Orange and Rockland Utilities, Inc.
Asset Health Report

Introduction

The Moreland Commission on Utility Storm Preparation and Response ("Commission") issued its Final Report ("Final Report") on June 22, 2013. The Final Report contained various recommendations including the following recommendation set forth in Section 5.1 of the Report:

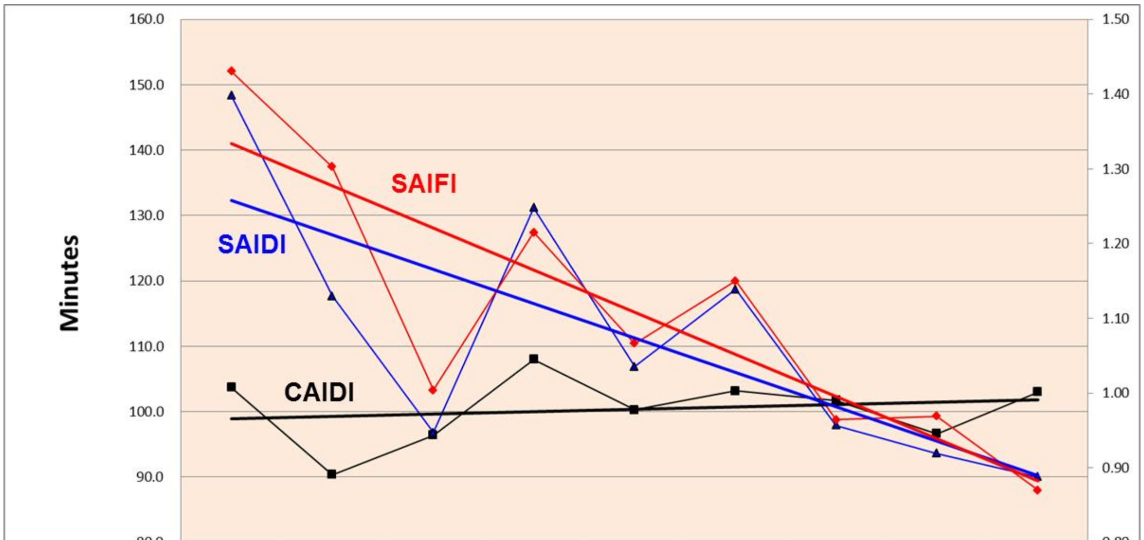
> **The PSC should direct the six investor-owned utilities to file an Asset Health Report for all of its major asset classes to be used in prioritizing and maximizing the effectiveness of the utilities' capital expenditure filings. LIPA should also be required to conduct a comparable asset health assessment.**

This Asset Health Report, which assesses the current health of the Company's electric delivery system, constitutes Orange and Rockland Utilities, Inc.'s ("O&R" or "the Company") response to this recommendation.

As discussed below, O&R has bolstered its capital infrastructure investment program in the most recent ten to 15-year period, and follows inspection and maintenance procedures that provide continual assessments of, and upgrades to its electric transmission, substation and distribution delivery systems, which are detailed later in this Asset Health Report. O&R's capital infrastructure program focuses on both short-term and long-term initiatives to address the Company's design standards, load growth and aging assets. The Company maintains regular and ongoing communications through quarterly update meetings with Staff, who are familiar with the Company's robust electric planning and budgeting processes and capital infrastructure program. The Company has also just completed an update of its electric long-range planning study ("ELRP") that provides a comprehensive review of the state of its electric delivery system through the next 20 years under various load growth scenarios.

Maintenance, testing and condition assessment, as is more fully described subsequently in this Asset Health Report, assist in determining life expectancy trends for assets. O&R's continued improvement and good performance with respect to its system average interruption frequency index ("SAIFI") and system average interruption duration index ("SAIDI") reliability metrics, as well as improving performance trends in equipment related outages and customers affected per interruption, indicate that the Company's capital and maintenance programs are working effectively and are contributing significantly to the safe, adequate and reliable service the Company provides to its customers.

The graph below contains the service reliability trends for SAIFI, CAIDI[1] and SAIDI for the Company's overall service territory (including data from its systems in New Jersey and Pennsylvania) for the past nine years, the majority of which is in New York State. This highlights the substantial improvements the Company is making in service reliability and system availability.



	2005	2006	2007	2008	2009	2010	2011	2012	2013
Restoration (min)	103.7	90.4	96.4	108.0	100.3	103.2	101.7	96.6	103.0
Duration (min)	148.4	117.7	96.8	131.2	106.9	118.7	97.9	93.6	90.0
Frequency	1.43	1.30	1.00	1.22	1.07	1.15	0.96	0.97	0.87

O&R's electric planning processes, capital infrastructure projects, and system inspection and maintenance ("I&M") programs generally comport with good utility practice. For ease of review, the Company's response will address sequentially the Company's transmission, substation, and distribution assets.

[1] SAIFI and CAIDI have an inverse relationship. As large customer outages are reduced, thereby improving SAIFI, this reduces / minimizes the fast switching portions of an outage associated with large customer incidents that restores large blocks of customers more quickly. What remains are smaller blocks of customers more associated with the location and repair of the actual circuit damage, which is the longer portion of the restoration component that then dominates the CAIDI calculation, and will tend to increase system CAIDI as SAIFI improves. As O&R's SAIFI has substantially improved, the Company has done a good job controlling increases in CAIDI.

Electric Transmission and Substation ("T&S") Delivery System

The information set forth below provides a general description of certain asset classes associated with the Company's electric T&S operations.

Overhead ("OH") Transmission Line Assets

- **OH Transmission Lines – 345kV**
  - Approximately 75 miles
  - Construction Range – 1972 – 1984
  - Approximate Average age – 37 years in service
- **OH Transmission Lines - 138kV**
  - Approximately 85 miles
  - Construction range – 1929 – 2001
  - Approximate Average age – 42 years in service
- **OH Transmission Lines – 69kV**
  - Approximately 268 miles
  - Construction range – 1929 – 2008
  - Approximate Average age – 52 years in service
- **OH Transmission Lines – 35kV**
  - Approximately 29 miles
  - Construction Range – 1928 – 2008
  - Approximate Average age – 72 years in service

Underground ("UG") Transmission Line Assets

- **UG Transmission Lines - 138kV**
  - Approximately 6 miles
  - Construction Range - 1970 - 2006
  - Approximate Average Age - 24 years in service

- **UG Transmission Lines - 69kV**
  - Approximately 2 miles
  - Construction Range – 1972
  - Approximate Average Age – 41 years in service

Substation Transmission Transformer Assets

- **Substation Transmission Transformers – 345kV/138kV**
  - 5 transformers
  - Installation range – 1974 – 2002
  - Approximate Average age – 27 years in service

- **Substation Transmission Transformers - 138kV/69kV**
  - 8 transformers
  - Installation range – 1973 – 2007
  - Approximate Average age – 29 years in service

- **Substation Transmission Transformers - 138kV/34kV**
  - 1 transformer
  - Installation range – 1976
  - Approximate Average age – 37 years in service

