STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

DIVISION DOCKET NO. D-17-45

REVIEW OF

National Grid Storm Preparedness and Restoration Efforts Related to the Storm of October 29-30, 2017

Prepared By:

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March 14, 2018

STATE OF RHODE ISLAND
DIVISION OF PUBLIC UTILITIES AND CARRIERS
WARWICK, RHODE ISLAND

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I hereby certify this document was prepared by me or under my direct supervision. I also certify I am a duly registered professional engineer under the laws of the State of Rhode Island, Registration No. 8078.

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I. INTRODUCTION

On October 29-30, 2017, a weather event impacted Rhode Island causing a significant amount of tree damage and leaving a major portion of the State without power. The State's primary electric distribution company, the Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company"), worked to restore power, although many customers remained without power for several days. The complexity of the restoration process was compounded by conflicting outage report data provided to customers by National Grid which added to the confusion of a prolonged power outage. Subsequently, the State of Rhode Island Division of Public Utilities and Carriers ("Division") opened an investigation under Division Docket No. D-17-45 – Review of National Grid (Narragansett Electric Company) Storm Preparedness and Restoration Efforts Related to the Storm of October 29-30, 2017. On November 16, 2017, PowerServices, Inc. ("PowerServices") was engaged by the Division to review National Grid's storm preparedness and the utility's effectiveness in its efforts to restore power to its customers in the State. PowerServices assigned a team of engineers and management staff with extensive utility experience, including leading storm restoration responses to major storm events and hurricanes on the East Coast. PowerServices' role was to conduct a review of events and an assessment of National Grid's storm preparedness and restoration efforts, including pre-storm planning and staging, public communications, mobilization and restoration, and conformance with the Company's Electric Emergency Plan. PowerServices assessed the Company's performance as compared to area utilities also impacted by the Storm, and analyzed the potential benefits of Advanced Metering Infrastructure ("AMI") in storm restoration efforts. The result is this written report provided to the Division with our findings and evaluation, including recommendations for improvements, as may be needed, to National Grid's preparedness and storm response efforts. Our findings, conclusions, and recommendations are contained in this report. Additionally, PowerServices is available to present its findings, if requested.

II. REPORT

A. Background

PowerServices relied on multiple sources of data in the evaluation of National Grid's storm preparedness and response to the October 29–30, 2017 storm ("Storm"). A team of engineers and managers, including those with direct experience in storm response, conducted both field and data assessments to determine the Company's storm planning and restoration effectiveness. The following actions were taken by PowerServices in performing this review:

- On November 21, 2017, PowerServices initiated discussions with the Division to coordinate a field visit which would allow PowerServices' engineers the opportunity to physically assess areas impacted by the Storm. The Division arranged a conference call with National Grid on November 30, 2017, during which a date for PowerServices' field visit was set as December 11–13, 2017. Discussions included logistics and tentative plans for a National Grid representative to accompany each PowerServices engineer, creating two separate teams for field assessment. An engineer representing the Division was also scheduled to participate in the field visit.

- On November 22, 2017, the Division issued PowerServices' First Set of Data Requests to National Grid. With the understanding that the Company would be unable to respond to key questions prior to the December 11, 2017 field visit, a subset of data requests were extracted and provided to National Grid on December 1, 2017. PowerServices advanced these key data requests with the sole purpose of facilitating a productive field visit, and requested system maps indicating outage locations, substations and transmission routes, as well as the following specific requests:
  - Transmission lines that were out and, if possible, the location of the damages to the transmission lines.
  - Any substations that were out due to a transmission issue.
  - The circuits that were out and, if possible, the major cause of the outage such as trees on the conductor, conductor down, pole broke, etc.
  - The number of customers served by each circuit.
  - The length of the outage for each of the above categories.
  - The areas that had the longest outages and, if possible, the number of customers impacted.
- On December 4, 2017, the Company responded that a portion of the key questions would be answered by December 6, 2017.
- On December 6, 2017, National Grid informed the Division that responses would take the Company a few days beyond December 6, 2017.
- On December 8, 2017, National Grid provided responses to 11 of the First Set of Data Requests. Excluded from the responses were system maps and outage data specifically requested by PowerServices' in advance of the field visit.
- On December 11, 2017 the Division contacted National Grid to confirm PowerServices' kick-off meeting scheduled for December 12, 2017 at the Company's Melrose office, and emphasized the need to have pre-requisite data

provided. The Company responded that the field teams were prepared and National Grid crews would be able to point out things out to the Division and PowerServices during field visits.

- PowerServices' engineering team and a Division engineer met with National Grid the morning of December 12, 2017. Two teams were assembled to separately ride the service area and observe circuits impacted by the Storm. PowerServices assessed and documented field conditions, noting items such as areas affected by downed trees, line and pole conditions, and signs of deteriorated equipment. At that time, National Grid had not released service area maps or any outage information to PowerServices that identified which circuits were impacted or visited during the field assessment. This complicated PowerServices' documentation efforts and added time to the process.
- On December 13, 2017, National Grid responded to a subsequent portion of the First Set of Data Requests which included confidential information. PowerServices was inadvertently left off of the Service List, and did not receive the responses until January 10, 2017.
- On January 12, 2018, National Grid provided the remaining responses to the First Set of Data Requests. Several confidential attachments were separately sent to the Service List on CD-ROM. PowerServices received those attachments on January 24, 2017.
- On January 24–30, 2017, PowerServices reviewed the data request responses, including the confidential set of maps provided by the Company in response to PowerServices' repeated requests for actual copies of maps used for the December 12, 2017 field visit, which identified each area our engineers evaluated. The maps,

however, did not include any references to circuits impacted by the Storm, nor did the Company indicate the areas assessed during the field evaluation.

- On January 31, 2017, the Company was notified of the deficiencies, and PowerServices requested the Company re-submit several data request responses in executable format.
- On February 1, 2017, the Company provided one data request response in executable format and stated that for the production of subsequent responses it would be overly burdensome for National Grid to recreate the materials in the requested format. In addition, the Company provided a "tie map" used during the field visit, and on February 2, 2017, the Company indicated that "more granular" maps would be overnighted to PowerServices.
- On February 5, 2017, PowerServices received and reviewed additional maps provided by the Company, and again concluded that National Grid was deficient in providing the requested information. All maps received failed to indicate outage information or the specific areas observed during the field visit as guided by the Company's representatives. The Company provided no explanation for the excessive delay in providing the maps, nor did they make an attempt to include key information that would aid in cross-referencing the field visit notes to impacted circuits. A timelier submittal with requested information would have enabled a more productive evaluation.

Beyond direct requests for data from the Company, PowerServices obtained information from other utilities affected by the Storm. We researched available data, including National Weather Service reports related to the Storm as it formed in the Northeastern United States. We compared the statistical performance of National

Grid to other utilities affected by the Storm, including wind speeds, customer outages, and restoration time. We reviewed National Grid's social media accounts and compared the Company's communications, both before and during the Storm, to actual progress achieved in the field. We discussed restoration with field personnel during the December 12-13, 2017 visit. On February 1, 2018, the Company filed a *Report on October 29-30, 2017 Event, Damage Assessment, and Service Restoration* under Docket No. 2509 ("Summary Report"). This filing is directed by Order No. 20814, which requires the Company to provide a written report to the Division within 90 days following a major storm event. While our report references portions of the Company's Summary Report, our analysis relies on the detailed responses provided by the Company through formal data requests, which were far more comprehensive than the information supplied in the Summary Report. A full list of resources utilized by PowerServices in this evaluation is provided in Appendix A.

It is important to highlight that, in addition to the delayed and deficient map information, the Company took nearly two months to fully respond to PowerServices' November 22, 2017 data request. The Company specifically withheld key information; submitting data as late as February 1, 2018. Among the last responses provided were details regarding outages. Specifically, data Request R-I-9 asked the Company to provide the attributes of the impacted circuits, cause of outages, crew dispatch sequence, and restoration times. This core information is used to gauge effectiveness in preparing for, and executing a restoration plan. It is critical in evaluating a utility's storm response activities and is available upon system restoration, yet the Company did not provide the data until almost three months after the Storm. Rather than attempting to extract information in usable formats, the

Company provided hundreds of pages in Adobe Acrobat, which required manual analysis. PowerServices is particularly concerned that the Company did not make a more concerted effort to provide usable information in a timely manner. At a minimum, outage information and maps that correlated to PowerServices' field evaluation on December 12, 2017 could have been provided at the time of the field visit. National Grid's severe delays in producing data can only be interpreted as an effort to create barriers to the investigation. We believe the Company was delaying and impeding the process to enable the Company to complete its own report prior to the completion of the PowerServices report.

Furthermore, PowerServices observed that the Company's report on its planning and restoration activities filed on February 1, 2018 barely meets the minimum requirements of what we would consider an adequate storm summary. The Company incorporated very little detail in their report, and made minimal attempts to identify planning and restoration issues that arose from the Storm. Given that the Company is allotted 90 days to submit the report, more information should have been supplied. In comparing the Company's report to Eversource Connecticut's storm report, we find that Eversource Connecticut was able to produce a far superior report by November 16, 2017, or about two weeks after the storm. This additionally contributes to our overarching concern that the Company was extremely slow to provide responses to our data requests when we believe, like most utilities, the information requested was readily available immediately after the Storm.

PowerServices' evaluation of National Grid's storm preparedness and response follows the Storm's timeline and the Company's progression of actions: Pre-Storm,

Storm Onset, and Post-Storm. Within each category, PowerServices examines National Grid's actions and results as compared to prudent utility practices, the Company's Emergency Response Plan ("ERP"), and, where applicable, available data from other utilities affected by the Storm. An assessment of the Company's communication efforts is provided in Section II.F., along with a discussion of the potential benefits of Advanced Metering Infrastructure ("AMI") during storm events. Our report is organized to address each category, and includes a summary of key findings and recommendations.

B. Pre-Storm

1. Weather Predictions

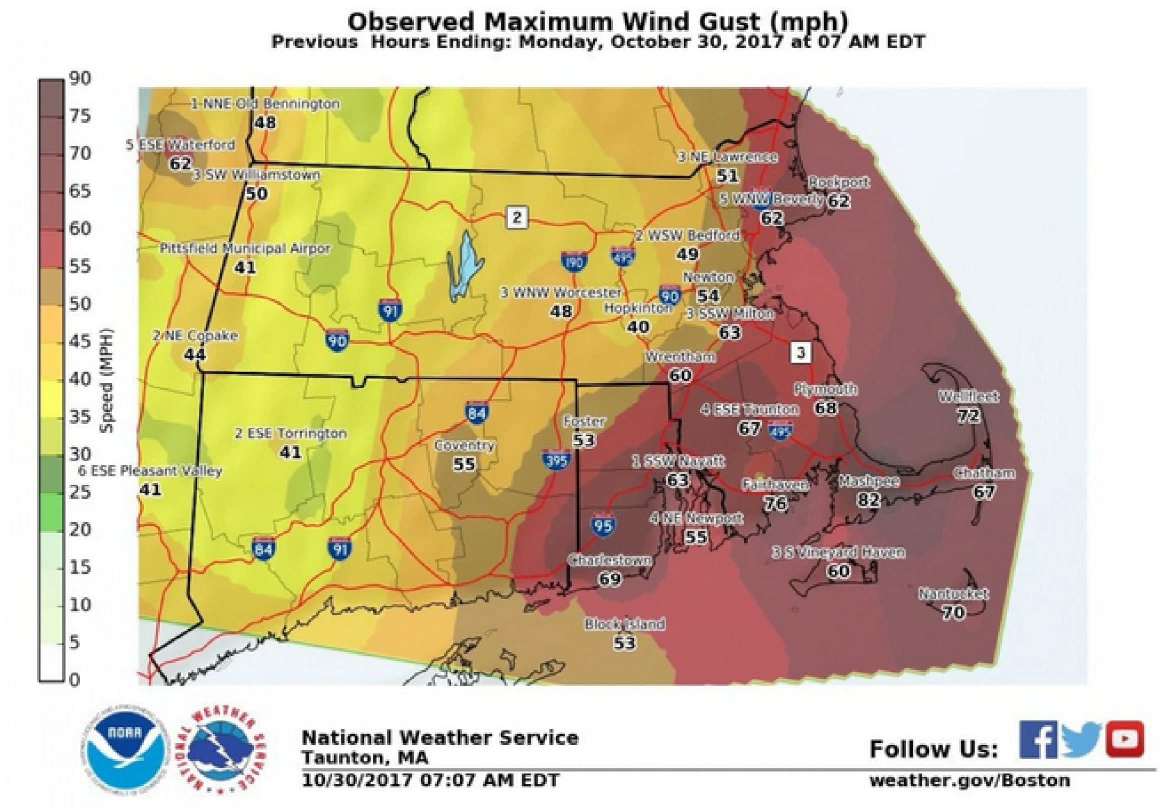
Key Findings: *National Grid's weather forecasting service, as well as several other weather services, underestimated the Storm's severity. Every Utility examined that was impacted by the Storm (National Grid-Rhode Island, Eversource-Connecticut, National Grid-Massachusetts, Eversource–Massachusetts, Emera-Maine, and Central Main Power-Maine) anticipated a less severe storm and planned on less damage, fewer outages and shorter restoration times than actually occurred.*

Recommendation*: The Company should supplement its weather forecasting service with additional tools. The Company should provide a comprehensive update on the Damage Prediction Modeling tool that was to be implemented in Massachusetts in 2013, and subsequently scheduled for Rhode Island.*

The Storm impacting the Northeast was not a traditional slow-moving tropical storm or hurricane that tracks the East Coast and develops over a period of weeks. It was a low-pressure system moving in from the Great Lakes region that drew moisture from the remnants of Tropical Storm Philippe. The result was a rapidly intensifying event described as a "weather bomb", or an event which atmospheric pressure drops quickly causing extremely high winds. Although October 26-27, 2017 weather service forecasts examined by PowerServices indicated a high confidence in an impactful system occurring on Sunday, October 29, 2017 and also Monday, October 30, 2017, the intensity and duration of the Storm was unknown at that time. National Grid utilizes DTN as their primary weather forecasting service company, as does Eversource. DTN initially anticipated that Rhode Island winds would exceed 30 mph, with gusts exceeding 35 mph. On Saturday, October 28, 2017, DTN revised the forecast calling for higher winds and on Sunday, October 29, 2017, the weather service called for peak wind gusts of 45-50 mph in most Rhode Island regions with gusts up to 60 mph along the coast. Moderate to heavy rain was also expected. According to DTN forecasters, there was a 5% chance of an Energy Event Index ("EEI") Category 4 and no chance for an EEI Category 5. An EEI Category 4 has wind speeds >= 60 mph with gusts >= 65 mph. An EEI Category 5 has wind speeds >= 70 mph with gusts >= 75 mph. DTN's forecast revisions for higher winds than originally anticipated were similar to those issued by weather services utilized by other Northeastern utilities. Overall, weather updates leading up to the Storm's arrival predicted sustained winds of 20-30 mph with wind gusts of 45-55 mph, and peak gusts to 55-65 mph to coastal areas of New England. [Response R-I-4, pp. 23-24] The forecast from DTN on Sunday, October 29, 2017 at 2:40 p.m. continued to reflect previous information, but that some gusts may increase by 5 mph and reach 70 mph on the coast. [Response Attachment R-I-4-2]

Once the Storm unleashed Sunday evening through Monday, actual wind speeds in Rhode Island reached 45-70 mph, followed by a second wind event, with wind gusts of 40-55 mph. Rainfall measured 1.5 to 5.0 inches. The Northeast, in general, experienced 40-60 mph inland and 60-80 mph in coastal regions.

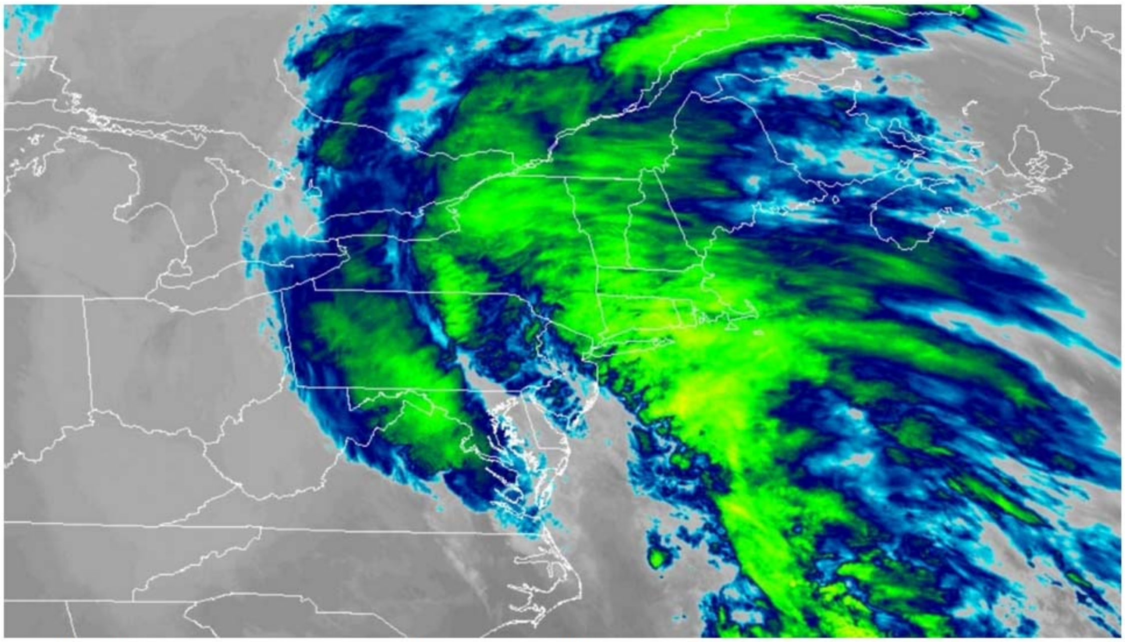
<u>Figure 1</u>



Peak wind gusts in southern New England. (National Weather Service)

Source: https://www.washingtonpost.com/news/capital-weather-gang/wp/2017/10/30/over-one-million-power-outages-in-the-northeast-after-blockbuster-fall-storm/

Figure 2



GOES-16 satellite view of storm Sunday evening. (CIRA-Colorado State/NOAA)

Source: https://www.washingtonpost.com/news/capital-weather-gang/wp/2017/10/30/over-one-million-power-outages-in-the-northeast-after-blockbuster-fall-storm/

The Storm's impact caused over 1.5 million power outages in multiple states; the most since Hurricane Sandy in 2012. High winds toppled trees, downed branches, snapped power poles, and caused widespread damage to electric systems. Some of the hardest hit states were Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and Maine. Utilities reported power outages beginning the night of Sunday, October 29, 2017, with peak outages occurring Monday, October 30, 2017. National Grid in Rhode Island reported 144,144 outages at peak, or 29% of customers, and 176,247 total outages.

