daily electric hourly load for the Company. MetrixIDR performs the daily electric hourly load forecasting that the Company's Electricity Supply Department uses to plan short-term electric purchasing.

Q. Please describe the upgrades proposed and why an upgrade is necessary.

A. The Company proposes to upgrade MetrixIDR to the latest version supported by the vendor (ITRON). Without this upgrade, the vendor will no longer support the existing system as it becomes outdated by 2018. A fully-functioning MetrixIDR is important to the Company's daily forecasting. If the system ceases to work or fails to meet the Company's forecasting accuracy standard, there can be increased challenges to daily operations. In addition, the upgraded system will further REV goals by implementing forecasting models and installing the systems necessary to provide hourly load forecasts for the Company's distribution areas/networks and radial feeders. This will also enable the Company to forecast by network/load area on a daily basis.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
COMPENSATION/BENEFITS PANEL

Q. Would the members of the Compensation and Benefits Panel (“Panel”) please state their names and business addresses?

A. Hector J. Reyes, and my business address is 4 Irving Place, New York, New York 10003. Susan Carson, and my business address is 4 Irving Place, New York, New York 10003. Roselyn Feinsod, and my business address is 199 Water Street, New York, New York 10038. Virginia Fischetti, and my business address is Merritt 7 Corporate Park, Building 201, Norwalk, Connecticut 06851.

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

A. I am employed by Consolidated Edison Company of New York, Inc. (“Con Edison”) as Director of Benefits.

Q. How long have you been employed by Con Edison?

A. I have been employed by Con Edison for 38 years.

Q. Please briefly outline your educational and business experience.

A. I graduated from Fordham University with a Bachelor of Science degree in Accounting in l976. In l982, I earned a Master of Science degree in Taxation from

Pace University. I joined Con Edison in l976 as a Staff Accountant in Corporate Accounting. Between l979 and l981, I was promoted to different supervisory positions in Corporate Accounting. In 1983, I was promoted to Assistant Manager, Accounting Research and Procedures. In l988, I was promoted to the position of Manager, Retirement and Insurance Benefits, and in l989, I was promoted to the position of Manager of Employee Benefits. In September l999, I was promoted to the position of Director of Benefits and Compensation. In July 2011, my title was changed to Director of Benefits.

Q. Please generally describe your current responsibilities.

A. My responsibilities as Director of Benefits include the development, implementation, communication, and administration of the Company’s employee benefits programs.

Q. Do you belong to any professional societies or organizations?

A. Yes. I am a member of the Board of Directors of the Northeast Business Group on Health (“NEBGH”). NEBGH is a not-for-profit coalition of over 150 health plan sponsors and health-related organizations the mission of which is to find practical solutions to contemporary health care issues in the New York metropolitan area.

Q. Have you previously submitted testimony on behalf of the Company before the New York Public Service Commission ("Commission")?

A. Yes. I have submitted testimony or testified in the last electric rate case for Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R," or the "Company") and have submitted testimony or testified in a number of Con Edison electric, gas, and steam rate cases as well.

Q. Ms. Carson, by whom are you employed and in what capacity?

A. I am employed by Con Edison as the Director of Compensation.

Q. Please describe your educational background.

A. I graduated from Fairleigh Dickinson University in 1985 with a Bachelor of Science degree in Accounting. I received a Master of Science degree in Management from New Jersey Institute of Technology in 1997. I am a Certified Public Accountant licensed in New Jersey.

Q. Please describe your work experience.

A. I have been employed by Con Edison for 11 years. I joined Con Edison in 2006 as the Director of Pension Management with responsibilities for the investment of all benefit plan assets. From 1997 to 2006, I was employed by Public Service Electric and Gas Company in a variety of functional areas at the Director level including pension management, investor relations and accounting. Prior to Public Service Electric and Gas I worked for several major corporations in a variety of accounting, long-range planning, and pension management positions. In November 2016, I assumed the position of Director of Compensation.

Q. Please generally describe your responsibilities as Director of Compensation.

A. My responsibilities as Director of Compensation include administration of the compensation plans for non-officer management employees, officers of O&R, as well as members of the Con Edison’s Board of Directors.

Q. Have you previously submitted testimony on behalf of the Company before the Commission?

A. No.

Q. Ms. Feinsod, by whom are you employed and in what capacity?

A. I am a Senior Partner and East Region Practice Leader for Retirement for Aon. I have worked with utilities such as Ameren Corporation, GPU, Inc., and PPL Corporation, in addition to O&R and Con Edison.

Q. What is Aon?

A. Aon provides risk management services, insurance and reinsurance brokerage, and human resource consulting services worldwide. The company operates through two segments, Risk and HR Solutions. More information on Aon is available at aon.com.

Q. Please summarize your educational and professional background.

A. I am a graduate of the College of Insurance with a Bachelor of Science in Actuarial Science. Before joining Aon, I was a Principal and a senior workforce strategy and retirement plan consultant to large global clients at Willis Towers Watson, formerly

Towers Perrin. At Aon, I am the Retirement Regional Leader for the East Region and a consultant to clients on compensation, benefits, and retirement issues. I specialize in workforce and total rewards strategy, mergers and acquisitions, and all aspects of retirement valuation and administration consulting. I have nearly 25 years of experience in consulting, having spent eight years with Towers Perrin and ten years with PricewaterhouseCoopers LLP prior to joining Aon.

Q. Do you belong to any professional societies or organizations?

A. I am a Fellow of the Society of Actuaries, and I have spoken at numerous professional conferences including World at Work, The Conference Board, the American Gas Association, and The Harvard School of Continuing Public Health.

Q. Have you previously submitted testimony on behalf of the Company before the Commission?

A. Yes. I filed testimony in the most recent Orange and Rockland electric and gas rate cases and filed testimony in the most recent Con Edison electric, gas, and steam rate cases.

Q. Ms. Fischetti, by whom are you employed and in what capacity?

A. I am a Partner and East Region Practice Leader for Executive Compensation for Aon. I have worked with utilities such as Avangrid, Constellation Energy Group, Inc., Dominion Resources, Public Service Electric and Gas Company, and NRG Energy Services in addition to O&R and Con Edison.

Q. Please summarize your educational and professional background.

A. I am a graduate of Amherst College with a Bachelor of Arts degree in Economics. I also have a MBA, Finance and International Business, from New York University's Stern School of Business. Prior to joining Hewitt Associates (previously Aon Hewitt, and now, Aon) in l997, I worked as a benefit and compensation consultant for Watson Wyatt (now Willis Towers Watson) in New York. At Aon, my work includes the benchmarking of total compensation, the design and implementation of compensation strategies and philosophies, pay structures, short-, mid-, and long-term variable pay programs, and severance and change-in-control benefits.

Q. Are you affiliated with any professional societies or organizations?

A. Yes. I am a member of The Conference Board, a global, independent business membership and research association working in the public interest. In addition, I have spoken to Society for Human Resource Management audiences on the topic of compensation and have had a cover article appear in the World of Work Journal (4^{th} quarter, 2005).

Q. Have you previously submitted testimony on behalf of the Company before the Commission?

A. Yes. I filed testimony in the most recent Orange and Rockland electric and gas rate cases and filed testimony in the most recent Con Edison electric, gas, and steam rate cases.

PURPOSE OF TESTIMONY

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

A. The purpose of our testimony is to demonstrate that the costs of the Company's benefits and compensation plans are reasonable business expenses that should be recovered in rates. The Panel's testimony demonstrates that the Company provides market-competitive benefits and compensation packages designed to attract and retain those employees the Company requires to provide customers with safe and reliable service. The Company continues to proactively manage long-range costs like those related to pensions and health care.

This direct testimony examines the overall level of employee "Benefits" and "Compensation" reflected in the revenue requirements of this filing and demonstrates that the Company's level of benefits and compensation in aggregate is market-competitive and meets the Commission's standards for assessing the overall competitiveness and reasonableness of such expenditures. The costs of the Company's benefits and compensation plans constitute reasonable business expenses that should be recoverable in rates for the reasons discussed below.

Q. What are the elements of the Benefits package that are reflected in the revenue requirements of this filing?

A. Benefits include retirement, active and retiree health, vacation, life insurance, and disability benefits.

Q. What are the elements of Compensation that are reflected in the revenue requirements of this filing?

A. Compensation includes base salary, the variable component of management pay (also known as the "Annual Team Incentive Program" or "ATIP"), and long-term equity grants.

Q. Has the Commission articulated criteria to determine whether the costs associated with a utility's benefits and compensation plans should be recoverable in rates?

A. Yes. In the Commission's rate order, issued February 21, 2014 in the Con Edison rate cases filed in 2013 (Case 13-E-0030, 13-G-0031, 13-S-0032)("Con Edison Rate Cases"), the Commission indicated that a utility should demonstrate the overall competitiveness and reasonableness of its total benefits and compensation package by including a comparison with a peer group comprised of similarly situated companies, including both utilities and general industry. In its rate order issued June 26, 2014 in the United Water New

York, Inc. rate case (Case 13-W-0295), the Commission reaffirmed that to obtain recovery of variable pay, a utility must demonstrate that the overall compensation, including the variable pay component, is reasonable relative to similarly situated companies.

Q. Has the Commission addressed any other criteria with respect to evaluating recovery of costs associated with a utility's benefits and compensation package?

A. Yes. In its rate order in the 2013 Con Edison Rate Cases, the Commission noted with approval Con Edison's willingness to conduct its comparative compensation/benefits study to achieve at least a 50 percent matching of positions in a blended peer group of utilities and New York metropolitan employers.

Q. What will the Panel address?

A. The Panel will address: (1) a review that the Company conducted, with the assistance of Aon, of O&R's total benefits and compensation package ("Review") in 2017 for non-officer management employees; (2) recent changes to its compensation and benefits plans for non-officer management employees, (3) officer and O&R Board of Directors ("O&R Board") compensation; (4) the

Company’s current labor contract (“Labor Contract”) with Local 503; and (5) employee benefits costs.

Q. What was the purpose of the Review?

A. The purpose of the Review was to assess the market competitiveness of the Company’s total benefits and compensation package for non-officer management employees of O&R. The Panel describes below the Review process, methodology, and results.

Q. In conducting the Review, did the Company re-evaluate its benefits and compensation package as compared to those offered by similarly situated companies?

A. Yes. Consistent with Commission policy and typical market practice, in assessing the overall competitiveness and reasonableness of O&R’s benefits and compensation package, the Review compared the Company’s package to those offered by a peer group of similarly situated companies.

Q. Were the peer companies limited to utility companies?

A. No, as recommended by the Commission, the Company evaluated total benefits and compensation relative to a blended peer group including both utility and non-utility, New York metropolitan general industry companies (“Blended Peer Group”).

Q. What were the Review’s overall findings with respect to the Blended Peer Group analysis?

A. As explained below, the Review found that the Company’s benefit programs and compensation for its non-officer management employees, as well as the combined benefits and compensation package value, are within a +/- ten percent range that is considered “competitive” with respect to the Blended Peer Group. In fact, the Company’s benefits and compensation programs are below the median of the Blended Peer Group.

Q. Did the Company make any recent changes to its benefits and compensation plans since its prior rate filing?

A. Yes. In 2015, the Company made modest improvements in the variable pay targets for the ATIP. This change was made to further align the compensation of the Company’s non-officer management employees with peer companies. The improvements ranged from one-half to four percent, depending on the band as noted in the table below.

Band	2014 ATIP Target	2015 ATIP Target
4H	21%	25%
4L	17%	21%
3H/3L	12%	15%
2H	7.5%	9%
2L	6%	7%
1H	5%	6%
EP/AL/AH	4.5%	5%

Q. Did the Company make any other changes?

A. Yes. In addition, the Company made three changes to its benefit plans:

1. The Company's defined benefit retirement plan was closed to new management hires effective January 1, 2017. Instead, pension benefits for an employee hired after January 1, 2017 are now provided through a defined contribution pension formula under the Thrift Savings Plan.

2. The Company added automated features in 2017 to the Thrift Savings Plan including auto-enrollment and auto-escalation.

3. A new, lower cost, Essential Health Plan was

added in 2017 as a medical plan choice for management participants.

Q. Does the rate request include compensation for members of the O&R Board?

A. Yes. One member of the three-person O&R Board, who is not an employee of either the Company or Con Edison, receives compensation. This non-Company/Con Edison O&R Board member receives an annual retainer of $35,000.

Q. Does the rate request include compensation for officers of the Company?

A. The rate request reflects only some elements of compensation for officers. The Company's compensation program for the Company's officers includes base salary, annual variable pay awards, long-term equity grants, and benefits. Such compensation constitutes a reasonable and necessary business expense the Company must incur to attract and retain qualified leaders to direct and oversee the safe and reliable operations of the Company. In order to limit the contested issues in this filing, the Company is electing not to seek recovery of the long-term equity grants and annual variable pay awards provided to the Company's officers. The Company may seek to recover all or part of these elements of compensation in future proceedings.

Q. Please address the Labor Contract.

A. The Labor Contract constitutes a fair and equitable contract that includes benefits and compensation programs that will continue to attract and retain qualified employees and that will reflect the needs of all stakeholders – employees, customers, and regulators – and supports the long-term sustainability of the Company. As discussed in more detail below, the Labor Contract is cost-effective and competitive, and will result in long-term savings primarily associated with changes to retirement benefits for current and future employees who are members of Local 503.

Q. Does the Panel address employee benefit expenses?

A. Yes, this direct testimony explains the forecast of employee benefit expenses based on historic costs and escalation of existing programs. This direct testimony also addresses program changes that the

Company has implemented for management employees, as well as the changes resulting from the Labor Contract. The Company made three changes to its employee benefit programs:

1. The Company’s defined benefit retirement plan was closed to new management hires effective January 1, 2017. Instead, pension benefits for employees hired after January 1, 2017 are provided under the Thrift Savings Plan through a defined contribution pension formula. The defined contribution pension formula provides the same compensation credits as the Cash Balance pension formula under the defined benefit retirement plan which is based on “points” (the sum of age plus service). The range is from 4 percent of earnings below the Social Security Wage Base (“SSWB”) plus 8 percent of earnings above the SSWB at 35 points or less to a maximum of 7 percent of earnings below the SSWB and 11 percent of earnings above the SSWB at 64 or more points. Earnings are based on an employee’s annual salary rate plus variable pay.

2. The Company added automated features in 2017 to the Thrift Savings Plan for both the management and Local 503 employees including auto-enrollment and auto-escalation. Participants who join the plan are enrolled at a contribution rate of 2 percent. In addition participant contributions to the Thrift Plan will increase by 1 percent per year up to 10 percent of pay.

3. A new, lower-cost Essential Health Plan with an HSA was added effective January 1, 2017 as a medical plan choice for management participants and effective January 1, 2018 for Local 503 employees. For the management participants, the plan features an annual deductible of $2,500 for individuals and $5,000 for families, with an 80 percent co-insurance for medical expenses incurred after the deductible is met. There are no required employee payroll contributions for this plan. Health costs shown in the exhibits are net of participant out-of-pocket payments such as co-payments and deductibles that are paid to providers for medical services. The plan

provisions for the Local 503 plan are discussed below. This direct testimony also reflects the Company’s wellness efforts and plan design changes that are expected to mitigate future plan cost increases. The Company’s employee benefit expenses are estimated to increase approximately 41 percent from the historic test year (*i.e.*, 12 months ended September 30, 2017)(“Historic Year”) to the end of the third rate year (*i.e.*, 12 months ending December 31, 2021)(“Rate Year”)or approximately 9.5 percent per year

Q. What other cost mitigation actions with respect to health care has the Company taken?

A. The Company has introduced several plan features intended to promote wellness and reward employees for using lower-cost services and in-network providers. In addition, wellness initiatives are enhanced to encourage healthy behaviors and mitigate future health care expenses.

Q. What other cost mitigation actions with respect to Pensions has the Company taken?

A. As noted above, the Company has closed its defined benefit pension plan to those management employees hired by the Company after January 1, 2017. Instead of accruing pension benefits under the defined benefit plan, new employees receive a non-contributory contribution each quarter to their Thrift Savings Plan account based on a “points” formula, where points are the total of an employee’s age and service. See the table below for the formula:

	Compensation Under the SSWB	Compensation Over the SSWB
<35	4%	8%
35-49	5%	9%
50-64	6%	10%
65+	7%	11%

The Company expects that this will reduce the long-term cost and risk of the defined benefit plan and reduces the longevity and investment risk of these future benefits.

There is not a near-term cost impact of the pension plan change given that the same formula is provided in the Thrift Savings plan that was provided in the defined benefit pension plan. The change to automatically enroll participants at two percent and escalate the contributions does not have a near-term cost impact given the high current Thrift Savings Plan participation and employee contribution rates at O&R.

Q. What other cost mitigation actions with respect to Post-Employment Benefits other than Pensions (“OPEBs”) has the Company taken?

A. The Company continues to take advantage of the Affordable Care Act (“ACA”) tax savings made available to employers providing prescription drug benefits to Medicare-eligible retirees. The plan known as an Employer Group Waiver Plan (“EGWP”), as described below, offers subsidies and reimbursements that reduce the cost of prescription benefits provided to Medicare-eligible retirees. The Company also made a change that is expected to significantly reduce health care plan enrollments of new retirees in the future. Effective January 1, 2013, those management employees who participate under the Cash Balance Pension Plan formula are responsible for paying for the full cost of retiree health coverage when they retire. Effective January 1, 2015, the eligibility rule for participating in the retiree health program was changed for union employees requiring additional service for each employee who retires on or after January 1, 2015. The service requirement was changed from 10 to 20 years for employees retiring at age 55 or older in order to be eligible to participate in the Retiree Health Program. In addition, future union retirees will pay more for their retiree health coverage. Each eligible employee who is hired on or after January 1, 2015, or their surviving spouse who is eligible to enroll in the retiree health program, will be responsible to pay fifty percent (50 percent) of the premium cost for Retiree Health Care Program coverage. It is expected that instead of enrolling in the Company’s retiree health care program, future retirees will choose to enroll in a lower-cost health care plan offered in the marketplace, such as through a public exchange.

Q. Has the Company compared its total benefits and compensation package with those of a peer group comprised of similarly situated companies?

A. Yes. O&R retained Aon to conduct a comprehensive review of its total benefits and compensation package for non-officer management employees, *i.e.*, the Review. Aon was selected because it is an industry leader in this type of review and has the experience, survey data, and tools needed to analyze the competitiveness of various benefit and compensation plans.

Q. Did Aon conduct the Review addressed in this testimony?

A. Yes, Aon conducted the Review.

REVIEW METHODOLOGY

Q. Please provide an overview of the general approach of the Review.

A. The Review compared O&R's non-officer management employee benefits and compensation package values to external benchmark data for the following components:

- Employee benefits (including pre- and post-retirement and Supplemental Retirement Plan ("SRP") benefits);
- Base salary;

- Variable pay; and
- Long-term equity grants.

Q. Please describe the peer companies that were used in the Review to analyze the competiveness and reasonableness of the Company's management benefit plan designs and annual benefit and compensation package values.

A. A peer group of 50 companies (*i.e.*, the Blended Peer Group) was used for comparison purposes, including 25 utility peers and 25 New York metropolitan general industry peers.

Q. Is the Panel sponsoring an exhibit in connection with the Blended Peer Group used in this analysis?

A. Yes. Please see the exhibit entitled "Peer Group and Geographic Differentials."

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-1)

Q. Was the exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please describe the Blended Peer Group.

A. The 25 utility peer companies have similar operations to Orange and Rockland and have employees with similar experience and skills in the utility industry as Orange and Rockland. The 25 New York metropolitan general industry peers include general industry companies with headquarters located in the New York metropolitan area (*i.e.*, New York, New Jersey, Pennsylvania, and Connecticut), and that have a significant number of salaried and hourly employees in the New York metropolitan area. These companies have similar operations to Orange and Rockland in its non-utility-specific areas such as finance, information technology, human resources, and legal. Together this group of 50 companies is representative of the labor market for management employees at Orange and Rockland. The Blended Peer Group also reflects a sample that has available data for both compensation and benefit benchmarking based on survey participation.

Q. Is the Blended Peer Group used in the Review identical to the blended peer group that Orange and Rockland used in its last electric and gas base rate cases (Case 14-E-0493 and 14-G-0494)?

A. No. The companies in the 2014 Blended Peer Group and the 2017 Blended Peer Group are largely, but not completely, identical. The need to substitute new companies into a peer group often occurs because not every company continues to participate in the information surveys that provide the data necessary for a benefit-compensation comparison. When that occurs, we substitute, as we did here, new peer companies that are similarly situated to O&R.

Q. Does the change in the participants in the Blended Peer Groups impact the overall findings of the analysis?

A. No. We have a sufficiently large enough sample size such that the selected companies continue to maintain a balance between New York Metropolitan General Industry and utility companies. The companies used for benchmarking depends on their annual survey participation.

Q What is included in the employee benefits value analysis?

A. There are two components to the benefit analysis. The first component is the employee benefits design analysis which compared the design features of the benefits programs at Orange and Rockland (*e.g.*, health plan co-payments, deductibles, and co-insurance) to the design features of the benefits programs at the members of the Blended Peer Group.

The second component is the benefit package value analysis. The benefit package value analysis includes a pay-weighted assessment of the program features that are based on salary (*e.g.*, pension benefit accrual formulas, thrift savings plan company match percentages, and the definition of covered pay).

Q. Please continue.

A. The annual benefit package value at Orange and Rockland was measured against the annual benefit package value of the peer companies' benefit designs to compare how compensation-based benefit programs affect the total value of the benefits packages included in the comparison. If, for example, an employee at Company A earns more pay than an employee at Company B in the same position, then the value of a Thrift Savings Plan company match (*i.e.*, five percent of pay) to the employee at Company A will be higher.

The employee benefit analysis performed in this manner allows for a more accurate comparison of the value of a benefits package than an analysis that is performed on a pay-neutral basis.

Q. Please describe the process used to assess the benefit designs of the benefits programs of the Company and its peer companies.

A. The benchmarking of employee benefits design was done using Aon's Benefit Index© ("Benefit Index"). The Benefit Index is a premier tool for comparing the relative worth of one company's benefits programs to those offered by a group of other companies. It has been used by companies since the 1970's to make such assessments.

Q. How are the benefit design competitiveness assessments made?

A. Benefit Index results are reached using a very specific process. Actuarial techniques measure the total value a representative population of employees would derive from O&R's benefits program and the benefits programs of each of the peer companies. All retirement income, death, disability, health care, and paid time-off benefits offered to employees are included, such as vacation and paid holidays. This actuarial analysis reflects the benefits that each program would be expected to pay during a year or the present value of the benefits employees would be expected to earn during a year but receive in the future. The same employee population and assumptions are used when measuring the values for each of the programs. This standardization verifies that the differences are attributable to plan designs, not pay levels. The impact of pay level differences is assessed in the benefit package value analysis of the Review. Finally, the benefit design features of O&R's benefits program were compared to the average for the peer companies' programs to arrive at a relative benefit design result reported by the Benefit Index.

Q. What is a Benefit Index benefit design result?

A. A Benefit Index benefit design result of 100.0 would be assigned if O&R's benefits exactly equaled the average of the benefits package value offered by the peer companies. Generally, differences in the overall benefit package value are not considered significant or material until they exceed ten percent (*i.e.*, less than 90.0 or greater than 110.0 as compared to O&R). A Benefit Index benefit design result within this range would be viewed as "competitive."

Q. Which benefits programs are included?

A. The benefits analyzed included the following programs to which an annualized value was attributed:

- **All Post-Retirement Benefits:** Post-retirement benefits reviewed included pension, thrift savings (401(k) and defined contribution pension plan), retiree health, hospital, medical, vision care, prescription drug, and life insurance.
- **All Pre-Retirement Benefits:** Pre-retirement benefits reviewed included hospital, medical, dental, hearing, and vision, and sick, short- and long-term disability, and paid vacation and holidays.

Q. Is the Panel sponsoring an exhibit in connection with the Benefit Index results used in this analysis?

A. Yes. Please see the exhibit entitled "BENEFIT INDEX RESULTS."

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-2)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT___(CBP-2).

A. This exhibit summarizes the details of the results of the Benefit Index analysis of the current O&R benefit plan designs, including a comparison to the Blended Peer Group.

In aggregate, the O&R benefit plan, with a Benefit Index design score of 106.4, is within a +/- ten percent range (*i.e.*, between 90 and 110) that is considered “competitive” with respect to the Blended Peer Group.

Q. Did the Panel also analyze the competitiveness and reasonableness of the Company’s management compensation components?

A. Yes.

Q. How was the compensation competitiveness assessment made?

A. The compensation competitiveness assessment included a comparison of base salary, annual variable pay (at target), and long-term equity grants for O&R positions and for the Blended Peer Group positions. The annualized value of each pay component is included in the analysis (*e.g.*, annual base salary).

Q. How did Aon combine the Benefit Index results with the compensation benchmarking to develop the total benefits and compensation package value?

A. Aon followed a standard methodology consistent with industry practice and that Aon employed in the last Orange and Rockland rate case in 2014. First, Aon determined which positions at O&R matched positions among the Blended Peer Group, based on a comparison of functional responsibilities, job duties, and organizational level for which data is available from the survey sources. Next, Aon compared the benefit and compensation data for each of these positions at O&R to the benefit and compensation data for the same positions among the Blended Peer Group companies. Finally, Aon aggregated these results to evaluate O&R's overall competitive position relative to the Blended Peer Group median.

Q. Why did Aon compare O&R total benefits and compensation to the median, but compared the O&R

benefit designs to the average for the Benefit Index?

A. Median and average are both reasonable methods to make observations in a data analysis, and either may be used when doing a total benefits and compensation analysis. However, the use of median is an industry practice in total benefits and compensation studies because the median normalizes a data sample by placing equal emphasis on each observation, thereby mitigating the influence of extreme outlier values, if any. In benefit design reviews, the need to mitigate for extreme outliers is less important (program designs, not pay levels, are being examined). Therefore, it is a standard industry practice to use market average or market typical design when analyzing program design features.

Q. If the analysis were based on the average instead of the median in the total benefits and compensation study, would the result have been materially different?

A. No. The Blended Peer Group results are substantially similar using both market reference points. Using the median, O&R’s total benefits and compensation was 5.1

percent below the Blended Peer Group median (or 94.9 percent of the median). Using the average, O&R total benefits and compensation was 3.0 percent below the Blended Peer Group average (or 97.0 percent of the average).

Q. What companies were used to assess the competitiveness of O&R’s total benefits and compensation package value?

A. The Blended Peer Group was used in all of the analysis: the benefits design benchmarking and the total benefits and compensation positional analysis.

Q. What data sources were used for the Review?

A. Three data sources were used, all using the same Blended Peer Group: (1) the Aon Benefit Index Database; (2) the Aon Total Compensation Measurement Database; and (3) the Willis Towers Watson Compensation Survey.

Q. Was the compensation survey data adjusted for geography?

A. Yes. It is a common industry practice to use national compensation data for analyzing management level roles. However, given O&R’s metropolitan New York location, a location with a significantly higher than national cost of labor, a geographic adjustment was applied to the national data (*i.e.*, those utility members of the Blended Peer Group located outside the New York metropolitan area) to account for this cost of labor difference relative to the Blended Peer Group data used in the Review.

Q. How many non-officer management positions and employees were included in the total benefits and compensation analysis?