<u>Transmission Breaker Assets</u>

- **Transmission Breakers – 345kV**
  - 1 breaker
  - Installation Range – 1999
  - Approximate Average age – 14 years in service
- **Transmission Breakers – 138kV**
  - 69 breakers
  - Installation Range – 1966-2012
  - Approximate Average age – 21 years in service
- **Transmission Breakers – 69kV**
  - 80 breakers
  - Installation range - 1947 - 2010
  - Approximate Average age – 28 years in service
- **Transmission Breakers – 35kV**
  - 22 breakers
  - Installation range – 1949-2005
  - Approximate Average age – 41 years in service

<u>Substation Distribution Transformer Assets</u>

- **Substation Distribution Transformers – 138kV**
  - 25 Transformers
  - Installation range – 1973-2012
  - Approximate Average age – 17 years in service
- **Substation Distribution Transformers – 69kV**
  - 37 transformers
  - Installation range – 1962-2008
  - Approximate Average age – 28 years in service
- **Substation Distribution Transformers – 35kV**
  - 6 transformers
  - Installation range – 1973-2010
  - Approximate Average age – 21 years in service

<u>T&S Capital Infrastructure System Improvements</u>

In general, O&R's asset management program for many of its larger assets, such as its transmission lines and substation transformer banks, are addressed by upgrades and replacements through the Company's capital infrastructure investment program. Each year, the Company performs detailed planning studies that determine electric load growth and assess the performance of the electric delivery system throughout a future forecast period against its design standards. The electric design standards primarily incorporate risk assessment methodology that provides criteria to assess if the electric facilities are, or will be, operating outside of acceptable tolerances with respect to equipment loading and customer exposure. As facilities are determined to not meet design standard tolerances, they are identified for upgrades in the Company's capital budget forecast. The severity with which the facilities fail to meet the design standards, and timing of such, are primary determinants for prioritization of the Company's budget projects.

In 2013, the Company also incorporated a new budgeting optimization model that improves its methodology and focus on prioritizing its overall project portfolio. This model employs a number of strategic business drivers to assess and compare corporate projects to determine the highest priority projects. Some of these drivers include safety, reliability impact, costs, and customer needs. The Company's investment in its capital infrastructure has increased in the recent ten- to fifteen-year period, principally to address load growth, as well as to meet the Company's design standards. The Company periodically reviews and, if necessary, updates its design standards to incorporate best practices and new technology to maintain a risk assessment methodology that balances system performance, system availability, costs and customer exposure.

Assets in the T&S system are predominantly replaced when the Company's T&D planning studies indicate that their thermal limitations will be exceeded or when equipment operating capability and conditions no longer satisfy acceptable operating parameters (*i.e*., load growth and/or design standard violations), when maintenance and testing assessments indicate likely or imminent failure (*i.e*., condition assessments), or when replacement parts for maintenance are no longer available (*i.e.*, equipment obsolescence). Assessment of assets through planning studies and with respect to design standards was discussed in detail above. Maintenance assessment and testing will be described in significantly more detail later in this Asset Health Report.

In 2013, O&R completed an update of its 20-year. That study indicates that within the first ten years of the study timeframe (*i.e*., 2014 to 2023), O&R expects to add six new transmission lines, and upgrade / reconductor 12 existing transmission lines, which include the four lines that make up the West Point loop. The Company also plans to add ten new distribution stations and two transmission stations, as well as upgrade eight existing distribution stations from single-bank to multi-bank stations or replace the existing banks with larger transformers. This will add a total of 22 new distribution banks, two 345/138kV banks, and three 138/69kV banks that will significantly benefit the electric delivery system. Bulk power system interface reliability improvements will be made at Sugarloaf, Lovett and Ramapo, which are critical 345kV inputs to the O&R system. Also, sixty-eight new breakers will be installed and fifteen existing breakers are expected be replaced in this ten-year timeframe.

T&S Inspection and Maintenance Programs and Assessments

As described below, O&R inspects, assesses, and maintains its T&S system assets on a routine basis. Visual inspections and test results conducted during these inspections and maintenance procedures are the predominant methods of determining the assessed condition and equipment replacement plans.

OH Transmission Line Maintenance

O&R performs periodic inspections on all OH transmission lines that it owns and/or operates. The Company's OH transmission line maintenance program is based on the Company's "Overhead Transmission Line Maintenance Specifications and Procedure Book." This document describes the various types of inspection, and their frequency, that the Company conducts on its OH transmission lines. The following is a summary of the type and frequency of these inspections:

- Annual Ground Patrols (Semi-Annual for 500kV and 345kV Lines);
- Bi-monthly Helicopter Patrols (Monthly for 500kV and 345kV Lines);
- Climbing Inspections;
    - As required for lines below 345kV based on visual inspections or increased line activity;
    - Every five years for 345kV lines and above;
- Emergency Patrols as required based on visual inspections or increased line activity;
- Ground Resistance Measurements;
    - As required for lines below 345kV based on visual inspections or increased line activity;
    - Every five years for 345kV lines and above;
- Semi-annual Infrared Inspections; and
- Annual Wood Pole Inspections.

With respect to the assessed conditions of OH transmission lines, the helicopter patrol records, foot patrol records, infrared thermal vision records, wood pole inspection records and all other pertinent maintenance records related to OH transmission line maintenance are kept on file for a minimum period of three years at O&R's offices in Blooming Grove, New York. Facility problems and defects found as a result of the inspection programs are prioritized for repair based on the conditions found and their severity and likelihood for failure.

UG Transmission Line Maintenance

O&R performs periodic inspections and maintenance on all UG transmission lines that it owns and/or operates. The following is a summary of the type and frequency of these inspections:

- Monthly inspections of terminations, cathodic protection, pressurizing plants;
- Annual inspections of Rights-of-Way ("ROWs");
- Annual Pressurizing Plant testing;
- Semi-annual infrared testing of terminations;
- Manhole inspections every five years; and
- Fluid filled lines are tagged with a perfluorocarbon tracer gas ("PFT").

With respect to the assessed conditions of UG transmission lines, pertinent inspection and maintenance records are kept on file at O&R's offices, in Spring Valley, New York. Facility problems and defects found as a result of the inspection programs are prioritized for repair based on the conditions found and their severity and likelihood for failure.

Transmission Line ROW Vegetation Management

Vegetation on O&R's ROWs is maintained in accordance with the Company's "Transmission Vegetation Management ("VM") Plan" which is on file with the Commission. The plan is updated whenever modifications or changes are made to the program. This plan was most recently updated in April 2012. Annually, summaries of the previous year's maintenance and the current year's maintenance schedule are prepared and filed with the Commission. Maintenance schedules identify treatment techniques which have been applied or will be applied to each line during the year. They are kept on file at the Company's Blooming Grove facility. The O&R owned non-bulk transmission lines are maintained on a four-year cycle. The bulk supply lines (200kV and above) are maintained on a three-year basis. Prior to the beginning of any transmission line maintenance, the Company completes thorough customer and municipal notification and communication including the identification of off-ROW hazard trees. The outreach to both customers and municipalities includes the scope of the work, details on non-compatible tree and brush removal, debris issues, herbicide applications, map and easement review, and a review of any special conditions relating to the transmission VM work.

