nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

June 29, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4307 - 2013 Electric Infrastructure, Safety and Reliability Plan Pursuant to R.I.G.L. §39-1-27.7.1
Flood Mitigation Plan & Vegetation Management Program and Inspection and Maintenance Program Methodology

Dear Ms. Massaro:

In accordance with the Rhode Island Public Utilities Commission's (the "Commission') written Order 20724 issued May 3, 2012 in the above-referenced docket, please find ten (10) copies of National Grid's[1] Flood Mitigation Plan, and its methodology for tracking the costs and benefits of its Vegetation and Management Program and Inspection and Maintenance Program. In its Order, the Commission directed the Company and the Rhode Island Division of Public Utilities and Carriers (the "Division") to collaborate to develop the methodology by which such costs and benefits will be tracked and reported on by the Company in its future Electric Infrastructure, Safety and Reliability ("ISR") Plan filings. The enclosed methodology reflects that collaborative effort and has been agreed to by the Division.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Leo Wold, Esq.
Steve Scialabba, RI Division

[1] Filed on behalf of The Narragansett Electric Company d/b/a National Grid (referred to herein as "National Grid" or the "Company").

National Grid

The Narragansett Electric Company

Rhode Island Flood Mitigation Plan

June 29, 2012

Docket No. 4307

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

nationalgrid

Table of Contents

1. Introduction

Major river flooding on the Pawtuxet River, Pawcatuck River, Blackstone River, and Hunts River from March 30 through April 1, 2010 required that The Narragansett Electric Company's ("the Company's") substations located in these river areas be deenergized due to excessive water levels. Table 1 shows the substations that were affected by the flood waters.

Table 1: Substations Affected by the March 2010 Floods

Substation Name	Substation Address	Voltage	Impact River	Approx. Water Height
Pontiac	14 Ross Simon Dr – Cranston	115kV-12.47kV	Pawtuxet	5 Ft
Sockanosett	19 Electronic Dr – Warwick	115kV-23kV	Pawtuxet	6.5 Ft
Westerly	69 Canal St – Westerly	34kV-12.47kV	Pawcatuck	6.5 Ft
Hope	15 Hope Furnace Rd – Scituate	23kV-12.47kV	Pawtuxet	3 Ft
Pawtuxet	70 Bellows St – Warwick	23kV-4.16kV	Pawtuxet	6 Ft
Warwick Mall	400 Bald Hill Rd – Warwick	23kV-12.47kV	Pawtuxet	5 Ft
Hunt River	5890 Post Rd – Warwick	34kV-12.47kV	Hunts	3 Ft
Riverside	1000 Florence Dr Ext – Woonsocket	115kV-13.8kV	Blackstone	2 Ft

Water levels reached between two feet and eight feet in these locations. Flood waters from the Pawtuxet, Blackstone, Pawcatuck, and Hunts Rivers were brackish, contained raw sewage, debris, and other contaminants. In addition to reliability impacts to customers, the impacted areas represented a significant health and safety risk to personnel, and there was significant damage to mechanical, electrical, control, and communications equipment in these substations and their control houses.

To maintain service to those customers normally supplied from the flooded substations, the following actions were necessary until repairs or replacement of substation equipment affected by the flood waters were complete and the substations could be re-energized:

- Transfer of load to area substations not affected by the flood waters;
- Installation of temporary equipment, such as mobile substations, padmounted transformers, and mobile generation; and
- Increased loading levels on area distribution equipment.

The Westerly, Sockanosset, and Pontiac substations sustained the most damage due to the high flood water. At the Westerly and Sockanosett substations, temporary repairs and temporary equipment replacement were made to restore these locations to service, with a reduced level of operating flexibility. At all other locations, repairs were made restoring the full capabilities of the substation.

2. Substation Flood Risk Assessment

In March 2010, National Grid commenced a Substation Flood Risk Assessment that included an evaluation of substations located in Rhode Island. The purpose of the study was to develop a strategic plan to address flood threats to substations through identification of flood sensitive equipment. Inland and coastal Federal Emergency Management Agency (“FEMA”) flood zones were overlaid with the physical limits (perimeter fence, driveway) of the Company’s substations. Special consideration was given to substations that had sustained flooding in the past. A desktop analysis revealed insufficient elevation information for a comparison of yard grade to the base flood elevation presented on the FEMA maps. Datum discrepancies[1] required field surveys to detail yard elevation, foundation elevation, and certain equipment panel elevations. This information was then compared to the base flood elevation to identify at risk equipment. Table 2 outlines the results of the assessment.