A. To provide a robust representation of the Company’s non-officer management employee base, Aon compared approximately fifty-five percent of the O&R non-officer management employees (*i.e.*, 292 employees) across the Company’s pay structure to the Blended Peer Group companies.

Q. Is fifty-five percent coverage sufficient to draw valid conclusions from the Review?

A. Yes. The positions included in the analysis covered several functional areas: Electric Operations, Gas Operations, Customer Service, and Information Technology, among others, and all of the non-officer management salary bands at O&R with significant numbers of non-officer management employees: 1L/1H, 2L/2H, 3L/3H, and 4L/4H. The results of the analysis, therefore, are representative of O&R’s pay positioning across the entire non-officer management employee population.

Q. Why were some O&R non-officer management positions excluded from the Review?

A. In performing the positional analysis, benchmark jobs were identified for approximately 97 percent of O&R’s non-officer management employees (*i.e.*, 518 employees). The remaining 3 percent are in positions at O&R that were not included in the compensation survey data sources. Of the 97 percent “benchmark” jobs, there was sufficient Blended Peer Group data to provide analysis for 292 of O&R’s non-officer management employees.

Summary of Benchmarking

	Employee Count	Percentage of Employees
Benchmark Identified - Data Available	292	54.9%
Benchmark Identified - Insufficient Data Available	226	42.5%
Non-Benchmark Role	14	2.6%
Total Employees	532	

Q. Why were some of the “benchmark” jobs not included in the Review?

A. For some benchmark jobs, there was insufficient data reported by the Blended Peer Group companies to the compensation survey sources to include the position in the Review. In performing the positional analysis Aon adhered to the United States Department of Justice safe harbor guidelines, which indicate the need for a minimum of five data points with no more than 20 percent of the sample from any single peer company. If fewer data points were available for a benchmark position, Aon excluded that position from the Review.

Q. Is the Panel sponsoring an exhibit in connection with the positions included in the Review?

A. Yes. Please see the exhibit entitled “CENSUS”.

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-3)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT___(CBP-3).

A. This exhibit lists all non-officer management positions at O&R, and whether the position was included in the Review. Positions were excluded for one of the following reasons:

- “Insufficient Benchmark Data” indicates the O&R position is a benchmark position but there is insufficient Blended Peer Group data (*i.e.*, less than five comparator matches) to include the position; or
- “Non-Benchmark Job” indicates the O&R position is

not similar to any survey benchmark positions in terms of functional responsibilities, job duties, and/or organizational level.

Q. Is the Panel sponsoring an exhibit in connection with the competitive positioning of Total Benefits and Compensation of O&R positions benchmarked as part of the Review?

A. Yes. Please see the exhibit entitled “Total Benefits and Compensation Results.”

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-4)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT___(CBP-4).

A. This exhibit identifies the O&R employee positions included in the comprehensive review as compared to the Blended Peer Group. This exhibit includes the following information:

- Band;
- O&R title and department;
- Benchmark title;

- O&R total benefits and compensation;
- Market total benefits and compensation at the 50th percentile (median) and average; and
- Variance for each O&R position to market using the average and the median.

Q. What did Aon's analysis indicate when comparing O&R to the Blended Peer Group?

A. In the aggregate, Aon found that O&R's non-officer management total benefits and compensation package value to be "market competitive." O&R's total benefits and compensation was 5.1 percent below the Blended Peer Group median (or 94.9 percent of the median). Using the average, O&R total benefits and compensation was 3.0 percent below the Blended Peer Group average (or 97.0 percent of the average).

Q. Is the Panel sponsoring an exhibit in connection with the results of the Aon analysis?

A. Yes. Please see the exhibit entitled "SUMMARY OF RESULTS."

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-5)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT___(CBP-5).

A. This exhibit identifies the aggregate results, relative to both the average and the median of the Review Aon performed using the Blended Peer Group by each component of total benefits and compensation discussed above:

- Base Salary;
- Target Cash Compensation (sum of Base Salary and the variable component of management pay, assuming target performance);
- Long-term equity grants;
- Total Direct Compensation (sum of Target Cash Compensation and long-term equity grants);
- Total Benefit Value (estimated annual value of employee benefits); and
- Total Benefits and Compensation (sum of Total Direct Compensation and Total Benefit Value).

Q. Please provide a summary of the Blended Peer Group analysis findings with respect to the annual variable pay.

A. The O&R target annual ATIP award opportunities lag the market at most Band levels, even after taking into account the modifications to ATIP award opportunities since the last rate filing.

Q. Is the Panel sponsoring an exhibit in connection with the findings regarding annual ATIP award opportunities?

A. Yes. Please see the exhibit entitled “ANNUAL VARIABLE PERFORMANCE-BASED PAY COMPARISONS.”

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-6)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT___(CBP-6).

A. This exhibit identifies the O&R Band and the annual ATIP target award opportunity for employees in each Band compared to the range of and median target annual variable pay award opportunities for employees at the Blended Peer Group companies at equivalent salary levels.

Q. Please summarize your findings.

A. In summary, the results of the Review demonstrate that the costs of the total benefits program and compensation, including the variable and long-term equity components of non-officer management base pay, and SRP, are appropriate business expenses incurred so that the Company can meet its obligation to provide safe and reliable utility service to its customers. Accordingly, the Company has included the costs of these programs in the gas and electric revenue requirements.

NON-OFFICER COMPENSATION

Q. Please describe the Company's overall compensation philosophy.

A. The philosophy of the Company is to provide compensation that is competitive with the median levels of compensation provided by a peer group of similarly situated companies. This approach to setting compensation levels permits the Company to be reasonably competitive in the labor market and to be able to attract, and fairly compensate, employees important to the success of the Company. In targeting the median levels for compensation measured against a market competitive norm, the Company has taken a conservative, low-cost approach, which benefits its customers.

Q. Does the base compensation for O&R’s non-officer management employees include base salary, variable pay component, and a long-term equity grant component?

A. Yes.

Q. Is O&R unusual in its inclusion of a variable pay component as part of base compensation?

A. No. Tying a portion of employees’ base compensation to performance has become commonplace both in American business generally and for public utilities as well.

Q. Please continue.

A. The variable pay component of base compensation in the Company’s plan is earned only if the Company reaches pre-set financial and operating performance goals that are directly linked to specific measurable standards consistent with the Company’s goal of providing safe and reliable service to customers. These performance goals encompass reliability, safety, customer-service performance indicators, environmental excellence, public safety and effective cost management. The specific performance goals are tracked on a calendar year basis and must be achieved each year.

Q. Has the Commission addressed its standards for recovery of the variable component of management pay?

A. Yes, the Commission has addressed this topic in several O&R rate case related orders. In its *Order Denying Petitions for Rehearing and/or Clarification* issued on November 21, 2011, in Case 10-E-0362 (p. 6) the Commission stated:

> The second point we wanted to emphasize is that it is not necessary to maintain an artificial distinction between compensation in the form of traditional pay and benefits and compensation that is incentive based. As we have stated previously, we recognize that variable compensation and incentive plans are common management tools aimed at encouraging performance improvements that can lead to more competitive operations. Consequently, if a utility can demonstrate that total compensation including incentive compensation for a class of employees is reasonable, with a comparable total compensation study of similarly situated companies being the preferred methodology, our concern about the relationship of incentive plan objectives to ratepayer interests is substantially diminished. As long as the plan does not promote employee behavior that would be contrary to ratepayer interests or Commission policies, the fact that it may contain financial, budgetary or other goals that

> benefit shareholders as well as ratepayers will not, by itself, be grounds for disallowing funding in rates, even if the relative benefits are unquantified.

Q. Please describe the O&R ATIP.

A. ATIP is the variable pay component of non-officer management compensation. The ATIP performance measures are approved by the O&R Board at the start of the performance period. At the conclusion of the performance period, actual results are compared to the established targets and final results are approved by the Board. ATIP represents the portion of employees' annual base salary that is dependent upon the attainment of certain predetermined, measurable corporate and individual goals. ATIP must be earned each year. In linking a portion of annual salary to defined and measurable performance criteria, the Company's compensation philosophy strives to reward each employee's contribution to the overall operating, customer service performance, and financial strength of the Company.

Q. Which employees are eligible for ATIP?

A. ATIP is available to all management employees and includes both team and individual components. The team portion of the award comprises 60 percent of the total available award and the individual portion of the award comprises 40 percent. Each employee's potential individual award is based on the individual's contribution toward the overall corporate initiatives and achievement of goals, and on his or her position within the non-officer management salary bands of O&R. ATIP goals are established annually and include both operating and customer service and financial targets. The O&R Board approves the corporate goals, and the corporate award in the first quarter following the completion of the plan year.

Q. Please continue.

A. The ATIP goals for 2017 included Customer Service (weighted at 50 percent), Operating Budget (weighted at 25 percent), and Net Income (weighted at 25 percent) and Capital Projects (5 percent). Fully 75 percent of ATIP goals are achieved through customer service and managing the Company's operating budget. This combination sends the proper signals so that employees focus on providing the highest levels of customer service while remaining focused on seeking cost savings and efficiencies. When Company employees are within or under budgets that are reflective of productivity and/or cost savings initiatives, customers receive the tangible benefit of lower costs for the provision of service in the long term.

Q. Please describe the Customer Service goals.

A. The Customer Service goal includes 20 distinct measures that fall into four categories – Employee and Public Safety, Environmental and Sustainability, Operational Excellence and Customer Experience. Payout for the achievement of the Customer Service goal is based on the number of individual targets achieved, with no payout for the Customer Service Goals if less than 12 of the 20 targets are attained.

Q. Is the Panel sponsoring an exhibit listing the Customer Service Goals?

A. Yes. Please see the exhibit entitled “Customer Service Performance Metrics - 2017.”

MARK FOR IDENTIFICATION AS EXHIBIT___(CBP-7)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes.

Q. Please explain the information set forth in EXHIBIT___(CBP-7).

A. This exhibit lists each of the twenty customer service goals, the unit of measure, and the 2017 targets.

Q. How do customers benefit from the attainment of Customer Service goals?

A. These goals are established to enhance particular areas of public and employee safety, environment and sustainability, operational excellence and customer experience. To the extent that such goals are achieved, customers benefit directly. The Company's concern for customer satisfaction and providing a high level of service and overall safety is demonstrated in linking ATIP compensation to particular goals. For example, operational excellence is demonstrated in setting the Outage Frequency goal and Outage Duration goal. Managing calls answered, processing of customer service applications, and keeping appointments demonstrate concern for customer service and satisfaction. Other examples of direct customer benefits from the attainment of ATIP goals include: the Storm Scorecard goal which measures the Company's efficiency in managing storm situations and is aimed at quick restoration of customer utility service during storms; the Employee and Public Safety goals are aimed at protecting the work force and the public but could lead to reduced insurance costs as accident incident rates are reduced; and the Environment and Sustainability goals are intended to motivate a rigorous focus on environmental compliance and continuous improvement of the Company's environmental stewardship.

Q. How do customers benefit from the attainment of the Operating Budget, Net Income, and Capital Projects goals?

A. Customers benefit both directly and indirectly when the Operating Budget, Net Income, and Capital Projects ATIP goals are achieved. Customers derive benefits from achieving the net income levels that attest to the Company's financial strength and stability. O&R competes for capital in a capital-intensive industry. A company that attains rigorous financial and operating budget goals will ultimately benefit its customers.

Q. Why should the Company be permitted to recover the cost of long-term equity grants?

A. The Company provides long-term equity grants to non-officer management employees to promote employee behavior to drive the future success of the Company and to retain quality employees critical to achieve this success. Payouts are made only after the consistent demonstration of achieving performance indicators over a period of time, as measure by the three-year average of the ATIP. Equity grants are a component of the overall compensation and benefits package for non-officer management employees and are a necessary and reasonable business expense incurred by the Company in order to attract the talented employees necessary to provide safe and reliable service. Long-term equity grants are included as part of the overall total compensation package for non-officer management employees that is below the median compensation levels compared with the Blended Peer Group.

Q. How much is reflected in the revenue requirement for equity grants?

A. As set forth in Accounting Panel Exhibits AP-3, the revenue requirements reflect the following: $312,000(RY1), $320,000(RY2), and $329,000(RY3) for electric equity grants and $154,000(RY1), $158,000(RY2), and $163,000(RY3) for gas equity grants.

COMPENSATION PROGRAM FOR OFFICERS

Q. What are the elements of the Company’s compensation program for its officers?

A. The elements of the Company’s compensation program are the same for officers as they are for non-officer management employees -- base salary, a variable component, and long-term equity grants that are competitive with the median levels of officer compensation provided by a peer group of comparable companies.

Q. Please describe how the Company establishes compensation levels for officers.

A. The Management Development and Compensation (“MD&C”) Committee of the CEI Board of Directors establishes, reviews, and administers the officer compensation program for all officers, including the President and CEO of Orange and Rockland and the Vice Presidents of Orange and Rockland. The MD&C Committee has retained Mercer, a wholly-owned subsidiary of Marsh & McLennan Companies, Inc., as an independent compensation consultant, to provide it with information, analyses, and recommendations regarding officer compensation.

Q. How does Mercer benchmark officer compensation?

A. Mercer uses an industry peer group of publicly-traded utility companies and general industry companies to benchmark the compensation paid to all officers.

Q. Please explain the information set forth in EXHIBIT___CBP-8 (Officer Compensation Benchmarking).

A. This exhibit lists all officer positions at Orange and Rockland and the benchmarked total compensation, by element as provided by Mercer to the MDC in July 2017.

Q. Please explain the information set forth in EXHIBIT___CBP-8 (Officer Compensation Benchmarking).

A. This exhibit provides the benchmark results, by component of compensation (Base Salary, Variable Pay, and Long-Term Equity) for the Orange and Rockland officer positions. For each component, the exhibit provides:

- Position Title;
- Current Base Salary (February 2017);
- Market benchmark at the 25th, 50th, and 75th percentile for each component; and
- Total Compensation (dollar amount) for the Orange & Rockland officers, as well as the 25th, 50th, and 75th percentile benchmark levels.

Q. What conclusions can be reached from the benchmarking results?

A. The base salary and total compensation for the Orange and Rockland officers are within the +/- 15 percent of the 50th percentile Mercer considers to be “at market.” In fact, both the Base Salary and Total Compensation are at approximately median levels for all three positions. Therefore, officer compensation costs, including variable pay and long-term equity grants, represent a reasonable business expense that should be fully recoverable.

Q. Is the Company seeking to recover all elements of officer compensation, *i.e.*, base salary, the variable pay component, and long-term equity grants, in this rate filing?

A. No. The Company has elected not to seek recovery of the variable pay component and long-term equity grants provided to the Company’s officers, even though the cost of these two elements of officer compensation are reasonable and necessary business expenses the Company must incur to attract and retain officers to manage its operations and provide safe and reliable service to customers. The Company reserves the right to seek recovery of these costs in future rate filings.

Q. How were the benefits for officers evaluated?

A. Benefits for Officers (*e.g.*, health, life insurance, retirement, vacation) are the same for all management employees and are therefore included with the overall Aon review.

LABOR CONTRACT

Q. What portion of the Company’s work force is unionized?

A. Approximately 52 percent of the Company’s 1,100 employees are members of Local 503. The total benefits and compensation for these workers are determined by collective bargaining.

Q. When did the Company most recently conclude negotiation of the Labor Contract with Local 503

A. The contract between Local 503 and O&R that was to expire on May 31, 2017 was extended through May 31, 2019.

Q. Please describe the wage increases included in the Labor Contract Extension.

A. The following wage increases were granted to each eligible employee who is on the active weekly payroll on the effective date of such increase.

- Effective June 1, 2017, a 3.0 percent general wage increase for all regular employees; and
- Effective June 1, 2018, a 3.0 percent general wage increase for all regular employees.

Q. Please describe the changes to the Local 503 employees' health care coverage.

A. Beginning January 1, 2018, the health care plan for Local 503 employees will include a new lower-cost High Deductible Health Plan choice. The new Essential Health Plan choice features an annual deductible of $2,500 deductible for individuals, and $5,000 deductible for families, with an 80 percent co-insurance for medical expenses incurred after the deductible is met. There are lower weekly employee payroll contributions for this plan and are $3 per week for individual coverage, $6 per week for individual plus one and $8 for family coverage

Q. Does the Local 503 Contract Extension include any other health care-related changes?

A. Yes. The Contract Extension provides for implementing additional features intended to promote wellness and reward employees for using more efficient medical services and lower-cost providers. For example, employees will pay a lower copayment for using the Cigna Care Network ("CCN") providers, made up of highly rated medical providers within Cigna's regular network of medical providers who charge a lower copayment than their non-CCN providers. Other features added to the health care plans include Telehealth and Convenience Care Clinics. Telehealth is a service that allows employees to access non-urgent care – including some prescriptions – for a wide range of minor conditions anytime and anywhere. With Telehealth, employees receive medical care that is less expensive by connecting to a board-certified doctor via secure video chat or phone instead of an office visit. For employees who need medical care for routine conditions, such as a sinus infection, earache, rash, or minor burn, when their doctor is not available, the Company added Convenience Care Clinics to the health care plans. At a Convenience Care Clinic, employees can receive medical treatment at a lower copayment and cost to the health care plan.

Q. Did the Contract Extension include other wellness initiatives?

A. Yes. To encourage healthy behaviors and help mitigate future health care increases, the Company will expand its wellness initiatives to include reimbursements of up to $100 per year for each employee up to another $100 per year for the spouse for wellness-related activities, such as weight-reduction programs, gym memberships. Another cost mitigation action taken by the Company focuses on preventive care. Employees are encouraged to obtain a medical screening each year and participate in completing a health plan assessment tool. Those who complete these wellness related activities are eligible for the wellness reimbursement as well as receipt of credit toward their weekly healthcare contribution expense.

Q. Were similar changes made to the health plans offered to management employees?

A. Yes. The Cigna Care Network, Telehealth, Convenience Care Clinics, wellness reimbursements for wellness-related activities in addition to excused time for a preventive colonoscopy were added to the health plans for management employees. These changes are designed to align health care benefits with market practices, moderate health care cost increases, and to help employees become more conscious of health care costs. Employees have a range of options, as discussed below, that are more consistent with other companies in the Blended Peer Group, to balance payroll contributions with out-of-pocket costs when employees use health care services. New wellness initiatives are available to encourage employees and their families to live a healthy lifestyle and help manage health care costs. Most of these options have been offered since the fall 2014 enrollment for coverage effective January 1, 2015. The new medical options will be very similar to those described above being offered to union employees.

Q. Will these medical plan options moderate future healthcare cost increases?

A. Yes. Helping employees become better consumers of health care services contributes to more efficient use of the health care plans which contributes to mitigating future cost increases. Additionally, focusing on prevention can reduce the risk factors that lead to chronic diseases or slow their progression, leading to improved overall health and, in some cases, reduced health care spending. Health care changes implemented over the past four years have resulted in lowering the annual increases for Local 503 health care costs from over 10 percent to an annual average increase of 6.5 percent. Cigna, the Company's hospital and medical carrier, forecasts that the plan design changes negotiated as part of the Labor Contract Extension are expected to keep the forecasted future health care cost trend to approximately 6.5 percent annually. With the plan-design changes, (*i.e.*, increases in co-payments, deductibles, and out-of-pocket limits,) the new High Deductible Plan choice, and wellness initiatives, the Company is seeking to elevate employee awareness of health care costs and the importance of staying healthy, which should contribute to slowing the increasing health care cost trend and lowering future costs for our customers.

Q. Please discuss the changes in the amounts that Local 503 employees contribute toward health care coverage.

A. Effective January 1, 2018, Local 503 employees' contributions toward the highest cost plan choice (hospital, medical, prescription drug, and dental) increase from the current maximum of $58 per week for individual coverage, $105 for employee plus dependent coverage, and $150 per week for family coverage to $60 for individual coverage, $109 for employee plus dependent coverage, and $157 per week for family coverage. By the end of the Labor Contract Extension (for calendar year 2019), the maximum employee contributions will be $63 for individual coverage, $113 for employee plus dependent coverage and $160 per week for family coverage.

Q. Are there situations in which employees can contribute less?

A. Yes, Local 503 employees may contribute less for health care coverage depending on the coverage level and plan option they choose. The maximum rates stated above are for the co-pay Plan. The co-insurance plan closely resembles the co-pay plan (hospital, medical, and prescription drug coverage), with a slightly higher out-of-pocket cost at the point of service. The co-pay and co-insurance choices provide employees with the lowest out-of-pocket cost at the point of service, *i.e.*, when they incur a claim. This level of health care coverage also requires the highest level of employee payroll contributions per paycheck. While the other two options (High-Deductible Health Plan and Essential Health Plan) will have lower employee payroll contributions per paycheck, these plans will also require the employee to pay a higher out-of-pocket cost at the point of service. These two options are designed to help employees become more aware of actual health care costs and incent the employees to use the cost-efficient services and providers made available under each health care option. For example, in the co-pay plan, an employee who goes to his/her primary care physician for an office visit will be required to pay $20 for a CCN office visit. Therefore, if the cost of a comparable out-of-network physician fee is $400, the employee has a choice to pay $20 for an in-network service or $100 (the out-of-network co-insurance percent is 25 percent) for selecting an out-of-network provider. The plans that allow employees the greatest flexibility in managing their health care costs are the High-Deductible Health Plan or the new Essential Health Plan with a Health Savings Account (“HSA”). To continue to moderate cost increases, the Labor Contract Extension provides for various future plan design changes which increase the co-payments, deductibles, and annual out-of-pocket limits in 2018 and 2019.

Q. Are there other factors that may lower an employee’s contributions?

A. Yes, as part of the Labor Contract Extension, the Company included maximum rates for employee contributions under the above options which can be lower employee contributions depending on the plan an employee selects and the direction plan costs take in the future. To the extent that health care cost increase at a lower-than-expected rate, due to revised plan designs and employee utilization changes, employees will share in these savings by contributing amounts through payroll deductions that are less than the maximum rates set forth in the Labor Contract Extension. Reducing the health care cost trend helps to mitigate future premium increases which lowers the Company’s contribution toward health care coverage and results in lower costs for our customers.

Q. Please briefly describe the new Essential Health Plan with an HSA.

A. As was the case with the Essential Health Plan with an HSA for management employees discussed earlier in this testimony, a new Essential Health Plan with an HSA becomes available to Local 503 participants effective January 1, 2018. The Essential Health Plan will have the lowest employee payroll contributions per paycheck but higher out-of-pocket costs when employees receive medical care and services. Generally, healthy employees who actively manage their health care expenses will benefit from lower employee payroll contributions. In addition, the Essential Health Plan provides employees with some tax savings with an HSA.

Q. What are the annual deductibles, out-of-pocket limits, and co-insurance levels for the Essential Health Plan?

A. The Essential Health Plan will cover hospital, medical, and prescription drug charges all subject to the following deductibles, out-of-pocket limits, and co-insurance. Employees who elect this coverage will be required to pay all hospital, medical, and prescription drug charges, except for in-network preventive care, up to $2,500 for individuals or $5,000 for family in network coverage. Once the deductible is met, the plan will pay 80 percent of additional healthcare costs, and the employees will be responsible for the remaining 20 percent of the costs. The annual out-of-pocket limit for in network services, for an individual is $4,500 or $9,000 for family coverage, limited to $7,350 for each individual in family coverage. Once the employee reaches the out-of-pocket limit the plan covers additional health care costs at 100 percent. If an employee chooses to use out-of-network providers the deductible and out-of-pocket limits increase and the co-insurance (*i.e.*, the portion employees pay) increases to 40 percent. The annual out-of-network limit is increased to $7,500 for individuals or $15,000 for family coverage.

Q. What are the advantages of an HSA?

A. As noted previously, employees may elect to pay for increased out-of-pocket medical expenses under the Essential Health Plan by contributing pre-tax dollars to an HSA. One of the advantages of an HSA is that the unused balance rolls over from year to year. Therefore, employees will have a choice when they incur health care expenses: pay the expense out-of-pocket (to let the money in their HSA grow tax-free) or use their HSA to use pre-tax dollars to pay for some or all of their eligible expenses.

Q. Will the Company contribute to employees' HSAs?

A. No. Unlike the High Deductible Health Plan, the Company will not make a contribution to the employee's Essential Plan HSA. Employees can contribute on a pre-tax basis in 2018 $3,450 for individual coverage or $6,900 for family coverage. Employee pre-tax contributions will be subject to Internal Revenue Code limits each year.

Q. What retirement benefits were changed as part of the Labor Contract Extension?

A. The Labor Contract Extension provides for a pension change updating the “Pivot Year” for employees accruing a pension benefit under the Career Average Pay (“CAP”) pension formula.

Q. Please describe the change to pension benefits.

A. The Labor Contract Extension provides for a pivot year change from January 1, 2012 to January 1, 2014 for employees who retire on or after January 1, 2018. Pivot year changes are a common practice under the CAP pension formula. The pivot year element of the CAP pension formula provides a snapshot in time that determines both the salary and qualifying years of service for calculating the various components of the pension plan. Specifically, the CAP pension formula is comprised of these parts: a prior service accrual equal to 1.5 percent of the salary rate as of January

1 of the pivot year multiplied by the years of service from the pension plan entry date to the respective pivot year, and a future service accrual which is equal to two percent of base earnings accumulated from the pivot year date to the date of retirement. The formula also provides for an additional future service accrual equal to two times the annual salary rate in effect upon retirement multiplied by two percent. The total pension level is simply the sum of these parts. Unlike final average salary pension formulas which automatically update earnings, usually based on an average of earnings in the last several years of employment, the CAP pension formula does not have an automatic method to update earnings. Instead, the pivot year updates serve as the method to update earnings similar to the way final average salary pension formula earnings are updated. The replacement income attributed to a pension benefit significantly diminishes if the underlying earnings component of the formula is not periodically updated.

Q. What is the pension cost impact of changing the pivot year?

A. Updating the pivot year for Local 503 employees results in additional annual pension costs of $319,000 ($226,000 Electric and $93,000 Gas).

Q. Will the Company make a similar pivot year change for management employees?

A. Yes. The Company traditionally has extended this type of negotiated pension change after the Labor Contract is ratified. As previously stated, the pivot year update serves as the method to update earnings similar to the way final average salary formula earnings are updated. The replacement income attributed to a pension benefit significantly diminishes if the underlying earnings component of the formula is not periodically updated. The Company expects that the additional annual pension cost attributed to the pivot year update for management employees will be $649,000 ($459,000 Electric and $190,000 Gas).

Q. Did the Labor Contract Extension provide retiree health benefit changes for Local 503 employees?

A. No The Labor Contract Extension maintained the higher eligibility thresholds and cost sharing amount retirees contribute toward their retiree health program costs negotiated in the previous contract.

EMPLOYEE EXPENSES

Q. Did the Accounting Panel prepare the exhibit entitled "ORANGE AND ROCKLAND UTILITIES, INC., Electric Operating Expenses, Employee & Other Insurance Costs"?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ Electric; (AP-E3 SCHEDULE 6) Gas (AP-E3 Schedule 6)

Q. What does this exhibit show?

A. The exhibit is a summary of the Company's forecast of employee benefit expenses for the Rate Year, based on costs incurred in the Historic Year. The exhibit shows costs for health insurance costs net of employee payroll contributions, life insurance, other employee benefits, property insurance, Workers Compensation, Injuries & Damages, and Capitalized & Recovered Benefit Costs. The benefit expenses include adjustments for the revisions to the common allocation for electric and gas, normalizing adjustments for dividends received from life insurance and long-term disability plans carriers and a premium credit from the health insurance carrier for the Local 503 health care plan resulting from premium adjustments made by Cigna required under the Affordable Care Act.