Transmission Relay Maintenance

All transmission relays are inspected and maintained on a two- to six-year interval in accordance with the Northeast Power Coordinating Council ("NPCC") A-4/D3 compliance requirements. Under-frequency relays are checked on an annual basis and maintained in accordance with NPCC load shedding program requirements. Breaker trip coil and DC continuity test for bulk power system devices are performed periodically, at two to six year interval, in accordance with NPCC D-3 requirements. The substation battery banks and charger testing for bulk power system are maintained in accordance with NPCC D-3 requirements. Maintenance includes bench verification of the relay's operation and settings, and functional testing that verifies correct in-service operation. O&R uses automated relay testing with a Doble program. The computerized relay test set stores all of the settings and performance of the tested relays. These files are backed up on disc. Relay maintenance reports, as well as the reports for the past two years, are kept on file at the Company's Spring Valley Operations Center. The System Operations and Transmission and Substation Engineering Departments generate a report for all mis-operations on the bulk power system and equipment. These reports are kept on file, as well as are being forwarded to the NYISO. Mis-operation reports will typically include action items such as protection settings revisions and / or protection system upgrades.

<u>Substation Maintenance</u>

The following details the different class inspections and maintenance programs performed by the Substation Operations Department, and their associated time cycles. Intervals vary depending on equipment type, style and maintenance history. The Company's schedules generally comport with good utility practice, and can be modified for specific assets based on manufacturer recommendations and the Company's experience with respect to that assets' testing and condition assessment. For example, the Company may accelerate or increase maintenance schedules for certain manufacturers of load tap changing devices on transformers, based on either increased failure history or testing results that indicate higher gassing rates that lead to premature in-service failures.

Class #1 Inspection - Monthly

- Visual inspection of transformers and oil breakers for oil leaks, oil levels, nitrogen pressure, connections, condition of bushings and Oil Circuit Breaker ("OCB") operating mechanism.
- Visual inspection of battery banks, chargers, control board indicating lights, control house lights, and yard lights.
- Visual inspection of minor equipment including Potential Transformers ("PTs"), Current Transformers ("CTs"), Capacitive Coupled Potential Devices ("CCPDs"), disconnect switches and bus connections.
- Visual inspection of all structures, fences and yard surfaces.
- Counter readings taken of OCBs, Gas Circuit Breakers ("GCBs"), reclosers and tap changers.

Infrared Inspections – Semi-annually

- Identification of equipment and connection hot spots through infrared thermography.
- Completed prior to summer and during the summer peak season.
- Repairs completed based on an established temperature priority methodology.

Station Battery Tests - Annually

- Measure specific gravity and cell voltage.
- Test with Battery Impedance Testing Equipment.
- Clean batteries.

Fans, Pumps, Heaters and Compressors - Annually

- Check for proper operation prior to winter for heaters and compressors and prior to summer for fans and pumps.

Transformer Gas-in-Oil Analysis - Annually

- Take oil sample from each power transformer compartment and analyze for combustible gas content.

Doble Power Factor Test - Every 2-5 years

- Use Doble instrument to measure the integrity of the insulating medium of certain device.

OCB Timing - Every 3 - 10 Years

- Check the time it takes for each operation of certain breakers.

Relay Maintenance - Every 4 Years, Electromechanical; Every 6 Years Microprocessor Based With Self-Check.

- Clean, test and calibrate (as required) all relays involved in protective relay schemes.
- After testing and calibrating, perform a trip test to verify proper operation.

Class #3 Inspection - Every 2 - 5 Years

The Class #3 inspection consists of a visual inspection and testing.

The Class #3 inspection on transformers is to include, but is not limited to the following items:

1. Test oil;
2. Turn-to-Turn Ratio test TTR - Test, megger test;
3. Inspect all connectors, bushings;
4. Inspect for leaks (oil - nitrogen);
5. Check CT connections, alarm systems on banks; and
6. Doble Power Factor Test.

<u>Transformers with Load Tap Changers ("LTC")</u>

7. Test Oil in LTC cabinet; and
8. Test LTC control for proper operation.

The Class #3 inspection on OCBs is to include, but is not limited to, the following items:

1. Test Oil;
2. DLRO (Ductor Test) before and after;
3. Inspect and clean control cabinet;
4. Inspect and clean Pneumatic-Hydraulic or spring charged operating system; and
5. Operational Test.

The Class #3 inspection on reclosers is to include, but is not limited to the following items:

1. Test Oil;
2. DLRO (Ductor Test) before and after; and
3. Control cabinet clean, checkout and operational test.

<u>Reclosers with Vacuum Bottles</u>

4. Hi-Pot test.

The Class #3 inspection on Air Circuit Breakers (“ACBs”) is to include, but is not limited to, the following items:

1. DLRO (Ductor Test) before and after;
2. Inspect all contacts (action to be taken, if needed);
3. Inspect and test all Micro and Aux. contacts (close and trip circuit); and
4. Trip Test.

Class #4 Inspection - Various intervals (4-12 years) dependant on equipment type, style and maintenance history.
As necessitated by Class #3 Inspection results or as dictated by Gas in Oil analysis. The Class #4 inspection consists of a thorough inspection and testing of the apparatus listed below. The Class #4 also includes all inspections included in a Class #3.

The Class #4 inspection on transformers is to include, but is not limited to the following items:

1. Test oil - filter if needed;
2. TTR - Test, Megger Test;
3. Inspect all connectors, bushings;
4. Inspect for leaks (oil - nitrogen); and
5. Check CT connections, alarm systems on banks.

<u>Transformers with Load Tap Changer</u>

6. Drain oil from LTC cabinet, inspect all contacts;
7. Inspect and tighten all connections;
8. Clean complete LTC cabinet;
9. Filter or replace oil; and
10. Test LTC control for proper operation.

The Class #4 inspection on OCB's is to include, but is not limited to the following items:

1. DLRO (Ductor test) before and after;
2. Drop tanks - inspect and tighten all connections; clean all parts and tanks;
3. Test and filter or replace oil;
4. Inspect and clean control cabinet;
5. Inspect and clean Pneumatic-Hydraulic or spring charged operating systems; and
6. Operational Test.

The Class #4 inspection on reclosers is to include, but is not limited to the following items:

1. Drop tank (filter or replace oil);
2. Inspect all contacts - repair or replace (depending on the condition);
3. Check and tighten all connections;
4. Control cabinet, clean and checkout;
5. DLRO (Ductor Test) before and after; and
6. Trip Test.

<u>Recloser with Vacuum Bottles</u>

7. Hi-Pot test.

The Class #4 inspection on ACB's is to include, but is not limited to the following items:

1. DLRO (Ductor Test) before and after;
2. Inspect all contacts - clean and put protective grease coating on;
3. Inspect and clean all arc chutes;
4. Inspect and test all Micro and Aux. contacts (close and trip circuit);
5. Check and tighten all connections; and
6. Operational Test.

All inspection, assessment and maintenance records are retained as a hard copy for one year at O&R's Spring Valley Operations Center. These records are also retained electronically in the Company's work management system ("WMS"). Repeated callouts and equipment failures that show an abnormal trend are flagged in WMS.

The Doble power factor testing, transformer gas in oil analysis and infrared inspection records are stored electronically in the Company's Substation Information System ("SIS"). OCB timing maintenance records are presently kept on a separate electronic storage system that is provided with the test equipment for that asset.

Based on the Company's capital infrastructure program, inspection, maintenance, and condition assessment procedures for T&S assets, O&R considers these assets to be, overall, in good condition.

Electric Distribution Delivery System

The information shown below provides O&R's major distribution assets for each asset group, and the total number of assets (miles for conductor/cable).