The key finding from our analysis of weather predictions as compared to the actual event is that the Storm's severity was underestimated by National Grid's weather forecasting service, as well as several other weather services reviewed. PowerServices' examination of many impacted utilities that have produced reports or data (National Grid-Rhode Island, Eversource-Connecticut, National Grid-Massachusetts, Eversource–Massachusetts, Emera-Maine, and Central Main Power-Maine) showed that every utility anticipated a less severe storm and planned on less damage, fewer outages and shorter restoration times than actually occurred. Although the utilities adjusted their emergency plans as the weather prediction called for intensified storms, none pre-planned for the actual severity experienced.

The prevalence of inaccurate weather predictions and inadequate storm planning prior to the event has less weighting on our review when compared to National Grid's decisions and adjustments at the moment the Company realized that the Storm's severity was greater than anticipated. PowerServices' analysis focused on the Company's actions or inactions once the weather services increased the probability of higher wind speeds leading up to the Storm, and subsequent actions or inactions that the Company took in the midst of the Storm when outages exceeded predicted levels.

2. Storm Classification & Pre-Planning

Key Findings: *Leading up to the Storm, National Grid relied on its weather forecasting service and planned for an ERP Type 4 event, or up to 3% of customers out with restoration within 24 hours. National Grid appropriately followed ERP guidelines for a Type 4 event in pre-planning efforts, including weather monitoring, branch emergency staff activation, briefing calls, public information, and crew levels and assignments. However, National Grid was not adequately prepared for the Storm, which was more intense than anticipated, and did not make adjustments until the Storm was organized.*

Recommendation: *The Company should develop a mechanism within its ERP that outlines a means to rapidly adjust the ERP incident classification based on actual system impacts resulting from quickly changing weather patterns that increase in severity. The Company would also benefit from a review of the incident classifications and should adjust the ranges of expected customer interruptions used to determine event Types, add metrics that account for the number of lines affected, and include a detailed matrix of planned resources and staging locations depending on storm severity.*

National Grid began monitoring the Storm on October 26, 2017 as weather models indicated possible hazard wind gust events for the Northeast. On Friday, October 27, 2017 at 10:00 a.m., the Company held a call to review the weather forecast and began planning efforts for the possibility that the Storm would impact the Rhode Island system on October 29, 2017. As storm planning commenced and varying forecasts were assessed, National Grid reported that it "followed its Emergency Response Plan for a National Grid Type 4 event, expecting that the event would impact up to 3% of the Company's customers and that restorations would be accomplished in approximately 24 hours." [R-I-1, p. 3]. This plan remained consistent throughout the pre-event calls Saturday, October 28, 2017 and Sunday, October 29, 2017, both at 1:00 p.m. Based on the outcome of the calls, the Company "contacted its employees with storm assignments or operational responsibilities and apprised them of the need to report for storm assignments." [Response R-I-1, p. 3] The Company's Emergency Response Plan (pp. 36-44) indicates the following:

Event Type	Customer Interruptions	Customer Interruptions	Expected Restoration Time
Type 5	0% - 2%	9,839	Within 1 Operational Shift
Type 4	0% - 3%	14,759	Less than 24 Hours
Type 3	Up to 9%	44,276	Within 72 Hours
Type 2	Up to 30%	147,587	Within 1 Week
Type 1	Up to 100%	491,958	> 7 Days

Based on the Company's 491,958 total customers served[1], a Type 4 event implies that National Grid expected up to 14,759 customer interruptions, and that restoration would be complete within 24 hours.

The Company performed pre-storm activities in anticipation of an ERP Type 4 event. National Grid reported that in "accordance with the Emergency Response Plan and anticipated a National Grid Type 4 event, the Company activated the Branch Level Emergency Response Organization prior to the first Pre-Event Stage Briefing Call on Saturday, October 28, 2017 at 1:00 p.m. At that time, the Company planned to staff its Rhode Island branch in Providence on Sunday, October 30, 2017 at 6:00 p.m., and began appointing a branch level Emergency Response Organization structure for that location." [Response R-I-1, pp. 3-4]

A summary of pertinent activities documented on Pre-Event meeting notes of Company Staff for New England Operations (i.e. Massachusetts and Rhode Island) for October 28–29, 2017 from Response R-I-6 are as follows:

- Saturday, October 28, 2017 1:00 p.m.
  - Reviewed weather forecast
  - NE States Incident Commander stated Company is responding to a Type 4 event

[1] National Grid Electric ISR Plan FY 2019 Proposal, Section 2, page 1

- Staffing and shift requirements as set forth by Incident Commander
- Storm Room opened in Providence
- Control Center increased staffing numbers for this event
- Life Support and Critical Customers notifications were sent out
- Branch Director Update (Providence and North Kingston):
  - 14 overhead crews, 10 tree crews, and 10 troubleshooters
- Forestry: all requests have been fulfilled (specifics not specified); additional forestry staff will be ready Monday AM
- Storm Rooms/ETR management:
  - No exceptions from yesterday's plan
  - Per IS, phone upgrade plans have been successful, testing has been done and will continue
- Logistics: All set, no exceptions
- External Line Resources:
  - Secured 25 contractor crews, will be staged out of Marlboro, MA (for National Grid but not specifically Rhode Island, ready at 6am Monday
  - 4 COC OH crews will be staged at Jefferson Blvd, RI
- Transmission: no representation in RI, teams only stationed in MA
- Regulatory Liaison: Informed the RIDPUC of plans yesterday, they expect daily updates
- Emergency Planning: requested troubleshooter details for all areas
- State Incident Commander: "We are well prepared, have the ability to move crews to eastern and coastal areas if needed"
- Next Scheduled Call-Date & Time: 10/29/17 at 1pm – Final sanity check on the forecast

* Sunday, October 29, 2017 1:00 p.m.

- Reviewed weather forecast
- NE States Incident Commander stated Company is responding to a Type 4 event
  - Initial focus will be on 911 and Wires Down
  - "Restoration is secondary to public safety"
  - "Focus on effective communications with customers and DPU/PUC; focus on accurate ETR's when we get into the restoration stage
  - Storm Room to be opened in Providence Sunday at 6pm
- Control Center: no exceptions from yesterday's plans
- Customer Contact Center: no exceptions from yesterday's plans
- Branch Director Update (Providence/North Kingston):
  - 14 overhead crews, 10 tree crews, and 10 troubleshooters
- Forestry: no exceptions from yesterday's plans
- Storm Rooms/ETR management: no exceptions from yesterday's plans
- Logistics: no exceptions from yesterday's plans
- External Line Resources:
  - Secured 25 contractor crews, will be staged out of Marlboro, MA (for National Grid but not specifically Rhode Island, ready at 6am Monday
  - 4 COC OH crews will be staged at Jefferson Blvd, RI
- Transmission: no representation in RI, teams only stationed in MA

- – Wires Down: ready to provide support first thing Monday morning
- – Regulatory Liaison: MADPU requested formal Pre-Event Report
- – Public Information: safety update sent out via social media
- – Emergency Planning: all set
- – State Incident Commander: "We are well prepared, have the ability to move crews to eastern and coastal areas if needed"
- – Next Scheduled Call-Date & Time: 10/30/17 at 8am – Outage status, any changes to staffing plans

The actions and assignments described in the Operations Pre-staging meetings are in line with a Type 4 event as set forth in the Company's ERP. The pre-mobilization of crews included the *planned* staffing levels are shown below in anticipation of a Type 4 event [R-1-20].

Table 1: Pre-Planning Crew Numbers

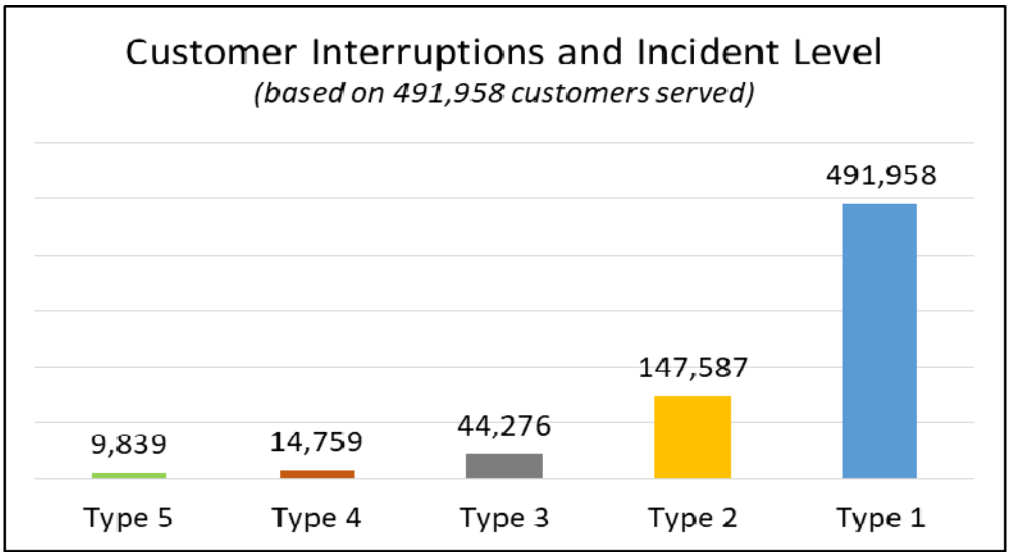
		10.29.17 17:00		10.30.17 07:00
Overhead		14 Crews		23.5 Crews
- Pager Crews		8 Crews		
Trouble Shooters		12 FTE		16 FTE
OH Contractors (COC)		0		17 Crews
Underground		5 FTE		33 FTE
O&M		4 FTE		39 FTE
Storm Room		20 FTE		35 FTE
- Supervisors		6 FTE		13 FTE
- Muni Room		0		4 FTE
- Forestry		3 FTE		7 FTE
Wires Down Room (Appraisers, Cut/Clear, Restoration)		*		23 FTE
Wires Down Field Support		*		69 FTE
Forestry		11 Crews		18 Crews
Fleet		0		15 FTE
Stores		0		12 FTE
IS Support		1 FTE		1 FTE

*Note: 10/29/2017 - Storm Room managed Wires Down with 9 FTEs from Underground & O&M

Overall, the Company's pre-planning efforts were appropriate for a Type 4 event, or a restoration effort that is expected to handle less than 10,000 customer interruptions in less than 24 hours. However, the crew levels are clearly not acceptable for a more severe storm, which the Company acknowledged by increasing resources early on October 30, 2017. We address the Company's efforts to adjust to the storm's severity and to add crews, particularly through mutual aid, throughout this report.

Our evaluation also raises questions regarding the Company's Incident Level classification within the ERP. Chart 1 below indicates the highest level of customer impacts for each event type based on the number of customers currently served by the Company.

Chart 1: ERP Incident Levels



In reviewing this chart, we note a very granular distinction between a Type 5, Type 4, and Type 3 event, or expected outages of less than 45,000 customers. The classification system then moves to the final two levels designed to handle nearly 500,000 outages. Essentially, the maximum customer interruptions from Type 3 through Type 1 events triple in each step. If the Company is planning for a low impact storm, it must categorize the response within a very narrow tolerance level, which will likely miss the mark. Conversely, if the Company underestimates impacts for more severe events, such as the case in this Storm, significant adjustments are required for a single step change in event classification. Unless the Company incorporates a method for more rapid adjustment within the ERP, the only way to fully prepare is to over-estimate storms to ensure that necessary resources are onboard.

We recommend that the Company reevaluate and refine the incident level categories in a way that reduces dramatic step increases between storm categories and provides greater planning flexibility. In addition, we find that the Company may improve storm response forecasting by using specific outage attributes when classifying events. For example, each storm classification should include parameters regarding the number of lines impacted and regions affected to appropriately plan on the type, magnitude, and location of resources required for restoration. We make this distinction since a storm that affects 2 transmission line locations and 75,000 customers is far different from a storm that results in 2,000 trouble locations impacting 75,000 customers. Currently, the Company's ERP makes global assessments of outage severity between event types which lack specificity. Moving forward, we recommend that the Company define outage metrics for each incident level. The Company should incorporate a detailed matrix of planned resources, both internal and external, required for restoration and describe whether multiple staging areas will be utilized. PowerServices is providing sample ERPs from New England utilities in Appendix D, including a detailed storm restoration matrix (*New England Utility 4*), that may be utilized by the Company as a template to improve its current resource requirements contained in the ERP as shown below (R-I-2, page 58).

<table>
<tr><th colspan="6">Typical Resource Requirements by Event Classification</th></tr>
<tr><th></th><th>Type 1</th><th>Type 2</th><th>Type 3</th><th>Type 4</th><th>Type 5</th></tr>
<tr><td>Internal Restoration Resources</td><td>Yes (All available)</td><td>Yes (All available)</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>Utility Mutual Assistance</td><td rowspan="2">Yes
~150+ line
~60+ forestry
~150+ support</td><td rowspan="2">Yes
~100+ line
~30+ forestry
~70+ support</td><td>As necessary</td><td>No</td><td>No</td></tr>
<tr><td>Contractors</td><td>Yes
~10+ line
~5+ forestry</td><td>0-15 line
0-10 forestry</td><td>No</td></tr>
<tr><td>Retirees</td><td>As Required</td><td>As Required</td><td>No</td><td>No</td><td>No</td></tr>
<tr><td>ICS Resources</td><td>Yes (Most or all at System, State and Branch Levels)</td><td>Yes (Most or all at System, State and Branch Levels)</td><td>Yes (Some or all at State and Branch Levels)</td><td>Yes (Typically only at Branch Level)</td><td>No</td></tr>
<tr><td>Support Resources</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>No</td></tr>
</table>

C. Storm Onset

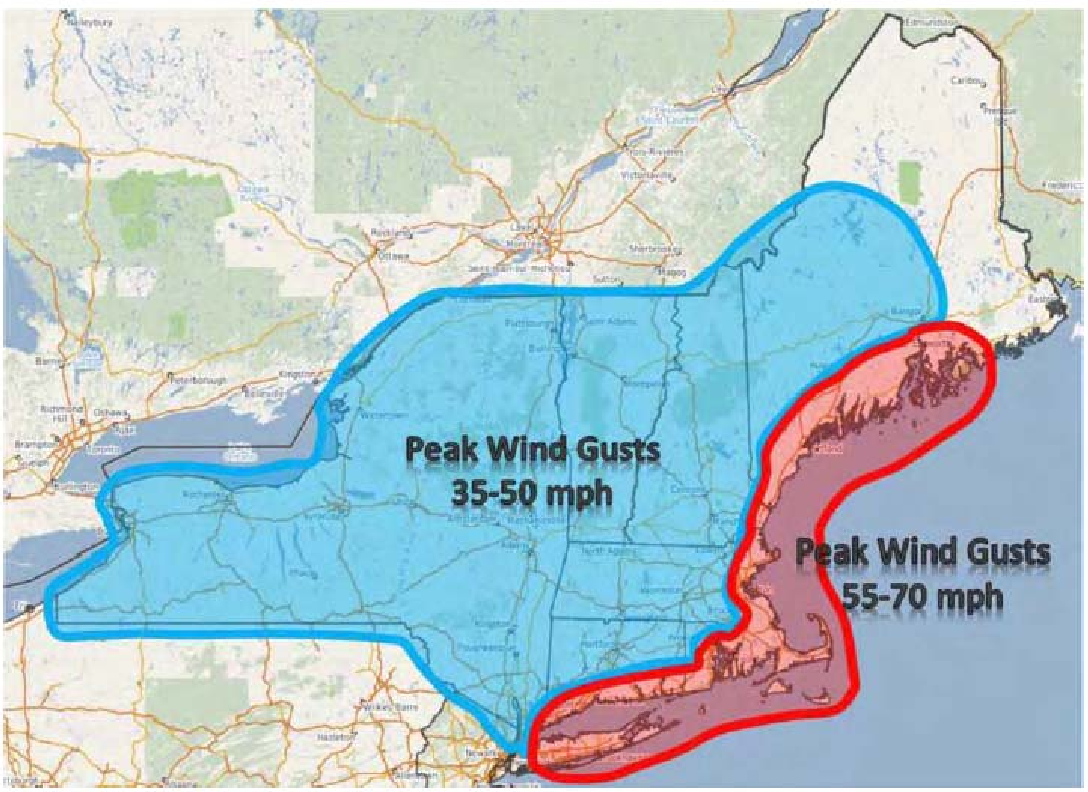
1. Storm Impacts

Key Findings: *As the Storm commenced the night of October 29, 2017, it rapidly intensified and exceeded forecasted wind speeds, impacting a larger area of National Grid's service territory than expected. Outages quickly escalated above a Type 4 Event, leaving a narrow window of time for adjustments to preparedness and resource acquisition. Northeast utilities impacted by the Storm reported similar outcomes, creating substantial need for external crews from regions beyond the Northeast and creating a multi-day restoration effort across most New England states.*