Q. Please describe how employee benefit costs are escalated.

A. Historic Year costs are escalated using trend factors and premium rates provided by the various insurance carriers(*i.e.,* Cigna for hospital/medical costs, CVS/Caremark for prescription drug costs, MetLife for dental costs, and the various Health Management Organizations ("HMOs") for the Company's HMO offerings) to estimate the 2018 through 2021 health care costs.

Q. Does the employee benefit expenses projection include any program changes?

A. Yes. The health care costs reflect additional hospital/medical and prescription drug plan design changes negotiated in the Contract Extension for Local 503 employees.

HEALTH INSURANCE COSTS

Q. Please explain the increase for health insurance shown on this exhibit.

A. The exhibit and supporting work papers shows the cost increases for health insurance less employee payroll contributions. Projections for 2018 through 2021 were developed using the Company's claim history and projections of premium cost changes provided by the Company's various health care vendors described above.

Q. Please discuss the Company's proposed escalators for health care expenses.

A. O&R recommends using the plan-specific escalators developed by the health care plan providers, rather than the GDP deflator. For example, Cigna has analyzed the Company's hospital, medical, vision care experience, and participant demographics against its book of business and projects that expenses will increase by 7 percent for the management plans and 6.5 percent for the Local 503 plan. For prescription drug costs, the Company worked with CVS/Caremark and developed an estimated increase of 6.0 percent based on claims experience, and MetLife estimates that dental costs will increase by 3.0 percent.

Q. Please explain why the Company should not use the GDP deflator for the escalation of health care costs.

A. In reviewing and analyzing historic claims experience and the projected increase in the Company's health care costs, based on information provided by the Company's health care plan providers, it is apparent that the increase is being driven by forces fundamentally different from those that drive the GDP deflator.

Q. Please explain.

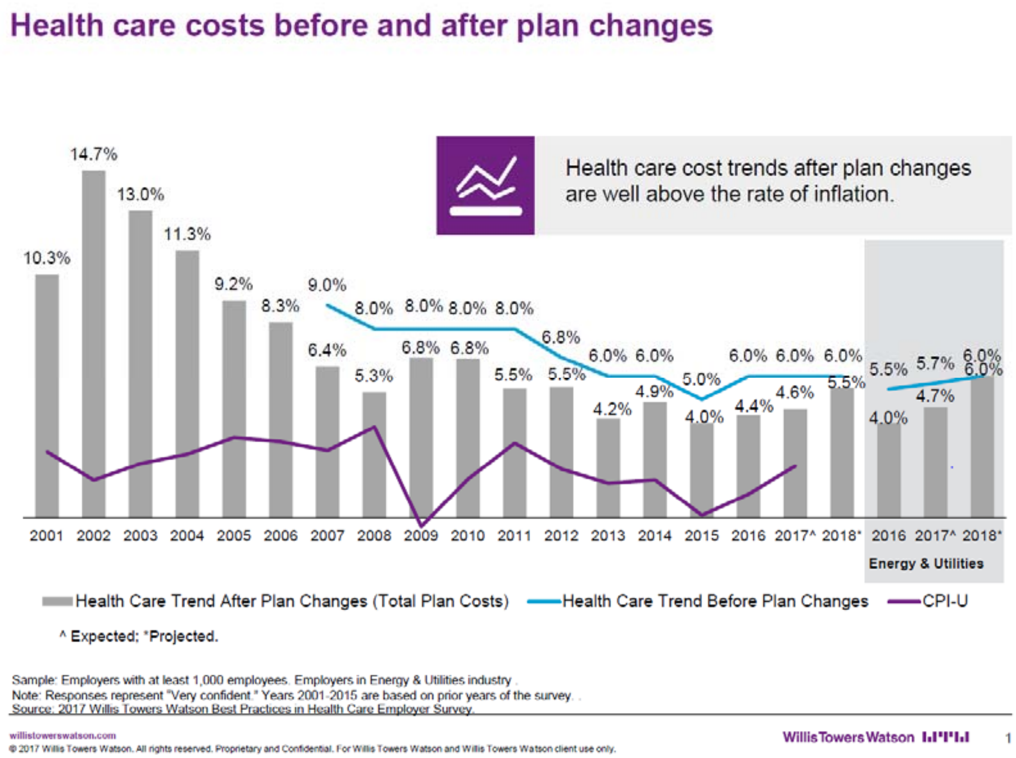
A. Increases in the GDP deflator are being driven largely by inflation-related increases in the unit costs of various products. In contrast, increases in health care costs are driven by increased use of medical procedures and high-cost specialty prescription drugs, as well as the availability and projected utilization of new high-cost medical procedures, treatments, and devices.

General inflation does not capture these factors, which are the primary drivers of the Company's overall health care costs. A general inflation factor, such as the Consumer Price Index ("CPI"), based on the cost of goods, services, and labor that affect all sectors of the economy, measures the average price change over time for a constant-quality, constant-quantity market basket of goods and services but fails to include the changes in the size and age structure of the population that affect the number of people using health care services. A general inflation factor may capture medical price inflation, *i.e.*, increases in the cost of providing a unit of care above and beyond inflation in the general economy, but not the increase attributed to the type of care, technology used, and services per unit of care delivered. For example, a hospitalization in 2019 might involve more tests, more procedures, more supplies, and use of different technology for the same condition than in 2017 or the use of new treatments for previously untreatable terminal conditions. Unlike the costs of new technologies for many products in the economy captured by the GDP deflator, whose initial prices are often set to compete with current technologies and then decrease over time, new medical technologies (such as 3D imaging replacing MRIs and X-rays) raise the cost of medical services beyond the general inflation rate. The development of new medical technologies and services are not designed to compete with existing technologies. Rather, they are designed and introduced into the market to enhance the ability of medical professionals to save the lives of patients and provide patients with an improved quality of life. For example, time is of the essence when treating stroke patients. Mobile stroke units are specially outfitted ambulances with trained medical personnel using telemedicine to perform blood tests, CT scans and TPA tests (TPA is used to breakdown blood clots) before the patient arrives at the hospital.

Q. Are there other items that a general inflation factor fails to include?

A. Yes. Adding to the cost of health care are many expensive diagnostic studies doctors order to protect themselves from potential litigation. In an article, Diagnostic Imaging reported that ordering multiple exams leave a trail that due diligence has been practiced in giving the patient the best possible care. This type of “defensive medicine” continues to be a steady contributor to increased utilization. Another factor adding to the cost of health care is the cost of securing medical information.

PricewaterhouseCoopers estimates that cybersecurity measures to prevent or mitigate increasingly sophisticated and aggressive large-scale breaches will also add to the cost of health care. In addition, health care costs are directly impacted by the age of the Company’s work force. For example, the management health care plans experienced a significant cost increase of almost 23 percent for the twelve months ended November 2017, which was mainly attributed to claims for participants age 50 and older. Another factor increasing health costs above inflation is attributed large catastrophic type claims that significantly impact plan costs. For example, catastrophic claims for the plans covering management employees comprised 25 percent of annual costs and have increased by almost 34 percent for the twelve months ended November 2017. Other cost drivers such as neoplasms and endocrine-related diseases have also increased at a rate greater than general inflation, more than doubling from 2016 to 2017 are expected to continue to increase at a similar rate over the next several years. For the Local 503 plan, we guard against absorbing costs of this risk with fixed premiums developed by Cigna. Cigna not only determines a premium rate for the Local 503 plan that is based on the Company's claims history but also includes a risk charge, state premium taxes and Affordable Care Act fees which have increased at a rate greater than general inflation. Therefore, escalating costs by GDP does not even cover these additional premium costs. Increases attributed to these unique circumstances that drive up health care costs above general inflation are not captured in a general inflation factor. According to the 22nd annual Best Practices in Health Care Employer Survey by Willis Towers Watson, employers expect health care costs to increase by 5.5 percent in 2018 after implementing plan changes, up from a 4.6 percent increase in 2017 and 6.0 percent for employers not making plan changes. Moreover, the survey reports that since 2001, health care cost increases have consistently been significantly greater than general inflation as shown in the following chart.



Q. Please continue.

A. A large portion of the increased spending for prescription drugs is attributed to an increase in utilization for high-cost specialty drugs used for the treatment of complex, chronic, or rare conditions such as various forms of cancer, rheumatoid arthritis, immune disorders, and endocrine-related diseases. Specialty drugs make up more than one third of the total drug spend for the Company plans and have increased by almost 13 percent. CVS Health expects that specialty drug spending will continue to grow at a similar rate in 2018 and after. Given this fundamental dichotomy, the use of the GDP deflator alone fails to recognize the primary reason these costs are escalating and is therefore not the proper methodology to measure the increase in health care costs. Use of the GDP deflator will serve to improperly understate the Company's health care costs for the Rate Year. A reasonable approach to estimating the trend of future health care costs would take into account the wellness, age, and past experience of the Company's employee and dependent population as well as the impact of legislation such as the Affordable Care Act ("ACA"). Estimating future costs in this manner is consistent with the industry practice of those actuaries who determine the premium rates for policies purchased from the Company. Therefore, to develop a more accurate estimate of the increase in health care costs, the Commission, instead of using GDP, should adjust Historic Year expenses by an inflation factor that not only includes general inflation but also incorporates other factors such as changes in utilization of services and procedures and employee demographics, the volume and mix of health care services, and the impact of legislation.

Q. What kind of inflation factor should be used that would be a better predictor of health care expenses?

A. When predicting future health care costs, we believe that the inflation factor supplied by the various health insurance carriers will result in a better estimate. The inflation factor supplied by insurance carriers not only includes the effects of general inflation on the health care market but also incorporates how the other factors described above impact future medical inflation. An article published by the American Society of Actuaries observed that it is the actuary’s role to build a model that predicts an individual’s cost to the insurer. The goal is to determine future healthcare costs by using prior costs, demographics, and diagnoses. The statistical analysis calculates the cost of future risks such as the financial effects that events such as birth, marriage, sickness, accidental injury, and death have on the cost of insurance and the financial obligations of benefit plans and other financial security systems.

All these are insurable events, and one of the actuary's main functions is to calculate the cost of financing these events whether by insurance or other means. The article provides as an illustration and highlights the actuary’s role in designing pension plans and developing their funding requirements. If soundly funded, pension plans will pay the benefits that are promised.

From a measurement point of view, the Company’s future health care costs are measurable and predictable. The Company’s health care program covers a statistically valid employee and dependent population, which can be used to estimate the cost of future claims.

Q. Are there other factors that impact the future cost of providing health care?

A. Yes. Legislative and regulatory changes have impacted, and will continue to impact, the cost of providing health care.

Q. Does the Company’s projection for health care costs include changes to the health plans as a result of the ACA?

A. Yes. The financial impact of the ACA to the Company's health care costs assumes that there will be no changes to this legislation during the Rate Year. The Company has already absorbed additional costs in connection with this legislation, such as extending health care coverage to all dependent children up to age 26 and providing participants with preventive services that must be fully paid for by the Company. Prior to the change in law, coverage for a dependent child ended when a child reached age 19, unless the child was a full-time student in which case coverage would end at age 25. The additional costs of extending health care to dependent children to age 26 beyond the previous plan limits have grown to more than $1 million per year. In the area of preventive care, also due to the ACA, the Company is absorbing the premium costs for providing additional preventive health services at no cost to employees or dependents, which previously required some level of cost sharing by employees. Beginning in 2015, health care plans have been required to limit a participant's annual out-of-pocket costs and include office visits and emergency room co-payments toward their annual out-of-pocket limit. This change increases plan costs as office visits and emergency room co-payments are no longer considered or credited to participants' out-of-pocket limits. As a result, employees now reach their out-of-pocket maximums more quickly and the plan is required to pay all eligible expenses above the annual out-of-pocket maximum, which serves to increase the costs paid by the Company by almost $1 million per year. ACA taxes and other fees that did not exist prior to 2013 have added over $100,000 annually to the cost of health care plans.

Q. Are there any other provisions of the ACA that add costs to the Company's health care plans?

A. Yes. The ACA imposes an excise tax on health care providers and employers who offer health care plans that cost more than predetermined threshold levels set by the ACA. The excise tax is commonly referred to as the "Cadillac Tax." The tax will be imposed on insurance companies and employers, if self-insured, offering health care plans that exceed cost thresholds established by the federal government. For each participant enrolled in such a health plan, the imposed excise tax is equal to 40 percent of the gross premium dollars above the threshold. The ACA established thresholds that were scheduled for 2018 but have been changed to 2020 when the tax becomes effective, subject to increases based on future CPI changes in 2019 and 2020. After 2020, the threshold amounts are scheduled to increase each year by CPI.

Q. What is the expected financial impact to the Company?

A. Based upon current plan offerings and projected costs, the expected 2020 financial impact on annual health care costs for the active employees is an increase of \$2.0 million (\$1.4 million for electric and \$0.6 million for gas).

Q. What is the Company's strategy regarding the pending tax?

A. The Company will continue to look for ways to manage health care costs and promote wellness and efficient use of health care benefits to mitigate future increases. The Company is also monitoring legislative activities as some provisions of health care reform could potentially change. In addition, as all large employers will be affected by this tax, the Company will continue benchmarking the approaches and strategies of New York Metropolitan companies and utility peers to develop and consider ways to mitigate the impact of the tax while not adversely affecting the market competitive position of our compensation and benefit program.

Q. Has the Company experienced actual health care cost increases above general inflation?

A. Yes. The Company has experienced actual health care cost premium increases averaging 7.7 percent annually over five calendar years (*i.e.*, 2013 to 2017) preceding the health care plan changes noted above. Since making the health care plan changes, the growth in health care spending has remained about seven percent per year and estimated to increase by approximately 6.5 percent per year from the historic year through the end of the third Rate Year. Although the changes have helped to mitigate health care cost increases, the lower rate of increase is still far greater than GDP increases of approximately 2 percent over the same period and expected to increase in the near future.

Q. What is the impact on health care expenses of using a general inflation increase for projecting health care expenses instead of using a health care projection rate which factors in the different health care cost drivers?

A. Projecting health care costs using a general inflation factor instead of a health care specific projection rate that factors in the cost drivers described above results in an understatement of health care expenses that should be recovered as a reasonable business expense. For example, a comparison of the last five years actual growth in health care expenses to an increase solely based on general inflation in each of those years results in an understatement of actual care costs for the five years of over $2 million. The imposition of the GDP factor for the escalation of health care costs instead of the expected health care trend factor included in this filing would result in an understatement of health care costs for the three rate years of over $3 million.

OTHER MEASURES TAKEN TO MITIGATE COST INCREASES

Q. What actions has the Company taken to mitigate health and welfare costs?

A. The Company has taken numerous steps to contain and mitigate these costs. During 2013 and again in 2017, the Company introduced consumer-driven high-deductible health plans which are expected to mitigate future health care cost increases to change employee behavior toward being better consumers of health care services. The Company is placing an increasing emphasis on promoting healthy behavior to mitigate health care costs in the future. For the last several years during open enrollment management and Local 503 employees were asked to participate in some wellness initiatives. Cigna, our hospital/medical insurance carrier, collected health information from employees to assess the general health of our employee population and recommend future wellness programs and incentives that encourage employees to participate in health improvement activities. Employees and their enrolled spouse were offered a monetary incentive to complete a health assessment. This is a tool Cigna uses to obtain baseline health information as well as to provide employees and their spouse with insight into their health status and an action plan to address any potential health risks.

Management employees receive an incentive of $5.00 per pay period for completing their own health assessment and another $5.00 per pay period credit if their spouse completes the health assessment. Under the Labor Contract, Local 503 members will receive an incentive of $3.00 per pay period for completing the health assessment and another $2.00 per pay period credit if their spouse also completes the health assessment. In addition, management employees receive an incentive of $5.00 per pay period if they take a basic medical screening that includes blood pressure, cholesterol, blood sugar, and body mass index, all of which are essential for identifying potential health issues. Management employees will receive another $5.00 per pay period incentive if their enrolled spouse takes a medical screening. Under the Labor Contract, Local 503 members will receive an incentive of $3.00 per pay period if they take a basic medical screening and another $2.00 per pay period if their enrolled spouse also takes a medical screening. The Company’s 2018 wellness initiative continues to include a surcharge for tobacco usage (for management employees and Local 503 members), which has a direct correlation to increased health risks leading to higher medical costs Employees who voluntarily identify themselves as tobacco users or who do not complete the tobacco usage question during open enrollment will be required to make an additional $240 payroll contribution toward their health care coverage each year. An employee who is a tobacco user can avoid the additional health care contribution by enrolling in a tobacco cessation program. Under the Labor Contract, Local 503 members will also be subject to a $3.00 per pay period tobacco surcharge for themselves and their covered spouses.

The Company added a new High Deductible Health Plan in 2017 for management employees and 2018 for Local 503 employees as a medical plan choice for participants called the Essential Health Plan. It features a $2500 deductible for individuals, $5000 deductible for families, with 80 percent coverage of expenses. There are no required monthly employee contributions for this plan so that all employees have a level of catastrophic coverage. The out-of-pocket limit is $4,500 for an individual, $7,150 for an individual plus family and $9,000 for the full family. The Company does not contribute to the HSA account but the participant does have the ability to contribute up to the IRS limits. The Company expects the addition of the plan option will increase participation in the High Deductible Plan options offered by the Company and encourage employees to more prudent in evaluating medical options which will help to offset future medical cost increases.

Q. Do the Company’s health care carriers offer any other programs to employees to assist them in adopting a healthy lifestyle?

A. Yes. Cigna offers a Health Matters Program that is designed to facilitate healthy behavior and promote the achievement of health-related goals for at-risk individuals. Cigna has been able to identify that 49 percent of management employees and 43 percent of union employees have engaged in one or more of these programs. Of those engaged in these programs, approximately 55 percent are setting goals related to preventative care. Cigna also offers Your Health First coaching programs to address chronic health conditions including heart disease, asthma, diabetes, osteoarthritis, depression, and lower back pain. These programs are developed in accordance with recognized subject matter experts, the American Heart Association, the American Academy of Allergy, Asthma and Immunology, the American Diabetes Association, and others. Approximately 30 percent of those who participated in the Your First Coaching program or 885 individuals since 2016 were identified as having a chronic medical condition which is a significant driver to health care costs.

Cigna has identified 474 individuals for lifestyle coaching such as weight loss, stress management, and tobacco cessation programs. These programs are available to all employees and their dependents.

Q. Does Cigna offer programs to all employees and dependents to assist with other wellness coaching that could help in controlling health care costs?

A. Yes. Cigna offers coaching programs around healthy eating, physical activity, hyperlipidemia, and maintaining an overall healthy lifestyle and has identified 500 individuals for engagement opportunities. CIGNA utilizes telephonic as well as digital means to provide outreach and engagement to employees and their dependents. The cost of these programs is included in the Cigna administrative fees.

Q. What other actions has the Company taken to manage health care costs?

A. The Company works with Cigna to find ways to encourage employees and their dependents to take a greater role in managing their health care expenditures. For example, if an employee or dependent needs durable medical equipment and prosthetic devices, pre-notification to the insurance carrier is required in order to be covered under the plan and a contractor who specializes in these devices is utilized to provide network discounts and efficient delivery of these services. Treatment plans are required by the claims administrator for physical and occupational therapy, speech therapy, and services performed for diagnosis or treatment of dislocations, subluxations, or misalignment of the vertebrae before such programs may begin. The Company has continued to utilize co-payments for emergency room visits to discourage employees from using the emergency room for routine medical treatments and has promoted the use of urgent care centers, convenience care clinics, and telephonic medicine to reduce the cost of emergency-type services.

Q. Does CVS Health, the administrator of the Company’s prescription drug plans, offer any programs to assist employees to better manage their prescription drug costs?

A. Yes. For those employees or dependents with chronic and genetic disorders, there is a separate Specialty Pharmacy program, administered by the CVS Health, which manages the dispensing and use of high-cost specialty drugs. While the percentage of individuals utilizing specialty drugs remains at approximately one percent, the cost of specialty medications make up one third of the total pharmacy costs. The Specialty

Pharmacy program manages numerous health conditions, including Crohn’s disease, cystic fibrosis, macular degeneration, multiple sclerosis, pulmonary disease, Hepatitis-C, and other serious health conditions. The Specialty Pharmacy not only provides the patient with medications, but also provides proactive pharmacy care management services. When a patient is enrolled in the Specialty Pharmacy program, a pharmacist/nurse-led Care Team is assigned to each patient. A dedicated group of clinical experts helps to manage the patient’s condition effectively; provides early intervention; reviews dosing and medication schedules; trouble-shoots injection-related issues; discusses side effects with the patient; and supplies educational information. The pharmacists are available 24 hours a day, 365 days a year for emergency consultations. All medications are delivered promptly in temperature-controlled secure packing. With the medication, the patient receives any required ancillary supplies such as needles, syringes, alcohol swabs, and guidance on disposal of items. The Special Pharmacy Program also coordinates care with the doctor and health plan. In addition, CVS Health offers a Specialty Guideline Management Program in coordination with the Specialty Pharmacy Program. This program builds upon the Specialty Pharmacy Program by offering a more rigorous review of each specialty referral. The criteria for the program are developed using evidence-based medical standards that are continually updated based on the most recent medically accepted guidelines. The program works with communications between CVS Health and the patient’s physician. If the physician decides to change therapy, Caremark telephones the patient to assist with better management of the new medication. For example, for patients who take Enbrel (TNF inhibitors), as a safety precaution, CVS Health assesses whether the patient has been tested for being a carrier of tuberculosis (with a skin test) because those medications contain a warning for patients with TB. CVS Health will also periodically assess the patient’s exposure to medication to verify its continued effectiveness and to determine whether there is a need to change to a different drug.

Q. Can you provide any other examples of how the program would work?

A. Yes. Votrient is prescribed for advanced renal cell carcinoma (kidney cancer) or for advanced soft tissue sarcoma (cancer that starts in soft tissue such as muscle). Though the FDA approved this medicine for the above uses, in clinical trials there have been instances of severe and fatal liver toxicity. As a safety measure, CVS Health coordinates with the employee’s physician to confirm that the liver function is being monitored.

Q. Are there any other programs available through CVS Health?

A. Yes. The Company works with CVS Health to help educate employees and their dependents to be better consumers. Employees are encouraged to use generic drugs where possible in order to mitigate plan costs as well as lower their own out-of-pocket costs by being a better consumer at the point of purchase. CVS Health prepares a report for each employee and dependent using the program and highlights their expenditures and opportunities for savings. This report, sent at least once a year to the employee and dependents, contains information on how the employee could achieve savings on future prescriptions by using the more efficient and less expensive mail order program or switching from a more expensive brand name drug to a less expensive generic substitute, when available.

Q. Does the Company offer employees any programs to encourage healthy behaviors?

A. Yes. Nutrition education services are available to employees. Healthy food choices help employees better manage their weight and chronic health conditions such as diabetes and heart disease. In addition, Work Home Wellness counseling is available to all employees to help them manage stress and other mental and nervous conditions. For the last several years, the Company has been providing employees with free flu shots. In 2015 the number of employees who received a flu shot was 223. During calendar year 2016, 216 employees received flu shots and in 2017, 184 employees also received flu shots provided onsite.

Q. Are there any other steps that the Company is taking to mitigate health care costs?

A. Yes. The Company conducts periodic audits of the health and welfare plans to confirm the correct processing of claims and determine that the claims are processed in accordance with the plan design for each of the health care options. For example, claims are currently being audited for the Cigna hospital and medical plans, MetLife dental plan, and Caremark Health prescription drug plan. Upon completion of the audit, if there are any overpayments to health care providers, the Company will recover those overpayments. In addition, the Company continues to annually review its cost-sharing arrangement with employees to maintain a reasonable and competitive cost sharing level with employees.

OTHER EMPLOYEE BENEFITS

Q. What changes did the Company make to its Thrift Savings 401(k) Plan for 2018?

A. The Company has updated the Thrift Savings 401(k) Plan in 2017 to automatically enroll both management and Local 503 participants in a two percent contribution and to escalate the contributions by one percent per year to ten percent of pay. This will mean that the Company’s employees will participate in the plan so that they will accumulate enough assets for retirement. As noted previously the Company did close the defined benefit plan to employees hired after January 1, 20127 for management employees and after May 31, 2014 for Local 503 employees.

POST EMPLOYMENT BENEFITS OTHER THAN PENSIONS

Q. Please describe the Company’s OPEB programs.

A. The Company’s OPEB programs are comprised of the Retiree Health Program, which includes major medical, hospitalization, vision, and pharmaceutical benefits. The Company also offers a limited retiree term life insurance program.

Q. What is the status of the Company’s OPEB plans?

A. Starting with the Retiree Health Program, O&R offers management retirees who are age 55 with ten years of service at the time they retire from employment, and their eligible dependents, a voluntary Retiree Health Program. The Retiree Health Program offers enrolled retirees a prescription drug plan and comprehensive hospital, medical, and vision care plans with a network of participating providers. Once a retiree or covered dependent becomes eligible for Medicare, the Retiree Health Program coordinates his or her health care expenses with Medicare. For Medicare-eligible retirees, Medicare is the primary payer of hospital and medical claims, and the Retiree Health Program is the secondary payer. Under the prescription drug plan, once a retiree and covered dependent become eligible for Medicare Part D, retirees may continue their coverage under the Retiree Health Program or enroll in the Medicare program for their prescription drug coverage. The Company also provides retired management employees who were age 50 as of January 1, 2013, with retiree term life insurance benefits of $25,000. Local 503 retirees are eligible for $12,500 in life insurance at no cost if they retire at age 55 with 10 years of service.

Q. What steps has the Company taken to manage or mitigate OPEB costs related to the Retiree Health Program?

A. For the Retiree Health Program discussed above, the Company implemented a cost-sharing formula in 2014 for management employees retiring under the CAP pension formula. Under the cost-sharing formula, the Company’s contribution toward program costs is limited to its contribution in the preceding year plus inflation as measured by the change in the CPI. Contributions for retirees increase if Retiree Health Program cost increases are above CPI. Effective January 1, 2013, the Company’s subsidy under the cost-sharing formula has been eliminated for management employees retiring under the Cash Balance pension formula. Employees under the Cash Balance pension formula who meet the eligibility requirements and enroll in the Retiree Health Program will be responsible for paying the full cost of Retiree Health coverage offered through the Company. Under the Labor Contract, Local 503 employees hired on or after January 1, 2015 will be required to pay 50 percent of the premium cost if they enroll for coverage when they retire. In addition, the Labor Contract provides for an increase in the eligibility requirements for Retiree Health coverage from age 55 with ten years of service to age 55 with 20 years of service. These changes will reduce future plan costs as new employees are hired. The reduction to annual OPEB costs attributed to changes to both management and union employees is $14.9 million ($9.8 million Electric and $5.1 million Gas).

Q. What other steps has the Company taken to manage or mitigate OPEB costs related to the Retiree Health Program?

A. The Company has implemented an Employer Group Waiver Plan ("EGWP") for Medicare-eligible retirees who are eligible for federal subsidies for prescription drugs that reduce Company and retiree costs and results in OPEB cost savings.