Conductor (miles)

		Miles	Age	Overall Condition
4 kV	OH	867*	Various	Good
	UG	41**	Various	Good
13 kV	OH	2016*	Various	Good
	UG	1305**	Various	Good
34.5 kV	OH	147*	Various	Good
	UG	10**	Various	Good

* circuit miles
** trench miles

Other Distribution / Line Equipment

	Qty.	Age	Overall Condition
Poles	139,364	Various	Good
Transformers	54,512	Various	Good
Switches	13,697	Various	Good
Regulators	72	Various	Good
Capacitors	394	Various	Good
Sectionalizers, Reclosers	173	Various	Good
Box Switches	2377	Various	Good

Distribution Capital Infrastructure System Improvements and I&M Programs / Assessments

In general, O&R's asset management program for distribution assets are addressed by upgrades and replacements through the Company's capital infrastructure investment program which were described in detail in the T&S section above, and through its I&M programs, some with both capital and O&M spending components, as are described in more detail below.

The Company's investment in its capital infrastructure has increased in the recent ten- to 15-year period, principally to address load growth, as well as to meet the Company's design standards. This investment has resulted in replacement of some aging assets. A significant portion of these distribution capital improvement projects are aligned with the substation system infrastructure improvement projects that the Company has identified, to allow the increased substation capacity being installed to be efficiently and effectively employed in order to provide improved load-serving capability, reliability, and contingency backup on the distribution system. Portions of the system are also upgraded through annual blankets and projects associated with new business, system interference work, system integrity/reliability work, and from the repair and replacement of facilities associated with damage sustained during storm events.

As described below, O&R inspects, assesses, and maintains its distribution system assets on a routine and periodic basis. Visual inspections and test results conducted during these programs, inspections and maintenance procedures are the predominant methods of determining the assessed condition and equipment repair and replacement plans.

DISTRIBUTION VEGETATION MANAGEMENT

The distribution VM program is a vegetation clearance and control methodology based upon a 3.5- to 4-year cycle. The circuits to be maintained each year are selected using the normal scheduled maintenance cycle. A tree-related outage spreadsheet, derived from OMS and Performance and Operational Engineering, is used to monitor circuits based on vegetation-related outage performance. Patrols are completed as VM supervisors and other company personnel move throughout the service territory. Any identified vegetation issues requiring attention to prevent service interruptions are reported for further investigation and remediation by the VM Department. Beginning in June 2013, Nelson Tree Service and Trees, Inc., has been retained by the Company to complete the scheduled distribution VM programs. This new contract is for a three-year period and will expire in May 2016.

Production reports and reverse billing is managed through Environmental Consultants, Inc.'s, computer program entitled Trim Evaluation and Report System ("TRES"). This computer system is the main component in tracking production and costs and is the system used to reconcile weekly costs between the Company and the vendor prior to the billing and invoicing process. The Company maintains VM records for each substation worked, with completion dates and mileage maintained. Audits are performed by the Company VM Supervisor or Company contractor representative on the circuits as the vegetation work proceeds, so as to maintain the quality of work and line clearance specifications. Additionally, Contractor Field Observation Reports are completed monthly. These observations, completed by Company VM Supervisors and Company contractor representatives, are also performed on the contractors performing the work and focus on work quality as well as several safety-related items.

VISUAL INSPECTION PROGRAM

By Order issued on January 5, 2005, with subsequent revisions issued on July 21, 2005, December 15, 2008, and March22, 2013 in Case 04-M-0159, the Commission required that O&R initiate a Visual Inspection Program encompassing 20% of all O&R facilities annually, such that within five years all facilities have been visually reviewed. Consistent with that Order, O&R initiated the visual inspection program in 2005 and continues to do so annually. O&R conducts separate visual inspections of its transmission and distribution systems. Non-Company labor performs the majority of the work. Electric Operation’s Transmission and Distribution Maintenance group, located in Spring Valley, New York, administers the Visual Inspection Program. Transmission visual inspection records are currently on file in the Company’s Blooming Grove, New York facility with Electric Operation’s Extra High Voltage Department. Data is stored in a proprietary system called Fastgate. Distribution visual inspection records are stored with the inspection vendor and O&R’s Electric Information Management System (“EIMS”). Necessary repairs are prioritized and completed in accordance with an established priority rating system.

STRAY VOLTAGE TESTING PROGRAM

By Order issued on January 5, 2005, with subsequent revisions issued on July 21, 2005, December 15, 2008 and March 22, 2013 in Case 04-M-0159, the Commission required that O&R initiate a Stray Voltage Testing Program encompassing annual stray voltage testing of all O&R underground (buried) facilities, including manhole covers, pull box covers, submersible transformer grates and metal hand holes) capable of conducting electricity, third party facilities bonded electrically to the O&R system, including, municipal street and traffic light systems. In addition, stray voltage testing shall be performed in conjunction with visual inspections, completing stray voltage testing on 20% of the transmission and distribution systems annually. O&R conducts separate stray voltage testing for its transmission and distribution systems. Non-Company labor performs the majority of the work. Electric Operation’s Transmission and Distribution Maintenance group, located in Spring Valley, New York, administers the Stray Voltage Program. Stray Voltage records on distribution equipment are currently available in EIMS and transmission equipment resides in Fastgate.

DISTRIBUTION LINE MAINTENANCE

The following details all of the distribution line maintenance programs performed by O&R’s Overhead and Underground Electric Operations Departments.

CAPACITOR MAINTENANCE PROGRAM

All switched capacitor banks are inspected in accordance with the Capacitor Maintenance procedure. Maintenance schedules have been set by the Divisions and are tailored to best meet the Divisions’ needs.

REGULATOR MAINTENANCE PROGRAM

Regulator inspections and functional tests are performed annually in accordance with the Regulator Maintenance Procedure. As system conditions allow, deficiencies are corrected prior to the system peak.

RECLOSER SECTIONALIZER MAINTENANCE PROGRAM

Recloser/Sectionalizer inspections and functional tests are performed in accordance with the Recloser/Sectionalizer Maintenance Procedure. A visual inspection of all line units is performed annually, and functional tests are performed every three years.

INFRARED THERMAL INSPECTION PROGRAM

This program is administered annually on all three-phase OH facilities, and on a three-year cycle for all single-phase OH facilities. Necessary repairs are prioritized by temperature rise and completed as follows:

- Priority 1 - immediate attention required;
- Priority 2 - repair within seven days; and
- Priority 3 (all others) - repair as resources allow and/or monitor in next IR cycle.

CIRCUIT OWNERSHIP PROGRAM

Three times a year, *i.e.,* once in the spring, once in the summer and once in the fall, all circuits on the distribution system are patrolled by circuit owners, who are predominantly Electric Operations personnel. In addition all circuits may be patrolled by their owners before and after a storm. The circuit owners report conditions that may adversely affect the reliability of each circuit. These conditions are promptly mitigated to facilitate the best possible performance of the distribution system. This program is being modified this year to target circuits that have a relatively poor performance based on their impact on Customers Affected and Customer Hours of interruption.