Recommendation: *National Grid should evaluate the ERP and incorporate methods to rapidly adjust when the storm event level and system impacts exceed the incident level assigned for pre-planning. See related recommendations in Section C.2.*

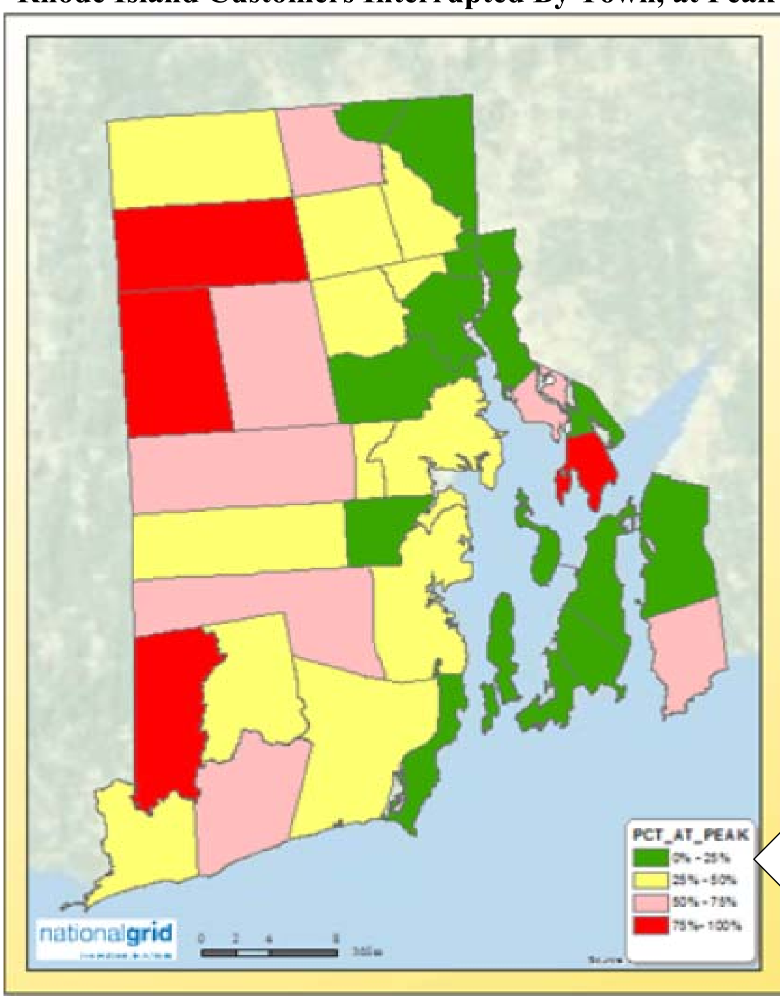
During the night of October 29, 2017, strong high winds began to impact the Northeast Coast and Rhode Island. There were two specific periods of high winds and gusts. National Grid reports that the first wind gusts occurred between 8:00 p.m. October 29, 2017, and 5:00 a.m. October 30, 2017. The second period of gusts continued throughout Monday, October 30, 2017, hampering restoration efforts due to downed trees and branches. The Company states that early Monday morning, sustained winds of approximately 60 mph and gusts of 72 mph were experienced in Warwick. [R-I-1, p. 5].

Figure 3: Weather Impact

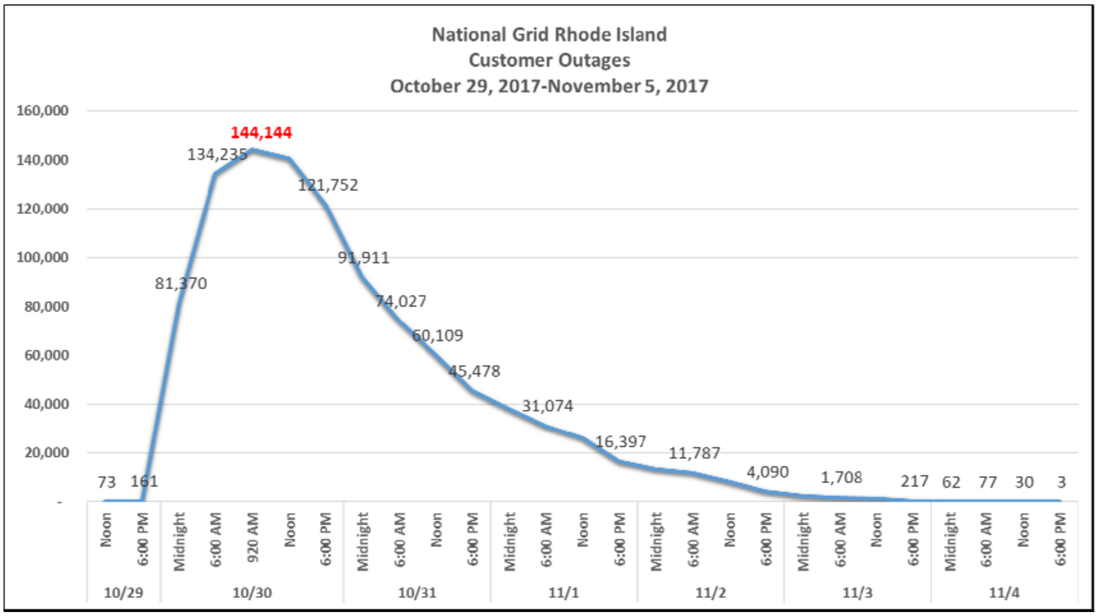


The first outages in Rhode Island were recorded between 1:00–2:00 a.m. on October 29, 2017, which were feeder-specific and cleared by 4:00 a.m. (R-I-10 data). Several smaller outages, impacting less than 300 customers at any given time, began occurring by 8:00 a.m. with significant increases beginning at 10:00 p.m. The Company reported that the Storm began "…in the late evening hours on Sunday, October 29, 2017, with 51,000 customers out-of-service in Rhode Island by approximately 11:00 p.m., and 87,000 customers out of service by midnight. At approximately 9:20 a.m. on Monday, October 30, 2017, the peak customer outages totaled 144,144." [R-I-1, p. 8]. The Company experienced interruptions in all 38 communities it serves. The following map of peak outage locations and timeline of outages reflects the rapid intensity and widespread nature of the Storm. A chart with customer outages, total customers interrupted, and restored customers is provided in Appendix B.

Rhode Island Customers Interrupted By Town, at Peak



Source: R-I-1, page 7



Source: R-I-10

The Storm impacted nearly 30% of National Grid Rhode Island customers. It created a damaging wind and rain event across a broader region of the Northeast, causing over 1.5 million outages. Many utilities faced similar or more severe weather effects than the Company, including numerous downed trees, fallen branches, and flooding that caused power outages. A review of data from several Northeastern utilities indicates that peak outages affected between 4%–66% of customers served, with the most damage occurring in coastal regions and Maine. For New Hampshire, the Storm caused the fourth largest power outage in state history[2]. Utilities across the Northeast generally report that planning adjustments and storm classification revisions were initiated at the Storm's onset, or October 30, 2017, once the unexpected severity was presented. Member utilities of the North Atlantic Mutual Assistance Group[3] ("NAMAG"), including National Grid, initiated requests for external crews, resulting in limited availability of resources. The need for mutual aid most certainly challenged

[2] http://nhpr.org/post/top-5-power-outages-new-hampshire#stream/0
[3] North Atlantic Mutual Assistance Group is a regional mutual assistance groups primarily serving northeastern states.

NAMAG's ability to fulfill requests, since a large portion of member utilities are located in the Northeast and were affected by the same Storm. Mutual aid assistance was ultimately provided from broader regions, including Canada, the Great Lakes Region, and the Southeast.

The Restoration times for each utility varied, and were as short as one day, while two major utilities in Maine, Emera and Central Maine Power, reported complete restoration on November 6 and 8, 2017, respectively. Most utilities reported significant restoration (85%–99%) within the first three days, which is typical since system components that have the highest customer impact are prioritized in a restoration plan. A table of storm metrics for National Grid Rhode Island as compared to thirteen impacted utilities is provided in Appendix C, *October 29-30 Storm: Northeast Utility Impacts and Restoration*.

2. Storm Classification Adjustments

Key Findings: *Once the severity of the Storm was understood by National Grid on October 30, 2017, the Company updated the incident level to an ERP Type 3 Event, although restoration needs were consistent with a Type 2 Event. National Grid implemented portions of restoration consistent with a Type 2 event, but never formally declared a more critical incident level. Failure to assign, communicate, and enact upon a single and appropriate storm incident level fostered restoration deficiencies.*

Recommendations: *The Company needs to assess how it should adjust its ERP to foster a proactive program of rapidly identifying and communicating, both internally and externally, the escalation of event Type. Failure to escalate the severity and event*

Type classification is one of the most serious deficiencies identified in the storm assessment process. National Grid appears to lack a free flowing and nimble communications system, and protocol which permits and encourages identification, communications, and action steps being implemented when it is clearly known within the operational ranks of the Company that a storm has become far more severe than the classification and plans have indicated. This fostered inadequate communications to the public and an overall lower level of urgency and need within the Company.

As previously outlined, National Grid anticipated and prepared for the Storm as a Type 4 event with approximately 15,000, or 3%, customer interruptions, and restoration within 24 hours. The Company monitored the impacts of the Storm, but it was not until Monday, October 30, 2017 at approximately 1:00 a.m. that the State Incident Commander elevated the response to a National Grid Type 3 event. A Type 3 event is classified as one where restoration activities are generally accomplished within a 72-hour period, and typically results in up to 9% of customers interrupted. National Grid states that the "…State Incident Commander then requested additional staff to be activated and increased the request for additional external contractor resources. Also at this time, the Company initiated mutual assistance request for 500 line crews and 210 forestry crews for all of the Company's New England response. The New England State Emergency Response Organization was activated prior to the New England State Restoration Stage Briefing Call #1 at 8:00 a.m. that day. On that 8:00 a.m. call, the Company communicated the change to a Type 3 response." [R-I-1, pp. 5-6]

Although National Grid appears to have taken swift action in reclassifying the storm event and mobilizing additional crews once actual outages escalated, their decision to change to a Type 3 response is inconsistent with the parameters of the ERP. Based on the customer interruption thresholds, the Storm should have been classified as a Type 2 event, and in actuality it nearly reached the lower threshold of a Type 1 event. The following Table 2 summarizes National Grid's event categories within the ERP, corresponding customer interruption thresholds, and actual outages. Comparing the actual outages to thresholds indicates that the Storm was a Type 2 as early as 11:00 p.m. on October 29, 2017, yet the Company only recognized a Type 3 event hours later, after crossing the Type 2 event threshold.

Table 2: Forecasted to Actual Incident Outages Summary

Incident Level	Range of Customer Interruptions		Corresponding Upper Limit of Customer Interruptions*	Actual Peak Outages / % of Customers					
				10/29/17 11:00pm		10/30/17 12:00am		10/30/17 9:20am	
Type 5	0 to	2%	9,839						
Type 4	0 to	3%	14,759						
Type 3	up to	9%	44,276						
Type 2	up to	30%	147,587	51,000	10%	87,000	18%	144,144	29%
Type 1	up to	100%	491,958						

** based on total of 491,958 customers served by National Grid in Rhode Island*

In addition, ERP guidelines for resource needs also suggest that National Grid should have considered this a Type 2 event. Specifically, resource activation for a Type 2 event as documented in the ERP indicates that the Company may:

- Supplement its internal workforce with approximately 100 or greater external line crews.
- Supplement its normal compliment of forestry crews with approximately 30 or greater forestry crews.

- Augment Company personnel with 70 or greater contract personnel to provide additional support functions.

Responses to PowerServices' data requests indicate that the Company called on an additional 175 crews for assistance in Rhode Island, a level that meets the threshold of 150 or more external crews for a Type 1 event. Forestry crews were increased by 75, again meeting the threshold of 60 or more crews for a Type 1 event. It is not apparent if the Company expanded personnel for support functions.

Lastly, a Type 3 event has an expected restoration time of less than 72 hours, or three days. A Type 2 event has an expected restoration of less than seven days. It is conceivable that National Grid had a high level of confidence in meeting a three-day restoration target when revising to a Type 3 event instead of a Type 2 event, but the outage data made available as the Storm progressed supported a more difficult and complex restoration effort. The outages impacted customers across the entire state, and outage data indicated many isolated interruptions. Complete restoration was not a matter of quickly switching in transmission lines or substations that would restore power to large numbers of customers at once. It was known that the Storm was a very high wind event, causing numerous downed trees and branches. This would necessitate extensive tree work and time to clear roads and rights-of-way in order to access outage locations for line repair. The Company should have taken these factors into account and recognized that a three-day restoration window would be extremely difficult. Complete restoration was not achieved in three days; in fact, it required five days. It should have been recognized that the first day would be devoted to responding to and assisting with 911 and public safety measures.

In reviewing the data that the Company had recorded during the Storm, including peak outage numbers, the widespread pattern of interruptions, high winds causing downed trees, the need for 175 additional line crews, and the need for 75 additional forestry crews, it is clear that the restoration requirements were more aligned with a Type 2 event than a Type 3 event. PowerServices acknowledges that storm classifications have an element of judgement, and these thresholds are not exact indicators. We also acknowledge that the Company's ERP takes into account many factors, including the complexity of the storm. However, the outage data was very clear at the onset: the October 29–30 Storm caused outages for nearly 30% of the Company's customers, when 3% were expected. The Company's restoration needs were consistent with a Type 2 event, yet the Company never formally declared a more critical incident level than a Type 3 event. Although National Grid implemented some portions of restoration consistent with an ERP Type 2 event, other areas were following protocols of the officially declared Type 3 event. For instance, although the field crew levels were raised and may have been sufficiently organized, other areas, such as outage assessment, customer call centers, community and state organization outreach, IT, and other support functions, may not have been as well prepared. Failure to assign, communicate, and enact upon a single and appropriate storm incident level fostered restoration deficiencies. In PowerServices' opinion, the consequences were primarily evident in external communication and coordination efforts, including miscalculations and multiple revisions of Estimated Times of Restoration ("ETR") that frustrated customers. These are addressed in more detail later in our report.

D. Post-Storm

1. Mutual Aid

In preparation for the Storm, the Company had planned to pre-stage 58.5 crews and 267 FTE by 5:00 p.m. October 30, 2017. [R-I-20]. Once the Storm commenced, and the event level was elevated to Type 3, National Grid ordered an immediate acquisition of an additional 200 external contractor crews for its New England response, including Rhode Island and Massachusetts, at approximately 1:00 a.m. Monday, October 30, 2017. The Company reported that by October 30, 2017, at 7:00 a.m., resources increased to 64 overhead line crews, 17 contractor crews, 24 forestry crews, and 42 underground and substation resources. [Summary Report, p. 3].

A comparison of planned crews to the actual available crews on October 30, 2017 is provided in Table 3. The data for field crews (overhead, underground, substation and forestry only) shows the Company was able to add 46.5 crews and 9 FTE once the storm category changed from a Type 4 to a Type 3 event. There were 105 crews and 42 FTE at 7 a.m. October 30, at which time there were over 130,000 outages reported.

Table 3: Comparison of Planned vs. Actual Field Crews (October 30th)

	Planned 10/30/17 @ 17:00	Actual 10/30/17 @ 7 a.m.	Increase
Overhead	23.5 Crews	64 crews	40.5 crews
OH Contractors (COC)	17 Crews	17 crews	0 crews
Underground/Substation	33 FTE	42 FTE	9 FTE
Forestry	18 Crews	24 crews	6 crews
Total # Crews	58.5	105	46.5
Total # FTE	33	42	9

In addition to attempts to secure external contractors, National Grid notified NAMAG with a request for resources at approximately 4:30 a.m. on October 30, 2017. The Company initiated a mutual assistance request for a total of 500 line crews and 210 forestry crews for all of National Grid's New England response to the Storm. Of the total request, Rhode Island would be allocated 175 line crews and 75 forestry crews.

At this point, National Grid and other NAMAG members had significant requests for mutual assistance. During a 1:00 p.m. call on October 30, 2017, NAMAG extended member requests to Edison Electric Institute member mutual assistance groups in adjacent regions, including the Great Lakes Mutual Assistance Group and the South East Exchange. [National Grid Massachusetts Final Event Report, p. 14] Crews from various locations responded, and the Company states that it was "able to secure about half of its original request for distribution line FTEs (512 of the 1,000 FTEs requested)," through the NAMAG. [National Grid Massachusetts Final Event Report, p. 14] Although the Company did not indicate how many of the 512 mutual assistance crews were allocated between Massachusetts and Rhode Island, we can derive the magnitude and timing of crew additions from the Company's response to R-I-21, which requested the details of staging activities and mobilization.

Based upon the data provided in R-I-21, below is a table of the total overhead crews on site which includes National Grid and contracted line crews, along with the number of tree crews for each day. The overhead line crews were at a peak with 248.5 crews on Thursday and Friday, November 2–3, 2017. For those days, the Company had a combination of National Grid crews from Rhode Island, Massachusetts, and New York, augmented by 174 contracted overhead crews. The tree crews peaked at 188 on the same days.