Q. What is an EGWP?

A. An EGWP is a Medicare Part D plan regulated by the Centers for Medicare and Medicaid Services that will supplement the retiree prescription drug benefits currently offered to retirees who are Medicare-eligible effective January 1, 2013. Under the EGWP, the Company foregoes receiving the Retiree Drug Subsidy ("RDS") and instead our pharmacy benefits manager, CVS Health, contracts directly with the government prescription drug program. CVS Health will handle all administration and federal interactions and collect the RDS subsidy for our retiree drug plan. Employers with an EGWP retiree drug plan will experience savings under the Coverage Gap Discount Program, which was passed as part of health care reform. For employers providing prescription drug benefits through an EGWP, the Coverage Gap Discount, the direct subsidies, and the catastrophic reinsurance payments have a significant cost reduction impact.

Q. What savings does the Company expect to realize as a result of implementing the EGWP?

A. Since the inception of the program, the EGWP has reduced plan obligations by approximately $12 million and annual expense by $1.6 million ($1.1 million Electric and $0.5 million Gas).

Q. Were there any initiatives with respect to the Company’s OPEB programs that were considered and rejected?

A. No.

PENSION PROGRAM

Q. Please describe the Company’s pension program.

A. Originally, the O&R Retirement Plan was a defined benefit pension plan that provided vested employees with pension benefits under different formulas, depending on their date of hire. Over time, however, the O&R Retirement Plan has changed. Management employees hired on or before January 1, 2001; and members of Local 503 hired on or before January 1, 2010; are covered under a traditional CAP pension formula based on an employee’s earnings throughout an employee’s career. Employees may qualify for an unreduced early retirement benefit at age 55 if they have at least 85 points of age and years of service Employees with less than 85 points may retire at age 55 with a reduction to their pension of 25 percent (four percent per year prior to age 60) if they have at least ten years of service. Management employees who had not attained age 50 as of January 1, 2013 will have their pension benefit reduced from age 55 to 60 of five percent per year on their benefit accrued post-2013. Pension benefits for employees retiring before age 55 are not payable until at least age 55. Management employees hired after January 1, 2017 and Local 503 members hired after June 1, 2014 are not eligible for the Defined Benefit pension plan. Instead they receive a company contribution to the Thrift Savings Plan.

Q. What steps has the Company taken to manage or mitigate pension costs?

A. The Company has amended the O&R Retirement Plan to reduce future liabilities and annual costs by prospectively not allowing newly hired employees after January 1, 2017 to participate in the Cash Balance Plan. Management employees hired on or after January 1, 2017 are not eligible for the Cash Balance plan; union employees who are members of Local 503 hired on or after June 1, 2014 are now all covered only under the Thrift Savings plan defined contribution formula and not under a Cash Balance pension formula. Employees covered by the Company contribution to the Thrift Savings Plan will earn a retirement benefit over a career that is presents less risk to the Company than the benefit earned under the Cash Balance

Formula because the participant is responsible for the investments returns and the benefit provided does not depend on future life expectancy.

Q. What savings does the Company expect to realize as a result of changing the pension benefits from the cash balance formula to the defined contribution pension formula under the Thrift Savings 401(k) Plan for Management Employees after January 1, 2017 and Local 503 employees under the Labor Contract after January 1, 2015?

A. The Company expects that changing to a defined contribution pension formula for management and union employees will initially result in some savings as new employees are hired. Larger savings are expected in the distant future as the population of employees under the defined contribution pension formula grows. In addition, replacing the Cash Balance defined benefit pension plan with a defined contribution pension plan for new Management and Local 503 hires helps to better manage future pension costs and liabilities by significantly reducing the Company’s financial risk and volatility associated with funding a defined benefit pension plan. The changes to the defined benefit retirement plan do not have a short-term cost impact because the contributions made to the defined benefit plan are being shifted to the Thrift Savings Plan. As noted previously, given high participation and savings rates in the Thrift Savings Plan, there no near term impact of the two percent auto enrollment and escalation changes.

Q. Did the 2017 Review include the Supplemental Retirement Plan ("SRP") benefit provided to Orange and Rockland management employees?

A. Yes. The 2017 Review included all benefits provided to non-officer and officer management employees. The SRP provides management employees upon retirement with the portion of their earned pension benefit that is above the federal tax law limitation applicable to the Company's tax qualified defined benefit retirement plan. The SRP formulas for active employees are the same as the pension formulas of the retirement plan but make up for pension benefits that have been earned but could not be paid under the retirement plan due to plan provisions of Internal Revenue Service limits imposed on the accrual and payment of pension benefits under tax qualified pension plans.

Q. Does the new federal tax legislation have an impact on the SRP?

A. No new tax implications are expected as of the preparation of this testimony. Any changes will be presented in the Company's updated testimony.

Q. Does the rate request include recovery for the cost of the SRP as part of the retirement expense?

A. Yes. And we note that the SRP costs include funding costs related to SRP retirement benefits earned and still payable to former employees.

Q. Are the SRP benefits consistent with the Blended Peer programs?

A. Yes. As part of the Review, the Company looked at the SRP programs provided for current employees for the 50 companies in the Blended Peer Group. Forty-two of the 50 Blended Peer Group companies provide SRP-type benefits. Providing SRP benefits is consistent with the Blended Peer practices and serves to maintain the O&R retirement benefit at a competitive level with the Blended Peer Group. Please see the table below for a summary of the SRP benefit prevalence for the Blended Peer Group. Eighty-four percent of the peer companies that provided supplemental benefit information to the Aon Total Compensation Measurement Database provide a SRP benefit and it is market practice to also include in their SRP arrangement the various prior pension formulas that were used to determine the SRP benefit earned by the peer companies' former employees. The Company found that as a general rule, once SRP benefits are earned, they are not modified.

Summary of SRP Benefits

50 Blended Peer Companies – General Industry and Utility

Maintain a SRP Type Benefit	***General Industry***	***Utility***	***Total***
Yes	20	22	42
No	5	3	8
Total	25	25	50

Q. What is the annual expense attributed to pension benefits earned under the SRP?

A. The net pension cost is approximately $1.6 million per year ($1.1 million Electric and $0.5 million Gas).

Q. In conducting the Review did the Company evaluate its benefits and compensation package as compared to those offered by other comparable companies?

A. Yes. Consistent with Commission policy and typical market practice, in assessing the overall competitiveness and reasonableness of O&R's benefits and compensation package, the Review compared the Company's package to those offered by a peer group of similarly situated companies, *i.e.*, the Blended Peer Group.

Q. Does that conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ENVIRONMENT HEALTH AND SAFETY PANEL – ELECTRIC/GAS

Table of Contents

Introduction

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

A. (**Prall)** Stephen Prall, 390 West Route 59, Spring Valley, New York, 10977.

(McCormick) Maribeth McCormick, 3 Old Chester Road, Goshen, NY 10924.

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

A. (**Prall)** I am the Director of Environment Health and Safety ("EH&S").

(McCormick) I am a Technical Manager in the EH&S Department.

Q. Please describe your educational backgrounds.

A. **(Prall)** I received a Bachelor of Science degree in Nuclear Engineering in 1995 from the State University of New York, and a Masters of Business Administration degree in 1998 from Rensselaer Polytechnic Institute, in Troy, New York.

(McCormick) I received a Bachelor of Science degree in Environmental Studies from Ramapo College in 1986. In 2011, I received a Project Management Certificate from the State University of New York at Stony Brook.

Q. Please describe your work experiences.

A. **(Prall)** I worked for Consolidated Edison Company of New York, Inc. ("Con Edison") for 13 years until 2002 in a variety of positions including Nuclear Chemist, Radiochemistry Supervisor, Nuclear Quality Assurance Engineer, and Project Auditor. I have worked at Orange and Rockland since 2002 in a variety of positions including Manager of Training, Section Manager of Compliance, and Section Manager of Electric Operations Transmission and Distribution Maintenance. I was promoted to my current position in December 2015.

(McCormick) In 1983, I began working in the Environmental Services Department as a staff specialist with responsibilities in the areas of environmental compliance and permitting with my primary responsibilities related to polychlorinated biphenyls ("PCBs"), hazardous wastes, spill prevention and emergency spill response. In 1985, I was assigned responsibility for overseeing the investigation and remediation of the Company's former manufactured gas plant ("MGP") sites and sites for which the Company is alleged to have responsibility under the Comprehensive Environmental Response, Compensation, and Liability Act and comparable state laws ("Superfund"). I was promoted to the Position of Section Manager – Environmental Services in 2002. In that position, I managed the Environmental Services Department staff and was responsible for all of the Company's environmental programs. In 2008, I assumed my current position as Technical Manager.

Q. Do you belong to any professional organizations?

A. **(Prall)** Yes. I am a member of the Project Management Institute and represent the company with the National Safety Council ("NSC"), Electric Power Research Institute ("EPRI"), Edison Electric Institute ("EEI"), Network of Employers for Traffic Safety ("NETS"), Northeast Gas Association ("NGA") and the American Gas Association ("AGA").

(McCormick) Yes, I serve as the Company's representative with the MGP Consortium and

Environmental Energy Alliance of New York (“EEANY”) MGP Work Group.

Q. Please generally describe your current responsibilities.

A. **(Prall)** As Director, I oversee implementation of the Company’s EH&S programs and performance of the Company’s Quality Assurance program. The EH&S programs include environmental compliance (*e.g.,* permitting, spills, hazardous wastes), health and safety (*e.g.,* injury reporting and reduction, motor vehicle collision reporting and reduction, industrial hygiene, fire safety), remediation programs (*e.g.*, MGP and non-MGP sites), and EH&S management system. Quality Assurance involves the independent review of the Company’s compliance programs.

(McCormick) As Technical Manager, I manage the implementation of site investigation and remediation programs for former MGP sites and non-MGP sites. This includes oversight and direction of construction activities at the Company’s MGP and non-MGP remediation projects. I also work with the Company’s Public Affairs Department to develop and implement community participation programs necessary to support Site Investigation and Remediation ("SIR") programs and act as the Company liaison with regulatory agencies, principally the New York State Department of Environmental Conservation ("DEC"), property owners, environmental and industry groups, as well as the general community, with respect to SIR matters.

Q. Have you previously testified before the New York Public Service Commission ("Commission") or other regulatory bodies on energy matters?

A. **(Prall)** Yes. I submitted testimony to the Commission in Case 14-E-0493. I have also submitted testimony to the New Jersey Board of Public Utilities in Docket Numbers ER13111135 and ER14030250 and the Pennsylvania Public Utility Commission in Docket M-2009-2094773.

(McCormick) Yes. I submitted testimony to the Commission in Cases 14-E-0493 and 14-G-0494.

Purpose

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

A. The Panel will describe the Company's SIR program activities, particularly with respect to its MGP sites. This includes SIR program expenditures that are required under laws and regulations, agreements, administrative consent orders ("ACOs"), and permit requirements. The Panel will also describe the steps the Company takes to control and mitigate its SIR program costs. The Panel will also describe several efforts to improve the safety and security of the Company's workforce, the general public, and the environment.

SIR Program

Q. Please provide an overview of the Company's SIR program.

A. The Company has a comprehensive on-going program for managing its SIR sites and verifying that required remedial response measures (*i.e.*, investigations followed by any necessary remedial actions) are properly performed for sites that have been contaminated by past releases of petroleum products, hazardous wastes, and/or hazardous substances from the Company's and its predecessor companies' facilities and/or operations. The predominant focus of this program is MGP sites. To a lesser extent, the

Company's SIR program also addresses the remediation of the West Nyack Operations Centers (the "West Nyack Site"), a single underground storage tank ("UST") site, and Third-Party Superfund sites, as described more fully herein.

MGP Sites

Q. Please provide a brief background on the Company's and its predecessor companies' former MGPs.

A. MGPs provided energy in the form of combustible gases of varying composition to municipal street lighting systems and to homes and businesses in cities and towns across the more densely populated regions of the United States. In the case of the areas served by Orange and Rockland and its predecessor companies, MGPs operated from the late 1850s through the early 1960s. The MGPs converted coal (oven gas) or a combination of coke or coal, oil, and water in the form of steam (carbureted water gas) into a gas product that could be used for lighting, cooking, and heating prior to the time when electricity and natural gas came into use for these purposes. There were more than 200 MGPs in New York State and an estimated 3,000 to 5,000 in the United States, mostly in the Northeast and Midwest, prior to these plants becoming obsolete due to the construction of natural gas pipelines and large electric generating stations.

Q. What are the current environmental concerns related to MGP sites?

A. Manufactured gas production was a complex process that entailed the production, handling, and storage of significant quantities of feedstock materials, by-products, and residuals that contained organic and inorganic chemical constituents. Though not considered hazardous during the periods when MGPs were operating, these by-products and residuals are now considered to be hazardous substances under Federal and New York State laws and regulations. These regulations state that when released to soil, groundwater, or waterways, these by-products and residuals may pose a threat to human health or the environment. The materials of primary concern at MGP sites include coal tar, coal tar-related emulsions, carbureting oils, scrubber oils, and gas purification wastes.

Q. What are the DEC's requirements regarding SIR for MGP sites?

A. The DEC has required New York State's investor-owned utilities, such as the Company, to investigate and, when necessary to protect human health and the environment, undertake remedial response actions for the sites of their former MGPs. Most New York State utilities have entered into ACOs or cleanup agreements with the DEC pursuant to which the utility will undertake remediation of an MGP site in accordance with DEC requirements and under DEC monitoring. In some cases, such as for the Company, these ACOs or cleanup agreements cover multiple sites. The New York State Department of Health ("DOH"), which works with the DEC in evaluating the results of MGP site investigations and determining the need for remedial response actions for them, views the primary goal of these investigations as assessing potential human exposure to MGP-related contaminants.

Q. Could you please provide some additional information on the Company's MGP sites?

A. The Company and its predecessor companies' manufactured gas at MGP sites located across Rockland and Orange Counties. Pursuant to two ACOs the Company has entered into with the DEC, the Company must investigate and, if necessary, develop and implement DEC and DOH-approved remedial action plans for all of its and its predecessor companies' seven confirmed MGP sites. Of these seven MGP sites, four are still owned in whole or in part by the Company. Three of these sites are now owned in their entirety by parties other than Orange and Rockland and have been redeveloped by their new owners for other uses, including residential and commercial development. In addition, since the execution of these ACOs, the Company has identified, investigated, and remediated another site – the McVeigh Road site. Though not an MGP site, MGP tar was disposed of at this location.

Q. Please identify and describe Orange and Rockland's seven MGP sites, including the McVeigh Road site, and the current SIR status of these sites.

A. Nyack Gas Plant

This site is currently a privately-owned vacant property located along Gedney Street and the Hudson River in Nyack. Significant subsurface contamination of soils, groundwater, and bedrock was found on the site. In addition, MGP impacts were identified in nearby Hudson River sediments. The DEC issued a Record of Decision (“ROD”) for the land portion, Operable Unit 1 (“OU-1”), of the site in March 2004 requiring remediation of impacted media. The Company completed remediation activities for OU-1 in November 2007 and included a combination of excavation and in situ treatment technologies including chemical oxidation and solidification. The DEC issued a ROD for the shore line soils and river sediments, Operable Unit 2 (“OU-2”), in March 2011. This ROD required shallow soil excavation, in situ solidification (“ISS”) of deeper soils, and removal of impacted sediments. The remedial design for the OU-2 remedy was completed in 2013. Remedial construction began in March 2014 and was completed in spring 2015. Following the completion of remedial construction for both operable units, a Site Management Plan (“SMP”) was prepared and approved by

DEC. In addition to the SMP, a DEC-approved environmental easement was recorded for the site. DEC issued a Site Closure and Reclassification Letter in May 2016 indicating that Orange and Rockland had completed construction of the remedy and had entered the site management phase of the remedial process.

Suffern Gas Plant

In December 2008, Orange and Rockland purchased the former MGP site property that had been operated by Econo Truck/US Bus since the 1950s. This purchase has enabled Orange and Rockland to implement the necessary remediation to address the MGP impacts in subsurface structures, soils, and groundwater at and around the site. To comply with the Village of Suffern Building Department requirements, the Company demolished the Econo Truck/US Bus building in February 2010. Supplemental investigation activities were completed in October 2009 and May 2010. Sentinel wells were installed between the site and the Village of Suffern water well field and are monitored on a quarterly basis to verify that the Village water supply wells are not being impacted adversely by site contaminants. The Feasibility Study ("FS") for this site was finalized in 2013 and a ROD was issued by the DEC in March 2014. The remedy stipulated in the ROD includes excavation of subsurface soils to the water table (approximately 10 ft.) and ISS of impacted soil to a maximum depth of 35 ft. The ROD also requires institutional controls such as a deed restriction, a SMP, and development of a Water Supply Protection Plan that outlines steps to protect the Village water supply wells if impacts are identified in the sentinel wells. The Remedial Design was completed in August 2015 and a separate Groundwater Monitoring Plan for Remedial Construction was prepared in conjunction with the DEC and DOH and finalized in February 2016. Remedial construction began in April 2016. However, due to the discovery of a large boulder field in the ISS area, the remedial design was modified to also include jet grouting, resulting in an extended schedule for the completion of construction, which was completed in August 2017. In addition to the construction activities, weekly, biweekly, and quarterly groundwater sampling was conducted to monitor the groundwater so that remedial activities did not impact groundwater or the Village water supply wells. The Company will develop an SMP to outline the ongoing requirements for groundwater monitoring and protection of the ISS monolith.

Haverstraw Gas Plant (93 B Maple Avenue)

This site is privately owned and located in a residential area, with several residences immediately adjacent to the site. Remediation of the site and off-site properties, which included excavation of contaminated subsurface structures and soils and in situ chemical oxidation of subsurface soils, was completed in 2004 as an interim remedial measure ("IRM"). An IRM is a discrete set of remedial actions that can be conducted without completion of the extensive FS process in order to address an imminent threat or to obtain additional information for the FS. The DEC then issued two RODs (one in 2005 and one in 2006) for the various remediation phases, which incorporated the IRM as part of the remedy. In accordance with the 2006 ROD, the Company has developed a draft SMP that maintains the existing small warehouse building on the site as an engineering control. The institutional controls in the SMP restrict any intrusive activities under and around the small warehouse building and allow for the removal of the remaining contamination should the building be demolished in the future. An annual inspection and certification to confirm that these institutional controls remain in place will be required. The SMP has been reviewed by the DEC and is expected to be formally approved by the DEC once Orange and Rockland completes confirmatory Soil Vapor Intrusion ("SVI") testing inside the small warehouse building. Orange and Rockland has been in discussions with the property owner to negotiate access to the property for the SVI testing and implementation of the SMP.

<u>Haverstraw Gas Plant (Clove & Maple)</u>

This site is owned by the Company and was operated as a gas regulator station. The Company retired the regulator station in 2007. A comprehensive remedial investigation ("RI") and numerous supplemental investigations have been completed on the site and on several adjacent properties. Through these investigations, MGP residuals and contamination have been found in subsurface soils and groundwater both on and offsite, including an apartment complex and several residential properties. MGP impacts that are associated with this site have also been detected in nearby Hudson River sediments. The FS to evaluate remedial alternatives was completed in 2010. Due to the complexity of the remediation aspects of the site and the numerous third party property owners, the DEC separated the site into three operable units. The ROD for the onsite property (OU-1) owned by Orange and Rockland was issued in March 2011. The ROD for the offsite properties (OU-2) was issued in March 2012. The ROD for the sediments in the Hudson River (OU-3) has not been issued. During 2016, the OU-1 pre-design investigation was conducted and the engineering remedial design was completed in August 2017. Remedial construction is expected to begin in April 2018. Orange and Rockland prepared a Pre-design Investigation Work Plan for OU-2 in 2013. However, due to the sale of the apartment complex in 2014 and potential development plans for that parcel, the commencement of the OU-2 pre-design investigation ("PDI") has been deferred.

Fulton Street – Middletown

This site is a privately owned commercial property. A comprehensive RI and numerous supplemental investigations have been conducted on the site and on several adjacent properties including property operated by the U.S. Postal Service ("USPS"). These investigations have determined that significant MGP impacts are present in subsurface structures, soils and groundwater on site. They also identified MGP impacts on some of the offsite properties and beneath the road between the site and the USPS property. Following submittal of a draft FS to the DEC, the DEC requested that an additional investigation be conducted to supplement and refine the FS. The additional investigation was conducted in August 2016 and the results are being evaluated in conjunction with the remedial alternatives considered in the FS. The FS is expected to be finalized in 2018, followed by the issuance of a ROD by the DEC.

Genung Street – Middletown

This property is owned by the Company and is comprised of four individual parcels. Three of the parcels are vacant, and one is operated by the Company as a gas regulator station. The Company has completed a comprehensive RI and FS on the site. Significant contamination in subsurface soils and groundwater is present on one of the parcels and minor impacts have been noted in the other three parcels. A ROD was issued by the DEC in March 2005. The ROD stipulates that impacted soils will be excavated from the site, soil or pavement cover will be provided in areas exceeding certain regulatory guidance values, and institutional controls will be established to control the future use and development of the site. The pre-design investigation and engineering design activities will continue in 2018.

Port Jervis Gas Plant

This site is owned by the Company and serves as a satellite operating center for field crews, Survey and Construction Management. A comprehensive RI and numerous supplemental investigations have been completed at the site, on several adjacent properties, and in and along the Delaware River. Significant MGP impacts and contamination have been identified in subsurface structures, soils, and groundwater at both on and offsite locations. No significant impacts to the Delaware River have been identified. The FS was completed in 2006 and the DEC issued a ROD in December 2007. In order to implement the ROD, the Company purchased several adjoining properties in 2011. The soil excavation component of the remedy was completed in June 2013. Tar collection wells, to address contamination that was not removed during the excavation phase of the remedy, were installed in August 2014. The Company monitors these wells and collected tar is recovered from one of the wells on a monthly basis. The DEC has also directed the Company to proceed with installation of a groundwater treatment system to address offsite groundwater contamination. PDI activities for the groundwater treatment system, including an Air Sparge/Soil Vapor Extraction (“AS/SVE”) pilot test, were completed in 2017. Remedial design has been completed and installation of the AS/SVE system is planned for 2018. Ultimately, a deed restriction will be placed on the Orange and Rockland property and a SMP will be developed for both on and offsite impacted areas.

McVeigh Road

This site was identified in 2001 during the construction activities for the installation of a fire hydrant for the Company’s Middletown Tap Substation. The source of the contamination is unknown, but was confirmed to be MGP-related. The impacts were limited to sediments located within a small section of Monhagen Brook. Remediation of the site required excavation of impacted sediments and was completed in December 2009 with DEC oversight. The Company completed site restoration during the spring of 2010.

Q. What specific MGP SIR activities are expected to be conducted during the twelve months ending December 31, 2019 (“Rate Year”)?

A. During the Rate Year, the Company plans to: (1) complete remedial construction at OU-1 of the Clove and Maple Avenue Haverstraw MGP site; (2) proceed with remediation design and planning activities at OU-2 of the Clove and Maple Avenue Haverstraw site and at the Fulton Street Middletown site; (3) initiate remedial construction at the Genung Street Middletown site; and (4) implement SMP requirements and conduct periodic site inspections at sites where remedial construction is or will be complete such as Port Jervis, Suffern, and Nyack.

Q. Do you expect the Company to continue to conduct similar MGP site investigation and remediation activities over the next five years?

A. Yes. However, since the Company has completed remedial investigation of all of its sites, the investigation activities will be focused on data collection for remedial design. Remedial planning/design activities and/or remedial construction will be performed over the next five years.

Non-MGP Sites

Q. In addition to MGP sites, what other types of sites are covered by Orange and Rockland’s SIR efforts?

A. As noted above, the Company must address the West Nyack Site and a single UST site. The Company also is responsible for contributing to the investigation and remediation of environmental conditions at third-party Superfund sites. These are sites to which the Company shipped hazardous substances or waste for treatment, storage, or disposal and has been designated as a Potentially Responsible Party (“PRP”) for the investigation and remediation of site contamination by the United States Environmental Protection Agency (“EPA”), the DEC, or other government environmental agency pursuant to the Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”) or comparable state statutes, including statutes imposing liability for the costs of investigating and cleaning up oil spills.

<u>West Nyack Site</u>

The West Nyack Site is currently listed on the New York State Inactive Hazardous Waste Site Registry as a Class 4 Site. This means the site has been properly closed but requires continued management and monitoring. The remediation of impacted soils at the facility was completed in 1999. Quarterly groundwater monitoring was conducted at the site as directed by the DEC. In addition, indoor air and soil vapor sampling was conducted annually. Based on Orange and Rockland's successful efforts to identify the offsite source of groundwater contamination, effective the fourth quarter 2012, the DEC removed the requirements for the quarterly groundwater monitoring and indoor air and soil vapor sampling. A SMP was developed by the Company and approved by the DEC in 2012. The SMP restricts intrusive work on the site and requires maintenance and annual inspection of the impervious asphalt cap on the site.

UST Site

Q. How many UST sites are currently being addressed under the Company's SIR Program?

A. As noted above, the Company currently has one UST site located at its Spring Valley Operating Center. Soil and groundwater contamination were identified following investigation of a line leak in 2008. In 2013, the Company conducted soil remediation and tank removal in conjunction with installation of a replacement tank system. During the Rate Year, the Company anticipates that a limited amount of groundwater monitoring and reporting may be necessary.

Q. Do you expect the Company to continue to conduct similar UST site investigation and remediation activities over the next five years at any additional locations?

A. At this time, the Company has not identified any other UST sites that require investigation and/or remediation.

Third-Party Superfund Sites

Borne Chemical

The Borne Chemical site is a PRP site. The site was a 14-acre former petrochemical packaging/waste oil recycling facility located along the Arthur Kill waterway in Elizabeth, New Jersey. The site was abandoned in 1985 when its owner filed for bankruptcy. The site is being investigated and remediated by a PRP group in compliance with administrative directives issued by the New Jersey Department of Environmental Protection ("NJDEP") pursuant to the New Jersey Spill Compensation and Control Act ("Spill Act"). The Company joined the PRP group as part of a settlement with the members of the PRP group. As directed by the NJDEP, the PRP group has investigated the site and completed a $10 million NJDEP-approved program to clean out the oil and chemical storage tanks and piping systems located on the site. The PRP group is currently in the process of finalizing a Remedial Action Work Plan ("RAWP") for a portion of the site that consists of excavation and off-site disposal of contaminated soil where possible given site restrictions, installation of skimmer wells to address residual Light Non-Aqueous Phase Liquid ("LNAPL") in groundwater, capping, stormwater control, and deed restrictions. The PRP group is seeking to finalize this RAWP and obtain the necessary permits to allow the remediation work to commence during 2018. A separate RAWP for groundwater, which has been finalized and approved by the New Jersey Department of Environmental Protection, calls for injection of zero valent iron, followed by enhanced anaerobic bioremediation, testing to evaluate effectiveness, and long-term monitored natural attenuation. The PRP group began implementing this groundwater remediation on a portion of the site in 2018 and plans to implement this groundwater remedy on another part of the site in conjunction with the anticipated construction of a cap in late 2018 or early 2019.

The Company’s share of estimated total liability for the Borne Chemical site is 2.12%, except for the site’s groundwater remedy, for which the Company’s share of estimated total liability is approximately 2.32% because fewer PRPs are participating in implementation of the groundwater remedy.