POLES

The Company’s pole inspection program consists of a visual inspection of the pole and hardware on 10 – 12% of all poles each year. On poles older than 15 years, a sound test is done first, followed by a boring test if required. When a boring test finds pockets of decay, these pockets are treated with a fumigant. When needed, the poles are either partially or fully excavated to a depth of 18" to look for decay. When decay is found, the poles are shaven, treated with a paste treatment that is applied to the pole, and then wrapped with felt paper. When a pole is determined to have less than 67% strength remaining, the pole will then either be “C-trussed” with a steel truss, or replaced. The determining factor for C-trussing is where the decay is located and if the resultant loading on the pole will be acceptable utilizing the C-truss.

TELEVISION INTERFERENCE (“TVI”) PROGRAM

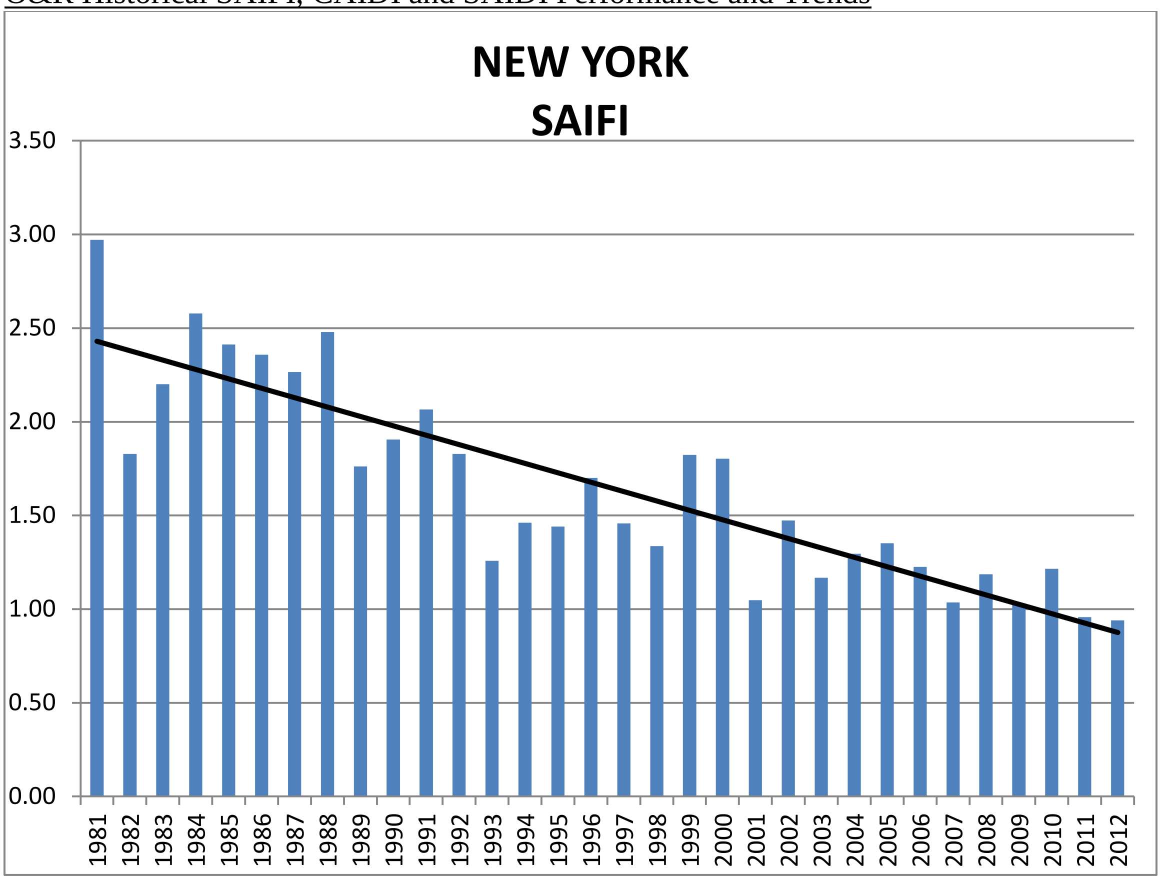
The TVI program is used on an as needed basis and is implemented when a customer experiences either television or radio interference that may be caused by emissions from power transmission or distribution equipment. An omni-directional tuning device is employed to investigate the source of the emission. If the source is determined to be from Company-owned equipment, the defect is corrected promptly.

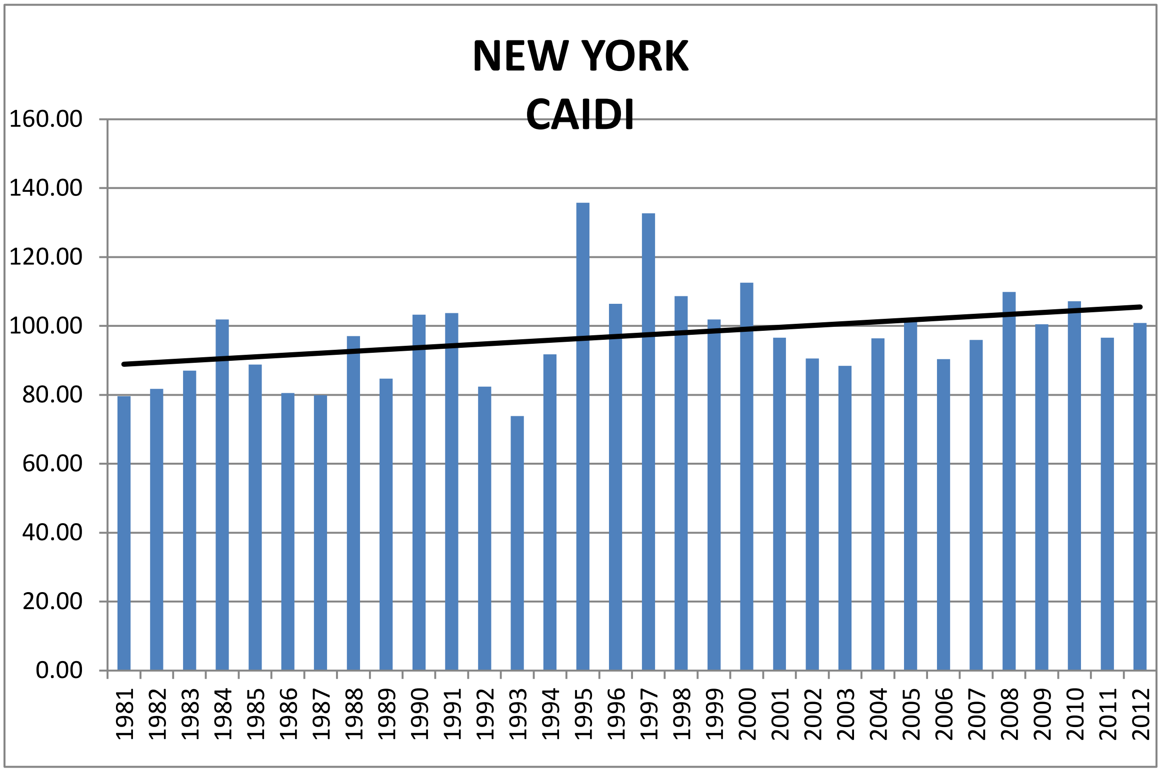
UNDERGROUND CABLE REHABILITATION AND REPLACEMENT

All underground system outages resulting from cable system failures are analyzed on an individual subdivision basis and a priority listing developed. From specific equipment analysis, it is determined if the cable is to be rehabilitated or replaced. In subdivisions that contain older cable that have not had multiple cable failures, the rehabilitation process to extend life is considered, instead of replacement. Rehabilitation is accomplished by injecting a patented silicone based fluid into the interstices of the cable, which impregnates the insulation and fills the voids. This process restores the dielectric properties of the deteriorated cable. Underground residential development facilities are selected for cable replacement based upon their frequency of cable failure, and either do not fit the criteria for rehabilitation or have been unsuccessfully rehabilitated.