Table 4: Overhead Line and Tree Crew Mobilization

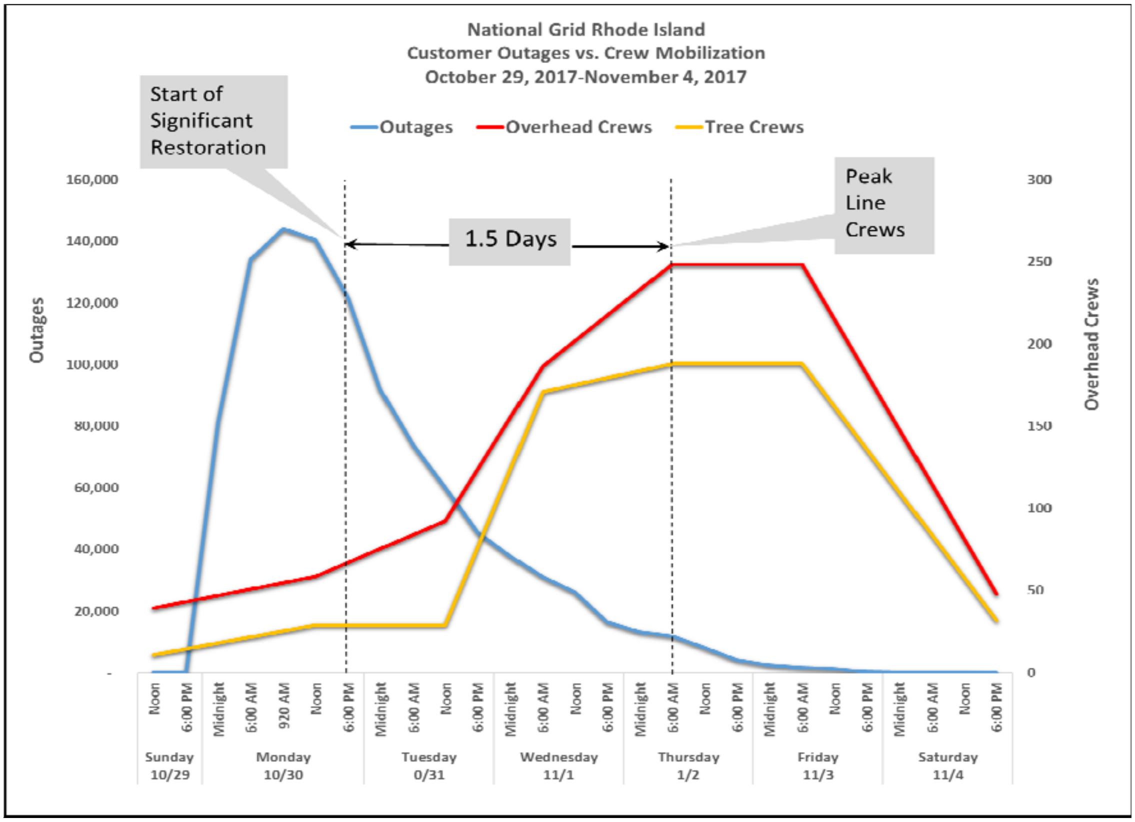
		Overhead Line Crews						
		NG-RI	Beeper Crews	NG-MA	NG-NY	Contracted Overhead	Total Line Crews	Total Tree Crews
10/29	**Sunday**	35.5	4				39.5	11
10/30	**Monday**	41.5				17	58.5	29
10/31	**Tuesday**	41.5				51	92.5	29
11/1	**Wednesday**	41.5			27	118	186.5	171
11/2	**Thursday**	41.5		6	27	174	248.5	188
11/3	**Friday**	41.5		6	27	174	248.5	188
11/4	**Saturday**	31				17	48	32

The mobilization efforts show a dramatic increase in external crew numbers starting two days after the Storm. National Grid's request for mutual assistance at 4:30 a.m. on Monday appears to have resulted in the first crews arriving on Wednesday, November 1, 2017. It is assumed that the delayed response was driven by the lack of mutual assistance within the immediate region. Crews from as far as North Carolina were dispatched to assist with restoration, which required significant travel time. Although the level of overhead and tree crews reached adequate numbers, it was unrealistic for the Company to complete restoration within 72 hours, in accordance with a Type 3 event, when crews were arriving 48 hours after the event.

A graphical representation of the timing of outages as compared to crew mobilization is shown in Chart 2. For purposes of this comparison, it is assumed that crews were on site at 6:00 a.m. each day since the Company's response to R-

I-21 did not include exact arrival times. The graph clearly indicates that the majority of crews were mobilized after the significant restoration had occurred. The Company had peak resources when outages totaled less than 20,000.

Chart 2: Customer Outages vs. Crew Mobilization



PowerServices compared National Grid's mutual assistance crew mobilization with Eversource Connecticut ("Eversource"), a neighboring utility and NAMAG member that experienced 201,222 outages at peak. Eversource released a comprehensive storm report and supporting information on November 16, 2017, only 2 weeks after the storm. The report indicates that Eversource, similar to National Grid, underestimated the storm impact and made efforts to supplement crews once outages increased above projections. Eversource's preparedness briefings provide a timeline of mutual aid assistance starting with the first efforts to actively secure additional resources on Monday, October 30, 2017. Eversource reported at 9:00 p.m. Tuesday, October 31, 2017, 200 crews from Florida, Ohio, Alabama, and Tennessee were being received at a staging area to assist with restoration. This compares to the arrival of National Grid's external resources sometime on Wednesday, November 1, 2017.

Our overarching conclusion is that National Grid secured adequate external resources, and, once on site, their efforts assisted in restoration of customer outages. However, there were significant delays in acquiring resources, and by the time external crews were mobilized the Company had restored power to a majority of customers. This does not imply that external crews were not necessary; but it is our observation that had the external crews been available earlier, the Company could have accelerated restoration, particularly for the multiple individual outages that lingered for days. In our estimate, the Company could have achieved a complete restoration at least 1 to 1.5 days earlier. In addition, we do not understand the allocation of mutual assistance between National Grid Rhode Island and Massachusetts, and recommend that the Company further report on the methodology to assign both contractors and mutual assistance crews between the jurisdictions, and provide a more detailed description of crew allocation and timing of mobilization during the Storm. Lastly, we ask that the Company provide details on its agreement with NAMAG, including any explanation as to why mutual aid resources were delayed as compared to Eversource Connecticut, another NAMAG member.

2. Damage Assessment

System assessments commenced on October 30, 2017, once the last wind events subsided and personnel could safely mobilize to the field. Leading into restoration, National Grid had a total of 131 damage appraisers working from the Melrose location. The damage was widespread, affecting all of the 38 communities the Company serves in Rhode Island. High winds resulting in downed trees and branches were the primary cause of outages, including one transmission line. Although the Company could not confirm the number or health of downed trees [R-I-30], the statistics regarding customer outages by cause in Table 5 below clearly show that the majority of outage minutes were the result of fallen trees and broken limbs. [R-I-14].

Table 5: Customer Outage Minutes by Cause

Cause	Total Customer Outage Minutes	Capital Customer Outage Minutes	Coastal Cusomer Outage Minutes
Grand Total	**0**	**0**	**0**
Tree Fell	175810884	87288901	88521983
Tree - Broken Limb	82848294.25	41928916.25	40919378
Unknown	57077092	31690584	25386508
Device Failed	7187200	6225017	962183
Tree Growth	3204103	3203945	158
Vehicle	322215	321020	1195
Deterioration	233231	1059	232172
Insulation failure - cable	159744	0	159744
Other Company Activities	39790	13817	25973
Animal	11077	5483	5594
Control Trouble	5261	5261	0
Moisture	4389	0	4389
Construction by Company Contractor	3880	2056	1824
Operating / testing error	2931	0	2931
Lightning	1522	0	1522
Tree - Vines	1284	0	1284
Non-Company Activities	217	217	0

National Grid Rhode Island reported the following impacts:

- Two transmission lines affected
- Ten substations affected
- 172 broken poles
- 45 transformer replacements
- 15,000 feet of lines replaced

The Company's damages as compared to other impacted utilities are as follows in Table 6:

Table 6: Utilities Damage Comparison

State	Utility	Outages at Peak	% Peak Outages to Total Customers Served	transmission lines affected	substations affected	broken poles	transformers replaced	lines replaced (feet)
Rhode Island	National Grid	144,144	29%	2	10	172	45	15,000
Massachusetts	Eversource (East + West)	112,860	8%	3		69	55	96,000
Massachusetts	National Grid	222,768	17%	10 transmission 25 sub-transmission		311	90	32,000
Connecticut	Eversource	201,222	17%	10		231	420	4,821
Maine	Central Maine Power	404,676	66%	31 sections		1,445	1,692	
Maine	Emera Maine	87,754	55%	15		210	186	52,800

3. Restoration

The Company reported that restoration efforts followed its ERP, focusing first "…on public safety, and then on the overall goal of maximizing customer restoration when lines became energized. The Company prioritized its workforce to focus on repairing transmission lines, substations, sub-transmission, and initial mainline distribution work, balancing resources between areas with the most damage to provide electricity sources to the largest areas without power." [R-I-1, p. 8]. Our review indicates that the sequence of work, as outlined by the ERP, appears to have been followed in that live wires and public safety hazards were addressed first. In fact, the Company seems to have done an excellent job of this in that they would utilize metering technicians to stand watch over downed lines until they could be cleared by qualified personnel. There was only minor transmission work to be rectified before moving to substations and then primary circuits.

The combination of increasing crew numbers and a strategy to prioritize largest areas without power led to significant restoration through November 1, 2017. The following Table 7 shows outage numbers at specific points in time, starting with the peak at 9:20 a.m., October 30, 2017. By 9:00 a.m. November 1, 2017, 80% of all outages had been restored. [R-I-10]

Table 7: Percentage of Outage Restorations by Date and Time

Day	Date	Time	Peak Outages	Percent Restoration
Monday	October 30	920 AM	144,144	0%
Monday	October 30	6:00 PM	121,752	16%
Tuesday	October 31	9:00 AM	71,866	50%
Wednesday	November 1	9:00 AM	29,425	80%

The Company's immediate successes are consistent with utility restoration practices that focus on portions of the system that serve the largest number of customers. It is the last 20% of restoration that is more time-consuming and requires targeted efforts and more crews. As contracted crews were on-boarded, the Company methodically restored the more isolated individual outages. On November 4, 2017, National Grid had 48 line crews and 32 tree crews working on less than 100 outages. A single outage was recorded at 11:00 p.m. on November 4, 2017. The Company did not provide a complete time of restoration, but, based on outage data, restoration started by 6:00 p.m. October 30, 2017, and reached residual, single digits by 6:00 p.m. November 4, 2017, requiring five (5) days for complete restoration.

We discussed the delays in acquiring external crews in a previous section, and note that the Company ramped crew levels to meet a more severe event. The Company reported that 817 field crews were secured at peak to restore power to customers in Rhode Island. The peak number included damage assessors, appraisers, transmission, substation, distribution, and forestry crews. [Summary Report, p. 8]. A single branch office was activated in Providence, Rhode Island and staffed by a Branch Officer.

[Summary Report, p. 2] Although the Company secured significant field resources, a second branch office was not opened which would have better enabled decentralized coordination of staff. In comparing National Grid Rhode Island and National Grid Massachusetts restoration efforts, we observed that Massachusetts activated four branch offices, and a fifth that was not fully staffed. National Grid had a higher number of outages at peak in Massachusetts than in Rhode Island (222,768 outages in Massachusetts and 144,144 in Rhode Island). National Grid Massachusetts, however, adjusted the number and location of branch offices as they revised the incident level to Type 3 during the Storm. [National Grid Massachusetts Wind Storm Final Event Report, p. 12-13]. We believe National Grid should have made similar adjustments in Rhode Island, and opened a subsequent branch office to improve field coordination. The Company dramatically increased field crews, but did not activate and staff a decentralized location to manage the additional resources, which would have improved restoration efficiencies.

Overall, the Company did a good job in restoration efforts once crews were on-boarded and mobilized. National Grid prioritized safety and reported no injuries during the Storm restoration. They established a Rhode Island Branch Director and a single branch office, although a second branch office and support resources would have aided in restoration efficiencies.

The relentlessness and efforts of National Grid's personnel and contracted aid cannot be questioned, and credit should be given where it is due. Clearing trees and wind-blown debris, changing out poles, and repairing and replacing electrical distribution facilities is challenging and dangerous work. The crews were committed to restoring power to their customers and they did it in a safe manner. The restoration efforts were valiant and tireless. This was attested by many of their grateful customers verbally and tangibly through various forms, including social media.

Through the field investigation it was obvious to PowerServices how much pride National Grid personnel, particularly the front line field workers, take in performing their jobs, operating and maintaining their electric system, and providing reliable service. This is further evidenced by the progress on outage restoration they accomplished before the crew level from outside resources actually ramped up. This pride carried over into the focus and drive required to stay the course until electric service had been restored to every customer.

E. Field Evaluation

As part of our comprehensive review, PowerServices included a field visit of National Grid's service territory to physically assess the areas of damage. The field evaluation was not an effort to correlate specific damage to actual restoration time, but rather an opportunity to evaluate asset and right-of-way ("ROW") conditions and infrastructure condition. The Storm resulted in numerous downed trees and branches that were the cause of the majority of outages. A downed tree on a power line that is not well maintained or that has poles with inferior integrity would tend to cause more outages than if the infrastructure were well maintained. Since the majority of outages were due to trees, a closer examination of field conditions combined with post-Storm statistics was performed.

To assess the Company's distribution infrastructure and ROW conditions, PowerServices scheduled a meeting with National Grid personnel at the earliest available date after commencement of the project. On December 12, 2017, two PowerServices engineers, and an engineer representing the Division, met at the Company's Melrose office. Two teams were formed, accompanied by National Grid field personnel. The Company selected areas of the service territory that were highly impacted, and, over a period of two days, several sites were assessed. The specific areas and circuits examined are not provided in this report, since the Company failed to release the maps used during the field visit with no explanation as to why they would not provide this information.

1. Vegetation Management and Rights-of-Way ("ROW")

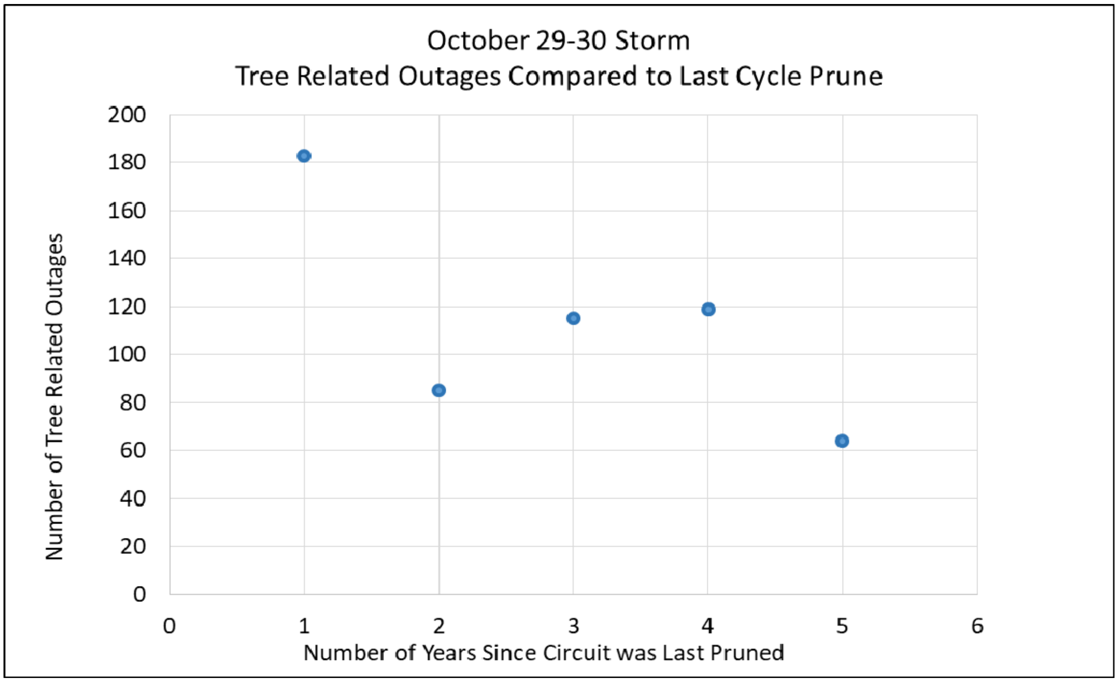
Key Findings: *The Company conducts a robust and effective vegetation management program, including a 4-year system pruning cycle accompanied by enhanced hazard tree mitigation. There is no direct correlation in the tree trimming cycle and outages caused by trees during the Storm. Circuits that underwent tree trimming in 2017 had higher numbers of outages due to trees than those trimmed in 2013. The Company's vegetation management program is robust and effective for "blue sky" days, and is designed to protect the system during normal weather anomalies*

Recommendation: *Although no vegetation management program will mitigate all tree related power outages, National Grid may consider enhancements to protect the system during severe storms with high winds, including "ground-to-sky" clearing on all circuits, increasing side clearances, and aggressive removal of all hazard trees. In PowerServices' opinion, however, the benefits may not outweigh the cost and public relations impacts. Furthermore, the adverse reaction by property owners and communities which encourage tree preservation and protection would be expected.*

PowerServices' engineers observed that ROW conditions were acceptable and trimmed in accordance with National Grid's vegetation management standards. In accordance with the Company's RI Distribution Line Clearance Specifications (R-I-8), overhead distribution lines are pruned to provide a minimum of 10 feet of overhead clearance in maintained areas and 15 feet in un-maintained areas, 6 feet of side clearance, and 10 feet below the wires. Sub-transmission and major backbone circuits are cleared to more stringent tolerances. National Grid currently prunes the system on a 4-year cycle, while removing danger trees under an Enhanced Hazard Tree Mitigation ("EHTM") program. Their vegetation management activities are documented in the Company's Infrastructure, Safety and Reliability ("ISR") Plan and reviewed annually by PowerServices. The field visit generated no concerns with the Company's implementation of the vegetation management and EHTM programs, except to note that current standards limit removal of overhanging branches. The standards allow for removal of only dead or damaged overhead limbs and branches, but that allows multitudes of overhanging branches to remain, which pose a risk of falling in high winds. These branches would be removed under a "ground-to-sky" clearing policy. In addition, pruning or removing danger trees located on private property requires property rights to allow vegetation management work. Absent revision of these standards to allow the Company unfettered access to trees on private property, which would be very difficult to gain, National Grid will continue to experience tree-related power interruptions or outages. It should be further noted that no amount of tree or branch removals, unless a complete clear cutting is implemented, will mitigate tree related outages. There were instances noted during the field inspection where trees fell from across the road and took down the line. It is nearly impossible to clear every danger tree.