[1] FEMA map datum = NAVD 88 (North American Vertical Datum 1988)

Table 2: Substation Flood Assessment

Substation	Town	Yard Grade To March 2010 Flood Levels (ft)	Yard Grade To 100-Year Flood Elev. (ft)	Flood Risk Level (1)
Riverside Substation No. 8	Woonsocket	-2.0	-6.5	High
Staples Substation No. 112	Cumberland	NA	N/A	Low (2)
Johnston Substation No. 18	Johnston	NA	N/A	Low (2)
Pawtuxet Substation No. 31	Warwick	-6.0	-5.1	High
Sockanosset Substation No. 24	Warwick	-6.5	-1.7	High
Pontiac Substation No. 27	Cranston	-5.0	0.4	Medium
Warwick Mall Substation No. 28	Warwick	-5.0	-1.4	High
Hope Substation No. 15	Scituate	-3.0	1.7	Medium
Hunt River Substation No. 40	Warwick	-3.0	-4	High
Hope Valley Substation No. 41	Hopkinton	NA	1.2	Medium
Westerly Substation No. 16	Westerly	-6.5	-2.2	High
Jepson Substation No. 37	Portsmouth	NA	1.8	Medium
South Aquidneck Substation No. 122	Middletown	NA	-2.7	Medium

(1) For comparison purposes, equipment vulnerability is rated as follows:
High – below flood elevation to at flood elevation
Medium – 0 to 2 feet above flood elevation
Low – 2+ feet above flood elevation
(2) Based on the Company's analysis, it appears that flooding at this location is drainage related rather than flood zone related.

From the assessment, solutions were developed for those substations identified as high and medium in the Flood Risk column in Table 2. Solutions were developed to mitigate the risk for flood conditions comparable to those experienced in the spring of 2010 or to the FEMA's published 100-year flood elevation, whichever is higher. Each solution is expected to allow the substation to be restored as quickly as possible based on the severity of the flood event. Solutions are in line with future infrastructure requirements. The solutions include:

- Retirement of existing substations if, in addition to flood concerns, opportunities exist to address area capacity and substation asset condition issues;
- Rebuilding sections of existing substations that are in areas susceptible to flood conditions with elevated equipment; and
- Elevation of specific equipment susceptible to flood conditions within the substation.

Each location was also evaluated for installation of flood protection barriers; however, none of the substations were determined to be suitable candidates. Flood protection barriers provide resistance to flood waters and are designed to keep water out of the property by sealing potential water entry points. These measures can be either temporary in nature, where they are applied shortly before a flood, or permanently installed. It was determined that barriers are not sufficient as the flood waters experienced exceed the 4’-6” height of the commercially available barriers. If base flood evaluations or previously flooding history did indicate a 4’-6” high barrier would be adequate, and flood barriers were installed permanently, the system requires maintenance and special provisions for substation access and access to equipment. Installations at some locations may require land acquisition due to station footprint.

Permanent resilience measures, such as raising equipment, aim to mitigate damage to equipment from flood water entry thereby facilitating the quickest possible recovery of the system.

The Company's substation design criteria was also evaluated as part of the study and revised to include consideration of flood issues. The design criteria now states that: 1) future substation locations avoid flood zone areas; 2) design elevations shall be a minimum of 24 inches above 100-year flood elevation; and 3) consideration of substation relocations be evaluated for major rebuild/upgrade projects for substations that are in a flood zone.

3. Project Specifics

Project details are provided below for each substation with "Medium" or "High" equipment vulnerabilities per Table 2 above. Details include the recommended solution, alternatives considered, and conceptual costs and schedules.[2]

3.1. Sockanosett Substation

Sockanosett Substation has two main 23kV lines that supply the Elmwood #7 outdoor substation and the Auburn #73 substation. These 23kV lines also supply large industrial customers. The total load at risk at this station is approximately 28MW, which will impact approximately 11,500 customers, both commercial and residential, if flooding of this nature occurs again.

[2] Schedules have been revised from those provided in the FY 2013 ISR Division Data Request 2-9 (Asset Condition) in Docket No. 4307. Recommended solutions have been revised from those provided in the FY 2013 ISR Division Data Request 2-9 (Asset Condition) for Warwick Mall and Hunt River.