Electric Delivery System Performance Trends

O&R Historical SAIFI, CAIDI and SAIDI Performance and Trends

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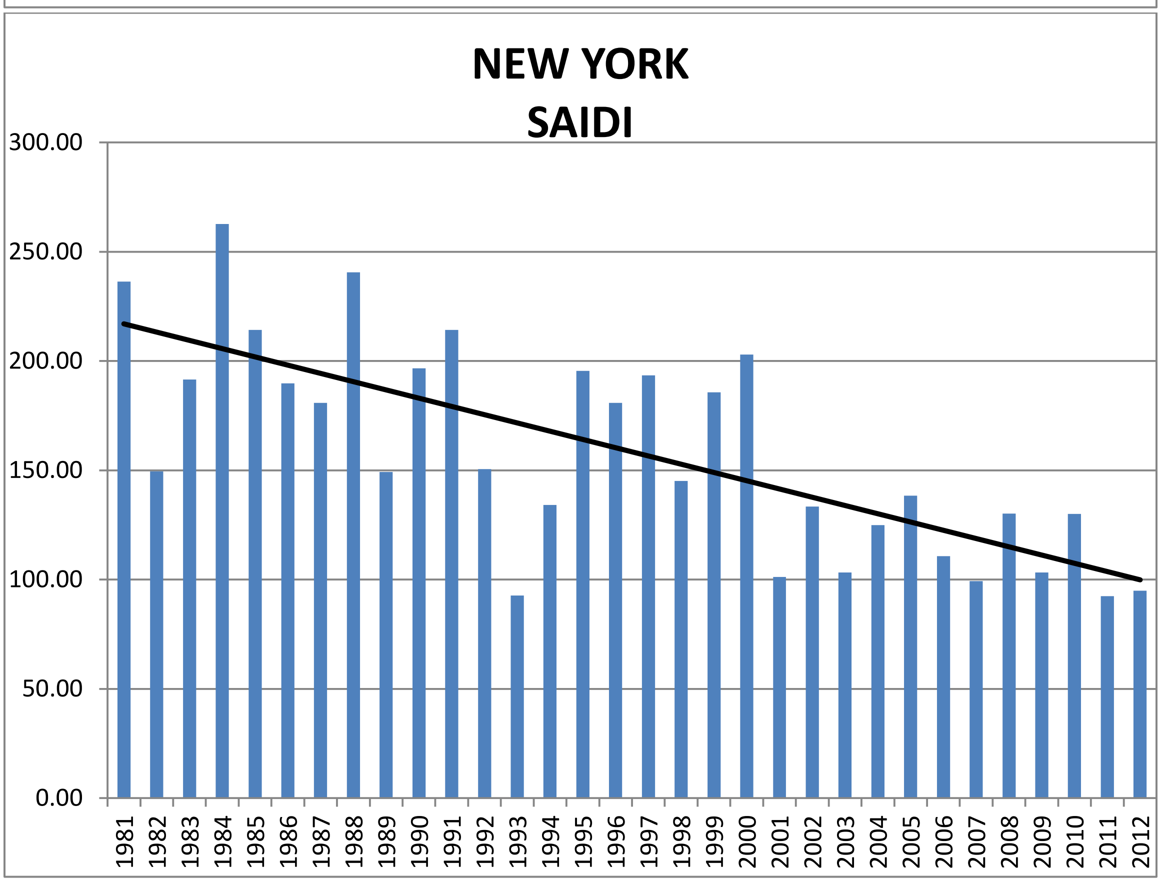
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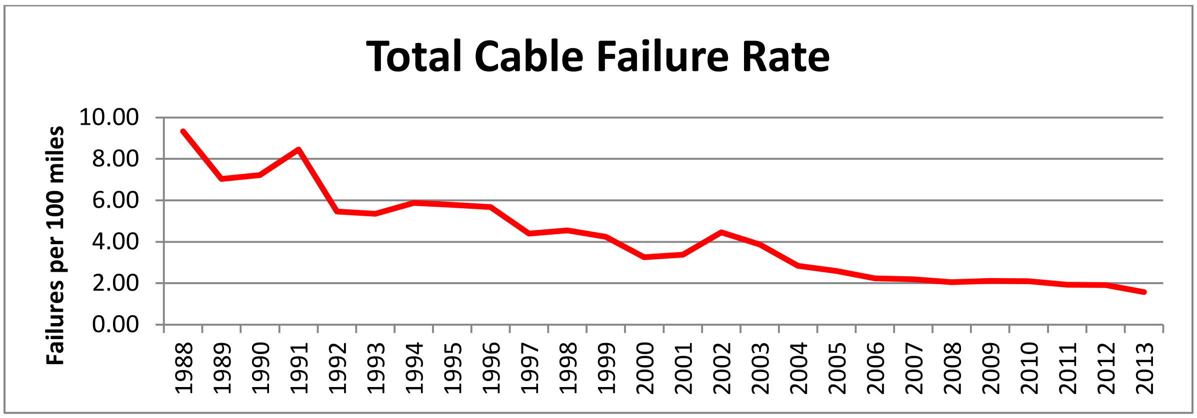
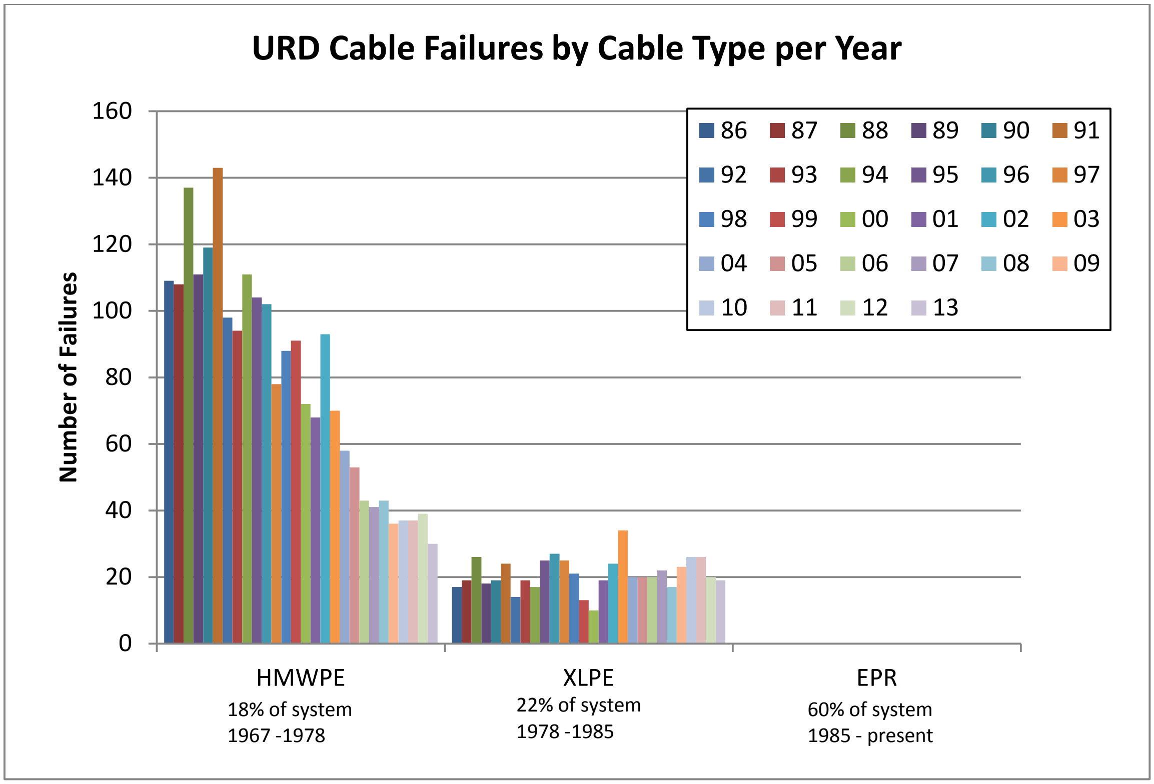
1981 1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012