A closer review of tree related outages as compared to the most recent year of circuit pruning is also performed. The objective is to determine if there is a correlation between the numbers of tree related outages and timing of cycle trimming. PowerServices reviewed the Company's outage data provided in R-I-9 and sorted tree related outage events by the year that each corresponding circuit underwent cycle pruning. The data compiled in Chart 3 below shows that the number of outages is actually the highest for circuits pruned in 2017, or the most recent year, and lowest for the circuit pruned in the first year, or 2013.

Chart 3: Tree Related Outages Comparison



A more logical conclusion is that circuits pruned in 2013 have more vegetation growth and are prone to more tree related outages, and circuits pruned in 2107 have lower vegetation growth and outages, which turns out not to be the case. This snapshot of statistics does not suggest that National Grid failed to adequately trim circuits in 2017. The data simply indicates that, in the event of a severe storm with high winds, all of the system is susceptible to downed trees and branches regardless of the year of most recent vegetation management. For this Storm, there is no correlation between outage events and ROW clearing. The Company's vegetation management program is robust and effective for "blue sky" days and normal weather anomalies. Major event days with high winds will continue to create challenges, which is consistent with electric utility operations in general. The Company may consider revising its program to include "ground-to-sky" clearing on all circuits, increases in side clearances, and aggressively removing all hazard trees, but in PowerServices' opinion the benefits would not outweigh the cost.

2. Infrastructure Condition

***Key findings**: PowerServices' field visit did not result in concerns after inspection of impacted circuits. Deteriorated infrastructure, mostly due to age, was noted. National Grid is proactively managing condition based issues through its I&M and Asset Replacement Programs as part of the annual ISR Plan. The Company is also evaluating each system region and systematically planning major capital projects to address capacity and condition issues. Capital spend under the annual ISR is nearly $100 million.*

***Recommendation:** There are no changes or enhancements recommended to the Company's current inspection and maintenance activities, which are reviewed annually under National Grid's ISR Plan.*

PowerServices' December 12–13, 2017 field visit included an assessment of infrastructure conditions. There were no overall concerns with visual condition of the poles and crossarms. Some equipment condition issues, such as aging overhead copper conductors, were noted. PowerServices is aware that, through its annual ISR Plan, the Company is systematically modeling and assessing its service territory to identify condition and capacity concerns. The Company is continually planning and executing projects to replace lines and equipment, and spending nearly $100 million a year for capital improvements.

In addition, as part of its annual ISR Plan, National Grid implements strategies and programs targeting equipment replacement to maintain reliable performance. These initiatives, emanated from the Company's Feeder Hardening Program that started in 2012 and has been completed, have grown significantly in scope and budget. A key component is the Inspection and Maintenance ("I&M") Program, which is a condition based assessment to address deteriorated assets on the distribution and sub-transmission system. Inspections are performed on a five-year cycle, and the Company completed the final year of the first five-year inspection cycle in FY2016. Feeder repairs are executed under a prospective schedule while imminent issues are repaired immediately. Concurrently, the Company proactively replaces aged equipment and system components that are damaged, fail, or show signs of imminent failure.

PowerServices requested a copy of the Company's I&M reports for each affected circuit. The Company responded that 246 feeders were impacted, and provided a 31,477 page report containing I&M assessments for 217 impacted feeders [R-I-25].

The report noted the structures inspected, identified problems, and assigned a repair category from Level 1 (emergency repair) to Level 4. Review of the data indicates that issues affecting line integrity, such as rotting poles, have been classified with a higher repair priority. The Company is replacing aging poles and, although age is not the sole predictor for condition, the current distribution pole age is 39 years [R-I-32]. We believe the Company has a prudent strategy in maintaining its 281,775 distribution poles in Rhode Island[4].

In PowerServices' opinion, overall, the Company's systematic approach to inspection, maintenance, and equipment replacement over the past six years has improved resiliency and reliability. The Company balances system condition expenditures with risk and capital program management to relieve upward pressure on electric rates. Although a more aggressive storm hardening program and increased expenditures for areas with identified condition deficiencies may mitigate some storm outages, it is unlikely such increases in capital investment would have a measurable benefit for a storm such as was experienced in October 2017. Tree failure and large limb failure will cause massive damage to any overhead electric system, and no amount of hardening of overhead lines will appreciably reduce the impact. Elimination of the trees and overhanging limbs are the only solution, albeit very difficult if not impossible to achieve. Increased use of underground is a solution; however, and comes with a very significant cost that most ratepayers find unacceptable.

[4] National Grid Electric ISR Plan FY 2019 Proposal, Section 2, page 1

F. Communication & AMI

1. ERP & Communication Practices

***Observation**: Overall, the Company adhered to the minimum elements of the ERP related to communication, although there is no documentation to assess if the daily contact requirements for Life Support Customers were achieved. The Company's social media messaging was adequate and sites were updated several times per day with accurate information, other than under-reporting numbers of outages. There were periods of time where the Company stopped responding to customer complaints, likely adding to the customer's level of frustration on confidence in Company information. .*

***Recommendation**: National Grid should provide evidence of LSC contact requirements. The Company should improve the consistency and content of its social media outreach to offset customer complaints and situations where customers share incorrect information. National Grid would have been well served by preparing pre-drafted template messages to address the common issues that customers' question, allowing for quick and accurate responses.*

Major storms, particularly those that present unexpected damage and outages, require extensive communications and coordination. National Grid's ERP provides a framework for storm restoration, including communication guidelines. The ERP established an Emergency Response Organization led by the State Incident Commander, who is responsible for the overall management of the emergency at the state level, including internal and external communications. The ERP provides a framework for communication, but does not have specific requirements for a particular type or level of emergency.

The Company established Pre-Event Stage Briefing Calls with the first occurring on Saturday, October 28, 2017 at 1:00 p.m. [R-I-1, page 1]. As the emergency escalated across multiple business areas, strategic levels of response were activated. Although the Company did not activate the highest level for this Storm, the Crisis Management Team ("CMT"), it did provide situational awareness to the CMT via daily briefings [R-I-3].

On Saturday, October 28, 2017, the Contact Center took the following steps to facilitate communications with the Company’s customers as required by the ERP:

- Secured additional staffing for October 29 through November 4,
- Established and created 12- to 16-hour shifts for representatives in New England,
- Assigned support to assist with Life Support customer monitoring and outreach,
- Scheduled management personnel for 12- to 16-hour rotating shifts, and
- Contacted the Company’s third-party vendor to provide additional support for incoming calls.

The Contact Center initiated automated calls to Life Support customers on Saturday, October 28, 2017 at 2:00 p.m. to notify them of the upcoming weather, recommend taking necessary precautions and preparations to ensure their wellbeing in the event of an outage, as required in the ERP. The message also advised Life Support Customers (“LSCs”) to contact 911 or their local public safety officials in the event of an emergency. The ERP guides the Customer Contact Center to track the status of

LSCs during emergencies, with daily attempts to inform them of the extent of the interruption and estimated restoration. There is no indication in the responses from the Company that this action was performed daily, and it appears this occurred only once prior to the event. There were social media postings October 29-30, 2017 providing instructions for customers with medical needs, but no indication that direct contact was made with individuals.

The Company provided information to customers prior to the event through the Company website, social media, and interviews with the media. This included, but was not limited to, communications on the following subject areas: information about how the Company prepares for a storm; information how to report and check on outages; safety tips; and, information for customers about how to receive text message alerts and updates from the Company.

National Grid's media relations staff fielded one call from reporters in Rhode Island about the Company's storm preparations on Saturday, October 28, 2017. The Company provided a Community Liaison to each municipality within the State who were in constant communication with their LPCs to expedite the flow of information between the Company and municipal representatives. Several municipal authorities shared their praise of this action.

The ERP recommends customer communications utilize all available media, including popular media and/or technology. The Company is utilizing the following media in communicating with customers:

- Broadcast Text Alerts – for major emergencies, sending no more than four messages per day.
- ETR Text Messages – updates providing customers with the total number of outages for an area and the estimated restoration times. The feed for this information is from the OMS.
- Website and Mobile Applications – for outage reporting, allows customers to view the outage map, view area outage summaries, and report or check the status of their outage directly from their mobile device. These are populated from the OMS.
- Facebook – Company Facebook page and Rhode Island Facebook page where customers can receive information specific to their region.
- YouTube – Company provides videos on outages and restoration for viewing.
- Twitter – Company utilizes Twitter to keep customers informed.
- Email Notifications.
- Print and Broadcast Outlets – Utilized as conditions warrant to convey safety, storm restoration status, projections for service restoration or other emergency information.

Our review indicates that most of the communication channels were used during the event, with the exception of YouTube. There is no indication in the Company's responses that broadcast messaging or Interactive Voice Response ("IVR") announcements were used to communicate information as the ERP states. However, once the event was underway, there were social media comments that indicate customers received broadcast messages stating power would be out up to seventy-two (72) hours. The Company used social media throughout the event to communicate with their customers several times each day, except on November 1, 2017. The only post on that day was regarding ETR estimates. Initially, the Company shared information with customers urging safety due to downed power lines and advising customers to check on the elderly. Once the severity of the Storm was understood, the Company reported outages were worse than predicted and provided a link to the outage map. The Company did a good job sharing information for the safety of their customers. Throughout the event, National Grid provided information about high winds, downed power lines and general safety tips.

Company responses indicate the internet based outage reporting system was functional during the event, and outages were reported digitally via National Grid's website, mobile website or mobile app, or by phone. There was a short service interruption, but it was resolved within 1.5 hours. During that time, customers who attempted to report an outage online were brought to a system maintenance page that indicated the login function was unavailable. The system maintenance page provided customers with a link to National Grid's "Contact Us" webpage with various phone numbers for emergency and outage reporting. The most significant deficiency, however, was the Company's failure to provide timely and accurate outage restoration information, as discussed in more detail below.

2. Estimated Time of Restoration ("ETR")

Observation*: The Company experienced several instances of ETR mismanagement including severe underestimation of restoration times, inadvertent uploading of incorrect ETRs, and multiple revisions to ETRs that only served to confuse and frustrate customers. The Company lacked appropriate planning and oversight of the*

ETR process and failed to disseminate reasonably accurate restoration information to customers. At one point, a default ETR was utilized that did not reflect the severity of the Storm. Providing customers with a lower restoration time than will likely be achieved instantly leads to an "over-promised and under-delivered" scenario, inviting customer skepticism and complaints.

Recommendation: *We recommend that the Company reevaluate the policy of displaying default ETRs which only serves to confuse customers when refined data is far different than what was previously published. ETR's should be assigned once storm severity is clear and a reasonable assessment of outages has been determined. We recommend the Company take measures that prevent the upload of unapproved ETRs.*

The Company receives outage reports from customers through a web portal, Interactive Voice Response ("IVR") system, or by phone via the Customer Contact Center. The information resides in the Company's Outage Management system ("OMS") which is updated approximately every fifteen (15) minutes. [R-I-37] According to the Company, the OMS "… uses algorithms to predict an open protective device based on reported customer outage locations and lists the number of affected customers downstream of the open device. As repairs are made to the feeders, National Grid employees in the Control Room and Storm Room update the OMS to reflect restoration and new open devices, and in doing so the OMS automatically adjusts the number of customers affected". [R-I-37] During the initial period after a storm, the Company collects outage reports and damage information, then prepares general ETRs at the beginning of the restoration phase. ETRs are refined and updated based on the progress of repairs. The Company graphically displays ETRs on its publically available outage map.

In the early part of this Storm event, National Grid reported the OMS generated ETRs based on the incident classification, or Type 4. This indicates that before the OMS uses actual outage data in an algorithm to determine ETRs, the system assigns a default ETR based on the Company's pre-storm assumptions. Our concern with a default ETR is that it is likely to underestimate restoration time when storm severity is greater than anticipated. Providing customers with a lower restoration time than will likely be achieved instantly leads to an "over-promised and under-delivered" scenario, inviting customer skepticism and complaints. The Company should reevaluate the policy of assigning a default ETR and consider publishing ETRs once the storm severity is clear and a reasonable assessment of outages has been determined.

The Company goes on to report that once the default ETR was uploaded, the '…actual storm damage and number of customer outages were higher than predicted. On the morning of Monday, October 30, 2017, the Company removed the originally predicted ETRs as the Company assessed the damage and developed more accurate ETRs. As the information became available, the Company uploaded the updated ETRs into the outage map. The Company continued to update the ETRs throughout the restoration process as information became available to the Company. In addition, on another occasion, ETRs were inadvertently uploaded before their approval". [R-I-38, p. 1]

Our concerns with the Company's subsequent steps in posting ETRs relate back to the extensive discussion on their failure to properly classify the Storm. Specifically, once outages exceeded predicted levels for a Type 4 event, the Company adjusted to a Type 3 event, with restoration within seventy-two (72) hours. As explained earlier, the number of outages recorded by Monday morning suggest that the Storm was a Type 2 event with restoration within one week. We are not able to validate the revised ETRs posted by the Company once outages exceeded predictions, since the Company was unable to produce historical outage maps. However, all indications are that the Company based ETRs on a Type 3 event. Once again, the Company under-estimated restoration times. We again recommend that the Company re-evaluate the policy of displaying default ETRs which only serve to confuse customers when refined data is far different than what was previously published. ETR's should be assigned once storm severity is clear and a reasonable assessment of outages has been determined.

Regarding the inadvertent uploading of customer ETRs, the Company did not provide details on the number of incorrect ETRs or how long they were posted before corrections were made. This is a mistake that could have far reaching effects. The display of inaccurate data, particularly over a long period of time, sends the wrong signal to customers and undermines their confidence in updates. We recommend the Company take measures that prevent the upload of unapproved ETRs.

In summary, the Company faced significant communication needs in response to a storm that impacted every community it serves and created far more outages than predicted. The Company effectively managed receipt of the 120,326 outages reported digitally via National Grid's website, mobile website, or mobile application, along with the 58,055 outages reported by phone. However, the Company failed to disseminate reasonably accurate restoration information to customers. The Company experienced issues with the reported ETRs displayed on the outage maps and releasing ETRs prior to internal approval. These are critical errors, because many customers complained about their ETRs changing. Customers felt that the Company fell short on their planning because they underestimated the severity of the storm and poorly communicated ETRs, and we agree. Transparency is critical in gaining customer confidence. We recommend the Company re-evaluate their process of determining and posting ETRs, consistent with recommendations in this report.

3. AMI

As part of this evaluation, PowerServices was asked to analyze the potential benefits of AMI in storm restoration efforts. Currently, the Company uses automatic meter reading, or AMR, which is a "one-way" technology where consumption data is recorded and transmitted to the utility, and is generally collected by a drive-by vehicle or handheld device. AMR meters provide meter reading and billing efficiencies, but the meters are not interactive. Conversely, AMI allows real-time, on-demand interaction with metering points. A utility can, for instance, collect consumption data for billing, disconnect or re-connect services, and transmit signals for demand response from a central location. There are additional benefits during power outages and restoration efforts such as:

- Automatic notification ("last gasp") to the Utility in event of service disruptions.
- Automatic notification to the Utility when power is restored.
- Ability for Utility to "ping" a meter, or send a signal to determine its status.

- Improving crew dispatch by targeting restoration in areas with known service interruptions.
- Functionality for the customer to receive automatic notifications of power outages and restoration.

AMI systems work with an OMS by automatically providing outage information rather than relying on the customer to report outages by phone, web sites, or mobile applications. This early notification system is beneficial for the utility in determining the number of outages and impacted regions, and this information is used to assess the storm severity and restoration needs. In addition, utility operators can use the "ping" functionality to determine clusters of outages and aid in the prediction of restorations. Confirming the location of area outages before crews are dispatched improves the restoration process and ultimately reduces outage time. The "ping" functionality is also advantageous in determining that power is restored to a location, mitigating the need for crews to make a site visit and confirm power is on.

Like any advanced technology deployed by utilities, PowerServices' is an advocate when the benefits to customers exceed the cost of implementation. AMI has multiple benefits, and as such, it would be unreasonable to isolate the costs and benefits related solely to storm response. We firmly believe a more automated system of identifying outages would benefit National Grid. The ability to refine predicted restoration times and respond more efficiently would also be advantageous, particularly given the Company's difficulty in determining ETRs. The one area improvements can be quantified relate to confirmation of power restoration. We noted that, in the Company's response to Data Request R-I-9, there were hundreds (estimated between

500 and 600) of documented instances where field crews were dispatched to a customer site for a repair, and upon arrival they noted power was already restored. The outage report includes descriptions for these instances such as “OK on arrival” or “has power on”. This process is inefficient, with wasted time that should have been spent restoring electric service elsewhere. A more sophisticated outage confirmation system, and certainly AMI, would mitigate the time and cost for field checks. Furthermore, AMI would clearly enhance the entire dispatch process including, but not limited to, 1) allowing improved assessment and dispatch of crews to the optimum areas for the highest level of customer restoration first; 2) assuring that crews are only dispatched to areas, particularly tap lines, that actually have remained without power after the initial restoration activities; and 3) the more timely dispatch of crews to areas which have remained interrupted when dispatchers were expecting the areas to have been restored during prior activities.