3.1.1. Recommended Option: Elevate the 23kV Equipment

- Install an outdoor Metal-clad Switchgear Power Center ("MCSPC") located on an elevated foundation with a steel ramp, stairway and work platform with rails.
- Relocate the 115kV high side circuit switchers ("CS") control box to 98 inches above grade or replace them with submersible rated control cabinets.
- Design and procure spare control panels, base control for Load Tap Changer ("LTC"), and LTC control for transformers T1 and T2 to enable a retrofit in the event of flood conditions that impact the controls.
- Install an open bus from T1 and T2 to the new MCSPC, reusing a portion of the existing buses.
- Install 23kV getaway cables from the switchgear to each of the two supply circuit riser poles.
- Install 23kV cables from the switchgear to each of the two capacitor banks.
- Raise the existing capacitor bank control cabinets as high as possible above grade.

3.1.1.1. Conceptual Cost[3]

$5.12 million

3.1.1.2. Conceptual Milestone Schedule

Final Design – March 2014

Construction Start – June 2014

[3] Conceptual costs are developed in the project identification phase of a project, prior to completion of preliminary engineering, and have an accuracy of -25% to + 50%.

Construction Finish – November 2015

3.1.2. Alternatives

3.1.2.1. Alternative 1: Relocation of Sockanosett Substation

Relocation of Sockanosett Substation out of flood areas would require land acquisition and potential 23kV and 115kV line extensions. This option was not pursued as substation costs would be comparable to Alternative 1, with additional unquantified land and permitting costs and risks. Furthermore, land availability, with proximity to 23kV and 115kV facilities in the area is extremely limited.

3.2. Westerly Substation

3.2.1. Recommended Option: Transfer Load to Other Area Substations and Retire Westerly Substation

The recommended option is to retire Westerly substation by transferring its load to other area substations. The scope of this work includes:

- Build out proposed new Hopkinton Substation to provide capacity for Westerly load. This requires installing a second power transformer and metal-clad switchgear with 4-feeder positions at Hopkinton substation.
- Upgrade the existing Langworthy Substation to provide capacity for Westerly load.
- Remove and retire the existing Westerly substation

3.2.1.1. Conceptual Cost

$10.90 million

3.2.1.2. Conceptual Milestone Schedule

Final Design – February 2014

Construction Start – May 2014

Construction Finish – June 2015

3.2.2. Alternatives

3.2.2.1. Alternative 1: Replace and Elevate Westerly Substation

Alternative 1 would replace and elevate the Westerly substation. This alternative is not recommended because it is higher in cost. The conceptual estimate of this plan is $14.0 million with the following scope of work:

- Install an outdoor MCSPC located on an elevated foundation 84 inches above grade and a steel ramp, stairway and work platform with rails. The MCSPC would be located in the area of the older abandoned switch-yard structures.
- Replace both T2 and T4 transformers with 242/32/40 MVA, LTC transformers and relocate them to the area of the older abandoned switch-yard. Delta/zigzag transformers would be required to phase with the rest of the system and with the new Hopkinton substation.
- Install steel stairways and work platforms with rails for workers access to the transformer control cabinets.

- Replace the 34.5 kV high side breakers with CS and relocate them to the area of the older abandoned switch-yard. The CS shall be specified with the control box mounted as high as possible above grade.
- Install open bus from T2 and T4 to the new MCSPC.
- Extend the two 34.5 kV supply lines to the new transformer location.
- Install 15kV getaway cables from the switchgear to each feeder riser pole.
- Relocate the existing capacitor banks to the area of the older abandoned switch-yard and install 15kV cables from the switchgear to each capacitor bank.

3.2.2.2. Alternative 2: Relocate the Substation

Alternative 2 would relocate the Westerly substation to the existing building on site. This alternative is not recommended because it is higher in cost. The conceptual estimate of this plan is $14.0 million with the following scope of work:

- Install an indoor metal-clad switchgear located in the abandoned brick substation building, which is located at a higher elevation than the existing yard and did not flood (except for the basement).
- Replace the windows and doors in the building and re-point the bricks where needed. Scrape and paint the interior walls and ceilings where needed. Replace the heating system with a HVAC system that would be installed on the first floor. Upgrade electrical systems, doors and other components of the building to satisfy current code.