Ellis Road

The Ellis Road/American Electric Corporation site is a PRP site. The site is a former PCB waste consolidation, storage, and treatment facility that was operated by the now defunct American Electric Corporation (“AEC”) from 1979 until 1984. In 1984, the warehouse building that AEC used at the site for the processing and storage of regulated PCB equipment and materials was destroyed by a fire that caused the release of PCBs into the environment. The EPA performed an emergency response action and a series of initial removal actions to secure the site and to prevent further releases of PCBs. The EPA subsequently identified AEC's former customers and demanded that they fund an additional removal action for the site. The Company was designated a PRP for the site because it shipped 440 gallons of PCB-contaminated waste water to the site for treatment. Approximately 200 of AEC's former customers, including Orange and Rockland, joined together in 1988 to form a PRP Group. In 1989, the members of the PRP Group entered into an EPA administrative order on consent (“Consent Order”) that obligated the group to perform EPA’s required site removal action. Between 1990 and 1991, the PRP Group performed the required removal action and excavated PCB-contaminated surface soil, disposed of about 20,000 gallons of PCB-contaminated liquid waste, and emptied and decontaminated the above ground storage tanks that EPA installed at the site as part of its initial emergency response and removal actions. The site is located near residential properties. After soil and groundwater sampling detected PCBs at concentrations that exceeded the EPA’s residential PCB cleanup standards, at the end of 2011, the EPA notified all presently existing site PRPs of the need for a new removal action and demanded they enter into another Consent Order. Under the 2012 Consent Order, the group was responsible for reimbursing EPA site oversight costs, and was required to either implement or fund the implementation of the required removal action. In 2012, the Company entered into an agreement with the other PRP Group members regarding the allocation of costs that would be incurred pursuant to the 2012 Consent Order. The total cost of cleanup for the site is currently estimated to be $5.4 million. The Company's share of estimated total liability for this site is 0.24%. No costs for the Company are currently projected for this site.

Metal Bank

The Metal Bank Superfund Site is a PRP site. The site is a ten-acre former scrap metal reclamation facility located along the Delaware River in northeastern Philadelphia. It was added to the Superfund National Priorities List in 1983 after the EPA and the U.S. Coast Guard documented releases of PCB-contaminated oil from the site into the Delaware River. The Company is a member of a PRP steering committee comprised of electric utilities that shipped scrap transformers to the site during the late 1960s and 1970s. Under a consent decree with the government following litigation amongst the EPA, the PRP steering committee, and the former and current site owners and operators, the PRP steering committee members performed the required remediation work for the site and affected Delaware River sediment. The PRP steering committee members also received a contribution of approximately $4.1 million from the principals of the former site operator and were entitled to seek reimbursement of their remediation work-related costs from the $13.2 million trust fund established as part of the settlement of their claims against the bankruptcy estate of the corporate parent of the then current site owners and operators. The implementation of the remedy was completed in 2010. During 2016, repairs were made to the sheet pile wall which was part of the remedy. The PRP steering committee has initiated an action against the remedial design engineers for costs incurred in connection with this work. As required under their consent decree with the government, the PRP steering committee is currently implementing monitoring activities as part of the site’s completed remedy.

During 2013, state and federal natural resource trustees provided the PRP steering committee and other site PRPs with a copy of their Natural Resource Damage Assessment and Restoration Options Report (“DAROR”). This report contained an assessment of natural resource damages (“NRD”) allegedly caused by releases of hazardous substances at the site. The natural resource trustees for the Metal Bank site include the National Oceanic and Atmospheric Administration, the United States Department of the Interior, the National Fish and Wildlife Service, and several other Pennsylvania agencies. The DAROR focuses on losses to soil, sediment, and fish resulting from releases of PCBs from the site and habitat losses caused by the EPA’s required site remedial construction activities. Such losses are estimated by comparing PCB concentrations in site soils, Delaware River sediment, and fish tissue to literature-based adverse effects thresholds. The PRP steering committee has assessed the DAROR and provided information to the trustees questioning the extent, if any, of NRD associated with the site. Negotiations with the trustees regarding NRD issues are expected to continue during the next year. During 2015, EPA sent each site PRP a notice letter regarding potential liability for a removal action at a neighboring property located at 6801 State Road, Philadelphia, PA (“State Road”) allegedly operated by Metal Bank. During 2016, the PRP steering committee entered into an Administrative Settlement Agreement and Order on Consent (“State Road Settlement”) with the EPA to resolve their respective responsibilities for the costs to clean up PCB-contaminated soil at the State Road site. Under the State Road Settlement, the PRP steering committee completed the repair of the asphalt cover over areas of contamination at the State Road site during October 2016 at a cost of approximately $155,000, and the EPA reimbursed the PRP steering committee for the costs of the repair with money available from a previous settlement with the owners and operators of the sites.

During July 2017, the Pennsylvania Department of Environmental Protection ("PADEP") submitted a cost recovery claim to the PRP steering committee for costs incurred during the period of July 1, 2002 through May 31, 2017 totaling $98,314. The PRP steering committee and PADEP agreed to resolve this claim for $45,000.

The Company's share of estimated total liability for this site is 4.58%.

Cost Projections

Q. Have you prepared an estimate of projected SIR costs in connection with this rate case?

A. Yes. That estimate is shown in Exhibit EHS-1 and Exhibit EHS-2 bearing the caption "SIR Projections by Quarter Q4 2017 to Q4 2022."

Q. Were Exhibits EHS-1 and EHS-2 prepared by you or under your supervision?

A. Yes.

Q. Please describe what is shown in Exhibit EHS-1 and EHS-2.

A. Exhibits EHS-1 and EHS-2 detail the projected SIR expenditures for the previously described MGP and non-MGP sites.

Q. How much does the Company expect to spend in total during the linking period (*i.e.*, October 1, 2017 through December 31, 2018)("Linking Period"), the Rate Year, and the two subsequent 12 month periods following the Rate Year for its SIR Program?

A. The expenditures shown for those periods in Exhibits EHS-1 and EHS-2 aggregate to $75,777,256. For the Linking Period, the total expenditure for the SIR Program is projected to be approximately $15,065,135 and for the Rate Year, an expenditure of approximately $11,922,386 is projected. The Panel would note that, as discussed by the Company's Accounting Panel, the Company is not proposing a multi-year rate plan. However, in addition to providing projections for the Rate Year, the Panel does address projected expenditures in the two years following the Rate Year in this proceeding. For the sake of convenience, these two years will be referred to as Rate Year 2 or RY2 (*i.e.*, January 1, 2020 through December 31, 2020) and

Rate Year 3 or RY3 (*i.e.*, January 1, 2021 through December 31, 2021). For Rate Year 2, an expenditure of approximately $15,188,142 is projected for the SIR Program and for Rate Year 3, an expenditure of approximately $33,601,593 is projected.

Q. Please discuss the major reasons for the projected SIR Program expenditures of $75,777,256.

A. The major drivers of the projected SIR Program expenditures are construction and remedial action activities at the MGP sites that are not yet remediated. These sites include the Port Jervis groundwater treatment system, the two Middletown MGP sites, and the Clove and Maple Avenue, Haverstraw MGP site (both OU-1 and OU-2). The Company will also conduct remedial design work to implement these remedies.

Q. How were the projected expenditures in Exhibits EHS-1 and EHS-2 determined?

A. The projections for the MGP projects are calculated by cost loading the projected schedule for each of the MGP sites to generate project/program cost forecasts. The costs for the West Nyack project and Spring Valley

UST site are estimated based on projected annual monitoring costs. The costs for the third-party superfund sites are based on estimates of the Company's share of the PRP group costs. The Accounting Panel's direct testimony explains the allocation of these expenditures and the amount included in the Company's revenue requirement.

Q. Could actual expenditures differ from these estimates?

A. Yes. The projected expenditures represent what the Company expects to spend on these programs during the Linking Period, the Rate Year, Rate Year 2, and Rate Year 3 based on information that is currently available. The projected schedules and estimated costs presented in Exhibits EHS-1 and EHS-2 are subject to change based on design and construction related contingencies, which may include regulatory review and approval schedules, regulatory agency decisions, access and cooperation issues with property owners, property owner development plans, community concerns, permitting, and new information. Delays in a project may result in acceleration or substitution of other projects.

It is important to note that each site is different due to various factors (*e.g.*, nature of the site, level of contamination, and site usage). Given these differences, remediation costs will vary accordingly. It should also be noted that the MGP spending projections for known 2017 actuals, along with the West Nyack Site and the Spring Valley UST sites will be updated throughout this rate proceeding.

SIR Cost Control Efforts

Q. What steps has Orange and Rockland taken to control its SIR costs and liabilities?

A. The Company follows the management/mitigation practices set forth in the Inventory of Best Practices for Utility SIR Programs adopted by the State’s electric and gas utilities pursuant to the Commission’s Order issued November 28, 2012 in Case 11-M-0034. Specific details regarding Orange and Rockland’s SIR cost control efforts are detailed below.

<u>Development of Remedies</u> - When permissible under applicable laws and regulations, the Company attempts to pursue remediation requirements with regulatory

agencies based on the present and contemplated future use of sites, so that the remedies selected by the agencies are not more stringent than necessary for such uses. For example, if the present and contemplated future use of a site is for industrial or commercial purposes, the Company attempts to negotiate remediation requirements that are consistent with such uses, rather than the more stringent remediation requirements that would apply at sites with residential uses.

When desirable and permissible under applicable laws and regulations, the Company attempts to negotiate with regulatory agencies and third-party property owners, remediation work plans that rely in whole, or in part, on post-remediation engineering and/or institutional controls in order to avoid more costly remediation to “unrestricted use” standards. In addition, when investigation results show that remediation may not be necessary to protect human health and/or the environment, the Company advocates its position to the regulatory agencies so that remediation requirements are not imposed unnecessarily. For example, at the Port Jervis MGP site, the Company was able to convince the DEC that excavation at the site should be limited to accessible source areas and that it was not necessary to disrupt and relocate existing infrastructure such as a gas regulator station and large municipal storm drain. The DEC concurred with the Company that excavation substantially below the water table was not necessary and that a non-aqueous phase liquid ("NAPL") recovery system would provide an effective remedy in conjunction with a requirement that the site remain zoned for commercial/industrial use only. The Company also conducted a pilot study to determine the most effective well construction and installation methods for the NAPL recovery system. Based on the results of the pilot study, the DEC modified the requirements for the NAPL recovery system. The various efforts detailed above saved millions of dollars on the remediation for the Port Jervis site.

Experienced Staff –– The Remediation Section of the Company's EH&S Department is staffed with an experienced and dedicated full time project manager.

This project manager works closely with qualified consultants and contractors to develop and implement the best possible work plans and specifications, consistent with applicable government agency requirements. The Company also uses qualified consultants who are specially trained to perform constructability reviews of remedial design plans and specifications, manage these types of contracts and contractors, and oversee field work so that the contractors comply with the terms of their contracts. To further enhance project management of remedial construction, the Company’s Project Management department supports the Remediation Project Manager in the implementation of the required remedial action. The Project Management department reviews and approves the bid specifications, coordinates the remedial construction bidding with the Company’s Purchasing department, manages the remedial action contracts, and oversees remedial construction so that contractors comply with the terms in their contracts.

Reuse of Excavated Material - Whenever feasible and acceptable to the DEC and DOH, excavated soil and stone are reused as backfill at remediation sites. For example, during remediation at the Port Jervis and Suffern MGP sites, non-impacted soil was excavated and reused as subsurface backfill. In addition, ISS and jet grout spoils were used at the Suffern MGP site as backfill. This resulted in a reduction in the disposal costs of the spoils and a reduction in the amount of backfill that needed to be brought on site to backfill some of the excavated areas.

Cost Effective Investigations - When appropriate and acceptable to the DEC, the Company incorporates "step-out" procedures in its RI and PDI work plans. These procedures allow the Company's project manager and a DEC project manager to expand the scope of an investigation while field work is being performed. Broadening the scope of an investigation while field work is in progress helps minimize the need to prepare work plans for and conduct subsequent rounds of investigation.

Participation in External Organizations –– The Company actively participates in national and state industry forums and research organizations, such as the MGP

Consortium, the Utility Solid Waste Activities Group ("USWAG") Remediation & Response Committee, EEANY, and EPRI. By participating in these forums and groups, the Company benefits from the experience and knowledge of other members. The Company is also better able to keep its staff abreast of changing regulatory requirements, technical developments in the remediation industry, and innovative technologies. In addition, some of these organizations (*e.g.*, USWAG, EEANY) provide comment on regulatory proposals on behalf of companies like O&R in an attempt to obtain more reasonable, more flexible, and less costly requirements.

Competitive Procurement - The Company competitively bids all remediation projects and retains qualified contractors. In addition, the Company employs internal controls, including comprehensive procurement procedures and remediation contractor management protocols, so that project work is performed properly and cost effectively.

Pre-Remedial Design Investigation and Treatability Studies - When appropriate, the Company performs PDIs to fill data gaps in order to develop the best possible remediation work plans and specifications for regulatory agency approval and for competitive bidding.

Insurance Cost Recovery – The Company has notified its excess liability insurance carriers of EPA and DEC demands that the Company pay for or implement site investigation and remediation work. It also has pursued indemnification of the costs of such work with its excess liability insurance carriers and, when necessary and appropriate, pursued litigation against insurance carriers that deny or reserve coverage for such costs.

Claims for Indemnification- When possible, the Company attempts to transfer the liability for future environmental remediation costs in agreements with third-parties in connection with the purchase or sale of real property or other assets. The Company also seeks indemnities for such future liabilities.

Identification of Other PRPs – The Company attempts to identify other PRPs and, when appropriate, attempts to recover investigation or remediation costs from such entities. For example, the Company undertook an investigation program in 2009 to demonstrate to the DEC that chlorinated solvent impacts on the West Nyack Site were attributable to an off-site source. The Company was successful in convincing the DEC and DOH to view available information on an area wide basis. Based on further submissions from the Company, the eventual ROD issued by the DEC in connection with the remediation of that off-site source acknowledged the impacts to the West Nyack site and the Company is no longer required to conduct quarterly groundwater monitoring at the West Nyack site. This has resulted in a savings of $80,000 per year.

Participation in PRP Groups –– The Company also actively participates in Superfund site PRP Groups that engage in negotiations with the government on consent decrees and orders that equitably allocate liability among all financially viable PRPs and, when warranted, institute Superfund cost contribution actions against recalcitrant PRPs.

For example, in connection with the Clarkstown Landfill site, a New York State Superfund site, O&R,

along with other PRPs, entered into a consent decree with New York State and the Town of Clarkstown to settle response cost claims. Under the consent decree, O&R paid $83,000 in full settlement of its share of past and future response costs. O&R and the other settling PRPs then retained counsel to pursue recoveries from non-settling responsible parties. These efforts have, to date, resulted in settlement payments to O&R totaling $58,047, representing recovery of approximately 70% of the Company’s initial payment.

Treatment, Storage, and Disposable Facility Audits - To minimize the potential that it will become a PRP at newly listed Superfund sites, the Company in conjunction with Con Edison has established a list of acceptable waste treatment, storage, and disposal facilities (“TSDFs”) and periodically reevaluates the list. The Company’s procedures require that new TSDFs be approved before they are used by either company. The most recent review and update of the approved TSDF list was completed during September 2017.

Due Diligence in Property Transfer - To minimize the potential that property transfers might result in significant SIR costs, properties for prospective sale and purchase are extensively evaluated to identify potential environmental risks using environmental site assessment procedures.

Compliance with Rate Case Filing Requirements

Q. Are you familiar with the Commission's rate case filing requirements with respect to SIR costs?

A. Yes, we are. In its Order of November 28, 2012, in Case 11-M-0034 ("Order"), the Commission adopted several rate case filing requirements with respect to SIR costs in order to enhance its oversight of these costs.

Q. Please state what these filing requirements are.

A. The Commission's order states that in any future rate filing in which a utility seeks to recover SIR expenses, it must provide sworn testimony: (1) establishing that the remediation process is in compliance with existing timetables and DEC requirements, or providing explanations for any divergence; (2) discussing the utility's cost control efforts, including an attestation to utility compliance with the best practices inventory; and (3) indicating the results of any internal process the utility may have conducted with respect to review of SIR procedures, and in particular explaining how internal controls are brought to bear on site investigation and remediation projects.

Q. Please discuss the Company's compliance with these requirements.

A. For a discussion of the Company's compliance with DEC requirements for remediation programs, including current schedules, see the SIR Program section of our testimony. Pursuant to the Commission's Order, the utilities have established an inventory of best practices, which has been accepted by the PSC staff. By this testimony, we are attesting that Orange and Rockland complies with the best practices inventory. We discuss in detail above the Company's SIR cost control efforts and practices in the section of our testimony entitled "SIR Cost Control Efforts." Finally, we discuss above the Company's internal controls and how those controls are brought to bear on site investigation and remediation projects.

<u>Other Capital and Operation and Maintenance ("O&M") Programs</u>

Q. Are there any other O&M programs the Panel will be sponsoring?

A. Yes, in addition to the programs described above, the Panel will also address the following programs:

- Motor Vehicle Collision Reduction Program;
- Spill Response Staffing Supplementation Program;
- Contaminated Site Reference Document Collection and Maintenance Program;
- Mobile Enhancements to Contractor Oversight System; and
- Security Enhancements.

Motor Vehicle Collision Reduction Program

Q. Please explain the need for the proposed Motor Vehicle Collision Reduction Program ("MVCRP").

A. Over the past several years, the Company has experienced an increase in the number of motor vehicle collisions that have resulted in damages to Company vehicles. These collisions include both non-preventable collisions and avoidable collisions. Non-preventable collisions are accidents caused by other drivers colliding with Company vehicles. Avoidable collisions are defined as an accident in which the driver failed to do everything that they reasonably could have done to avoid the collision. The table below shows the number of non-preventable collisions involving a Company fleet vehicle over the past six years.

Year	Non-Preventable Vehicle Collisions
2017	43
2016	33
2015	35
2014	39
2013	23
2012	15

These collisions have resulted in two recordable injuries and have cost the Company approximately $125,000 annually to repair or replace damage caused by these collisions.

Over the past six years, when compared to EEI and AGA peer companies, the Company has ranked in the top of the fourth and bottom of the third quartile (the fourth quartile being the worst), respectively for avoidable motor vehicle collisions. While Company vehicles were involved in one preventable motor vehicle collision for every 150,000 miles driven, peer companies from the EEI and AGA study drove 212,662 miles and 329,830 miles, respectively, per one preventable motor vehicle collision.

Given this level of performance, the Company requested an AGA peer review to help it identify the root causes of these collisions. This peer review took place in May 2016 and involved employees from peer companies spending one week reviewing Company procedures, documents, and accident reports. The review also included formal interviews with Company employees and contractors that operate fleet vehicles. Based on this review, the AGA recommended: 1) the Company establish a formal driver safety program that includes on-going training; and 2) consider implementation of an in-vehicle monitoring system program.

Q. Please describe the Company’s planned MVCRP initiative.

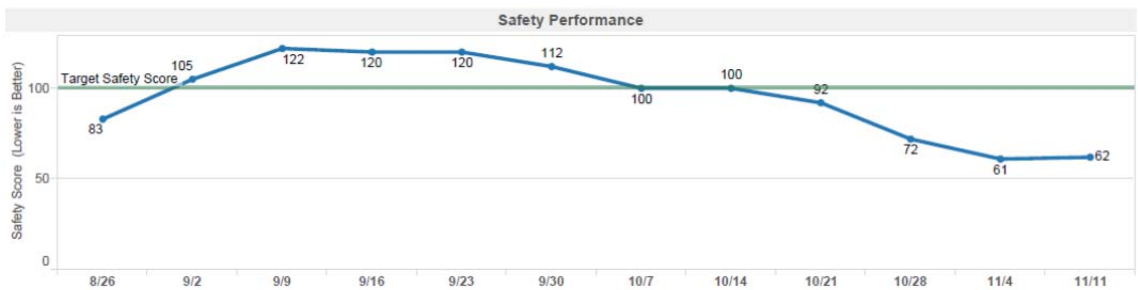
A. The MVCRP is a multi-pronged effort to improve driver safety and reduce the number of collisions involving Company vehicles. The first component is a research and development pilot project that is currently underway that involves installing and operating In-Vehicle Monitoring Systems ("IVMS") in 75 Company owned fleet vehicles. IVMS, developed by SmartDrive Systems, contain both forward and driver facing cameras that are able to provide the Company with driver performance data like instances of hard braking, incomplete stops, speeding, and unsafe following distance. Drivers that engage in these types of behaviors are more likely to be involved in a collision. The data collected via IVMS can be used by the Company to identify opportunities to provide targeted feedback on risky driving behaviors.

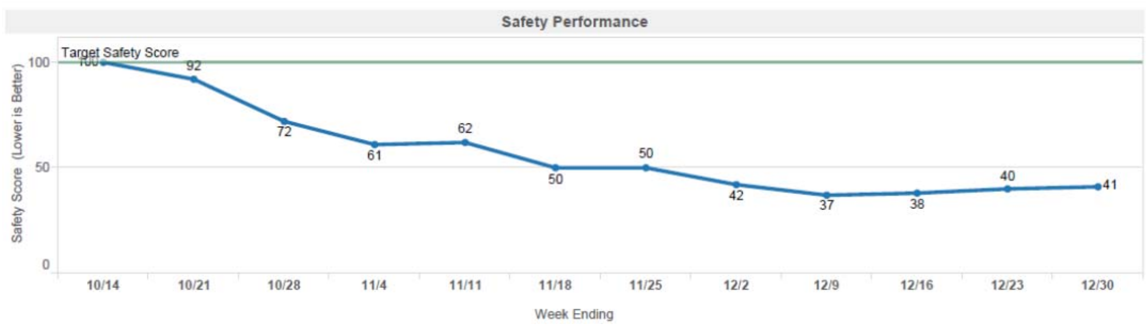
Q. What is the anticipated timeframe for this program?

A. This pilot program began in August 2017 and will continue through February 2018. Though the pilot program will not be completed by the time of this filing, the Company has seen a marked improvement in driver behavior and proposes expanding the use of

IVMS. As illustrated in Figure 1 below, the Company’s Motor Vehicle Safety Score has shown improvement.

Figure 1: Company Motor Vehicle Safety Score





The composition of the Motor Vehicle Company’s Safety Score, as well as improvements realized by the Company as demonstrated by reductions of risky driving behaviors, are outlined in Table 1 below.

Table 1: Composition of Motor Vehicle Safety Score

Metric	Contribution to December Safety Score	Reduction seen between September and December 31
Driver Seatbelt Unfastened	12	-63%
Excessive Speeding (> 10 mph Over Limit)	7	-36%
Incomplete Stop at Stop Sign	32	-60%
Moderate Speeding (<= 10 mph Over Limit)	36	-46%
Non-hands free electronic device use	6	-67%
Unsafe Following (<2 seconds)	18	-40%

Given these improvements, over the next year the Company proposes to purchase and permanently deploy 100 IVMS, which will cover approximately 25% of the Company’s fleet vehicles.

Q. Does the Company’s program include training?

A. Yes, another component of the MVCRP is improving the training provided to employees that operate Company fleet vehicles. The Company currently provides four days of training to employees that do not have, but are required to obtain, a commercial driver’s license (“CDL”) for their position. Once an employee has a CDL, no additional training is currently provided and no training is currently provided to employees that are not required to obtain a CDL. However, the aforementioned peer reviews showed that nearly 80% of the Company's EEI/AGA peers provide some form of ongoing driver training that was typically required every three years for all drivers, not just those with a CDL.

Q. Will training be provided on an ongoing basis?

A. Yes. To better align with our peers, the Company proposes to establish a formal training program for all its drivers that operate fleet vehicles. The three year program involves eight hours of classroom and behind the wheel training during the first year. The second year involves peer assessment/observations with trained coaches, and the third year involves two hours in a driving simulator, and two hours completing coursework using eLearning modules. In each of the next three years, 200 drivers will start this program. By 2020, all 600 employees that drive Company fleet vehicles, those both with and without a CDL, will have completed some form of training.

Q. Has the Company joined any industry organizations related to traffic safety?

A. Yes. To supplement this training program, the Company has also become a member of the Network of Employers for Traffic Safety ("NETS") which is a collaborative group of employer road safety professionals whose objective is to advance road safety for employees, their family members and members of the communities where they live and work. Members help one another improve road safety and reduce losses through fleet safety benchmarking and sharing proven, best practice approaches.

Q. Are there any other significant components to the MVRP?

A. Yes, the remaining components of this program include:

1. Requiring drivers to perform a 360 degree walk around of the vehicle prior to movement to inspect for damage and verify that no hazards are present. By implementing this procedural requirement, the Company will be more aligned with its industry peers
2. Establishing a Navigator Program that requires active participation by passengers to protect the safety of the vehicle, driver and other

passengers. Active participation includes the passenger looking out for hazards, correcting the driver, and acting as another set of eyes and ears for the driver

3. Developing, communicating, and clear policies that foster safe driving habits.
4. Developing enhanced collision investigation protocols (*e.g.*, accident investigation techniques, documentation of the investigation, and a review of investigation results). This documentation will then be used to develop coaching modules to reduce the risk of future collisions. By establishing these protocols, the Company will be more consistent with its AGA peers that have established similar documentation requirements.

Q. What is the intended outcome of this Company program?

A. The program is intended to reduce the Company's preventable and non-preventable motor vehicle collisions. Specifically, by 2020 the goal is to reduce or maintain the number and severity of non-preventable collisions and reduce preventable collisions by 37%, demonstrated by driving 250,000 miles per preventable motor vehicle collision from a three year average of 182,214 miles.

Q. What are the estimated O&M expenditures of the MVCRP?

A. The total estimated O&M expenditure for this program is $101,830 in RY1, $101,830 in RY2, and $101,830 in RY3. These O&M expenditures are for the training program and the ongoing maintenance of the IVMS.

Q. What is the estimated addition to plant for this program?

A. There will be an initial capital investment of $144,000 that will close to plant during RY1. For additional information on this program and request, please see the white paper contained in Exhibit EHS-3

Spill Response Staffing Supplementation Program

Q. Please explain the need for the Spill Response Staffing Supplementation Program.

A. The Company’s EH&S Department currently manages a team of five trained and qualified employees to respond to spills of dielectric fluid and other chemicals. This group is responsible for cleaning up and remediating spills that result from the failure of dielectric fluid-filled electrical equipment. To minimize the impact on the environment, the safety of the general public and Company employees, and Company property and equipment, it is essential that spills are remediated quickly and in a compliant manner.

Q. Are there particular circumstances that pose a challenge in responding to these spills?

A. Yes. During storms, while the Company addresses spills as quickly as possible and in a compliant manner, providing this environmental response function can at times become a critical path to smaller embedded outages that can extend restoration for individuals. For example, as we experienced during Superstorm Sandy and Hurricane Irene, in certain instances restoration times were delayed because spills needed to be addressed as a critical path item. After these weather events, the Company spent a significant amount of time evaluating how it responded to these weather events and how it should structure its organization to respond to such future weather events. As part of this effort, the Company developed a Storm Response Staffing Plan that outlined the personnel needs from each department based on the severity of the weather event.