Our final observation regarding AMI is that the technology relies on a robust and resilient communications system. A utility must consider the architecture, interoperability, and performance of a communication system for daily operations, in addition to performance under severe conditions and power outages. AMI deployment is not limited to advanced meters at customer sites. There are many system components used to accumulate and transmit data. A loss of electrical supply to communications equipment may result in loss of AMI functionality. This was the case for Emera, Maine, when they were unable to utilize AMI infrastructure at various substation locations from October 31 to November 2[5]. We emphasize this point to illustrate the need for the Company to not only have a robust communications

[5] *October 2017 Wind Storm Emera Maine Report; January 18, 2018, page 12*

system to support AMI, but to ensure that restoration plans always consider that technology can fail when needed the most.

III. SUMMARY OF RECOMMENDATIONS AND STORM RESTORATION ENHANCEMENTS

If the Company is planning for a low impact storm, it must categorize the response within a very narrow tolerance level which will likely miss the mark. Conversely, if the Company underestimates impacts for more severe events, such as the case in this Storm, significant adjustments are required for a single step change in event classification. Unless the Company incorporates a method for more rapid adjustment within the ERP, the only way to fully prepare is to over-estimate storms to ensure that necessary resources are onboard, which will often result in excessive and unnecessary costs. Although there will always be a balance between restoration duration speed and cost which can be second guessed, in storms such as the October 2017 storm, clear deficiencies in actions and many inactions by the Company which should have been avoided are identified. The following is a summary of the recommendations which are dispersed throughout our report, noting key findings and explaining the facts which support the key findings and recommendations.

1. The Company should supplement its weather forecasting service with additional tools. The Company should provide the Division with a comprehensive update on the Damage Prediction Modeling tool that was to be implemented in Massachusetts in 2013, and subsequently scheduled for Rhode Island. The update should contain a detailed description of the software performance, expected benefits, rationale for

delayed implementation, and all development and implementation costs incurred or forecasted.

2. The Company should develop a mechanism and communications process within its ERP that outlines a means to rapidly adjust the ERP incident classification based on actual system impacts resulting from quickly changing weather patterns that increase in severity. The adjustments should foster a proactive program of rapidly identifying and communicating, both internally and externally, the escalation of event Type. Failure to escalate the severity and event Type classification is one of the most serious deficiencies identified in this storm assessment process. National Grid appears to lack a free flowing and nimble communications system, and protocol which permits and encourages identification, communications, and action steps being implemented when it is clearly known within the operational ranks of the Company that a storm has become far more severe than the classification and plans have indicated. Absent a clear path to make adjustments within the ERP, the Company is prone to inadequate communications to the public, delays in securing mutual assistance, and an overall lower level of urgency that results in subpar restoration.

3. The Company should review incident classifications and adjust the ranges of expected outages used to determine an event Type. The current classification system makes a very large outage level change in the last two classifications, which may be contributing to the slow reaching and buildup of needed resources when a storm's severity escalates and the internal classification and communication mechanisms are not in place to take timely action. In addition, the Company should define and utilize specific outage metrics, such as lines impacted and regions affected, in assigning

incident levels rather than relying on global attributes. The ERP revisions should also incorporate a matrix of planned resources, both internal and external, required for restoration and describe whether multiple staging areas will be utilized. PowerServices recommends that the Company obtain ERPs from at least six (6) New England and New York utilities to review the structure and event classification criteria (examples provided in Appendix D). The Division and the Company should work together to further adjust and enhance National Grid Rhode Island's ERP to ultimately derive a detailed storm restoration matrix. Specifically, PowerServices suggests the outage levels in Table 8 as a basis for the Company's discussions with the Division, with an objective that the Company complete a comprehensive template with components similar to those within the *New England Utility 4* example in Appendix D.

Table 8: Recommended Outage Levels

Event Type	Customer Interruptions
Type 6	0-5%
Type 5	5-15%
Type 4	15-25%
Type 3	25-45%
Type 2	45-75%
Type 1	Over 75%

4. The Company should perform a root cause analysis to determine the breakdown in internal communications and processes that resulted in ETR mismanagement, including severe underestimation of restoration times, inadvertent uploading of incorrect ETRs, and multiple revisions to ETRs that only served to confuse and frustrate customers. Concurrently, the Company should incorporate a process to develop initial ETRs based on actual field assessments, rather than rely on default values generated by predictions. The Company should develop an enhanced process

of flowing accurate changes in the Estimated Time of Restoration ("ETR") through public communications channels to mitigate the customer frustrations and lack of confidence in the Company's outage restoration process and estimates. The Company should improve external communications by leveraging all forms of social media throughout a storm event, including YouTube videos which may be prerecorded or live stream. The Company should report the results of this ETR management root cause analysis and proposed ERP improvements to the Division.

5. The Company should incorporate results of the ETR management root cause analysis and other storm lessons learned, including dispatching deficiencies into the AMI pilot and implementation process. An AMI system in this storm would have eliminated or significantly reduced the nearly 600 instances of crews being dispatched to locations for which power had already been restored. Additionally, AMI will nearly always provide for early outage detection and a far superior indication of outage severity and areas of greatest impact over the current OMS system, which relies on customer notifications. This will often result in improved incident level classification, reduced restoration time, and greater focus on the areas with highest impact first. Section II F. outlines five (5) distinct benefits AMI creates for the storm restoration process.

6. Although no vegetation management program will mitigate all tree related power outages, National Grid may consider enhancements to protect the system during severe storms with high winds, including "ground-to-sky" clearing on all circuits, increasing side clearances, and aggressive removal of all hazard trees. In PowerServices' opinion, however, the benefits may not outweigh the cost and public relations impacts. Furthermore, the adverse reaction by property owners and

communities which encourage tree preservation and protection would be expected. The Company should begin a community outreach program in order to develop a level of community cooperation for a broader vegetation management clearing area. This is best accomplished immediately after a storm when the impacts of extended outage durations is fresh on the customer and communities mind, and they may be more receptive to increased areas of “ground-to-sky” clearing that removes all overhead branches, regardless of tree condition, and creates wider clearing zones on either side of the circuit.

7. National Grid should provide evidence of LSC contact requirements. The Company should improve the consistency and content of its social media outreach to offset customer complaints and situations where customers share incorrect information. National Grid would have been well served by preparing pre-drafted template messages to address the common issues that customers question, allowing for quick and accurate responses.
8. The Company must accelerate and expand its storm report to encompass a much broader set of factual information and how its report reflects on the actual facts and timelines, including detailed information on the timing of mutual aide additions and the allocation methodology between National Grid’s jurisdictions. The report should also be coordinated with the dissemination of other information shared with the Division and other outside parties in order to eliminate obvious discrepancies. The current requirement to deliver a report within ninety (90) days is well beyond the time that comparable utilities filed storm reports with their respective Commissions. (Table_10). PowerServices recommends that the filing requirement for National Grid Rhode Island be reduced to forty-five (45) days.

Table 10: Comparable Utility Storm Report Filing Response Times

State	Utility	Storm Report Date (for October 29-30, 2017 Event)
Connecticut	Eversource	11/16/2017
Massachusetts	Eversource	12/4/2017
Massachusetts	National Grid	12/4/2017
Maine	Central Maine Power	1/18/2018
Maine	Emera Maine	1/18/2018
Rhode Island	National Grid	2/1/2018

Additionally, the Company's current storm report outline, provided in Appendix E, includes recommendations for enhanced components and data that should be included in each filed report. The Division and Company should collaborate to improve the storm report in a way that meaningful information is provided to all interest groups.

9. The Company needs to implement a data collection and processing method which is much more efficient and timely. The excessive delays in responding to the Division's data requests is inexcusable, particularly when placed in the context that a regional utility is able to collect data and delivers a comprehensive storm report within two weeks of storm restoration. PowerServices recommends that going forward, the Company should respond to the Division's data requests within ten (10) business days since most of the information is available, unless otherwise agreed by the Division.

10. The Company should quickly implement multiple staging areas in any storm with widespread outages impacting a large area. The ancillary staging areas should be opened much earlier in the process to assure better restoration coordination with local

teams. The branch location methods used in Massachusetts should be implemented in Rhode Island.

11. The Division should institute a separate evaluation of the Mutual Aid process and NAMAG to determine if Rhode Island is consistently being provided resources in an appropriate priority scheme and at proportional levels to requests from other regional utilities. Additionally, it should be determined if National Grid in Rhode Island has created the appropriate contractor priority system within its ongoing construction and maintenance contracts with both its tree clearing contract crews and construction contract crews. The Company should require any crews which are embedded at a utility are subject to be held by that utility until released to other utilities. This assures those crews are immediately available for the Company as its own crews.

IV. CONCLUSION

There is no dispute that the storm dramatically changed over time, and the weather predictions initially underestimated the severity of the storm, thus there was a higher level of resulting damage, which could be expected. The Northeast utilities, from Rhode Island to Maine, were seriously impacted by this storm. The responsiveness of the impacted utilities and ability to restore power in a timely manner were directly related to how rapidly each company recognized the storms strengthening and the overall effect it would have on the electric system. National Grid, unfortunately, failed to recognize the expanded impact of the storm in a reasonably timely manner and, therefore, neither classified the storm event properly nor took action in a manner that would allow it to have adequate resources in place at the time they were most needed. This resulted in an extended restoration duration of as much as 36 hours. The Company's storm report characterizes the final restoration time much earlier than the actual facts support. Our report documents how we reached the conclusion that the Company's full restoration was 36 hours beyond what it should have been.

The Company's actions and inactions, which are considered deficiencies that lead to restoration delays and incorrect communications to the public, are summarized as follows:

1. The Company failed to have redundant weather analysis processes that recognized the increased intensity of the storm and the outage impact it would have.

2. The Company failed to make rapid adjustments within the ERP to assure the needed resources were onboard.

3. The Company **never** identified and communicated internally or externally the maximum Incident Level classification.

4. The Company's failure to properly classify the type of storm and outage event resulted in communications of overly optimistic restoration times, both internally and to the public.

5. The Company's slow reaction to the changing events and storm magnitude allowed other utilities in New England, such as Eversource, to secure regional mutual aide resources for storm restoration first, leaving National Grid with securing more of its

resources from greater distances. Thus, the Company did not have maximum resources on the system within a reasonable time after reaching the peak outage level.

6. The Company's inactions in adjusting storm classification and internal communications concerning storm and outage severity was the main cause for the significant delay in acquiring resources, which resulted in as much as a 36 hour delay in the full restoration of power.

7. Even at this time the Company, based on its Summary Report, apparently believes its full restoration occurred earlier than the factual data supports. There were crews working on power restoration after the time the Company represents is the final restoration date and time. This type of disconnect between the facts and the Company's belief is a further indication of a flawed and broken communication and data processing system.
8. The Company's February 1, 2018 report barely meets the minimum requirements of what we consider an adequate storm assessment summary. The Company is provided ninety (90) days to produce the report, which is excessive considering that comparable utilities produce robust reports in as little as two weeks. The Company must accelerate and enhance its storm reporting, which should be delivered within forty-five (45) days following a major event.

9. Absent changes by the Company in numerous areas as recommended, our opinion is that Rhode Island electric customers will continue to have delayed outage restoration as compared to other regional utility customers, combined with unnecessary inaccuracy in estimated restoration times being communicated.

10. The Company must put forth a plan which documents how it will make adjustments to avoid future storm event classification errors, and incorporate a process in the ERP to categorize events and rapidly recognize and adjust to changing storm and outage circumstances while not being the last utility to successfully acquire needed mutual aide resources. Lastly, National Grid must specifically describe how the Company implemented each of the Division's Directives, resulting from the November 20, 2012 Report and Order related to Tropical Storm Irene, to include a current update for each Directive as opposed to the report provided by the Company that was prepared nearly five years ago.

V. APPENDICES

Appendix A – List of Resources Utilized by PowerServices

Appendix B – Rhode Island Customer Interruption & Restoration Graph

Appendix C – October 29-30 Storm: Northeast Utility Impacts and Restoration

Appendix D – New England Utility Response Level Matrixes

Appendix E – Company's Current Storm Report Outline

Appendix A

List of Resources Utilized by PowerServices

Appendix A

List of Resources Utilized by PowerServices

1. National Grid's data request responses to Data Request Set 1 (issued November 22, 2017) comprised of 41 questions. Company responses included over 1,500 pages, excluding the majority of system maps.

2. Eversource Connecticut Storm Report (November 16, 2017)

3. Emera Maine October 2017 Wind Storm Report and associated filings (January 18, 2018) (Maine PUC Docket No. 2017-00324: Investigation into the Response by Public Utilities to the October 2017 storm)

4. Central Maine Power filing (January 18, 2018) (Maine PUC Docket No. 2017-00324: Investigation into the Response by Public Utilities to the October 2017 storm)

5. Eversource Energy Final Event Report on October 29, 2017 Storm Event

6. Massachusetts Electric Company-Nantucket Electric Company d/b/a National Grid Final Event Report October 29, 2017 Wind Storm D.P.U. 17-ERP-09; December 4, 2017 Submitted to: Massachusetts Department of Public Utilities

7. NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy Final Event Report on October 29, 2017 Storm Event Massachusetts Department of Public Utilities D.P.U. 17-ERP-10; December 4, 2017

8. The Narragansett Electric Company d/b/a National Grid Report on October 29-30, 2017 Event, Damage Assessment, and Service Restoration; Filed with RI PUC February 1, 2018; Docket No. 2509

9. Eversource Annual Reports

10. National Grid Annual Reports

11. National Weather Service Data

12. Independent weather service data

13. Internet based news articles from at least eight states affected by the storm

14. Website and social media information and reports posted for over ten electric utilities affected by the storm.

15. National Grid field personnel interviews during field evaluation

16. National Grid Emergency Response Plan

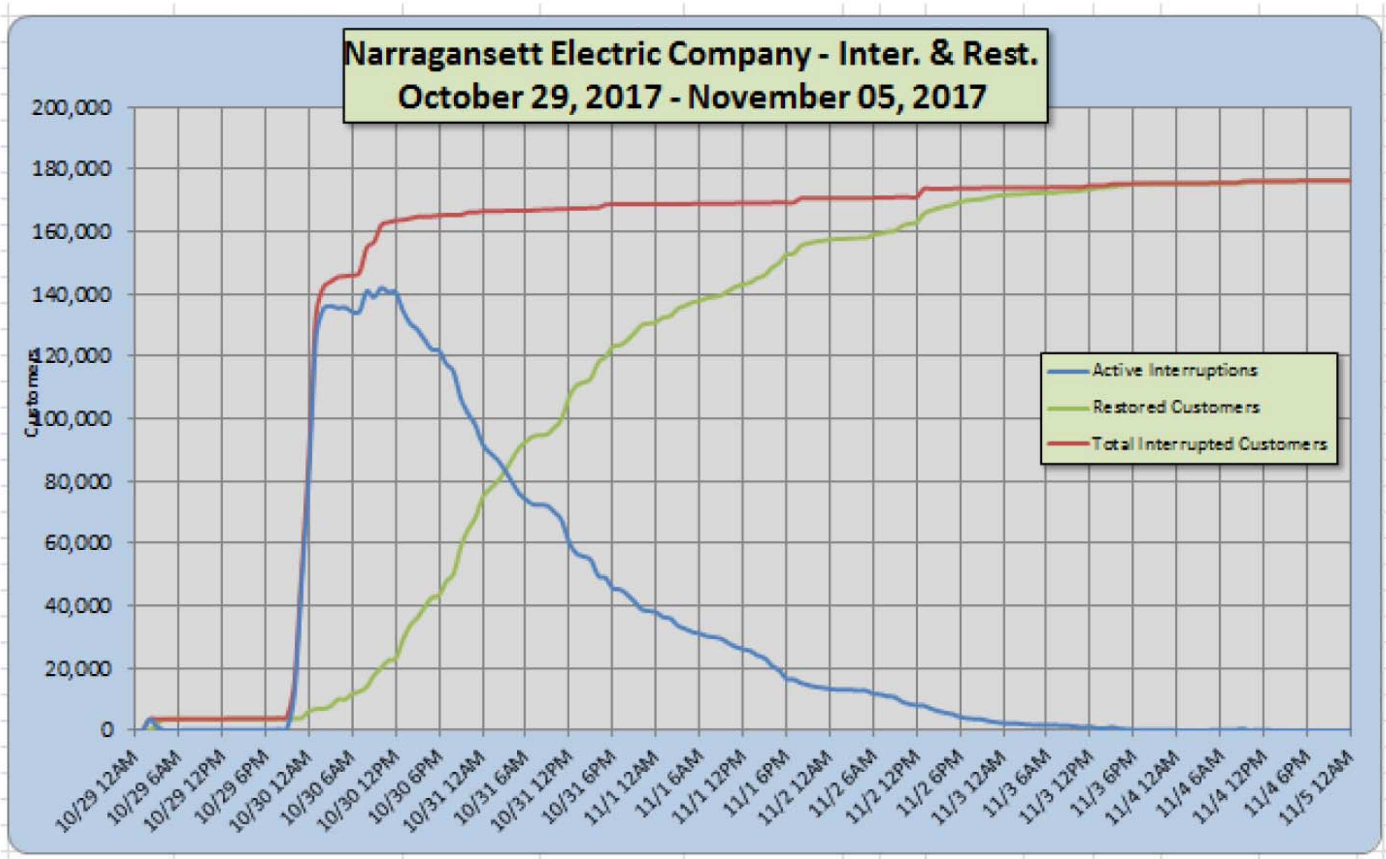
17. North Atlantic Mutual Assistance Group information

Appendix B

Rhode Island Customer Interruption & Restoration Graph

Appendix B

Rhode Island Customer Interruption & Restoration Graph
Source: R-I-1, page 9, Figure 3