- Remove the retired 4kV relay and control panels and install new relay and control panels.
- Replace both T2 and T4 with 24/32/40 MVA, LTC transformers and relocate them to the area closer to the brick building. Delta/zigzag transformers are required to phase with the rest of the system and with the new Hopkinton substation. Purchase these transformers with controls located 84 inches above grade or with submersible rated control cabinets and submersible cable connectors for ancillary equipment. Some lower mounted fans will be destroyed during a flood event.
- Replace the two 34.5kV high side breakers with CS and relocate them to the area of the relocated transformers. The CS shall be specified with the control box mounted as high as possible above grade.
- Install 15kV underground cables from transformers T2 and T4 to the new metal-clad switchgear located in the building.
- Extend the two 34.5kV overhead supply lines to the new transformer location.
- Install 15kV getaway cables from the switchgear to each feeder riser pole.
- Relocate the existing capacitor banks to an area closer to the building and install 15kV cables from the switchgear to each capacitor bank.

3.3.Pawtuxet Substation

3.3.1. Recommended Option: Retire the Substation

The recommended plan is to retire the Pawtuxet substation site and re-supply the load from other area substations. The recommended plan is the least cost option and is in-line with the long-term plan for this area to reduce this 4.16kV pocket of distribution load and to continue to expand the 12.47kV distribution system. The scope of this work includes:

- Convert a portion of the Pawtuxet 4.16kV load to the area 12.47kV system and supply the remainder of the load from Lakewood substation.
- Remove and retire the existing Pawtuxet substation.

3.3.1.1. Conceptual Cost

$0.70 million

3.3.1.2. Conceptual Milestone Schedule

Final Design – July2012

Construction Start – October 2012

Construction Finish – October 2013

3.3.2. Alternatives

3.3.2.1. Alternative 1: Elevate the Substation Equipment at Risk

This alternative would elevate the substation equipment at risk. This alternative is not recommended due to its higher cost and because it is not in-line with the long-term plan for this area to continue the expansion the 12.47kV system. The conceptual estimate for this option is

$2.20 million and offers no benefit over the recommended plan. The scope of this work would include:

- Install an outdoor MCSPC located on an elevated foundation with a steel stairway and work platform with rails. Install the MCSPC in a new location nearby. This option would require researching land availability to accommodate this construction.
- Install open bus from the transformer to the MCSPC.
- Replace the transformer with a 5 MVA, LTC type with the control cabinet mounted 90 inches above grade.

3.4. Pontiac Substation

3.4.1. Recommended Option: Elevate the Substation Equipment at risk

The recommended plan is to elevate the substation equipment at risk. This is the least cost option and has the following scope of work:

- Design and procure spare control panels, base control for LTC, and LTC control for transformers T1 and T2 to enable retrofit in event of flood conditions that impact the controls.
- Replace three Bay C vacuum breakers with VSA reclosers mounted with the control cabinets as high as possible without raising the foundations.
- Move the fan control cable junction box to a level of 66 inches above grade and replace the control cables to the fans.

- Raise equipment within the control house, such as the batteries and some relays, as required to be out of the flood zone.

3.4.1.1. Conceptual Cost

$2.30 million

3.4.1.2. Conceptual Milestone Schedule

Final Design – March 2014

Construction Start – June 2014

Construction Finish – December 2015

3.4.2. Alternatives

3.4.2.1. Alternative 1: Relocate Substation

The relocation of Pontiac substation is not recommended. Land availability with proximity to 12.47kV and 115kV facilities in the area is extremely limited and the cost to relocate this station would be much higher than the recommended plan.

3.5. Warwick Mall Substation

3.5.1. Recommended Option: Retire Substation

The recommended plan is to retire the Warwick Mall substation site and re-supply the load from other area substations. The scope of this work includes:

- Install a new feeder at Pontiac substation to provide capacity to supply the Warwick Mall substation load.
- Remove and retire the existing Warwick Mall substation

3.5.1.1. Conceptual Cost

$1.60 million

3.5.1.2. Conceptual Milestone Schedule

Final Design – March 2014

Construction Start – June 2014

Construction Finish – December 2015

3.5.2. Alternatives

3.5.2.1. Alternative 1: Elevate the Substation Equipment at risk

This alternative would elevate the substation equipment at risk. This alternative is not recommended because it is not in-line with future area system plans to reduce load on the highly utilized 23kV supply system. The scope of this work would include:

- Replace existing reclosers 28F1 and 28F2 with VSA reclosers and Form 6 controls.
- Raise the 28F2 regulator control cabinet as high as possible above grade.
- Raise both regulator by-pass switches for worker safety clearance.
- Install (2) new galvanized steel frame raising kits to raise the regulator by-pass switches.
- Design and procure spare control cabinets for transformer T1 and T2 control cabinets to enable retrofit in the event of a flood conditions impacting the controls.
- Raise the T1 and T2 grounding CTs as high as possible above grade.
- Raise the AC distribution panels as high as possible above grade.