Q. Please continue.

A. At the highest level of storm response, where past experience has shown the number of spills can exceed 400 during a particular weather event, EH&S’ Storm Response Staffing Plan indicates the need for twelve trained personnel on duty. The Company is currently staffed with five trained personnel internally and, without additional trained contractors to supplement existing staff, is unable to provide this level of coverage. Though the Company currently supplements its existing staff with internal resources, and individuals from Con Edison and/or retirees, these additional resources typically provide access to only an additional three trained personnel. These supplemental personnel are generally sufficient to respond to spills that occur during a typical storm, but as previously mentioned the Company would not be able to meet the resources required at the highest level of storm response.

Q. How does the Company plan to address this issue?

A. The Company is proposing the seasonal retention of four additional trained consultants to supplement existing company personnel to meet the requirements of established storm response resource levels. In order that these individuals are familiar with its procedures relating to spill responses, the Company will train the four consultants on 'blue sky' days so they are able to quickly respond to spills during weather events. These consultants would undergo approximately 12 weeks of training per year (three weeks each) to maintain proficiency and system knowledge. They will be called upon if and when additional resources are required to comply with EH&S' Storm Response Staffing Plan.

Q. What are the estimated O&M expenditures to cover the annual training described above for the Spill Response Staffing Supplementation Program?

A. The estimated O&M expenditures for this program are $23,570 in RY1, $23,570 in RY2, and $23,570 in RY3 for the additional training. For additional information on this request, please see the white paper contained in Exhibit EHS-3.

Contaminated Site Reference Document Collection and Maintenance Program

Q. Please explain the need for the Contaminated Site Reference Document Collection and Maintenance Program.

A. Throughout the Company's service territory, 240 historically contaminated sites have been identified which are not currently owned by the Company. Contamination persists at many of these sites. When the Company must perform intrusive work on these sites, there is the potential risk to employees, the public, and the environment from the release of contaminants resulting from the handling of contaminated waste and additional health and safety protocols must be followed. To mitigate against the potential risks, the Company has compiled detailed information for these sites, including the type of contaminants and the location on each site. Approximately 50% of these sites have been assessed in order to identify required protective equipment and appropriate procedures for the management of contaminated materials if intrusive work is required.

Q. Please describe the proposed Contaminated Site Reference Document Collection and Maintenance Program.

A. This proposed program will enable the Company to engage environmental consultants to complete the evaluation and analysis of the remaining 50% of known contaminated sites and to develop contaminated site reference documents for shared use and reference and to help facilitate employee and public safety if intrusive work must be performed at a contaminated site. The reference documentation will provide specific direction to Company and contractor crews working on these sites. In addition, the documents will outline the required precautions and planned responses at each site to ensure compliance with any regulatory restrictions imposed on these sites.

Q. How has this work been accomplished in the past?

A. The Company has been doing this work with internal resources, based upon their availability. Going forward the Company plans to employ a dedicated resource to perform this analysis and evaluation in a more proactive manner.

Q. What is the projected O&M expenditure for the Contaminated Site Reference Document Collection and Maintenance Program?

A. The projected O&M expenditure for this program is $41,000 in RY1, $41,000 in RY2, and $41,000 in RY3. For additional information on this request, please see the white paper contained in Exhibit EHS-3

Mobile Enhancements to Contractor Oversight System

Q. Please describe the Company's current Contractor Oversight System ("COS").

A. The Company implemented the current COS in April 2004. It is a corporate system that allows the inspections performed by supervisors and field inspectors of the various business areas (Safety, Quality, and Operations) for both electric and gas commodities to enter field observations on a contractor's performance and employee performance in the areas of safety and procedure compliance. Once performance data is entered into the system, users can evaluate the overall performance of specific contractors and organizations. This performance information is also used by Procurement to evaluate contractor performance for inclusion on bid lists and to apply a bid multiplier to prospective bidders based on their performance.

Q. Are there any limitations to the current system?

A. Yes. The current COS system does not have mobile integration capabilities and as a result there is a duplication of data entry workload. Field inspectors capture their findings manually in the field on paper and must later either manually enter the data or provide their papers to a clerk who then must manually enter the data into the COS system. This manual process increases the risk of data entry error and information delays and therefore makes it difficult to perform reliable statistical analysis using this data. Though data is typically captured in the COS system within 24-48 hours of inspection, there are times where it can take a week or more, depending on workloads of the inspector or clerk.

Q. Please describe the proposed modifications to the current COS and some of the expected benefits.

A. To avoid the duplication of workload and the delay in uploading performance results into the system, the Company is proposing a COS-Mobile Enhancement (“COS-

ME") that will allow field inspectors to complete performance evaluations and upload the results to the COS via a mobile device while still in the field. By implementing these mobile enhancements, data on contractor performance will be accessible in real-time and the need to duplicate data entry efforts will be significantly reduced and eventually eliminated. This ability to access real-time data will make it easier for the Company to track its performance on Key Performance Indicators ("KPI") and perform analyses on safety and compliance trends more frequently. Monitoring KPIs and trends more frequently will enable the Company to be more proactive in managing risk and identifying opportunities to improve the safety and performance of its contract employees.

Q. Are there any other benefits?

A. Yes, another benefit of the proposed COS-ME program will be the standardization of inspections and data capturing across the two commodities. The current paper performance documents are different depending on electric or gas commodity and sometimes vary based on group within a specific commodity. By moving to a mobile platform, the evaluation tools will be standardized and will make it easier to analyze contractor performance across commodities and groups. Lastly, the COS-ME will have capabilities that will guide field inspections to target specific areas during an inspection.

Q. What is the projected addition to plant of this Contractor Oversight System – Mobile Enhancement?

A. The projected addition to plant of the COS-ME program is approximately $921,000 in Rate Year 2. There are not expected to be any additional capital or O&M expenses beyond this initial cost for the upgrade. For additional information on this request, please see the white paper contained in Exhibit EHS-3

Security Enhancements

Q. Is the Company proposing any modifications to its existing Corporate Security efforts?

A. Yes. The Company is proposing adding the following security enhancements in the Northern Division:

- Security Officer at the Blooming Grove Operations Center: The Company is proposing adding a Security Officer that would be posted primarily in the Blooming Grove Operations Center Customer Service lobby during business hours (42.5 hours per week) to control access to the facility, issue visitor identification badges, secure entry to the restricted area, assist customers, and provide a uniformed presence in the public lobby. This Security Officer would also respond to alarms at the control center and to issues on the property, as needed.

- Mobile Security Officer in the Northern Division: This Mobile Security Officer ("Rover") would be responsible for patrolling sites in the Northern Division, and quickly responding to alarms, suspicious conditions, and malfunctioning gates. The Rover would work after hours during the week and around the clock on weekends.
- Expand Hours at Blooming Grove Main Gate: The Company is proposing to add an additional security guard at the main entry gate during the

high traffic hours of 6 a.m. to 8 a.m., ten hours per week, to prevent unauthorized entry.

Q. Please explain why the Company is seeking these security enhancements in the Northern Division?

A. By preventing damage, theft, and liability from injuries, Orange and Rockland protects its customers from incurring unnecessary costs. While the Company currently employs a robust security force in the more populated Eastern Division, the Company currently staffs the guard booths in its entire Northern Division as follows; Blooming Grove is staffed 6am to 6pm on weekdays, Middletown is staffed 6am to 10pm weekdays, and 8am to 4pm on weekends. The Northern Division has two large operations centers, several smaller workout locations, two payment centers, an Alternate Energy Control Center classified as a NERC CIP (Critical Infrastructure Protection) High Impact Facility, numerous electric substations including six substations classified as NERC CIP Low Impact Facilities, and gas gate stations that include Tier I and II security sites. The alternate control center is a NERC High Impact Facility and the Northern Division also includes five NERC low impact substations with BES cyber system assets. Many of the Northern sites are in less populated areas and receive less police patrols and natural surveillance from neighbors and passersby than sites in the more populated and well-traveled areas in the Eastern Division. To provide a consistent level of security across the Company’s entire service territory, additional security personnel are required.

Q. What are the expected O&M expenditures associated with the proposed security upgrades?

A. The projected O&M expenditures are $212,000 in RY1, $215,000 in RY2, and $212,000 in RY3. For additional information on this request, please see the white paper contained in Exhibit EHS-3.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
DEMAND ANALYSIS AND COST OF SERVICE PANEL - ELECTRIC

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ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
DEMAND ANALYSIS AND COST OF SERVICE PANEL - ELECTRIC

I. INTRODUCTION

Q. Would the members of the Demand Analysis and Cost of Service Panel ("Panel") please state their names and business addresses.

A. Yan Flishenbaum, Kristin Graves, Lucy Villeta, and Michael Peres, 4 Irving Place, New York, New York 10003.

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

A. **(Flishenbaum)** I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison") as the Department Manager of the Load Research and Cost Analysis Section of the Rate Engineering Department.

(Graves) I am employed by Con Edison as the Section Manager of the Load Research section in the Rate Engineering Department.

(Villeta) I am employed by Con Edison as the Section Manager of the Cost Analysis section in the Rate Engineering Department.

(Peres) I am employed by Con Edison as a Senior Rate Analyst in the Load Research section in the Rate Engineering Department.

Q. Please summarize your educational background and business experience.

A. **(Flishenbaum)** I received a Bachelor of Business Administration Degree in Economics from Pace University in 2001 and a Master of Business Administration Degree in Finance and Economics from New York University in 2008. In 2001, I began my employment with Con Edison in the Cost Analysis Area of the Rate Engineering Department. In 2003, I was promoted to Analyst, mainly involved in the development of the costing methodologies related to unbundling. I was promoted to Senior Analyst in 2005. In 2008, I was promoted to Senior Rate Analyst responsible for developing the Company's cost-of-service models. In 2013 I was promoted to Section Manager of the Electric Rates area of the Rate Engineering Department. I was promoted to my current position in 2016.

(Graves) I received a Bachelor of Arts degree in Economics from the University of California at Davis in 1977, a Master of Science degree in Consumer Economics from Cornell University in 1981, and a Master of Arts degree in Geography and a Certificate in Geographic Information Science from Hunter College in 2015. I am an elected member of the Load Research and Analytics Committee of the Association of Edison Illuminating

Companies ("AEIC"). Since 2010, I have also been the instructor for the statistical sampling and other sections of the Advanced Applications in Load Research Seminar for the AEIC. I began my employment with Con Edison in 2005 as a Senior Analyst in Load Research. In 2014, I was promoted to Section Manager. In that capacity, I am responsible for preparing demand analyses related to electric service. In addition, I have a variety of duties related to load research sample design and data analysis. Prior to working for Con Edison, I worked for the New York Power Authority for over 13 years in the areas of load research and customer billing.

(Villeta) I received a Bachelor of Business Administration Degree in Finance with a minor in Management Information Systems from Pace University in September 1989. In October 1989, I began my employment with Con Edison as a Management Intern with rotational assignments in Forecasting and Economic Analysis, Accounting Research and Procedures (“ARP”) and Power Generation Services. In June 1990, I accepted my permanent assignment as an Associate Accountant in ARP. In 1995, I was promoted to Budget Analyst in Central

Customer Service. In 1998, I was promoted to Senior Analyst in Customer Operations responsible for managing the Call Center and Service Center budget. In 2001, I was promoted to Financial Manager of Staten Island and Electric Services. I have been in my current position since November 2005.

(Peres) I received a Bachelor of Science Degree in Electrical Engineering from the University of Pennsylvania in 1985 and a Master of Business Administration Degree in Finance and Economics from New York University in 2013. I began my employment with Con Edison in 2008 as an Analyst in Load Research. In 2011, I was promoted to Senior Analyst. In 2016, I was promoted to Senior Rate Analyst responsible for preparing demand analyses.

Q. Have you ever testified before the New York Public Service Commission ("NYPSC") or any other state utility commission?

A. **(Flishenbaum)** Yes. I have testified in numerous regulatory proceedings before the NYPSC and the Pennsylvania Public Utility Commission (“PAPUC”).

(Graves) Yes. I have testified before the NYPSC.

(Villeta) Yes. I have testified before the NYPSC, the New Jersey Board of Public Utilities, and the PAPUC.

(Peres) No.

II. PURPOSE OF TESTIMONY

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

A. Our testimony presents Orange and Rockland Utilities, Inc.'s ("Orange and Rockland", "O&R", or the "Company"):

(1) Electric Class Demand Study;

(2) Electric Embedded Cost of Service ("ECOS") Study, including the development of unbundled costs associated with competitive services;

(3) Electric Marginal Cost Study; and

(4) O&R Integration with the Customer Usage System.

Q. Please summarize your testimony.

A. First, we address the Company's Electric Class Demand Study for calendar year 2015 which presents the demand cost responsibility measures that are used in the ECOS Study for each customer service classification ("SC"). Second, we present the Company's ECOS Study and the associated unbundled cost components for calendar year 2015 which:

- functionalize and classify various costs for the electric system;
- allocate these functionalized costs to the customer classes;
- demonstrate each customer class's surplus or deficiency based on the application of a 10% tolerance band around the calculated total system rate of return;
- show a total system rate of return of 9.02% and rates of return for all SCs; and
- present the development of unbundled functional costs for competitive services pursuant to the NYPSC Statement of Policy on Unbundling and Order Directing Tariff Filings, issued August 25, 2004, in Case 00-M-0504 ("Unbundling Policy Statement").

Q. Is the Panel sponsoring any exhibits?

A. Yes, we are sponsoring the following four exhibits:

Exhibit ___ (DAC-1 – Electric Class Demand Study);

Exhibit ___ (DAC-2 – ECOS Study and Unbundled Cost Components, Schedules 1-5);

Exhibit ___ (DAC-3 – Electric Marginal Transmission and Distribution Cost Analysis); and

Exhibit ___ (DAC-4 - O&R Integration with Customer Usage System)

Q. How is the Panel's testimony organized?

A. The testimony is divided into the following four sections:

(1) Class Demand Study,

(2) ECOS Study and Unbundled Cost Components,

(3) Marginal Cost Study, and

(4) O&R Integration with Customer Usage System.

III. CLASS DEMAND STUDY

Q. Please describe the purpose of the Class Demand Study.

A. The Class Demand Study presents demand cost responsibility measures for each Company SC. These cost responsibility measures, in turn, are used in the ECOS Study presented in this proceeding.

Q. Briefly describe the cost responsibility measures developed in the Class Demand Study.

A. There are three cost responsibility measures developed in the Class Demand Study. The first reflects class demands at the time of the Company system peak. The second is class non-coincident peak responsibility, which reflects customer demands at times of the individual class peaks. The third, for low tension customers, reflects a balance between non-coincident peaks and individual customer maximum demands (“ICMDs”).

Q. Have you prepared an exhibit showing the Class Demand Study?

A. Yes. This exhibit is a document entitled "ORANGE AND ROCKLAND UTILITIES, INC., ELECTRIC CLASS DEMAND STUDY, YEAR 2015."

Q. What period does the Class Demand Study cover?

A. It covers calendar year 2015, and includes specific analyses of the summer and winter peak periods for that year.

Q. Please explain the general organization of Exhibit ___ (DAC-1).

A. The title page is followed by three pages of explanatory notes and an index for the study's tabular data. Tabular Reports 2 through 4 show step-by-step development of demand cost responsibility measures for each SC. These reports are followed by a Class Demand Summary Report.

Q. Please explain the method you used in developing Exhibit ___ (DAC-1).

A. The explanatory notes briefly set forth the procedures used to develop the class demand responsibility estimates shown in the exhibit. The discussion includes a short description of O&R's customer load testing program, which is the starting point for many of the calculations in the exhibit. Finally, it provides a brief description of each report in the exhibit.

Q. Please explain the analyses shown in Reports 2 through 4.

A. These reports show the step-by-step development of demand cost responsibilities for each SC. Data are first organized by energy or demand strata. The strata-level data are then added to develop subclass data, and the subclass data are further aggregated to form class data. Report 2 shows the starting data used in developing the class demand responsibilities, and shows either sample test customer load research data or profile data for customers eligible for mandatory day-ahead hourly pricing by stratum. Report 3 shows a summary of class population data by stratum for each SC. Finally, Report 4 shows the resulting class demand responsibilities by stratum for each SC. Reports 2, 3, and 4 are provided by class for both the summer and winter peak periods. The Class Demand Summary Report provides a summary of the class demand responsibilities for each season, obtained from Report 3 and Report 4.

Q. As a typical example of the calculation procedure used for each class in this exhibit, please describe the method employed in developing the summer and winter class demand responsibility estimates for SC No. 1-301, the Residential class.

A. Referring first to Report 2 (summer page 1, winter page 1), the data in Columns 3 through 9 were developed from load tests that the Company performed on sample residential test customers. Column 2 lists the sample test strata. Columns 3 and 4 show the range of consumption or demand for the customers in each test stratum. Column 5 shows the number of customers in each stratum for which test results were obtained. Column 6 shows the calculated average consumption or demand per customer for each test stratum. Columns 7 and 8 show the load test results reduced to average kilowatts per customer for each test stratum. Column 7 lists the average of July, August, and September maximum demands per customer (January and February averages are used for winter). Column 8 lists the maximum coincident demand per customer for each test stratum, based on averages for five selected system peak days for the summer or five selected system peak days for the winter during the test period. Column 9, derived from Columns 7 and 8, shows the calculated coincidence factor for each test stratum.

Q. Please describe the derivation of the coincidence factors.

A. The coincidence factors are derived from interval metered data collected during calendar year 2015. For each stratum of test customers, the recorded half-hourly demand data values obtained from each test location were averaged for the five seasonal system peak days. For this study, the coincidence factor is defined as the ratio of the per-customer maximum coincident half-hour demand of a stratum of test customers, averaged for five days, to the per-customer individual maximum non-coincident half-hour demands of the test customers in that stratum.

Q. Please continue your explanation of the SC No. 1-301 reports.

A. Turning to Report 3, the stratum definitions are shown in columns 3 and 4. The stratum-level customer count and kilowatthour sales for the residential class shown in Columns 5 and 6 are derived from billing records for the year 2015. Column 7 contains the average usage by stratum based on columns 5 and 6. The summer and winter coincident maximum half-hour demands for each stratum in the class population were then calculated using the respective sample test stratum load characteristics. These results appear in Column 11, and the computations are described in footnotes.

Q. Please continue.

A. Since each stratum's maximum half-hour demand (shown in Column 11) occurs at different times, complete daily profile curves were computed for each stratum in the class, again based on test results. Summation of all 48 half-hour stratum load curves at the customers' meters produced composite summer and winter load curves for the entire class. The summer and winter coincident half-hour demands for each stratum, shown in Column 5 of Report 4, were obtained by examining the stratum load curves at the time of the class peak. The summer and winter class load curves were further examined to determine the average class demands for the highest continuous four-hour period. Those results are shown in Column 6 of Report 4.

Q. Please continue.

A. The demands described so far have all been based on measurements and calculations at the customers' meters. To determine the system input level class responsibility shown in Column 8, the class demand at the customers' meters was divided by the annual distribution efficiency for the class. The class distribution efficiencies are shown in footnotes 8 and 9 of Report 4. After applying class distribution efficiencies, the calculated grand total of all the class load curves, developed through the procedures described thus far, closely approximates, but does not exactly match, the known total system load curve at each half-hour. The total discrepancy during the high load periods of the day is generally found to be a few percent during any half-hour. Accordingly, for sampled classes, a percentage adjustment factor for every half-hour was applied to each of the class demands. For those classes with sampled test data that were borrowed, an adjustment factor equal to two times the above-mentioned adjustment factor was applied. Classes that are 100% profile-metered did not receive any adjustment. After adjusting the class data, the total of all class profiles exactly matched the total system load curve. The demand values in Columns 7, 9, and 10 of Report 4 are the adjusted class demands. These values are the average demands obtained from class load profiles for the four peak hours of the system peak load shape or the class peak load shape.

Q. Do the computations and analyses, which you have just described for SC No. 1-301, Residential, apply to the other classes shown in this exhibit?

A. Yes. With a few exceptions, which we will describe, the analyses for the remaining classes are similar to those for SC No. 1-301.

Q. Please describe the exceptions to which you referred.

A. For customers eligible for mandatory day-ahead hourly pricing, the data shown in Report 2 were obtained from the billing profile records. For unmetered classes and traffic signals, a flat load shape was developed. For lighting served under SC Nos. 4 and 16, load shapes were developed taking hours of daylight into account.

Q. Please describe the contents of the Class Demand Summary Report.

A. The Class Demand Summary Report summarizes the seasonal demand responsibilities that were developed in Report 3 and Report 4 for each SC.

IV. ECOS STUDY

Q. Did you perform an ECOS Study for this proceeding?

A. Yes, we did. Exhibit ___ (DAC-2) is entitled "Orange and Rockland Utilities, Inc. – Embedded Cost of Service Study – Electric Department - Year 2015 Rates in Effect November 1, 2017."

Q. Please explain the general organization of the ECOS Study.

A. The ECOS Study begins with explanatory notes detailing sources of data and methods used in the preparation of the Study followed by seven tables of cost data.

Q. Please describe the ECOS Study and its unbundled cost components.

A. The ECOS Study consists of five schedules. Schedule 1 shows the results of the ECOS Study. Schedule 2 shows the Merchant Function Charge ("MFC") calculations. Schedule 3 shows the unbundled metering costs, consisting of meter ownership, meter service provider (including meter installations) and meter data service provider functions. Schedule 4 shows metering costs associated with customers eligible for the Mandatory Hourly Pricing ("MHP") program. They consist of the meter ownership, meter service provider (including meter installations) and meter data service provider costs the Company incurs to serve MHP-eligible customers. The development of MHP functions will be discussed later in this testimony. Schedule 5 shows the unbundled costs for printing and mailing a bill and receipts processing functions.

Q. What cost categories are analyzed in the ECOS Study?

A. The ECOS Study analyzes costs and revenues associated with the Company's delivery system (*i.e.*, transmission and distribution), and customer-related cost categories or functions. It also includes cost categories related to the electric merchant function, competitive metering functions, the receipts processing and the printing and mailing a bill functions. Because the ECOS Study strictly focuses on transmission and distribution, the major supply functional costs, *e.g.*, purchased power and generation costs are not included in the ECOS Study. Also, revenues and expenses associated with the System Benefits Charge ("SBC"), Regulatory 18-A Assessment and Renewable Portfolio Standard Program ("RPS") charge, costs which are considered a pass through to customers, have been excluded from the Study.

Q. What time period does the ECOS Study cover?

A. It covers calendar year 2015.

Q. What electric revenues are reflected in the ECOS Study?

A. Electric revenues reflect current delivery rates, which went into effect November 1, 2017.

Q. What customer classes are analyzed in the ECOS Study?

A. The Study analyzes classes of customers corresponding to the SCs contained in Orange and Rockland’s electric rate schedules, including retail access customers. A description of the type of customers served under each SC is shown beginning on page 15 of the ECOS Study’s explanatory notes.

Q. Did the Panel make any methodological changes to the ECOS Study since the Company’s last filing?

A. Yes, the Company made two methodological changes: the first was to include a customer component of the High Tension Distribution System; the second change is an introduction of a Services Study that impacts the allocation of the customer component of overhead and underground distribution conductors to customer classes, as well as the allocation of the cost of service connections to customer classes.

Q. Please continue.

A. In previous cost studies, high tension assets were classified as demand related and allocated to service classes on the basis of class non-coincident peaks. Secondary distribution assets were split into separate demand and customer functions based on a minimum system concept. In this ECOS Study, we have taken a parallel approach by identifying a demand and customer portion of the high tension system. Please see the ECOS explanatory notes on page 18 for the description of how primary distribution costs were split into demand/customer components. The resulting Primary Demand function continues to be allocated to classes on the basis of non-coincident demands, while the Primary Customer function is allocated on a composite allocator that combines overhead and underground services allocators as explained in the ECOS explanatory notes on page 9

Q. What is the Panel’s rationale for introducing a Primary Customer Component?

A. This change in methodology is consistent with the principles articulated by the National Association of Regulatory Utility Commissioners ("NARUC"). By functionalizing a portion of high tension assets as customer-related the Company is paralleling its methodology applied to secondary distribution assets. The incorporation of a customer component for high tension assets has been adopted by a number of New York State utilities as part of their cost allocation procedures. In fact, the NYPSC's Order in the recent Con Edison electric base rate case (Case 16-E-0060) upheld the validity of introducing a customer component for high tension.

Q. Please explain the Services Study and its impact on the allocation of the customer component of the overhead and underground distribution conductors and the cost of services in the ECOS Study.

A. In previous studies, the customer component of the overhead and underground distribution conductors was allocated to service classes based on their respective number of customers. Services were allocated to customer classes based on their respective non-coincident maximum class demands. For this study the Company conducted a

Services Study that was based on a statistically significant sample of service connections across O&R's service territory. By cross-referencing records of customer locations in the Company's mapping, property records and customer billing systems, we were able to determine the number of services and their associated book cost used in connecting customers in the sample to the Company's distribution system. From this information we developed two allocators: (1) the number of overhead and underground services by class, used to allocate the customer component of overhead and underground conductors; and (2) the actual book cost of services by class used to allocate the overhead and underground services functions in the ECOS Study.

Q. Please continue.

A. The Services Study is an appropriate allocation methodology for these costs because it reflects how the Company serves its customers. Many O&R electric customers share service connections to the distribution system. Therefore, the allocators for these costs should be developed based on this concept in order to follow the principles of cost causation.

Q. How are the results of the ECOS Study expressed?

A. The results of the ECOS Study are expressed as total Company (“total system”) and class rates-of-return.

Q. What is the total system rate of return shown in the ECOS Study?

A. The total system rate-of-return is 9.02%, as shown on Table 1, Page 1, Column (1), Line 17 of the ECOS Study. In addition, Table 1 sets forth rates-of-return for all classes included in the ECOS Study. For example, the SC No. 1- Residential General return is 7.91%, the SC No. 2-C&I Secondary return is 10.31%, the SC No. 9-Total Commercial return is 11.88%, and the SC No. 22-Total Industrial return is 8.80%.

Q. Has the NYPSC historically approved “tolerance bands” around the system rate-of-return in developing class revenue responsibilities?

A. Yes. Based on past practice, class revenue responsibility has been measured with respect to a +10% tolerance band around the total system rate-of-return. Classes would not be considered “surplus” or “deficient” if the class ECOS rate-of-return falls within this tolerance band. Classes that fall outside this range would be either surplus or deficient by the revenue amount, including appropriate state and federal income taxes, necessary to bring the realized return to the upper or lower level of the band. We propose to continue this practice in this case.

Q. Based on the application of the +10% tolerance band around the calculated total system rate of return of 9.02%, what are the ECOS study class surpluses and deficiencies?

A. The revenue surpluses are shown on Table 1, Line 26 and the revenue deficiencies are shown on Line 27. For example, the SC No. 2 - C&I Primary class has a revenue surplus of $559,200, while the SC No. 1- Residential General class has a revenue deficiency of $1,525,353.

Q. What is the significance, for example, of the SC No. 1– Residential General class deficiency?

A. The deficiency is the amount of revenue increase, at current rates, required to bring the SC No. 1- Residential General class return to the lower level of the tolerance band around the system rate-of-return.

Q. Please describe what is shown on Table 1A, which is the last page of Exhibit___ (DAC-2).

A. Due to the application of class tolerance bands, the total of the ECOS surpluses and deficiencies is a net surplus.

In order that ECOS Study indications are revenue neutral to the Company, Table 1A adjusts all classes' surpluses/deficiencies based on their respective delivery revenues used in the ECOS Study so that the sum of surpluses matches the sum of deficiencies.