PowerServices

Appendix C

October 29-30 Storm: Northeast Utility Impacts and Restoration

PowerServices

October 29-30 Storm: Northeast Utility Impacts and Restoration

State	Utility	Customers Served	Outages at Peak	% Peak Outages to Total Customers Served	Total Outages	% Total Outages to Total Customers Served	Service Area Size		Time/Date of Significant Restoration	Percentage Restored	Time/Date of Complete Restoration		Metering
Rhode Island	National Grid	491,958	144,144	29%	176,247	36%	1,076	square miles	11/2/17 @ 2:00 pm	95%	11/4/17 @ 6:00 pm	(1)	AMR with small AMI pilot
Connecticut	Eversource	1,200,000	201,222	17%	311,318	26%	2,341	square miles	11/1/17 @ 1:00 am	85%	11/2/17 @ 5:30 pm	(2)	AMR with AMI pilot
Massachusetts	Eversource-Eastern Mass	1,187,198	105,366	9%	209,413	18%	-	-	10/31/17 @ 1:00 pm	95%	11/3/17 @ 1:55 pm	(3)	AMR/ Opt-in AMI
Massachusetts	Eversource-Western	209,939	7,494	4%	14,608	7%	3,192	square miles	10/30/17 @ 4:00 pm	95%	10/31/17 @ 9:00 am	(3)	AMR/ Opt-in AMI
Massachusetts	National Grid	1,343,124	222,768	17%	330,610	25%	-	-	11/2/17 @ 2:20 pm	98%	11/4/2017	(4)	AMR with AMI pilot
Massachusetts	Unitil	28,999	-	0%	-	0%	170	square miles	10/30/17 @ 12:00 pm		-		-
Maine	Central Maine Power	612,000	404,676	66%	467,246	76%	11,000	-	11/3/17	97%	11/8/17 - no time provided		AMI but went down during
Maine	Emera Maine	159,000	87,754	55%	not reported	0%	10,400	-	11/4/17 @ 12:00 a.m.	98%	11/6/17 @ 6:00 pm		AMI and AMR
New Hampshire	Eversource	510,000	190,000	37%	312,000	61%	5,628	square miles	-	0%	11/3/17@ 3:00 pm	(5)	AMR
New Hampshire	Unitil	107,000	33,715	32%	not reported	0%	408	square miles	10/31/17 @ 8:00 pm	99%	-		AMI
New Hampshire	Liberty	43,700	11,000	25%	not reported	0%	-	-	11/2/17 @ 6:00 pm	0%	-		AMR
New Hampshire	New Hampshire Public Cooperative	84,000	52,300	62%	not reported	0%	5,500	miles of line	-	0%	11/4/17 @ 7:00 pm (99%)		AMI
New York	PSEG Long Island	1,100,000	46,654	4%	108,557	10%	1,230	square miles	10/31/17 @ 8:30 pm	99%	-		No AMI: planned for 2019

Notes:

(1) National Grid RI outage stats show 6,937 outages on 11/2/17 @ 2 pm. This is close to 7,200 [5% of 144,144] ---> stats indicate single digit outages 11/4 @ 6 pm; assume complete restoration

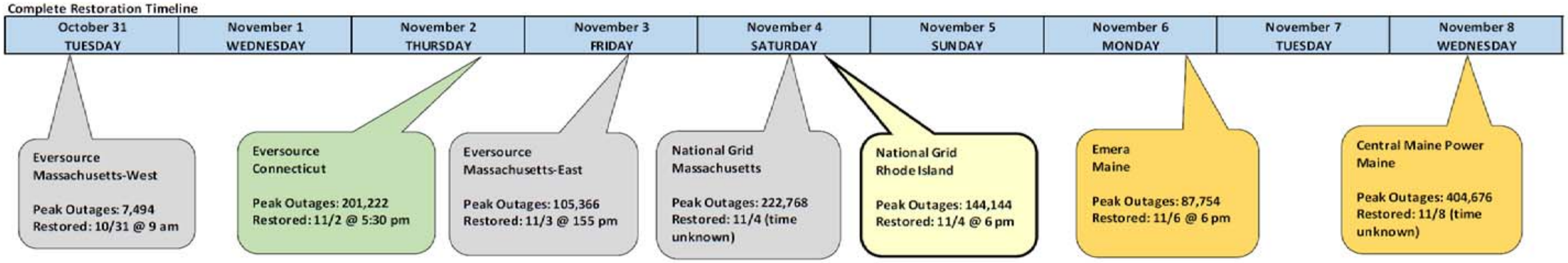
(2) Eversource - CT Storm Briefing, Attachment B, 11/2 briefing states restoration complete at 5:30 pm (page 52)

(3) Eversource Mass report indicated 1,395,587 customers but could not determine East/West. 2016 Annual report numbers are used

(4) see National Grid Mass storm report; page 25

(5) under 2,000 remaining per twitter post

Complete Restoration Timeline



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Appendix D

New England Utility Response Level Matrixes

Emergency Plan Event Level Matrix

Event Level	Typical Number of Customers out at Peak	Typical Number of Trouble Spots	Weather Type [2]	Typical Resource Strategy [3]	Typical Restoration Duration	Typical Global ETR Availability Timeframe	Typical ICS Structure Activation Level	Typical Damage Assessment and Typical Restoration Strategy [6]	Typical Logistics Strategy [7]
I	0% - 9% [1] (<125k)	<2000	Warm Weather	200 – 300 Line Resources	1-3 Days	< 24 hours	General Staff / PIO EOC[5]: Inactive - Active	Event / Hybrid	Centralized / Centralized Support with Division Staging Sites
			Cold Weather	250 – 350 Line Resources					
II	10% - 29% [1] (125k – 380K)	1500 – 10,000	Warm Weather	250 – 800 Line Resources	2-6 Days	< 36 hours	General Staff / PIO / All[4] EOC[5]: Active	Event / Hybrid / Circuit	Centralized Support with Division Staging Sites
			Cold Weather	300 – 1000 Line Resources					
III	30% - 49% [1] (375K – 650K)	8,000 – 25,000	Warm Weather	750 – 1250 Line Resources	5-10 Days	< 48 hours	All[4] EOC[5]: Active	Hybrid / Circuit	Decentralized Support with Division and District Staging Sites
			Cold Weather	800 – 1500 Line Resources					
IV	50% - 69% [1] (625k – 870k)	15,000 – 48,000	Warm Weather	1000 – 1800 Line Resources	8-21 Days	<48 hours	All[4] EOC[5]: Active	Hybrid / Circuit	Decentralized Support with District and Satellite Staging Sites
			Cold Weather	1250 – 2000 Line Resources					
V	70% - 100% [1] (> 870k)	> 35,000	Warm Weather	> 1500 Line Resources	> 18 Days	<48 hours	All[4] EOC[5]: Active	Circuit	Decentralized Support with District and Satellite Staging Sites
			Cold Weather	> 1750 Line Resources					

Type 1 Emergency Event (Full Scale Catastrophic Event)	Viewpoint	A Type 1 event is a catastrophic event, historically resulting in significant damage to the electrical transmission and distribution system. Type 1 events are rare but are usually forecasted in advance of the event. This event calls for the full implementation of ICS and all employees are assigned shifts and are scheduled in relation to their role in the ERP. All four Emergency Operations Centers (EOCs) are activated. This type of event is coordinated through daily Incident Command meetings/conference calls to coordinate pre-planning activities in advance of the event, restoration activities during the event and demobilization activities post event. Communication protocols are activated and discussion with local and state officials occurs prior to impact and through the restoration stage.
	Typical Event Characteristics	• The damage severity impacts the entire system such that restoration activities may require up to seven days or more once it is safe to begin restoration activities. • Typically > 15% (>150,000) customer interruptions. [TN 2] • Typically > 7,000 Lines of Trouble at Peak. [TN 3] • This type of event is anticipated to occur between 1 and 4 times in a ten-year period.
	Typical Response Organization	• The full Incident Command structure is activated. • All of the Command and General Staff positions are activated. • All EOCs are operational. • Additional restoration support functions such as Decentralized Dispatching, Wires Down and Damage Assessment will be established at a Branch, EOC and AWC level as directed by the Planning and Operations Section Chiefs and approved by the Incident Commander. • Remote Restoration Management Teams are activated in the most severely impacted areas at the discretion of the Operations and Planning Section Chief and approved by the Incident Commander. • Community Liaisons are activated at the EOCs, AWCs, or other areas as needed, to serve communities as directed by the Liaison Officer and approved by the Incident Commander. • Liaisons are typically activated to MEMA and the Cape Cod Multi-agency Coordination Center (MACC) depending upon level of State coordination required. • Staging Areas may be required to support external crews and resources.
	Typical Resource Activation (TN-4)	• Internal restoration resources normally available: 10 Secondary Line Crews, 100 Primary Line Crews, 68 Trouble Shooters (single-person crew). • This response requires outside assistance from other EESCO regions, contractors and/or mutual assistance from other utilities outside of the region. • The Company may supplement its internal workforce with between 35 and 250 or more external line crews. • The Company may supplement its normal complement of forestry crews with 50 to 150 or more additional crews. • The Company may supplement its normal complement of Damage Assessors with 0 to 50 or more additional Damage Assessors. • The Company may supplement its normal complement of Wire Guards with 0 to 200 or more additional Wire Guards. • Additional restoration support functions are staffed by company personnel and may be supported by up to 100 or more contract personnel.
	Communication/ Coordination	• Federal level coordination may be required. • The Incident Commander will brief the EESCO Emergency Coordination Team. • A written IAP is required for each operational period. • When a Type 1 event is anticipated Pre-Event Reporting is required. • When a Type 1 event is anticipated Pre-Event outreach to LSCs, Municipalities, Elected Officials and Regulators is performed. • Restoration Phase Reporting is required. • An After Action Review is required. • Post event meetings with the most severely affected communities will be held.

Type 2 Emergency Event (Serious Regional Event)	Viewpoint	A Type 2 event is a severe event, which has historically resulted in significant damage to the electrical transmission and distribution system in a region(s) or could be moderate damage across the entire territory. Type 2 events are uncommon, but are usually forecast in advance. This is a full implementation of ICS and most employees are assigned shifts and scheduled related to their role in ERP. This type of event is coordinated through daily Incident Command meetings/conference calls to coordinate pre-planning activities in advance of the event, restoration activities during the event and demobilization activities post event. All four Emergency Operation Centers are activated. Communication protocols are activated and extended discussions with local and state officials occurs prior to impact and through the restoration stage.
	Typical Event Characteristics	• The damage severity within a specific region or spread across the system is such that restoration activities are generally accomplished within a 96-hour period once it is safe to begin restoration activities. • Typically 5 to 17% (50,000 to 187,000) customer interruptions. [TN 2] • Typically 3,000 to 10,000 Lines of Trouble at Peak. [TN 3] • This type of event is anticipated to occur between 2 and 4 times in a five-year period.
	Typical Response Organization	• The full Incident Command structure is activated. • All of the Command and General Staff positions are activated. • All EOCs are operational. • Additional restoration support functions such as Decentralized Dispatching, Wires Down and Damage Assessment will be established at a Branch, EOC and AWC regional level as directed by the Planning and Operations Section Chiefs and approved by the Incident Commander. • Remote Restoration Management Teams are activated in the most severely impacted areas at the discretion of the Operations and Planning Section Chief and approved by the Incident Commander. • Community Liaisons are activated to EOCs and AWCs to serve communities as directed by the Liaison Officer and approved by the Incident Commander. • Liaisons are typically activated to MEMA and the Cape Cod MACC depending upon level of State coordination required. • Staging Areas may be required to support external crews and resources.
	Typical Resource Activation (TN-4)	• Internal restoration resources normally available: 10 Secondary Line Crews, 100 Primary Line Crews, 68 Trouble Shooters (single-person crew). • This response requires outside assistance from other EESCO regions, contractors and/or mutual assistance from other utilities outside of the region. • The Company may supplement its internal workforce with between 10 and 100 external line crews. • The Company may supplement its normal complement of forestry crews with 25 to 50 additional crews. • The Company may supplement its normal complement of Damage Assessors with 0 to 25 additional Damage Assessors. • The Company may supplement its normal complement of Wire Guards with 0 to 50 additional Wire Guards. • Additional restoration support functions are typically staffed by company personnel and may be supported by up to 0 to 50 contract personnel.
	Communication/ Coordination	• The Incident Commander may brief the EESCO Emergency Coordination Team. • A written IAP is required for each operational period. • When a Type 2 event is anticipated, Pre-Event Reporting is required. • When a Type 2 event is anticipated, Pre-Event outreach to LSCs, Municipalities, Elected Officials, and Regulators is performed. • Restoration Phase Reporting is required. • An After Action Review is required. • Post event meetings with the most severely affected communities may be held.

New England Utility 2 (Continued)

Type 3 Emergency Event (Moderate Regional Event)	**Viewpoint**	A Type 3 event represents the greatest range of uncertainty due to the severity of event being forecasted but with low to medium confidence levels for the degree of impact and geographical area that is threatened. This type of event historically resulted in significant damage to a district(s) or moderate damage to region(s). The approach is to prepare for multiple regions to potentially be impacted by activating the ICS structure and the opening of one or more EOCs. Employees will be assigned shifts and scheduled according to the threat, then moved to the areas with less impact to areas that received greater damage. This type of event is coordinated through daily Incident Command meetings/conference calls to coordinate pre-planning activities in advance of the event, restoration activities during the event and demobilization activities post event. Communication protocols are activated and extended discussions with local and state officials occurs prior to impact and through the restoration stage.
	Typical Event Characteristics	• The damage severity within a specific district or region(s) is such that restoration activities are generally accomplished within a 48-hour period. • Typically 2 to 7% (20,000 to 77,000) customer interruptions. [TN 2] • Typically 1,800 to 3000 Lines of Trouble at peak. [TN 3] • This type of event generally occurs between 1 and 5 times per year.
	Typical Response Organization	• The full Incident Command structure is activated. • One or more of the EOCs may be activated to match the complexity and breadth of the event. • Additional restoration support functions such as Decentralized Dispatching, Wires Down and Damage Assessment may be established at a branch, EOC or AWC level as directed by the Planning and Operations Section Chiefs and approved by the Incident Commander. • Community Liaisons are activated to operational EOCs AWCs as directed by Liaison Officer and approved by the Incident Commander. • Liaisons are typically activated to MEMA and the Cape Cod MACC depending upon level of State coordination required. • Staging Areas may be required in an area if it has been severely impacted and requires a concentrated amount of crews and resources.
	Typical Resource Activation (TN-4)	• Internal restoration resources normally available: 10 Secondary Line Crews, 100 Primary Line Crews, 68 Trouble Shooters (single-person crew). • This event may require assistance from other EESCO regions, contractors or mutual assistance. • The Company may supplement its internal workforce with between 0 and 25 external line crews. • The Company may supplement its normal complement of forestry crews with 0 to 20 additional tree crews. • Additional restoration support functions are typically staffed by company personnel.
	Communication/ Coordination	• A written IAP may be required for each operational period. • When a Type 3 event is anticipated Pre-Event Reporting is required • When a Type 3 event is anticipated Pre-Event outreach to Life Support Customers, Municipalities, Elected Officials, and Regulators is performed. • Restoration Phase Reporting is required.

Type 4 Non-Emergency Restoration Event (Upgraded Normal Operations)	**Viewpoint**	Type 4 events include (but are not limited to): distribution events that impact one or more district. Type 4 events may be due to thunderstorms, high winds, frequent and/or sever lightning, small to moderate winter storms or unanticipated events. Typically these events are managed by System Operations with assistance from Electric Field Operations. Control and management of the event typically remains centralized but may decentralize to one or more Emergency Operations Center depending on the damage. The Incident Command Staff is notified and specific section may be activated depending on the impact of the event.
	Typical Event Characteristics	• The damage severity within a specific district is such that restoration activities are generally accomplished in less than 24 hours. • The incident is usually limited to one or two operational periods in the Event Restoration phase. • Typically <2 % (20,000) customer interruptions. [TN 2] • Typically 700 to 1,800 Lines of Trouble at peak. [TN 3] • This type of event generally occurs less than 10 times per year.
	Typical Response Organization	• Incident Command Structure may be activated. • Command and General Staff positions activated as needed and the complexity of the event warrants • One or more EOCs may be operational depending of the geographical threat and complexity. • Community Liaisons may be staffed at the activated EOCs and AWCs as directed by the Liaison Officer and approved by the Incident Commander.
	Typical Resource Activation	• Internal restoration resources normally available: 10 Secondary Line Crews, 100 Primary Line Crews, 68 Trouble Shooters (single-person crew). • Restoration is generally accomplished with local assets possibly with assistance from other EESCO region distribution line assets • Typically 2-10 personnel may be deployed to EOCs and AWCs that have been activated at the discretion of the Planning and Operations Section Chiefs and approved by the Incident Commander to perform wire guard or damage assessment functions.
	Communication/ Coordination	• No written IAP is required • The operations and maintenance department may have briefings or regional conference calls to ensure the complexity of the event is fully communicated to management and that response staff receive the appropriate level of support required for the situation

Type 5 (Normal Operations)	Viewpoint	Type 5 events represent normal operations and are managed by the System Operations Dispatch Organization which is staffed 24/7/365. For small outages, system Operations will dispatch designated trouble resources to repair the outage. If upon arrival the Trouble Shooter determines additional resources are needed, a supervisor is assigned and will secure additional line crews from the Electric Field Operations organization.
	Typical Event Characteristics	• System activity is normal. • Incidents are contained within the first operational period and often within a 12 hour period after resources arrive on scene. • Typically <1 % (5,000) customer interruptions. [TN 2] • Typically 0 to 50 lines of trouble at peak. [TN 3] • Normal daily internal crew assignments.
	Typical Response Organization	• Incident Command Structure is not activated. • Emergency Operations Centers are not activated
	Typical Resource Activation	• Outage response is coordinated with local on-call personnel.
	Communication/ Coordination	• No written IAP is required.