UG Rehabilitation and Rebuild Program Performance and Trends

During the past 25 years that the UG Cable Rehabilitation and Rebuild program has been in effect, over 234 miles of URD cable have been replaced and over 182 miles of URD cable have been rehabilitated. The overall cable failure rate has improved from just over 9.3 failures per 100 miles of cable to 1.6 failures per 100 miles of cable; an improvement of over 82%. The results provided are for the Company's entire service territory, which includes data from its systems in New Jersey and Pennsylvania, with the majority being New York system data.



The chart below shows the cable failures by cable type for the Company for the past 25 years. A noticeable trend shows that the failures have decreased from 140 to 30 per year for the oldest type of cable which has reached its projected service life of 30 to 40 years. The cable addressed through this program has been the HMWPE and XLPE insulated cables. As illustrated in the chart, no EPR insulated cable has failed in service to date. This is a result of more detailed, stringent and improved engineering cable specifications and the use of select cable manufacturers that meet the Company's stringent specifications and standards.


URD Cable Failures by Cable Type per Year
Number of Failures
160
140
120
100
80
60
40
20
0
86
87
88
89
90
91
92
93
94
95
96
97
98
99
00
01
02
03
04
05
06
07
08
09
10
11
12
13
HMWPE
18% of system
1967 -1978
XLPE
22% of system
1978 -1985
EPR
60% of system
1985 - present

O&R Future-Looking Storm Hardening / System Resiliency Initiatives

As is demonstrated by the information provided above, O&R has a breadth of projects and programs that it already implements to maintain a safe and reliable electric delivery system, and improve the quality of service offered to customers. Nevertheless, the Company is keenly aware that the Commission and Staff are interested in O&R's efforts to review and implement initiatives that will provide certain system hardening and system resiliency benefits to better withstand and recover from future storm events.

Towards that end, and after the major storms of 2011 (*i.e.,* Hurricane Irene and the October Snowstorm) and Superstorm Sandy in 2012, the Company, in February 2013, formed a team to explore methodologies and alternatives focused on improving storm hardening and system resiliency. The mission of the team was to identify opportunities to improve storm reliability on O&R's electric system and make recommendations for improvements, considering costs and other critical factors. The overall Storm Hardening team divided into five sub-teams, consisting of subject matter experts from Operations and Engineering. These sub-teams focused for six months on analyzing opportunities in the following areas: undergrounding, automation and circuit reconfiguration, system materials and construction standards, system maintenance, and vegetation management. Some of the high-level conclusions and recommendations of these sub-teams are discussed below.

Undergrounding Team

The Undergrounding team was formed to determine if installing facilities below ground, as opposed to OH, can provide a cost-justifiable, hardening or resiliency benefit. Considering the expense of undergrounding, the team targeted conversion of OH facilities where it would prove most beneficial. In addition to existing construction, the team examined the current design practice for new substation exits to determine if it meets storm hardening requirements. The Undergrounding team analyzed existing double circuit construction, storm-damage- prone circuits, and critical transportation crossings. The team recommended the following:

- Where feasible, eliminate and/or reduce double circuit construction supplying common load areas;
- Install new underground exits to a point of path independence;
- Selectively underground portions of double circuits with a history of storm damage;
- Evaluate critical road crossings; and
- Selectively use spacer cable systems.

While not recommended, the team considered converting the Company's entire distribution system to underground. The team concluded that this effort would be cost prohibitive (on the order of $25+ billion, or approximately the cost to recover from 250

Superstorm Sandy's), would not be constructed in a reasonable amount of time, and would involve challenges with other stakeholders that customers would not embrace. The team also considered eliminating double circuit construction completely and found that a targeted approach would be more prudent; some double circuits have minimal tree exposure and the exposure in certain circumstances is lower. The probability of success of each of the Undergrounding team's recommendations is high and the hardening benefit is proven.

Automation and Circuit Reconfiguration Team

Automation has proven to be one of the most effective solutions in enhancing system resiliency. The Automation and Circuit Reconfiguration team reviewed the application and design standard of existing automation technologies on the Company's distribution system and explored new technologies available for mainline and spur automation. The team also explored ways to improve circuit configuration with alternative design oriented solutions. After analyzing the Company's distribution system to identify areas where increased automation would have the greatest resiliency benefit, the Automation and Circuit Reconfiguration team recommended the following:

- More prolific use of reclosing devices;
- Use of SCADA load break switches on main lines;
- Strategic use of single and three phase spur automation;
- Auto loop design standard enhancements;
- Segment customer count and distance reduction; and
- Improve restoration capability by closing single and three phase gaps on the OH distribution system.

System Construction Team

The System Construction team looked for opportunities to both harden the system and make it more resilient. The team investigated whether the system can be constructed to more effectively reduce storm related outages and if there are construction methods available that would allow for continued operation if damage occurs. The System Construction team reviewed the benefits of:

- Moving to National Electrical Safety Code ("NESC") Grade B construction;
- Reconstructing double circuit distribution pole lines to minimize customer exposure;
- Using aerial cable construction;
- Using spacer cable construction;
- Using breakaway connectors;
- Upgrading feeders to 900 amps;
- Using composite poles;

- Modifying pole loading calculations using 1" of ice vs. ½", which is the NESC standard for heavy loading districts; and
- Changing the size of guy wire to strengthen the system.

After exhaustive analysis, the team made a number of recommendations. The System Construction team recommended that the Company maintain the distribution system, as a general matter, at its current grade C construction. However, with respect to pole size for general construction, and for critical poles such as major equipment poles, high use junction poles or transportation crossings, the team recommended a move to a more hardened construction by increasing pole size and strength. The Company has decided to use Class 2 poles for all of its line construction, with the exception that for certain key equipment and junction poles, an even larger Class 1 or 1H pole will be used. With regard to double circuit poles, the team recommended that reconstruction be considered on a case by case basis. There are many options and the best alternative depends on system conditions at specific locations. The use of breakaway connectors will be limited, and installed as part of a pilot program; the technology is not mature enough to install on a broader scale. Composite poles will also be used on a limited basis as part of a pilot program. While the poles may provide some hardening benefit, there are other issues to consider, such as the ability for other parties to attach their facilities.