Q. Let us now turn to the methodology used in developing the ECOS Study. Please describe the procedures followed in the preparation of the ECOS Study.

A. There are two main steps in the preparation of the ECOS Study: (1) functionalization and classification of costs to operating functions, such as transmission, distribution, customer accounting and customer service with further division into sub-functions, such as distribution demand, distribution customer, services, overhead and underground; and (2) allocation of these functionalized costs to customer classes.

Q. Please describe the functionalization and classification step.

A. The functionalization and classification step assigns the broad accounting-based cost categories to the more detailed categories employed in the ECOS Study. This level of detail is required to differentiate, for example, demand-related costs from customer-related costs.

Q. Why is this necessary?

A. This provides for the proper allocation to the classes of the fixed and variable costs, *i.e.*, operation and maintenance (“O&M”) expense, based on cost causation.

Q. Please continue.

A. During the process of functionalization, all costs are classified as being demand-related, energy-related or customer-related. Demand-related costs are fixed costs resulting from the loads placed on the various components of the electric system. Energy-related costs are variable costs resulting from the total kilowatthours delivered during the year. Customer-related costs are fixed costs, which are caused by the presence of customers connected to the system, regardless of the amounts of their demand or energy usage.

Q. Please describe the allocation step in the ECOS Study.

A. This step allocates the functionalized and classified costs to the customer classes based on the appropriate demand, energy or customer allocation factors, which are shown on Table 7 of the ECOS Study.

Q. Does the ECOS Study present unbundled functional costs for competitive services as set forth in the Unbundling Policy Statement?

A. Yes. The ECOS Study separately identifies the following competitive functions: merchant function, meter ownership, meter service provider, meter installations, meter data service provider, receipts processing, and printing and mailing a bill.

Q. What costs are included in the merchant function?

A. The merchant function contains costs associated with procuring electric commodity, including an allocation of customer care-related activities, customer service-related activities, and information resources ("IR").

Q. What costs are included in the allocation of customer care and customer service-related activities?

A. The customer care allocation includes costs associated with the Company's call centers, service centers, and credit and collections/theft activities. The customer service allocation includes an assignment of education and outreach costs.

Q. How were these costs allocated to the merchant function?

A. Pursuant to the Unbundling Policy Statement, customer care and customer service-related costs were allocated to the merchant function on the basis of total revenues (including SBC, 18-A, ECA, MSC, transmission and distribution ("T&D"), MFC, Competitive Metering and Billing and Payment Processing revenues).

Q. How were IR costs allocated to the merchant function?

A. Pursuant to the Unbundling Policy Statement, IR costs were allocated on the basis of total revenues, with 50 percent of the resultant allocation included in the merchant function.

Q. Have you further unbundled the merchant function for use in developing rate components for competitive services?

A. Yes. Separate MFCs to recover the costs for two commodity-related competitive services as described below were developed for (1) SC No. 1 Total Residential and SC No. 19 Residential Voluntary Time of Use, (2) SC No. 2 Secondary, SC No. 20 Secondary Voluntary Time of Use, SC No. 4 Municipal Lighting, SC No. 5 Municipal and Private Lighting, and SC No. 16 Public and Private Lighting and SC No. 16 Energy Only and (3) SC No. 2 Primary, SC No. 3

Primary, SC No. 9 Commercial, SC No. 21 Primary Voluntary Time of Use and SC No. 22 Industrial.

Q. How have you defined these costs?

A. The MFC is made up of two components. The first consists of the costs associated with procuring commodity, IR, and education and outreach (hereafter referred to as the “competitive supply-related MFC component”). The second consists of costs associated with credit and collections/theft (hereafter referred to as the “competitive credit and collections-related MFC component”). Only full service customers pay both the competitive supply-related and competitive credit and collections-related MFC components.

Q. How are these components allocated to the SCs within the ECOS Study?

A. One hundred percent of electric procurement activity costs and 25 percent of credit and collections/theft, IR, and education and outreach costs were allocated on a per kilowatthour basis. The remaining 75 percent of credit and collections/theft, IR, and education and outreach costs were allocated on a per customer basis.

Q. Why were the customer care-type costs, such as credit and collections/theft, allocated predominantly on the basis of number of customers, while the electric procurement activity was allocated entirely on a volumetric (*i.e.*, kWh consumption) basis?

A. The Company followed basic cost causation principles and determined that customer care-type activities are predominantly driven by the existence of customers on the system as opposed to their usage characteristics. On the other hand, the functional cost of purchasing commodity is aligned with sales volumes. This allocation is consistent with the NYPSC's Order Adopting Unbundled Rates and Backout Credits and Specifying Terms for the Recovery of Revenues Lost As a Result of Such Rates and Credits, issued April 15, 2005, in Case 04-E-0572, approving Con Edison's unbundled rates.

Q. Is the allocation of the MFC components to various groups of customers shown in Exhibit __ (DAC-2), Schedule 2?

A. Yes. Schedule 2 of Exhibit __ (DAC-2), Schedule 2, pages 1 and 2, shows the allocation of the competitive supply-related MFC cost components and the competitive credit and collections-related MFC cost components to the residential and commercial categories of customers. This exhibit presents these two components as percentages of the T&D and competitive revenues (*i.e.*, MFC, Metering and BPP revenues) associated with SCs under the Company's electric tariff as used in the ECOS Study. Separate percentages are shown for the previously mentioned groups of customers for use in the development of the MFC, as detailed in the Electric Rate Panel's testimony.

Q. Did the Company allocate costs associated with the separate metering functions to various groups of customers?

A. Yes. Schedule 3, pages 1, 2 and 3 of Exhibit __ (DAC-2), shows the allocation of costs associated with the metering functions to the customer classes eligible to take metering services competitively. Schedule 3 presents the costs for the competitive metering functions as percentages of the T&D revenue requirement associated with service classifications under the Company's electric tariff as used in the ECOS Study.

Q. Please describe each competitive metering function.

A. The Meter Ownership function includes the fixed costs for metering equipment on customers' premises. Also included is a revenue based allocation of credit and collection/theft, uncollectibles and education and outreach costs. The Meter Service Provider function represents the labor associated with meter O&M, such as meter testing and meter replacement and removal. The function includes a revenue-based allocation of credit and collection/theft, uncollectibles and education and outreach. This function is combined with the meter installation function described below.

Q. Please continue.

A. The Meter Installations function represents the book cost of meter installations. Also included is a revenue-based allocation of credit and collection/ theft, uncollectibles and education and outreach.

Q. Please describe the Meter Data Service Provider function.

A. The Meter Data Service Provider function consists of the customer accounting expense of reading meters, as well as allocations for Call Center and Service Center operations and information resources, all based on a detailed study of those activities. Also included is a revenue-based allocation of credit and collection/theft, uncollectibles and education and outreach.

Q. Were any costs functionalized differently in the ECOS Study because of rate design requirements?

A. Yes. The ECOS Study separately identifies metering costs associated with MHP-eligible customers for MHP meters that are now widely in use in several classes throughout Orange and Rockland, which were not in such use for the last ECOS study. These costs are shown in the ECOS as separate MHP functions. Meter ownership-MHP, meter installation-MHP, and meter service provider-MHP functions contain costs associated with installing and maintaining interval meters for the benefit of MHP-eligible customers within several classes. The classes that have these MHP meters included are SC No. 2 Secondary, SC No. 2 Primary, SC No. 3 Primary, SC 20 Secondary Voluntary Time of Use and SC 21 Primary Voluntary Time of Use. The meter data service provider-MHP function consists of phone line installation costs, ongoing meter reading, and communication expenses and is applicable to all the MHP-eligible classes stated above. The meter data service provider–MHP function is also applicable to the SC No.9 Commercial and SC No. 22 Industrial classes, which are now required to pay for the full communications costs.

Schedule 4 of Exhibit ___ (DAC-2) shows the above described components of the $62.64 MHP metering charge.

Q. Is the allocation of unbundled costs for the printing and mailing a bill and receipts processing functions shown on Exhibit __ (DAC-2), Schedule 5?

A. Yes. Schedule 5 of Exhibit ___ (DAC-2), pages 1 and 2 shows the unbundled costs for printing and mailing a bill and receipts processing functions. The printing and mailing a bill function and the receipts processing function consist of the customer accounting expense of accepting customer payments and billing customers, including both direct costs and an allocation for Call Center and Service Center operations based on a detailed study of those activities. Credit and collection, education and outreach, and uncollectibles expenses were allocated to these functions on the basis of functional revenues. The unbundled average unit cost for receipts processing is 60 cents per bill. The average unit cost for printing and mailing a bill is 71 cents per bill. These two functions are combined to yield $1.31 per bill in unbundled costs associated with billing and payment processing. The costs associated with billing and payment processing do not vary by SC and, thus, the system-wide $1.31 per bill in unbundled costs is applicable to all SCs.

V. MARGINAL COST OF SERVICE STUDY

Q. Did you perform an analysis of the marginal cost to supply an additional kW of load on the T&D delivery system?

A. Yes, the analysis is shown on Exhibit ___ (DAC-3), which is entitled "ELECTRIC MARGINAL TRANSMISSION AND DISTRIBUTION COST ANALYSIS."

Q. Before turning to the exhibit, please provide a general background and description of the marginal cost analysis that you are presenting.

A. The Commission's Order in Con Edison Case 09-E-0428 directed that a marginal cost study be performed to enable the evaluation of the costs and benefits of the energy efficiency programs operating in Con Edison's service area. Con Edison retained NERA Economic Consulting ("NERA") to direct this effort. As a result of this collaboration with NERA, Con Edison developed the Marginal Cost of Service ("MCOS") Analysis based on a planning/engineering approach, whereby marginal costs were determined based on T&D planning practices, and the cost quantification was derived to the maximum extent practicable from either engineering estimates or actual costs of specific projects. While the initial scope of the NYPSC's Order in Case 09-E-0428 was to evaluate energy efficiency programs using an avoided cost methodology, this methodology was later expanded in Con Edison Case 13-E-0030, as well as in O&R Electric Case 14-E-0493, into a full-scope marginal cost analysis that compares all marginal costs to current rates in order to establish a basis for discounts under the Excelsior Jobs Program. This expanded NERA methodology, established and employed by Con Edison, sets the foundation for the MCOS analysis presented by O&R in this proceeding.

Q. Please describe the planning/engineering approach in more detail.

A. This methodology develops marginal costs by identifying load growth that drives expansion of a system element and examining the engineering costs of constructing and operating that element. More specifically, the Company identified segments of the T&D system where expansions due to load growth were planned. For each segment, the unit cost of a planned project to serve incremental demand was developed. Total investment dollars were converted to annual marginal costs using carrying charges, O&M and other applicable loading factors, such as common plant and working capital. For the transmission and substation segments of the system, marginal costs were developed on a year-by-year basis to reflect the phased-in nature of the Company’s long term construction schedules for these portions of the system.

Q. Please continue.

A. Marginal costs for the primary segment of the system were also developed based on the unit cost of planned investment. Primary load relief is routinely undertaken to expand capacity as load grows. As such, similar projects are done year after year. Hence, the marginal cost at the primary level is stated in current dollars and is applicable to all future years.

Q. Please continue.

A. Marginal costs at the transformer and secondary segments of a non-network system are zero when viewed on a demand basis. To avoid changing these facilities, they are built anticipating five to ten years of load growth and at any point will by design have some short-term excess capacity.

Hence, the marginal cost of increasing or decreasing load on these facilities in the short term is zero. The MCOS Analysis also presents marginal customer costs incurred when accommodating new customer connections. These costs are not marginal for existing customers, but they are marginal when viewed on a per customer basis for new customers and include the minimum system component of secondary lines and transformers as well as service costs, metering costs, customer accounting, customer service and informational expenses.

Q. Please describe Exhibit ___ (DAC-3).

A. Schedule 1 presents total system T&D marginal costs. These costs are presented in nominal dollars and are stated on a per-kW of system peak basis. Schedule 2 presents a comparison of marginal costs developed in Schedule 1 to current T&D revenues. The functional marginal costs in column 2 of Schedule 2 represent 10-year averages in current dollars. This 10-year averaging was done to reflect the parameters of the Excelsior Jobs Program. The “by-class” comparisons of marginal costs to T&D revenues shown on Schedule 2 reflect an equal weighting of the marginal costs incurred for new and existing customers and are used by the Electric Rate Panel in setting rates under the Excelsior Jobs program.

Q. Please describe how the Marginal Cost Study will be revised during the rate case process.

A. The Joint Proposal in the last Con Edison Electric Case 16-E-0060 calls for the development of a more granular marginal cost study that maybe used in a variety of Con Edison and Commission mandated initiatives, as well as future rate filings. Accordingly, Con Edison has retained the Brattle Group to assist in developing a new, more granular marginal cost methodology.

Q. Please continue.

A. This undertaking is scheduled to be completed in the first quarter of 2018 for Con Edison. The Company will then adopt the new, more granular marginal cost methodology developed by Con Edison and incorporate it in an update to the O&R marginal cost study filed at the outset of this proceeding. The updated O&R study will be available for review by interested parties during the course of this case.

VI. O&R INTEGRATION WITH CUSTOMER USAGE SYSTEM

Q. Please describe the Customer Usage System ("CUS") integration project you are proposing.

A. We are proposing an enhancement to the CUS project, which will serve to integrate and centralize sales reporting systems used for load research, cost of service, and rate and bill impact analyses. The CUS project was initiated because certain legacy systems will no longer be supported by the Company. The replacement is well-underway for Con Edison electric and gas. The work proposed here builds on the existing functionality to incorporate O&R electric and gas sales data into the same platform.

Q. Please continue.

A. Some O&R electric and gas billing determinants now reside in CUS, but their format differs greatly from those of Con Edison's electric and gas customers. This project will modify CUS to accept all relevant O&R customer data in the same format as that used for Con Edison's customers, allowing O&R customer data to take advantage of the business rules and features already established in CUS. These include complex logic for aligning raw account-level billed sales to standardized trip-based time periods, the integration of account-level billing data into summary billing at the customer premise level, and the enabling of "snapshot" point-in-time extracts of customer information to facilitate scenario analyses of customer usage data. As further enhancements are added to CUS, they will be readily applicable to O&R customer data.

Q. Please discuss the timeline and funding associated with these enhancements.

A. The enhancements are budgeted as a multi-year capital project with a total forecasted expenditure of $1 million. The capital project is scheduled to begin in 2019 and to be completed by 2023.

Q. Have you prepared an Exhibit ___ (DAC-4) entitled “O&R INTEGRATION WITH CUSTOMER USAGE SYSTEM,” that describes the capital expenditure for these enhancements by year?

A. Yes.

Q. The testimony of this panel applies to electric customers, but will the project affect both electric and gas customers?

A. Yes. Much of the business rules and functionality in CUS applies equally to the Company’s electric and gas billing determinants. Similarly, many of the input fields to CUS are common across both electric and gas. For this reason, we defined a single project that would apply to both services, and have also included the exhibit in the testimony of the Gas Rates Panel.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
DIRECT TESTIMONY OF
ELECTRIC RATE PANEL

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INTRODUCTION

Q. Would the members of the Electric Rate Panel please state your names and business addresses?

A. William Atzl, Cheryl Ruggiero, and Shajan Jacob, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed and what is your current position?

A. **(Atzl)** I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison") as the Director of the Rate Engineering Department.

(Ruggiero) I am employed by Con Edison as the Department Manager of the Orange & Rockland Rate Design section in the Rate Engineering Department.

(Jacob) I am employed by Con Edison as a Project Manager in the Orange & Rockland Rate Design section in the Rate Engineering Department.

Q. Please describe your educational background and work experience.

A. **(Atzl)** In 1983, I graduated from the State University of New York at Stony Brook with a Bachelor of Engineering degree in Mechanical Engineering. In 1989, I graduated from Pace University, White Plains, New York with a Master of Business Administration degree in Management Information Systems. I am a Licensed Professional Engineer in the State of New York. My first employment was with Long Island Lighting Company in 1983 where I held the position of Assistant Engineer in the New Business Department. In 1984, I joined Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R," or the "Company") and held various positions of increasing responsibility in Commercial Operations, Demand-Side Management, Energy Services and Rates. In October 1999, I joined Con Edison and held the position of Department Manager – Electric and Gas Rate Design – O&R and Director prior to promotion to my present position in September 2012.

(Ruggiero) In 2000, I graduated from Polytechnic University with a Bachelor of Science degree in Electrical Engineering. In 2009, I graduated from Baruch College with a Master in Business Administration degree in Finance and Investments. I joined Con Edison in 2000 as a Management Intern with rotational assignments in Electric Operations, Engineering Services, and Gas Operations. In July

2001, I accepted a position as Associate Engineer - A in Distribution Engineering. In November 2005, I accepted a position as Senior Analyst in Rate Engineering and, since then, I have held positions with increasing responsibility. I was promoted to my current position in March 2013.

(Jacob) I am a Project Manager in the Rate Engineering Department. I received a Bachelor of Science Degree in Chemistry from University of Kerala in 1977, a Bachelor of Business Administration from Saint Leo University in 1998, and a Master of Business Administration Degree in Finance from Rollins College in 1999. I began my employment with Con Edison in 2006 in the Rate Engineering Department as a Senior Analyst and, since then, I have held positions with increasing responsibility. I was promoted to my current position in July 2013. I am a Certified Energy Manager, which I earned from the Association of Energy Engineers in 2003, and I am also a Registered Gas Distribution Professional, which I earned from the Gas Technology Institute in 2010.

Q. Have you previously testified before the New York Public Service Commission ("Commission") or other regulatory bodies on energy matters?

A. **(Atzl)** Yes. I testified in numerous regulatory proceedings before the Commission, the New Jersey Board of Public Utilities (“BPU”), and the Pennsylvania Public Utility Commission (“PAPUC”).

(Ruggiero) Yes. I testified in numerous regulatory proceedings before the Commission and submitted testimony before the BPU and the PAPUC.

(Jacob) Yes. I have testified before the Commission.

PURPOSE OF TESTIMONY

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

A. We testify to Orange and Rockland’s proposed electric revenue allocation and rate design, including the impact of the proposed rate changes on customers’ bills; the Company’s proposed electric standby rate design; proposed changes to the Company’s Revenue Decoupling Mechanism (“RDM”); the Company’s proposed rate options for Plug-In Electric Vehicles (“PEVs”); the Company’s proposed cost recovery mechanism for

Non-Wires Alternative ("NWA") projects and Earning Adjustment Mechanisms ("EAM"); and other proposed tariff changes.

REVENUE ALLOCATION AND RATE DESIGN

Q. What is the revenue increase for the 12 months ending December 31, 2019 ("Rate Year") used in the proposed rate design?

A. The proposed revenue increase is $20,264,000, including applicable revenue taxes, which was provided to us by the Company's Accounting Panel.

Q. Please describe the first step in allocating the increased base rate revenue among the Company's service classifications ("SC").

A. First, we removed from the total incremental revenue requirement for the Rate Year, the amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. Removal of these tax-related revenues totaling $331,000 results in a proposed net revenue increase of $19,933,000.

Q. Did you make any adjustments to reflect the increased credits to be paid to low income customers?

A. Yes. Prior to allocating the proposed net revenue increase, we increased it by $9,923,000 to offset the credits that are projected to be paid to low income residential customers in the Rate Year. This results in an adjusted net revenue increase of $29,856,000.

Q. Please describe the next step in the revenue allocation process.

A. Next, Rate Year delivery revenues at the current rate level for each SC were realigned to reflect the deficiency and surplus indications identified in the embedded cost of service ("ECOS") study presented by the Demand Analysis and Cost of Service Panel ("DAC Panel").

Q. Did you attempt to eliminate fully the deficiencies and surpluses indicated by the ECOS study?

A. Before making final decisions on the elimination of the deficiency and surplus indications, we realigned the Rate Year delivery revenues to reflect the ECOS deficiency and surplus indications and then allocated the adjusted net delivery revenue increase among the

SCs in proportion to the relative contribution made by each class to the realigned total Rate Year delivery revenues. We then reviewed, by class, the combined impact of eliminating a deficiency or surplus and the impact of the delivery revenue increase. We found that fully eliminating the deficiencies and surpluses, coupled with the delivery revenue increase, would result in relatively large revenue impacts for SC No. 2, Secondary Space Heating. Therefore, to address the need to eliminate the surpluses and deficiencies while considering the impacts on customers, we implemented a two-step process of: (1) applying one third of the class-specific deficiency and surplus indications from the ECOS study in a revenue neutral manner prior to applying the delivery revenue increases; and (2) limiting the class-specific delivery revenue increase percentages to no less than -1.5 times or no more than 1.5 times the overall delivery revenue increase percentage after application of the class-specific deficiency and surplus indications from the ECOS study. This approach allows us to address revenue and cost imbalances while considering customer bill impacts. If this rate filing results in a multi-year rate plan, we intend to reduce further any deficiencies and surpluses in the additional rate years.

Q. Why did you apply one-third of class specific indications?

A. Applying one-third of the deficiencies and surpluses in each rate year would fully eliminate such deficiencies and surpluses during the term of a three-year rate plan.

Q. Please continue.

A. We next allocated the adjusted net delivery revenue increase among the SCs in proportion to the relative contribution made by each class to the realigned total Rate Year delivery revenues.

Q. Please continue.

A. We next determined what portions of the class-specific delivery revenue increases would be attributable to changes in both the competitive delivery rate components and the customer charges. The competitive delivery rate components include: (1) the billing and payment processing ("BPP") charge; (2) the merchant function charge (“MFC”) fixed components, that are the MFC procurement and credit and collections components; (3) the purchase of receivables (“POR”) credit and collections component; and (4) metering charges. As discussed by the DAC Panel, Exhibit __ (DAC-2, Schedule 2) presents the MFC fixed components and the POR credit and collections component as percentages of delivery revenue. Exhibit __ (DAC-2, Schedule 3) presents the metering charges as percentages of delivery revenue. Based on the increased level of proposed delivery revenue, we computed a revised level of revenue for the BPP charge, MFC fixed components, POR credit and collections component, and metering charges.

Q. What is the proposed BPP charge?

A. The DAC Panel noted that the electric unbundled cost for BPP is $1.31 per bill, which is higher than the current BPP charge of $1.02 per bill. In the gas rate case that is being filed today, the Gas Rate Panel noted that the gas unbundled cost for BPP is $1.28 per bill. In order to minimize potential customer confusion, the electric and gas BPP charges are being set equal to $1.30.

Q. Were there any exceptions to the manner of developing the competitive revenues?

A. Yes. In updating the metering charges for the applicable SCs, we also updated the metering charges applicable to those customers eligible for Mandatory Day Ahead Hourly Pricing (“MDAHP”). MDAHP is currently applicable to non-residential demand-billed customers in SC Nos. 2, 3, 20, and 21, whose billing demand exceeds 300 kW twice within a 12-month period, and to all customers in SC Nos. 9 and 22. We updated the metering charges applicable to customers eligible for MDAHP in SC Nos. 2, 3, 20 and 21 to be equal to the metering charges established by the DAC Panel in Exhibit __ (DAC-2, Schedule 4). For SC Nos. 9 and 22, where the entire classes are MDAHP eligible, the meter ownership charge and meter service provider charge were increased based on percentages provided by the DAC Panel in Exhibit ____ (DAC-2, Schedule 3) and the combined SC Nos. 9 and 22 proposed delivery revenue to develop common charges for these two classes since metering installations for customers in these classes are similar. The meter data service provider charge for SC Nos. 9 and 22 was set equal to that of the MDAHP meter data service provider charge for MDAHP eligible customers in SC Nos. 2, 3, 20, and 21 as presented in Exhibit __ (DAC-2, Schedule 4) since these costs are common among all MDAHP eligible classes.

Q. Do you have an exhibit which shows the proposed customer charges?

A. Yes. These customer charges are shown in Exhibit __ (ERP-1, Schedule 1).

Q. Please explain how you designed the proposed customer charges shown in Exhibit __ (ERP-1, Schedule 1).

A. In general, customer charges were kept at their current level since the majority of customer charges are reflective of customer costs, consistent with the ECOS study. For the SC No. 1 class, however, the customer charge is below the customer cost. Therefore, we have proposed to increase the SC No. 1 customer charge, but not as much as justified by the ECOS study to limit bill impacts for low usage customers. Therefore, even though the ECOS study presented by the DAC Panel shows an embedded customer cost of $24.11 per month for SC No. 1, we only increased the customer charge from $20.00 to $22.00.

Q. How did you determine the non-competitive delivery revenue increase excluding the revenue changes associated with changes in competitive delivery rate components and changes in customer charges?

A. The incremental revenue derived from the BPP, MFC fixed components, POR credit and collections component, metering charges, and customer charges were subtracted from the class-specific bundled delivery revenue increases to determine the non-competitive delivery revenue increase excluding customer charges, for each class.

Q. Did you restate the Rate Year non-competitive delivery revenue increases excluding customer charges, as determined above, on a historical period basis?

A. Yes. We restated the Rate Year non-competitive delivery revenue increases excluding customer charges by SC based on the twelve months ended September 30, 2017, *i.e.*, the historical period for which detailed billing data are available.

Q. Please describe how you developed the non-competitive delivery revenue increases excluding customer charges for the historical period.

A. Revenue ratios were developed for each class by dividing the historical period non-competitive delivery revenues excluding customer charges for each class by the Rate Year non-competitive delivery revenues excluding customer charges for each class at current rate levels. These revenue ratios for each class were applied to the Rate Year non-competitive delivery revenue increase excluding customer charges for each class to determine each class's non-competitive delivery revenue increase excluding customer charges for the historical period.

Q. Please explain how you designed the proposed usage delivery rates shown in Exhibit __ (ERP-1, Schedule 1) for SC No. 1.

A. Prior to applying the non-competitive delivery revenue increase excluding customer charges for the historical period for SC No. 1, we made revenue neutral changes to complete the phase out of certain end-use discounts under SC No. 1. In Case 10-E-0362 certain SC No. 1 special provisions were closed to new customers after July 1, 2011, and we began a gradual process to eliminate the associated discounts. In Cases 11-E-0408 and 14-E-0493, the Company further reduced these discounts in each rate year. In this case, we propose to eliminate the remaining differentials among usage rates. We made these changes on a revenue-neutral basis before applying the SC No. 1 revenue increase. Once these revenue neutral changes were made, we then applied the SC No. 1 non-competitive delivery revenue increase excluding customer charges for the historical period to the usage rates on an equal percentage basis.

Q. Please explain how you designed the proposed usage and demand delivery rates for the SC No. 2 – Secondary Demand Billed class as shown in Exhibit __ (ERP-1, Schedule 1).

A. Prior to applying the non-competitive delivery revenue increase excluding customer charges for the historical period for SC No. 2 – Secondary Demand Billed, we made revenue neutral changes to continue the phase out of declining block rates for this class. As directed in the Commission’s Order Establishing Rates for Electric Service, issued June 17, 2011 in Case 10-E-0362, the Company was required to file a plan to phase out the declining block rates in SC Nos. 2 and 3. In Case 11-E-0408, the Company eliminated the declining block rates in SC No. 2 Secondary Non-Demand Billed, SC No. 2 Primary, and SC No. 3. In Cases 11-E-0408 and 14-E-0493, we began the gradual process of eliminating the usage and demand rate differentials for SC No. 2 Secondary Demand Billed service. In this case, we took a two-step approach to continuing the process of eliminating these usage and demand rate differentials. First, we propose to shift 5% of delivery revenue from usage to demand on a seasonal basis. Next, we propose to shift 5% of usage revenue from the first usage block to the third usage block. If a multi-year rate plan results from this proceeding, the Company would propose to continue working towards the elimination of the usage and demand rate differentials in each of Rate Years 2 and 3.