- Raise the motor operators on the 2266 and 2230 air-break switches as high as possible above grade.

3.6. Hunt River Substation

3.6.1. Recommended Option: Retire Substation

The recommended plan is to retire the Hunt River substation site and re-supply the load from other area substations. The scope of this work includes:

- Install a new feeder at Kent County substation to provide capacity to supply the Hunt River substation load.
- Remove and retire the existing Hunt River substation.

3.6.1.1. Conceptual Cost

$0.70 million

3.6.1.2. Conceptual Milestone Schedule

Final Design – February 2015

Construction Start – May 2015

Construction Finish – December 2016

3.6.2. Alternatives

3.6.2.1. Alternative 1: Elevate Substation Equipment at Risk

This alternative would elevate the substation equipment at risk. This alternative is not recommended because it is not in-line with future area system plans and does not address asset condition issues. The scope of work would include:

- Replace existing recloser 40F1 with a VSA recloser and Form 6 controls.
- Raise the 40F1 regulator control cabinets to 42 inches above grade.
- Install a new foundation for 40F1 located on the centerline of the bay to meet electrical clearances.
- Replace the outdoor cabinet housing the RTU with larger one in order to raise other misc equipment inside to 30 inches above grade.
- Install a shelf in existing battery cabinet and move batteries to higher level 30 inches above grade.
- Raise the motor operators on the 3312 and 84T3 air-break switches to 42 inches above grade.
- Design and procure spare control cabinets for transformer T1 and T2 control cabinets to enable retrofit in the event of a flood conditions impacting the controls.
- Raise the transformer ground CT to as high as possible above grade.

3.7. Hope Substation

3.7.1. Recommended Option: Elevate Substation Equipment at Risk

The recommended plan is to elevate the substation equipment at risk. The scope of this work includes:

- Replace the control house with a prefabricated house with all relays and controls installed and wired. Install the new control house 52 inches above grade on elevated piers.

3.7.1.1. Conceptual Cost

$1.10 million

3.7.1.2. Conceptual Milestone Schedule

Final Design – March 2014

Construction Start – June 2014

Construction Finish – June 2015

3.7.2. Alternatives

3.7.2.1. Alternative 1: Replace Substation

Replacing Hope substation is not recommended because of the significantly higher cost over the recommended plan.

3.8. Riverside Substation

3.8.1. Recommended Option: Elevate the Substation Equipment at Risk

The recommended plan is to elevate the substation equipment at risk and addresses asset condition of 115kV circuit breakers, including:

- Design and procure spare control panels, base control for LTC, and LTC control for T1 and T2 to enable retrofit in event of flood conditions that impact the controls.
- Replace five existing 115kV Oil Circuit Breakers (OCBs) in 2014 as part of the Company's Circuit Breaker Replacement Program which will address asset condition issues and existing 115kV OCB mechanisms that are prone to flood conditions of 2.5 feet or more. New breakers would be relocated out of the flood plain.

3.8.1.1. Conceptual Cost

$0.5 million

3.8.1.2. Conceptual Milestone Schedule

Final Design – January 2013

Construction Start – June 2013

Construction Finish – October 2013

3.8.2. Alternatives

No alternatives were considered because of existing asset condition issues at this station. The asset condition solution will also address the flood issues at the Riverside substation.

3.9. South Aquidneck[4]

3.9.1. Recommended Option: No Action

The 23kV structure at South Aquidneck substation is located at the lowest yard elevation. The transformer and metalclad equipment is located at an elevation approximately 2 feet higher than the 23kV structure. Equipment components in the 23kV portion of the switchyard are manual devices and are located 3.5 ft above the base flood elevation. As a result of the limited risk to the transformer and metalclad equipment, no action is recommended at this station.

3.9.1.1. Conceptual Cost

Not Applicable

3.9.1.2. Conceptual Milestone Schedule

[4] South Aquidneck substation was not impacted in the March 2010 flood but was identified in the Flood Risk Assessment.