<u>System Maintenance Team</u>
The System Maintenance team evaluated the Company's existing maintenance programs to determine if opportunities exist to make the electric delivery system less susceptible to storm damage or improve the Company's ability to recover from damage resulting from a storm event. The Company's electric 138kV and 69kV high voltage system is primarily an OH system with almost 80% of the structures constructed from wood components. Wood is an efficient, readily available and cost effective construction material. However, it is a natural material vulnerable to the weather and subject to attack from insects and animals. The majority of defects and failures on the electric delivery system result from decay and destruction by natural forces. O&R can harden its system by replacing wood components with steel, particularly where practical on its high voltage system. In areas where the shoreline has eroded pole foundations, thereby compromising poles' strength as part of the original design, stream bank stabilization efforts are undertaken to restore the ground to a safe condition. Other recommendations, such as the purchase of wetland matting, are the result of the difficulty in accessing some facilities in order to make repairs during storms. Aggressively inspecting and replacing poles that are defective provides a benefit during storms, where survival of defective poles is scarce.

Vegetation Management Team

The Vegetation Management team was formed to review the Company's existing vegetation management programs and practices to determine if opportunities exist to make the electric delivery system less susceptible to storm damage caused by vegetation contact. As previously noted, the Company's electric system is primarily an OH system situated in heavily treed areas. This potential conflict with local vegetation is an exposure that has been mitigated through aggressive pruning and tree removal. The vegetation management that the Company has completed over several previous maintenance cycles has increased the aerial space between vegetation and live conductors and reduced the number of tree-caused outages. While performance has improved, the Company has determined there are further opportunities to improve reliability by targeting certain vegetation management practices. The Vegetation Management team identified the following opportunities:

- Expanded clearance standards will be used for all 34.5kV construction, and for 13.2kV and lower construction, will be completed on the mainline conductors from the substation to the circuits first mainline protective device;
- Enhanced hazard tree program;
- Use of branch reduction techniques;
- Conduct an urban tree health study;
- Perform an off – ROW hazard tree survey; and
- Target enhancements to municipality-identified critical infrastructure.

Consistent with the findings, conclusions and recommendations of the Company's Storm Hardening team as discussed above, O&R will be including in future corporate budgets, and proposing in future rate proceedings, incremental programs and projects that will be used to further storm hardening targeted portions of the Company's electric delivery system from the effects from major storms. Specifically, the Company will be seeking to propose and implement, at a minimum, the following high level initiatives:

- Enhanced Construction Methods;
    - Selective Undergrounding;
    - Enhanced OH System Construction;
    - Enhanced Transportation Crossings;
- Substation Flood Mitigation;
- Enhanced Vegetation Management;
- Accelerated Pole Reinforcement; and
- Expanded System Automation and Grid Enhancement Technologies.

Some of the Company's initial scope and projections for these incremental Storm Hardening and System Resiliency Programs are described in more detail below.

Selective Undergrounding

The selective undergrounding program will replace with underground construction one of the circuits from an existing OH double circuit distribution corridor that has a history of higher exposure to outage incidents. This proposed plan will install approximately five to six miles of selective undergrounding each year. Such selective undergrounding should serve to decrease customer outages, shorten outage duration, and help to avoid outages resulting from major storm events, in a cost effective manner. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

Enhanced OH System Construction

Storm resilient, enhanced OH system construction alternatives, such as spacer cable systems, will be installed in targeted applications to replace conventional construction, as well as fill in gaps to create new circuit ties in the OH distribution system that will provide hardening and system resiliency in a combined solution. Filling in gaps and establishing new circuit ties reduces the amount of radial distribution and provides a more storm resistant OH system. This should improve the resiliency of the distribution system, allow for reduced outage durations, and potential outage avoidance with hardened construction. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

Enhanced Transportation Crossings

This program will address distribution crossings of major highways, railroads, and waterways with more storm resistant systems. Existing transportation crossings will be upgraded with poles that are capable of withstanding higher wind loads, or replaced with total underground systems where this type of upgrade makes sense. Reinforced and updated equipment typically means less damage incurred, which reduces customer outages. It also maintains the availability of emergency routes during storm conditions. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

Substation Flood Mitigation

O&R has not had any significant flooding damage affecting continuity of service in the vast majority of its substations in recent years, where historically some of the worst flooding in the region occurred during Hurricane Irene. Although this has not been a significant problem within the O&R service territory, the Company would seek to initiate a team to perform an assessment of all substations located in the O&R service territory which lie within known Federal Emergency Management Agency ("FEMA"), or near FEMA flood zones and have historically had storm water intrusion. The team will determine where the greatest risk exists, and develop flood mitigation solutions designed to divert and keep flood water out of these substations in order to maintain continuity of service.

Enhanced Vegetation Management Program

The Company will propose to increase funding to cover the additional vegetation work proposed to harden the electric delivery system and improve reliability during damaging storms. The funding will cover the added costs of widening the Company's trim zones on a portion of the circuit mainline from the substation to the first mainline protective device, and additional work required for "branch reduction." The branch reduction work is based on a joint utility study through the Electric Power Research Institute ("EPRI"), which identified the pivot angle and leverage impact of large tree limbs that normally would not be trimmed during vegetation maintenance. This work has already been added to the Company's vegetation management program and has resulted in incremental costs. The work focuses on limbs >6" in diameter that overhang the conductors and would not normally be cut. These are now being cut to enhance tree health and lessen risk to the electric delivery system. The program targets areas where the greatest exposure exists for large customer outages. An expanded danger tree and hazard tree program will require additional funding as well. Resources need to be dedicated to aggressively patrol the electric delivery system to identify hazard trees, tracking tree locations, and interact with customers to remove these hazard and danger trees. The urban tree assessment will identify and manage danger trees. The Company will require incremental staffing to oversee and manage the expanded vegetation management program.

Accelerated Pole Reinforcement Program

The Company will propose to increase funding to support incremental costs associated with the replacement of defective poles. The program is required to accelerate the reinforcement and / or replacement of poles identified as defective during the inspection process. This program will include trussing of poles where it is deemed to be acceptable, and where complete replacement of the pole is necessary, that will be implemented. The Company envisions this to be at least a three- to five-year program.

Expanded System Automation and Grid Enhancement Technologies

The Company is nearing the completion of the implementation phase of its Smart Grid Pilot Project in the West Nyack/Snake Hill Road area of Rockland County, New York. As part of its ongoing efforts to implement a Distribution Management System ("DMS"), O&R is also in the final stages of testing and proofing this DMS in a laboratory environment to provide model-centric control of the electric distribution system through automatic feeder restoration and Volt /VAR control. The Company already has a NYSERDA grant to expand its DMS model, and automation / smart grid technology to 14 additional circuits in the Central Rockland area. The Company is preparing reports for the examination of costs and benefits of this technology expansion, and initial results look very favorable for a high benefit to cost perspective.

The Company would look to complete this Central Rockland area expansion to examine and realize the benefits in a larger scale model that will provide improved validation of the costs and benefits. It would then seek to strategically implement this model to target the expansion of these DMS concepts and distribution automation / Smart Grid technologies to areas of its electric distribution system that show the highest cost-benefit potential. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

The continued implementation of the Company's current infrastructure projects and service reliability programs, coupled with these forward-looking storm hardening and system resiliency projects and programs will improve the electric delivery systems capability to better withstand weather-related events and recover from them more quickly and efficiently.