Once these revenue neutral changes were made, we then applied the SC No. 2 – Secondary Demand Billed non-competitive delivery revenue increase excluding customer charges for the historical period to the demand rates.

Q. Please explain how you designed the proposed usage and demand delivery rates for the SC No. 2 – Primary class as shown in Exhibit __ (ERP-1, Schedule 1).

A. As previously mentioned, in Case 11-E-0408, the Company eliminated the declining block demand and usage rates in SC No. 2 – Primary. In Case 14-E-0493, the Company shifted 20% of the usage revenue to demand revenue in each Rate Year of the resulting rate plan. In this case, we have proposed to shift an additional 20% of the current usage revenue to demand revenue, on a revenue neutral basis, prior to applying the revenue increase. Once this revenue neutral change was made, we then applied the SC No. 2 – Primary non-competitive delivery revenue increase excluding customer charges for the historical period to the demand rates. Because the majority of transmission and distribution costs are associated with customer demands, shifting a portion of usage revenue to demand revenue and applying the revenue increase solely to demand charges more closely aligns how costs are incurred and collected from customers.

Q. Please explain how you designed the proposed usage and demand delivery rates for the SC No. 9 – Primary and Substation classes as shown in Exhibit __ (ERP-1, Schedule 1).

A. To better align the manner in which costs are incurred and collected from customers, for SC No. 9 – Primary and Substation, we have proposed to shift 25% of the usage revenue to demand revenue on a revenue neutral basis, prior to applying the revenue increases to demand charges.

Q. Please explain how you designed the proposed usage and demand delivery rates for the SC No. 20 class as shown in Exhibit __ (ERP-1, Schedule 1).

A. The SC No. 20 class is a non-residential voluntary time of use (“TOU”) class for customers taking service at secondary voltages. Under the current rate structure, there are off-peak and on-peak usage charges and an on-peak demand charge. The on-peak charges are seasonally differentiated. The applicable TOU pricing periods for the summer months are as follows: (a) Period I: Summer Peak – Monday through Friday, non-holidays, 1 PM to 7 PM; and (b) Period III: Summer Off-Peak – all other days and hours. The applicable TOU pricing periods for the winter months are as follows: (a) Period II: Winter Peak – Monday through Friday, non-holidays, 10 AM to 9 PM; and (b) Period III: Winter Off-Peak – all other days and hours. Currently, there is no off-peak demand charge. In this case, the Company proposes to establish an off-peak demand charge and to shift revenue from usage charges to peak period demand charges as well. An off-peak demand charge recognizes that off-peak customer demands can drive the costs of local facilities, those that are closer to a customer’s site. Therefore, a portion of demand-related costs should be recovered through both off-peak and on-peak demand charges. To establish an off-peak demand charge, we shifted 25% of the off-peak revenue from the usage charge to the demand charge. In addition, the Company has shifted 25% of revenue from usage charges to demand charges for Periods I and II on a revenue neutral basis to better align the manner in which costs are incurred and collected from customers. Once these revenue neutral changes were made, we then applied the SC No. 20 non-competitive delivery revenue increase excluding customer charges for the historical period to the demand rates.

Q. Please explain how you designed the proposed usage and demand delivery rates for SC Nos. 3, 9 – Transmission, 21, and 22 as shown in Exhibit __ (ERP-1, Schedule 1).

A. We propose to apply the entire increase in the non-competitive delivery revenue excluding customer charges for these classes to the demand charges. The usage charges for these classes will remain at their current level. Since the majority of transmission and distribution costs are associated with customer demands, applying the increase to demand charges aligns how costs are incurred and collected from customers.

Q. How did you design the proposed delivery rates for the remainder of the SCs, excluding the rates for SC No.

25 – Standby Service, as shown in Exhibit __ (ERP-1, Schedule 1)?

A. For all other SCs except SC No. 25, the usage and luminaire charges, where applicable, were generally increased or decreased by the class-specific percentage changes in non-competitive delivery revenue excluding customer charges. One exception to this methodology related to the currently available LED street lights in SC No. 4 that were introduced in 2017. Since the pricing for these luminaires was recently calculated and the ECOS study did not include revenues or costs associated with them, the rates for these LED street lights were held at the current level shown in the tariff.

Q. Are there are other rate design issues you would like to discuss?

A. Yes. We would like to discuss the discounts applicable to customers served under Rider C – Excelsior Jobs Program ("EJP").

Q. Have you revised the discounts applicable to customers who take service under EJP?

A. Yes. Discounts under the EJP are provided if marginal costs are less than average electric delivery rates. As explained in Rider C, if marginal costs change over time, the Company may file amended discounts. Based on the results of the marginal cost of service study prepared by the DAC Panel in this filing, the Company has amended the discounts contained in Rider C since marginal costs are less than average electric delivery rates.

Q. How did you determine the discounts for Rider C customers?

A. As discussed by the DAC Panel, Exhibit __ (DAC-3, Schedule 2) shows the ratio by which marginal costs are currently less than what is being recovered in delivery rates. In order to determine the EJP discounts, these ratios were subtracted from 1 to arrive at the percentage discounts by class. For new customers served under Rider C effective January 1, 2019, the following percentage reductions will be applied to their customer and delivery charges:

- SC Nos. 9 and 22 – 70%;
- SC Nos. 3 and 21 – 72%;

- SC No. 2 Secondary – 75%;
- SC No. 20 – 77%; and
- SC No. 2 Primary – 78%.

The EJP discount applicable to an SC No. 25 customer will be the discount of the customer’s otherwise applicable service classification.

Q. Would you please describe Exhibit __ (ERP-1, Schedule 2)?

A. Exhibit __ (ERP-1, Schedule 2) shows the impacts that the proposed rates will have on bills to full service customers at various levels of consumption.

Q. Would you please describe Schedule 3 of Exhibit __ (ERP-1)?

A. Schedule 3 shows the summary of present and proposed revenue. There are two items of note on this schedule. First, the change in revenue reflects the proposal of the Accounting Panel and Energy Efficiency Panel to move the recovery of energy efficiency costs from the Company’s Energy Cost Adjustment (“ECA”) mechanism into base rates, where these costs will be amortized over three years. Next, the column “Revenue

At Proposed Rates" in Schedule 3 includes an adjustment for the funding of low income credits, as we mentioned previously. This adjustment is offset by the low income credits that will be paid in the Rate Year to low income residential customers. The result of the Company's proposed revenue increase and these two items is a net revenue increase of $13,851,000, as shown on Schedule 3.

STANDBY RATE DESIGN

Q. Please describe the Company's Standby Service rates.

A. The Company's standby service rates are included in SC No. 25 and are applicable to sales and delivery of electric power supply provided by the Company, or delivery of electric power supply provided by an Energy Service Company ("ESCO") under the Company's Retail Access Program, for standby service purposes. Standby service is used to replace or supplement power and energy ordinarily generated by an on-site generator and also for "station use" by a wholesale generator. A number of provisions currently exist exempting certain customers from standby service. The rate applicable to non-exempt customers billed under

SC No. 25 is determined based on the service classification under which the customer would otherwise receive service. The delivery portion of the bill for a standby customer consists of the following components: a contract demand charge, as-used daily demand charges, and a customer charge.

Q. Please describe the general principles you applied in the rate design process for standby service.

A. Consistent with the currently effective SC No. 25 rate design, we prepared our proposed standby rate design consistent with the guidelines set forth in the Commission's Opinion 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued October 26, 2001 ("Standby Rates Order") in Case 99-M-1470. The Commission stated that "the standby rates for each service classification should produce the same revenues as the standard rates, using the class billing determinants." (Standby Rates Order, Appendix A, Page 2). Therefore, the billing determinants used to design standby rates are based on those used in the formulation of the proposed rates for the otherwise applicable non-standby service classifications.

We also used the cost allocation matrix contained in Appendix B of the March 11, 2003 Joint Proposal adopted by the Commission in its Order Establishing Electric Standby Rates, issued July 29, 2003, in Cases 02-E-0780 and 02-E-0781. This matrix shows the percentage allocation of costs between the as-used demand charge and the contract demand charge, at various service levels.

Q. Please describe the rate design process for the contract demand charges.

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

Q. Please describe the rate design process for the as-used daily demand charges.

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

Q. Please describe how you determined the customer charges for standby service.

A. The customer charges were generally based on the customer costs as indicated in the ECOS study provided by the DAC Panel.

Q. Did you propose any changes to standby rates in this case in response to the REV Track Two Order?

A. No. As directed by the REV Track Two Order, the Company has already made two compliance filings related to the recommendations for standby rates. The first filing, made on August 1, 2016, proposed a reliability credit and an offset tariff. The changes associated with that first filing became effective January 1, 2017. In the second filing, made on October 7, 2016, the Company examined the cost allocation matrix used to allocate costs between the as-used daily demand charges and the contract demand charges at various service levels. In that second filing, the Company proposed the continued use of the existing cost allocation matrix because it was aligned with cost causation and there is no basis for changing it. Should the Commission order the use of a different cost allocation matrix or methodology during the course of this proceeding, the Company will revise its proposed standby charges accordingly.

Q. Is the Company proposing any other changes to the tariff related to Standby Service besides the changes in rates?

A. Yes. Currently, the electric tariff states that Standby Service customers will be assessed metering charges, as set forth in the Standby Service customer's otherwise applicable service classification. In SC Nos. 2, 3, 20, and 21, there are separate metering charges for customers eligible for MDAHP and for all other customers. Currently, a customer on Rate I or Rate II of SC No. 25 could potentially be ineligible for MDAHP and receive the metering charges applicable to all other customers. However, both an MDAHP customer and a Standby Service customer require interval metering. Therefore, all Standby Service customers should be assessed the metering charges applicable to MDAHP-eligible customers under their otherwise applicable service classifications. We have amended SC No. 25 to state this requirement. Because there are no customers currently on Rate I or Rate II of SC No. 25, there is no revenue or customer bill impacts related to this change.

REVENUE DECOUPLING MECHANISM

Q. Are you proposing any changes to the RDM?

A. Yes.

Q. Please summarize the changes you are making to the RDM.

A. We are proposing the following: (1) the addition of SC Nos. 4 and 6 to the applicable RDM classes; (2) a change in the definition of the rate year; and (3) revised language related to the reconciliation of the RDM for the partial rate year.

Q. Please describe your first change.

A. We have added the Company’s municipal street lighting service classifications, SC Nos. 4 and 6, to the list of applicable classes for the RDM. These two classes have been combined as Group F in the RDM section of the tariff (*i.e.,* General Information Section No. 30). The description of the RDM was also added to SC Nos. 4 and 6 in the list of monthly rates applicable to these classes.

Q. Why have you proposed this change?

A. In compliance with the Joint Proposal adopted by the Commission in Case 14-E-0408, the Company made a filing to introduce additional LED streetlight offerings to municipalities and to propose a plan for the acceleration of the replacement of sodium vapor and mercury streetlights. The Commission approved a modified version of the Company's plan and directed the Company to implement an LED pricing methodology that results in LED monthly luminaire charges that are generally lower than the luminaire charges for comparable sodium vapor and mercury vapor luminaires and offer additional savings to municipalities via reduced kWh consumption. Therefore, due to the potential for reduced revenue from lower luminaire charges for LED luminaires that would be installed as energy efficiency measures, we have proposed the introduction of Group F to the RDM. Group F will specify a combined RDM revenue target for SC Nos. 4 and 6 and these classes would be subject to a common RDM Adjustment. The combining of these classes for RDM purposes recognizes the potential for customers to migrate from SC No. 4 to SC No. 6 and is consistent with the existing combination of other classes with migration potential such as the combination of SC Nos. 1 and 19 in Group A.

Q. Please describe your next change.

A. The Company’s current rate years resulting from Case 14-E-0493 are defined as the 12-month periods ending October 31 of each year. The Rate Year in this filing is defined as the 12-month period ending December 31, 2019. Therefore, due to the change in the definition of the beginning and ending month of the rate year, language was modified to change the definition of the annual RDM period from the 12-month period ending October 31 each year to the 12-month period ending December 31 of each year. The annual reconciliation of the RDM surcharge will be required to be filed no less than ten calendar days before February 1, the effective date of new RDM adjustments.

Q. Please describe your next change.

A. As a result of the change of the starting month of the rate year from November 1 to January 1, there will be a partial rate year for the period November 1, 2018 through December 31, 2018. The current RDM section of the electric tariff includes a provision stating that, in the case of a partial rate year, the RDM would operate as per the terms of the Joint Proposal adopted by the Commission in Case 14-E-0493. In this filing, we have amended that provision to refer specifically to the partial rate year described above.

Q. Have you amended General Information Section No. 30 to reflect revised RDM delivery revenue targets?

A. Yes. We have revised General Information Section No. 30 to: (a) set forth the RDM delivery revenue targets; and (b) update the threshold for implementing interim RDM adjustments to reflect 1.5% of the revised delivery revenue subject to the RDM.

ELECTRIC VEHICLES

Q. Are you proposing any tariff changes related to PEVs?

A. Yes. The Company proposes three changes: (1) to amend SC No. 19 to allow an SC No. 1 customer who registers its PEV with the Company to switch to SC No. 19 for the customer’s entire usage, with a one-year price guarantee; (2) to amend SC No. 19 to allow a customer who registers its PEV with the Company the option of establishing a separate account for the PEV charger under SC No. 19, while retaining an account under SC No. 1 for all other usage; and (3) to establish a PEV Quick Charging Station Program for commercial customers who construct and operate publicly accessible PEV quick charging stations.

Q. Please describe the price guarantee option.

A. A customer would receive the price guarantee if the entire household is served under the Company’s residential voluntary time-of-use service classification, SC No. 19, and the customer registers its PEV with the Company. At the end of the first year of service under SC No. 19, a customer would receive a credit for the difference, if any, between what the customer paid under SC No. 19, and what the customer would have paid under SC No. 1 rates over that one-year period, if the SC No. 19 cost was higher. The comparison (inclusive of the Increase in Rates and Charges) would be made on a total bill basis for Full Service Customers and on a delivery-only basis for Retail Access Customers. We have added this price guarantee as Special Provision C to SC No. 19.

Q. Are you proposing any mechanisms for the recovery of the price guarantee?

A. Yes. We propose that credits paid to customers under the price guarantee be recovered through the ECA.

Q. Please describe the proposed option for a separate account for PEV charging under SC No. 19.

A. The Company is proposing Special Provision D be added to SC No. 19 to allow SC No. 1 customers with separately metered PEV chargers to take service under a second account billed under SC No. 19 solely for PEV charging. The Company is also changing the applicability of SC No. 19 to permit service under SC No. 19 for the sole purpose of PEV charging.

Q. Will customers served under SC No. 19 Special Provision D be eligible for the price guarantee under SC No. 19 Special Provision C?

A. No. It is not appropriate to provide a price guarantee to customers served under Special Provision D. The price guarantee is established to encourage customers with PEVs to take service under SC No. 19 for their combined PEV and whole house load. Because Special Provision D is intended solely for PEV charging and excludes other household loads, the price guarantee is not appropriate since the risk of higher bills for other household loads does not exist. Whereas SC No. 19 rewards off-peak usage, a price guarantee would effectively offset any pricing signals to discourage PEV charging during peak periods. In addition, other customers will fund credits paid under the price guarantee, which we propose to recover through the ECA. The Company believes that other customers should not provide an additional subsidy.

Q. Do the Company’s proposed rate designs for SC No. 19 comply with New York State’s Senate Bill S3745 (the “Paulin Bill”) signed into law on October 23, 2017?

A. Yes. This legislation, codified in public service law section 66-o requires utilities in New York State to file with the Commission a residential tariff for eligible electric vehicles for the purpose of recharging such vehicles. These proposals meet the requirements of that legislation.

Q. Please describe the PEV Quick Charging Station Program.

A. The PEV Quick Charging Station Program is designed to incent the construction of charging stations in the Company’s service territory. To implement this program, the Company proposes to modify its Economic Development Rider, Rider H, to allow demand-billed participants that construct and own a publicly accessible charging station with a minimum of 65 kW of aggregate charging capacity to receive a 20% delivery rate discount under Rider H. Examples of locations for publicly accessible stations are supermarkets, malls and retail outlets, train stations, hotels, restaurants, and parking garages and parking lots where PEV quick charging is open to the general public. As is applicable to any other Rider H applicant, a PEV quick charging station must receive a comprehensive package of economic incentives conferred by the local municipality or state authorities.

Q. Is there a limit to the number of participants in the PEV Quick Charging Station Program?

A. Yes. The Company will allow up to 3 MW of aggregate PEV charging load to be eligible for the program.

Q. Over what time period would a participant receive a discount?

A. The discount would be available through December 31, 2025 (i.e., up to seven years after rates are expected to take effect in this proceeding). Customers commencing service under the PEV Quick Charging

Station Program after the effective date of the program will receive discounts for less than seven years. For example, a customer commencing service under the program in January 2020 would receive the discount for six years (*i.e.*, January 2020 through December 2025).

Q. Why is it appropriate for the discount to expire after December 31, 2025?

A. The Company believes that a delivery rate reduction timeframe of up to seven years is appropriate for the following reason. In today's market for public PEV charging, the principal barriers to development and profitability are upfront capital costs and operating costs, including the cost of electricity, at the current low station utilization rates. The Company expects that, over the next several years, increasing PEV market share will lead to increasing station utilization rates and the operating cost barrier will no longer exist. Therefore, participants should receive delivery rate reductions only during the time period that low utilization rates are expected to deter participants from entering the market. Upon program expiration, participants will be billed on their otherwise applicable rate.

Q. Is there a limit to the amount of load that can be used for purposes other than PEV charging?

A. Yes. The Company will require that the delivery rate discounts under the PEV Quick Charging Station Program focus on PEV quick charging infrastructure. Therefore, electric loads that are not associated with PEV quick charging infrastructure will be limited to 10 kW per account. This limit is necessary so that the Rider H delivery rate reductions do not subsidize other electric uses at the PEV quick charging stations.

Q. Are any of the requirements of Rider H waived for participants in the PEV Quick Charging Station Program?

A. Rider H currently includes an energy audit requirement for customers who are purchasing or leasing an existing building. We proposed that PEV Quick Charging Station Program participants be exempt from this requirement. Participants will build new PEV charging stations, with loads almost entirely associated with PEV quick charging infrastructure. The expectation is that since the latest technology will be installed at these stations, the energy audit requirement is unnecessary as there is no expected improvement to the technology in the short term.

COST RECOVERY FOR NWA PROJECTS AND EAMs

Q. How does the Company propose to recover the costs for NWA project costs and earned incentives as described in the Electric Infrastructure and Operations Panel's testimony?

A. As detailed in the Commission's November 16, 2017 order in Case 17-M-0178, *Petition of Orange and Rockland Utilities, Inc. for Authorization of a Program Advancement Proposal* ("November 2017 Order"), the Company was directed in its next base rate proceeding to, "propose a cost recovery mechanism for both NWA project costs and earned incentives that better matches NWA cost recovery with cost causation and 'beneficiaries pay' principles." The Company proposes to add an NWA Projects component to its ECA mechanism that will recover such costs and earned incentives.

Q. Please describe how NWA costs and incentives will be allocated to the Company's service classifications.

A. The Company proposes to allocate the amortized costs and incentives to service classification groups based on the service classification group's percentage contribution to the system peak as used to develop the ECOS study. The six service classification groups are as follows:

Group 1: SC Nos. 1 and 19;

Group 2: SC No. 2 Secondary – Non-Demand Billed;

Group 3: SC Nos. 2 Secondary – Demand Billed, 20, and 25 – Rate I;

Group 4: SC Nos. 2 Primary, 3, 21, and 25 – Rate II;

Group 5: SC Nos. 9, 22, and 25 – Rates III and IV; and

Group 6: SC Nos. 4, 5, 6, and 16.

Amortized costs and incentives will be collected on per-kWh basis for non-demand billed service classification groups (*i.e.*, Groups 1 and 2) and on a per kW basis for demand-billed service classification groups (for Standby Service customers, the costs and incentives will be collected on a per kW of Contract

Demand basis). Such allocation will meet the directive of the November 2017 Order that there should be a better match between NWA Project cost recovery and cost causation. Because customers in all service classifications will benefit from the NWA projects proposed, the beneficiaries' principle applies as well.

Q. How does the Company propose to recover any earned EAMs proposed by the Earning Adjustment Mechanisms Panel?

A. The Company proposes a component of the ECA that will recover earned EAMs. Such earned EAMs will be collected on an annual basis with collection beginning June 1 as described in the Earning Adjustment Mechanisms Panel's discussion on EAM cost recovery. Such earned amounts will be applicable to all customer classes and collected from customers over a 12-month period on a common cents per kWh basis.

OTHER TARIFF CHANGES

Q. Are you proposing any other changes to the Company's electric tariff?

A. Yes. We are proposing the following: (1) changes to certain mechanisms with rate years currently ending October 31 to account for a partial rate year and to change the definition of the starting month of the rate year; (2) changes related to the recovery of on-line auction platform costs; (3) the establishment of a mechanism for recovery and credit of positive and negative revenue adjustments stemming from the Company’s electric and customer service performance mechanisms; and (4) housekeeping changes.

Q. Please describe your first change.

A. As previously discussed, the rate year in the current electric rate plan is based on twelve-month periods ending October 31, whereas the proposal in this filing is for a rate year to be based on a 12-month period ending December 31. There are a number of mechanisms with reconciliations and/or targets currently tied to rate years ending October 31 that must be amended to account for a partial rate year (*i.e.,* the period November 1, 2018 through December 31, 2018) and to change the definition of the starting month of the rate year.

Q. Which mechanisms besides the RDM required a change to align with a rate year ending December 31 and/or to account for a partial rate year?

A. The following mechanisms require a change: (1) the Uncollectibles Percentage component of the POR discount percentage; (2) the credit and collections component of the POR discount percentage; (3) the transition adjustment for competitive services ("TACS"); and (4) the reconnection fee waiver.

Q. Please describe your changes to the Uncollectibles Percentage component of the POR discount percentage related to the change of the definition of the start and end date of the rate year.

A. Currently, the Uncollectibles Percentage component of the POR discount percentage is revised every November 1 based on the actual uncollectible experience applicable to all gas and electric POR-customers for the 12-month period ended the previous June 30. The Uncollectibles Percentage component of the POR discount percentage contained in General Information Section No. 7.5 has been revised to state that it will be set effective each January 1 based on the actual uncollectible experience applicable to all gas and electric POR-customers for the 12-month period ended the previous September 30. Using actual uncollectible experience through the 12-month period ended September 30 gives us more current data for a change in the rate effective January 1.

Q. Please describe your changes to the credit and collections component of the POR discount percentage related to the change of the definition of the start and end date of the rate year.

A. The credit and collections component of the POR discount percentage contained in General Information Section No. 7.5 has been revised to state that it will be set effective each January 1 instead of the November 1 date currently in the tariff.

Q. Please describe your changes to the TACS related to the change of the Rate Year.

A. The description of the effective period for the TACS contained in General Information Section No. 29 has been changed from the 12-month periods commencing November 1 to the 12-month periods commencing January 1 with the TACS being reset effective January 1 of every year beginning in January 2020. In addition, a section has been added to the TACS to describe the reconciliation of the partial rate year November 1, 2018 through December 31, 2018. The TACS will be reset effective January 1, 2019 to true-up the period November 1, 2018 through December 31, 2018 based on a target of $772,737 for the MFC fixed component lost revenue and a target of $111,634 for the credit and collections lost revenue associated with retail access. These targets are based on the sum of the monthly targets for November and December for Rate Year 2 contained in Appendix 18, Schedule 4, of the Joint Proposal adopted by the Commission in Case 14-E-0493. Any over- or under-collection for this partial period will be collected through a revised TACS that will be in effect for the 12-month period ending December 31, 2020.

Q. Please describe your changes to the reconnection fee waiver related to the change of the definition of the start and end date of the rate year.

A. As described in General Information Section No. 11.14, the Company will waive the reconnection fee one time for any customer enrolled in the Company’s low income program up to a total of $40,000 of waivers granted in any 12 month period from November 1 through October 31. The Company has added revised language to state that, for the 12 month period beginning January 1, 2019, and every 12 month period thereafter, the Company will waive the fee until a total of $40,000 of reconnect fees has been waived.

Q. Please describe your changes to the tariff to account for the recovery of costs associated with on-line auction platforms.

A. As described in the testimony of Company witness Joseph Briscese, the Company has amended General Information Section No. 15 of the tariff to clarify that costs associated with on-line auction platforms are recoverable as a supply cost via the Market Supply Charge.

Q. Please describe the proposed mechanism for recovery and credit of positive and negative revenue adjustments stemming from the Company’s electric and customer service performance mechanisms.

A. The Company will include with its proposed EAM incentive component of the ECA, an additional component to recover positive and negative revenue adjustments stemming from the Company's electric and customer service performance mechanisms as described in the direct testimony of the Accounting Panel. Any surcharge or credit will be applicable to all customer classes and collected from customers over a 12-month period on a common cents per kWh basis. The Company would perform an annual reconciliation of these revenue adjustments.

Q. Are you proposing any housekeeping changes to the electric tariff?

A. Yes. We are proposing the following housekeeping changes to the tariff:

- As detailed in the Accounting Panel's testimony, the Energy Efficiency ("EE") program costs have been moved to base rates; therefore, all references to the EE Tracker component that recovers these program costs have been removed from the tariff;

- Due to the elimination of the special provision discounts under SC No. 1, the language describing these discounts have been removed from SC No. 1;
- When the Company established separate rates for the SC No. 2 – Secondary Class in Case 11-E-0408 for demand billed and non-demand billed customers, the tariff did not include “Secondary” in the heading for the non-demand billed rates; therefore, we have edited this heading in SC No. 2;
- In SC No. 16, the Company has moved certain luminaires that are no longer available to the list of luminaires that are no longer offered by the Company; and
- The Company has amended General Information Section No. 15, Market Supply Charge to state how the Company calculates capacity costs for full service customers. Prior to the introduction of the Lower Hudson Valley Capacity Zone, the tariff states that each customer’s peak load at the time of the New York Control Area (“NYCA”) peak would

be adjusted for losses and to account for the Unforced Capacity ("UCAP") Requirements of the New York Independent System Operator ("NYISO"). After the introduction of the Lower Hudson Valley Capacity Zone, instead of making an adjustment to the customer's load at the time of the NYCA peak to account for the NYISO UCAP requirements, the Company instead made an adjustment to the NYISO capacity prices to account for the NYISO UCAP requirements. Since the calculation for capacity is based on a multiplication of the NYISO capacity prices, the NYISO UCAP requirements, and the customer's load, mathematically, the total capacity revenue is the same. The capacity language was amended in the Market Supply Charge section to more accurately reflect the mechanics of the calculation.

Q. Does this conclude your testimony?

A. Yes, it does.