Not Applicable

3.9.2. Alternatives

Not Applicable

3.10. Jepson[5]

3.10.1. Recommended Option: No Action

The 69kV switchyard at the Jepson substation is 1.8 feet above base flood elevation and is the lowest elevation in the switchyard. Equipment components at risk such as circuit breaker mechanisms are 3 feet above the base flood elevation. In addition, a concrete berm exists around the 69kV yard as a flood protection barrier. As a result, no action is recommended at this substation.

3.10.1.1. Conceptual Cost

Not Applicable

3.10.1.2. Conceptual Milestone Schedule

Not Applicable

3.10.2. Alternatives

Not Applicable

3.11. Hope Valley Substation[6]

3.11.1. Recommended Option: No Action

[5] Jepson substation was not impacted in the March 2010 flood but was identified in the Flood Risk Assessment.
[6] Hope Valley substation was not impacted in the March 2010 flood but was identified in the Flood Risk Assessment.

The 34.5 and 12.47kV yard at the Hope Valley substation is 1.2 feet above base flood elevation. Equipment components at risk such as the air break motor mechanisms are 3.5 feet above the base flood elevation. Additionally, Hope Valley has one 12.47kV feeder which can be resupplied via other alternate 12.47 circuits in the area. As a result, no action is recommended at this substation.

3.11.1.1. Conceptual Cost

Not Applicable

3.11.1.2. Conceptual Milestone Schedule

Not Applicable

3.11.2. Alternatives

Not Applicable

4. Summary

Based on the effects of the floods experienced in 2010 and the Risk Assessment conducted in and completed in 2011, the plan to address at risk substations currently in service in Rhode Island was developed. The plan is comprehensive in that it addresses flood issues as well as asset condition and capacity concerns to optimize expenditures to improve the network. Table 3 provides a summary of the total costs by year through 2017, along with proposed construction milestones. The Company's substation design criteria for future substation locations outlines requirements to avoid location of new substations in flood zone areas, design equipment elevations a minimum of 24 inches above 100-year flood elevation, and consider substation relocation out of flood areas for major rebuild/ upgrade projects.

Table 3: Flood Projects - Proposed Fiscal Year Cash Flow & Milestones

	PROJECTED TOTAL SPEND BY FISCAL YEAR ($M)						Final Design	Contruction Start	Contruction Finish
STATION	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**TOTAL**			
Sockanosett	$0.12	$0.40	$2.30	$2.30		$5.12	Mar-14	Jun-14	Nov-15
Westerly	$0.10	$1.00	$6.00	$3.80		$10.90	Feb-14	May-14	Jun-15
Pawtuxet	$0.25	$0.45				$0.70	Jun-12	Oct-12	Oct-13
Pontiac	$0.05	$0.25	$1.00	$1.00		$2.30	Mar-14	Jun-14	Dec-15
Warwick Mall	$0.05	$0.15	$0.70	$0.70		$1.60	Mar-14	Jun-14	Dec-15
Hunt River			$0.10	$0.30	$0.30	$0.70	Feb-15	May-15	Dec-16
Hope	$0.02	$0.10	$0.68	$0.30		$1.10	Mar-14	Jun-14	Jun-15
Riverside	$0.10	$0.40				$0.50	Jan-13	Jun-13	Oct-13
Total	**$0.69**	**$2.75**	**$10.78**	**$8.40**	**$0.30**	**$22.92**			

Narragansett Electric Infrastructure, Safety and Reliability Plan (ISR)
Vegetation Management Program and Inspection and Maintenance Program

In the Rhode Island Public Utilities Commission's (the "Commission") Report and Order issued on May 3, 2012 on National Grid's[1] 2013 Electric Infrastructure, Safety and Reliability ("ISR") Plan, which was approved by the Commission effective March 29, 2012 pursuant to an Open Meeting decision, the Commission directed the Company to collaborate with the Division to develop a method by which the costs and benefits of the Vegetation Management Program and Inspection and Maintenance Program will be tracked and reported in future ISR filings.[2]

National Grid met with the Division and its consultant, Mr. Gregory Booth on June 15, 2012 to collaboratively develop a method for the tracking and reporting of costs and benefits for both the Vegetation Management and Inspection and Maintenance programs. The description for each program outlined below contains the method by which the costs and benefits will be tracked and reported, and the frequency for which the reporting will occur. Both the methods and frequency below were agreed to by both National Grid and the Division.