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OASREP 5.1.3 Response Matrix

Level	Event Characteristics	Customers Affected	Expected # of Trouble Locations	Approximate # of Crews	Duration	Section Staffing: Electric Ops	Section Staffing: Logistics	Section Staffing: Communications	Section Staffing: Outage Analysis & Survey	Section Staffing: Resource Assessment & Coordination	Section Staffing: Employee & Labor Relations	Event Frequency	Area Impact	Event Severity
I	Small Impact Event (Thunder Storm, Heavy Wind, Heat Wave or Snow / Ice / Rain - potential) (Elec Ops response within normal staffing) Incident Command Center (ICC) not activated Logistics Support Center (LCS) & Customer Care Center not activated	< 20,000	<100	<50	< 12 hours	VP Ops - notified Elect. Ops. Directors - notified ERP Manager - notified **ESD (Region)** Supervisors Dispatchers Troubleshooters **EC&M (EOC)** Directors & Managers Supervisors Line Crews	Section Chief - Notified Warehouse Notified	Section Chief - Notified	Section Chief - Notified Impacted EOC(s) Outage Work Coord Technical Assistant Scouts Runner Coord Runners			10+ / yr	District (1 to 3) / Region	Limited
II	Moderate Impact Event Begin to exceed District internal resources May need support for other NSTAR Districts Incident Command Center (ICC) not activated Logistics Support Center (LCS) & Customer Care Center not activated	Between 20K and 50K	<250	<100	12 - 24 hours	VP Ops - notified Elect. Ops. Directors - notified ERP Manager System Operation Director Notified EOC **ESD (Region)** Supervisors Dispatchers Troubleshooters **M&C (EOC)** Directors & Managers Notified Admin Supv. Supervisors Line Crews Scouts NIS Unit Leader Fleet Support Comm Liaison (Region)	Section Chief - Notified Contract Mmgt Unit Leader Stock Keepers Fleet Support	Section Chief - Notified CIC Branch Director	Section Chief - Notified Impacted EOC(s) Outage Work Coord Technical Assistant Scouts Runner Coord Runners	External Resource Acquisition Branch Director Tree Crews Contractor Crews	Safety and Security Branch Director Safety Consultant	5 - 10 / yr	Region	Limited
III	Serious Impact Event Incident Command Center (ICC) is activated **OEP 1.1.4 - ERP Incident Preparation & Initiation** Gas Support notified.	Between 50K and 100K	250 - 500	<200	24 - 48 hours	VP Ops - Incident Commander Section Chiefs- ICC **Decentralize to 4 EOC Centers --Section Chiefs to Staff EOCs** **ICEP 1.1.4 - ERP Incident Preparation & Initiation** CALL TREEs Implemented Director & Managers - ICC System Operation Director Operation Coor. M3i Super User Supervisors Dispatchers Troubleshooters Line Crews Service Crew Corrd Service Crews Clerical Support Lock Out Coordinator	Section Chief Notified - IC Section Chiefs- ICC CALL TREEs Implemented Logistics Coord in EOC Procurement Branch Warehouse Branch Facilities Branch Fleet/Transportation Branch NIS Branch EAD Branch Finance Branch Claims and Risk Branch	Section Chief Notified - IC Section Chiefs- ICC **ICEP 1.1.4 - ERP Incident Preparation & Initiation** CALL TREEs Implemented Life Support Customers Comm Coord. @ EOC Media Unit Leader Customer Information Coor. Government Affairs & DPU Branch Director Comm Liaison (EOC) Municipal Info Comm. MEMA Liaison	Section Chief Notified - IC Section Chiefs- ICC CALL TREEs Implemented OA&S Div Mgr. @ in EOC Outage Work Coordinator. Technical Assist. Scout Rapid & Detail Survey Team Runner Coord. Runner FPS 2&3	Section Chief Notified - IC Section Chiefs- ICC **ICEP 1.1.4 - ERP Incident Preparation & Initiation** CALL TREEs Implemented Resource Acquisition Branch Director External Resource Group Manager Field Resource Unit Leader Mutual Aid Crews Tree Crews Foreign Contractor Crews Forecast and Analysis Director Restoration and Crew Forecasting Unit Leader Resource Coordinator Director Internal Resource Group Manager Internal Management Unit Leader Resource Tracking Branch Director Divisional Resource Tracking Manager Administrative Supervisor Clerical Support RAC Internal Resource CoordinationCoordinator	Section Chief Notified - IC Section Chiefs- ICC CALL TREEs Implemented Labor Relations Branch Director Safety and Security Branch Director Labor Consultants Security Group Manager Safety Consultant	1 - 5 / yr	Region	Critical

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OASREP 5.1.3 Response Matrix

Level	Event Characteristics	Customers Affected	Expected # of Trouble Locations	Approximate # of Crews	Duration	Section Staffing: Electric Ops	Logistics	Communications	Outage Analysis & Survey	Resource Assessment & Coordination	Employee & Labor Relations	Event Frequency	Area Impact	Event Severity
IV	Serious Impact Event **EOEP 1.1.4 - ERP Incident Preparation & Initiation** Gas Support notified.	> 100K	>500	>300	48 - 72 hours	**Decentralize to 4 EOC Centers --Section Chiefs to Staff EOCs-- Conference Call Schedule Initiated**								
						IC Declares ERP CALL TREE Implemented Director & Managers - ICC System Operation Director Operation Coor. M3i Super User Supervisors Dispatchers Troubleshooters Line Crews Service Crew Corrd Service Crews Clerical Support Lock Out Coordinator UG, Station & Transmission Circuit Ownership reviewed	IC Declares ERP CALL TREEs Implemented Logistics Coord in EOC Procurement Branch Warehouse Branch Facilities Branch Fleet/Transportation Branch NIS Branch EAD Branch Activate Logistics Support Center Activat[redacted] Receiving Center Receiving Center Branch Finance Branch Claims and Risk Branch	IC Declares ERP CALL TREEs Implemented Life Support Customers Comm Coord. @ EOC Media Unit Leader Customer Information Coor. Government Affairs & DPU Branch Director Comm Liaison (EOC) Municipal Info Comm. MEMA Liaison	IC Declares ERP CALL TREEs Implemented OA&S Div Mgr. @ in EOC Outage Work Coordinator. Technical Assist. Scout Rapid & Detail Survey Team Runner Coord. Runner FPS 2&3	IC Declares ERP CALL TREEs Implemented Resource Acquisition Branch Director External Resource Group Manager Field Resource Unit Leader Mutual Aid Crews Tree Crews Foreign Contractor Crews Forecast and Analysis Director Restoration and Crew Forecasting Unit Leader Resource Coordinator Director Internal Resource Group Manager Internal Management Unit Leader Resource Tracking Branch Director Divisional Resource Tracking Manager Administrative Supervisor Clerical Support RAC Internal Resource CoordinationCoordinator	IC Declares ERP CALL TREEs Implemented Section Chief - ICC Labor Relations Branch Director Safety and Security Branch Director Labor Consultants Security Group Manager Safety Consultant	One Event in 3 years	System Wide	Critical
V	Catastrophic System Event Hotel Accommodations Made Receiving Centers Activated Incident Command Center (ICC) is activated Logistics Support Center (LCS) & Customer Care Center	> 100K	>750	>350	>72 Hours	**Decentralize to 4 EOC Centers --Section Chiefs to Staff EOCs-- Conference Call Schedule Initiated**								
						IC Declares ERP CALL TREE Implemented Director & Managers - ICC System Operation Director Operation Coor. M3i Super User Supervisors Dispatchers Troubleshooters Line Crews Service Crew Corrd Service Crews Clerical Support Lock Out Coordinator UG, Station & Transmission Circuit Ownership reviewed	IC Declares ERP CALL TREEs Implemented Logistics Coord in EOC Procurement Branch Warehouse Branch Facilities Branch Fleet/Transportation Branch NIS Branch EAD Branch Activate Logistics Support Center Activate[redacted]t Receiving Center Receiving Center Branch Finance Branch Claims and Risk Branch	IC Declares ERP CALL TREEs Implemented Life Support Customers Comm Coord. @ EOC Media Unit Leader Customer Information Coor. Government Affairs & DPU Branch Director Comm Liaison (EOC) Municipal Info Comm. MEMA Liaison	IC Declares ERP CALL TREEs Implemented OA&S Coord. @ in EOC Outage Coordinator EOC Technical Assist. Technical Support FPS 2&3 Rapid & Detail Survey Team Scout Runner Work Packaging Team	IC Declares ERP CALL TREEs Implemented Resource Acquisition Branch Director External Resource Group Manager Field Resource Unit Leader Mutual Aid Crews Tree Crews Foreign Contractor Crews Forecast and Analysis Director Restoration and Crew Forecasting Unit Leader Resource Coordinator Director Internal Resource Group Manager Internal Management Unit Leader Resource Tracking Branch Director Divisional Resource Tracking Manager Administrative Supervisor Clerical Support RAC Internal Resource CoordinationCoordinator	IC Declares ERP CALL TREEs Implemented Section Chief - ICC Labor Relations Branch Director Safety and Security Branch Director Labor Consultants Security Group Manager Safety Consultant	One Event in 5 years	System Wide	Catastrophic

Attachment 1 - O&R STORM CLASSIFICATION MATRIX

Storm Category & Plan	PSC Cat	Typical Weather Conditions & System Impact	# Of Customers Projected Out of Service	Minimum Staffing levels (per division as appropriate): Operations										Customer Operations			EH&S		Planning & Analysis				Information				Liaison		Logistics							
				Restoration Leader / division	Trouble Shooter Crews	Construction Crews	Supplemental Crews	Line Clearance Crews	LC Crew Guides	Mutual Aid Crews	MA Restoration Leader	Priority Restoration Crews	Site Safety	CSR's	Special Response Team & PD/FD	Large Power Rep	Safety Rep	Environmental Rep	Damage Assessors	OMS Support	Analysis Planning	ETR Monitoring and Customer Call Backs	Corporate Communications	Public Information	Emergency Information Center	Communications Quality Control	Community Relations	CRT	Transportation	Telecommunications	Information Technology	Dry Ice	Stores	Facilities	Hotel/ Food	Security
1 – Upgraded (O&R Regional Resources)	1	- Isolated thunderstorms, rain and fast moving fronts - Sustained winds up to 20 mph - Gusts of 30 mph - Condition is short - Light damage to electric distribution system	<7500 <150 NP incidents	0	8	15	29	5	3	5	1	0	10	10	2	0	1	1	6	1	2	1	0	0	0	1	1	0	2	0	0	0	1	0	1	6
2 - Serious (O&R internal resources and contractors)	2	- Regional thunderstorm & lightning activity - Sustained winds greater than 35 mph - Gusts of 40 mph + - Condition is mid-term - Localized heavy damage to electric distribution system	7500 - 10,000 150 - 250 NP	2	8	30	29	5	5	5	1	1	15	25	4	1	2	2	20	2	2	1	0	0	0	2	2	0	3	2	1	0	1	1	1	6
			10,000 - 15,000 250 - 400 NP	2	8	40	29	10	5	10	1	1	20	35	6	1	3	4	40	2	4	2	4	4	4	2	2	2	3	10	1	0	1	1	1	6
			15,000 - 20,000 400 - 500 NP	2	8	50	29	15	5	15	1	1	30	45	8	1	2	4	40	2	5	2	4	4	4	2	2	4	4	12	1	0	1	1	1	7
3 – Serious (All O&R resources and localized Mutual Assistance)	3	- Widespread thunderstorms, heavy rain - Tropical depression or smaller Nor'easter type storms - Sustained winds 30 - 40 mph - Gusts of 40 - 50 mph - Widespread moderate to heavy damage to electric distribution system	20,000 - 30,000 250 - 500 NP	3	8	60	29	20	5	20	2	1	50	60	10	2	3	4	40	4	5	4	4	4	6	4	2	4	5	12	2	12	2	2	3	9
			30,000 - 40,000 500 - 750 NP	3	8	60	29	25	5	40	2	2	75	75	12	2	3	4	50	4	6	4	4	4	6	4	2	4	5	12	2	12	2	2	3	12
			40,000 - 50,000 750 - 1000 NP	3	8	75	29	30	5	60	3	2	100	90	18	3	3	6	60	6	6	5	4	4	7	4	2	4	6	12	2	12	2	2	3	22
4 – Full Scale (All O&R resources and extensive Mutual Assistance Resources)	3	- Tropical depression or hurricane - Sustained winds greater than 40 mph - Gusts of 45 mph + - Condition is exists for 12 hrs - >25% damage to electric distribution system	50 - 60,000 1000 NP	3	8	75	64	40	5	100	3	3	200	115	22	3	4	6	80	6	8	7	4	4	8	4	2	6	6	12	2	15	3	3	4	22
			60 - 80,000 1000 - 2000 NP	3	8	80	64	50	5	140	3	4	200	160	24	4	4	8	100	6	10	7	4	4	9	4	2	6	7	15	2	15	4	4	4	27
			80 - 100,000 2000 - 3000 NP	3	8	100	64	60	5	180	3	5	200	190	26	4	6	8	150	8	12	7	6	6	9	4	2	6	7	15	3	15	6	6	4	30
5 - Full Scale (All O&R resources and extensive Mutual Assistance Resources)		- Extreme weather events (thunderstorms, rain, snow, ice) - Sustained winds 30 - 39 mph - Gusts 40 - 50 mph - >50% damage to electric distribution system - Limited mobility due to damaged infrastructure	100K - 175K 3000 - 10,000 NP	3	8	150	213	100	10	300	3	5	300	250	28	5	8	10	200	8	16	8	8	8	10	6	2	8	8	15	4	18	8	6	4	30
Disaster Response (All O&R resources and extensive Mutual Assistance Resources)		- Catastrophic weather events (hurricane, heavy wet snow or severe icing) - >75% damage to electric distribution system - Limited communications & mobility due to infrastructure damage - Potential casualties	>175,000 >10,000 NP	3	8	200	280	150	15	450	3	6	500	295	30	5	10	12	400	8	20	8	10	10	10	6	2	8	8	15	5	21	10	6	4	30

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Appendix E

Company's Current Storm Report Outline

Appendix E: Recommended Storm Report Enhancements
(*PowerServices' recommendations are indicated in red, italicized and underlined*)

I. EXECUTIVE SUMMARY

II. INCIDENT ANTICIPATION

A. Determination of Incident Classification

Provide the factors considered in initially establishing or revising the expected incident classification level included the following:

- Expected number of customers without service;
- Expected duration of the restoration event;
- Recommendations of the State Planning Section Chief, Transmission and Distribution Control Centers, and other key staff;
- Current operational situation (such as number of outages, resources, and supplies);
- Current weather conditions;
- Damage appraisals;
- Forecasted weather conditions;
- Restoration priorities;
- Forecasted resource requirements; and
- Forecasted scheduling and pace of restoration work crews.

B. Activation of Incident Command System (ICS)

Provide copies of all daily briefings

C. Determination of Crew Needs and Pre-Staging

Provide a table indicating the number, type and location of planned resources (in accordance with the ERP designated Event Type), and the number, type, and location of actual resources secured. Include daily resource staffing levels from pre-storm through complete restoration. Indicate whether resources are internal, external contractors, or resources acquired through a mutual aid agreement.

III. THE STORM AND ITS IMPACT

A. Forecast

Provide information relied on to forecast the storm, including predictive modeling.

B. Impact

IV. RESTORATION

Provide a timeline of the storm progression, the hour and date that constitutes the start of restoration, and the hour and date that constitutes complete restoration.
Provide a chronological outage restoration assessment to include the hour by hour number of customers out (in executable format) for i. the Company's Capital and Coastal regions and for the total system, and for ii. each feeder affected.

Provide a summary of number of customer outages at peak and customer outage minutes, by cause, for the Company's Capital and Coastal regions.

Provide a specific list of all circuits impacted, in executable format, including:
a. Region
b. Substation
c. Circuit number
d. Voltage
e. Initial outage time and date
f. Time and date of field assessment and any subsequent assessments
g. Time and date that crews were dispatched to restore service
h. Description of required crews (tree and/or line), and whether crews were National Grid employees or contractors.
i. Time and date that crews commenced restoration work
j. Time and date that restoration was completed
k. Total time required to complete restoration
l. Description of restoration work
m. Total outage duration
n. Number of customers impacted at peak of the outage
o. Total number of customers served
p. Detailed cause of outage
q. Most recent date (month/year) that National Grid cleared the right-of-way
r. Most recent date (month/year) that Enhanced Hazard Tree Mitigation (EHTM) was performed
s. Number of poles replaced due to storm impacts
t. Number of transformers replaced due to storm impacts
u. Miles of downed conductor replaced or reinstalled
v. Number of downed trees

A. Timing and Priority of Service

B. Restoration Coordination

C. Personnel Resources
Describe all efforts to acquire mutual aid assistance, including time and date of first request, number and type of resources requested, and number, type and date of resources allocated.

D. Safe Work Practices

V. COMMUNICATIONS DURING AND AFTER THE EVENT
A. Communication Regarding Estimated Times for Restoration (ETRs)

B. Intra-Company

C. Public Officials

D. Customers
Provide a detailed table listing each method of communication utilized throughout the event, including the purpose and level of interaction. (e.g. IVR received X number of calls, made X outbound calls, website received X hits, received/sent X text messages, posted X times on Facebook, Twitter, YouTube, etc).

E. Media

VI. TECHNOLOGY ISSUES

Summarize all technology issues experienced during the event. Include detailed description, impact on communication or restoration, steps taken by the Company to resolve issues, determination of root cause, and Company's plan to implement improvements that mitigate future issues.

VII. CONCLUSION