Method for Tracking and Reporting Costs and Benefits

1. **Vegetation Management Program**
    a. Reliability Cost Benefit
        i. The Company will quantify the reliability benefits for both the Enhanced Hazard Tree Mitigation (EHTM) Program and the Cycle Pruning Program on a fiscal year basis. The EHTM Program is a targeted reliability program and, as such, the primary benefits are to reliability. The Cycle Pruning Program is primarily driven by public safety, but may provide secondary reliability benefits. The method for calculating the reliability benefit is as follows:
            1. The average number of tree-related Customers Interrupted (CI) for the three-year period prior to the project year will be used as a baseline.
            2. The standard deviation for the baseline three-year average will be provided.
            3. The project year will be excluded from the analysis.
            4. Tree-related CI will be calculated for the first full year post project, and additional years will be added as available.

---

[1] The Narragansett Electric Company d/b/a National Grid (referred to herein as "National Grid" or the "Company")
[2] Docket No. 4307, Report and Order, page 16.

5. Benefits will be determined by comparing the pre-project tree related CI against the post-project tree-related CI. Percent improvement by individual circuit, for the total annual work plan, and a running average percent improvement for all circuits completed in the program will be calculated.
6. Costs by feeder will be used to calculate a cost per change in CI
7. This analysis will be provided each year in the August 1 Annual Reconciliation Filing.

b. Damage Restoration Cost Benefit
   i. Actual damage restoration costs data is not available by interruption cause. The Company will use a manual process to track tree-related interruptions and provide estimated costs of restoration for all EHTM circuits. The method for calculating the cost/benefit is as follows:
   ii.
      1. The average number of tree-related Customers Interrupted (CI) for the three-year period prior to the project year will be used as a baseline
      2. The number of broken poles, broken crossarms and fuse trips that occur on three-phase sections of the circuit due to tree contacts will be summarized using data in the Outage Management System (OMS).
      3. Estimates will be generated for replacing poles, crossarms, and re-fusing on all three-phase circuit sections.
      4. An estimated cost of restoration will be developed for each three-phase interruption event, and all event costs for the three-year period will be summarized.
      5. The project year will be excluded from the analysis.
      6. Tree-related CI will be calculated for the first full year post project.
      7. Estimated costs of restoration will be developed for all tree interruptions during the post-project period.
      8. Pre- and post-project restoration costs will be compared to determine the improvement percentage.
      9. This analysis will be provided each year in the August 1 Annual Reconciliation Filing.

2. **Inspection & Maintenance Program:** The Inspection and Maintenance Program is primarily a safety and asset condition program, not a targeted reliability program. Secondary benefits may be seen in reliability. The method for calculating the safety and reliability cost/benefit is as follows:
    a. Safety Benefits
        i. The Company will track and report the following in its quarterly updates:
            1. Number of Items Corrected
            2. Number of Items Remaining in the Backlog
            3. Number of Elevated Voltage Instances Corrected
    b. Reliability Cost Benefit
        i. The Company will quantify the reliability benefits for the Inspection and Maintenance Program on a fiscal year basis.
            1. The average number of Customers Interrupted (CI) for applicable cause codes (deterioration and lightning) during the three-year period prior to the project year will be used as a baseline
            2. The standard deviation for the baseline three-year average will be provided.
            3. The project year will be excluded from the analysis.
            4. Related CI will be calculated for the first full year post project, and additional years will be added as available.
            5. Benefits will be determined by comparing the pre-project related CI against the post-project related CI. Percent improvement by individual circuit, for the total annual work plan, and a running average percent improvement for all circuits completed in the program will be calculated.
            6. Costs by feeder will be used to calculate a cost per change in CI.
            7. This analysis will be provided each year in the August 1 Annual Reconciliation Filing.

National Grid's initial report on the reliability cost benefit and damage restoration cost benefit of the Vegetation Management program using the method described above will be for the FY2011 program, and will be provided in August 2012 with the Company's Annual Reconciliation Filing. National Grid's initial report on the reliability cost benefit of the Inspection & Maintenance program using the method described above will be for the FY2013 program, which is the first year of the program, and will be provided in August 2014 with the Company's Annual Reconciliation Filing. Reports on the Safety benefits for the Inspection & Maintenance program, as described above, will start with the FY2013 program, and will be provided in the FY2013 quarterly reports.