Thomas R. Teehan
Senior Counsel

March 8, 2013

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4382 - National Grid's Proposed FY 2014 Electric Infrastructure, Safety, and Reliability Plan
<u>Responses to Commission Data Requests – Set 2</u>

Dear Ms. Massaro:

On behalf of National Grid[1], I have enclosed ten (10) copies of the Company's responses to the Commission's Second Set of Data Requests concerning the above-referenced proceeding.

The Company's responses to Commission 2-3, Commission 2-4, and Commission 2-5 will be forthcoming shortly.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4382 Service List
Leo Wold, Esq.
Steve Scialabba, Division

[1] The Narragansett Electric Company d/b/a National Grid (hereinafter referred to as "National Grid" or the "Company").

Commission 2-1

Request:

Please provide a copy of the Company's system and capacity loading policy mentioned on bates stamp page 11 of the 2014 Electric ISR Proposal. When was the last time this policy was revised/updated?

Response:

Please see Attachment COMM 2-1 for the Company's Distribution Planning Guide, which was last revised in February 2011.

Prepared by or under the supervision of: Jennifer L. Grimsley

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ____________________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0 1	10/14/2009 2/15/2011	Initial draft Final approved document	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management

Distribution Planning Criteria Strategy
Table of Contents

Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0 1	10/14/2009 2/15/2011	Initial draft Final approved document	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:
- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

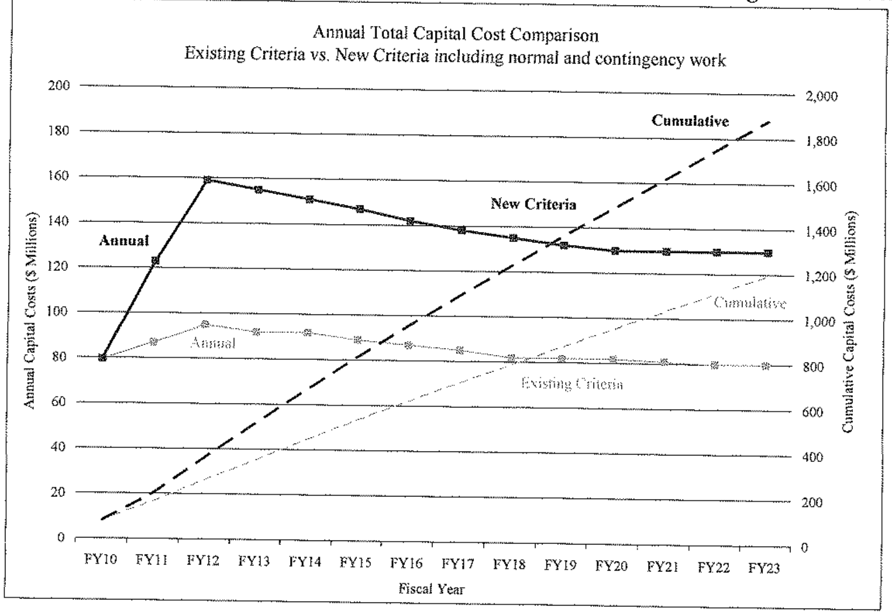
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

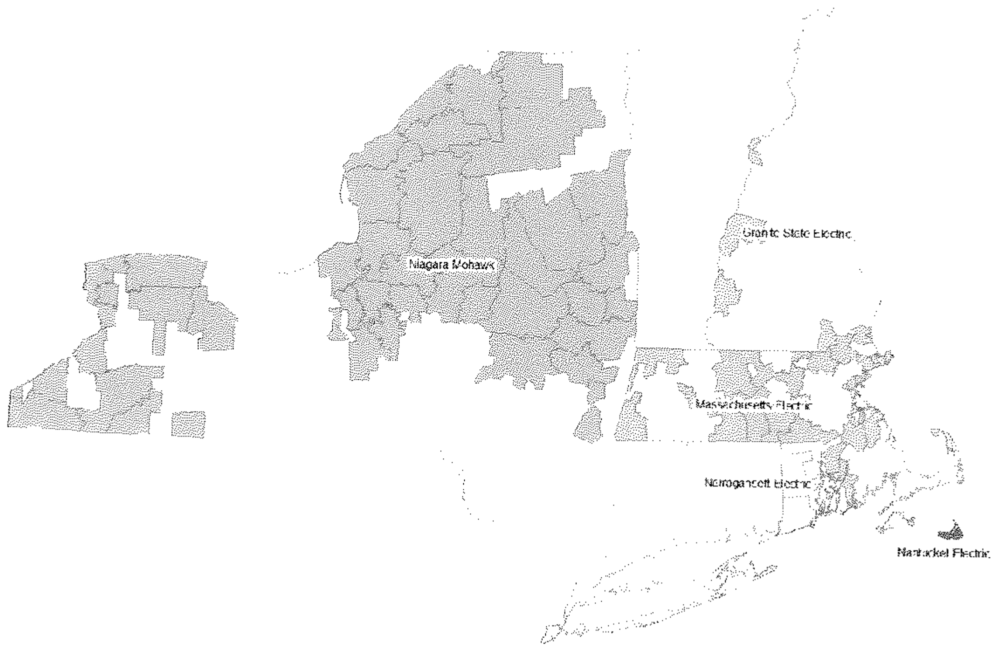
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

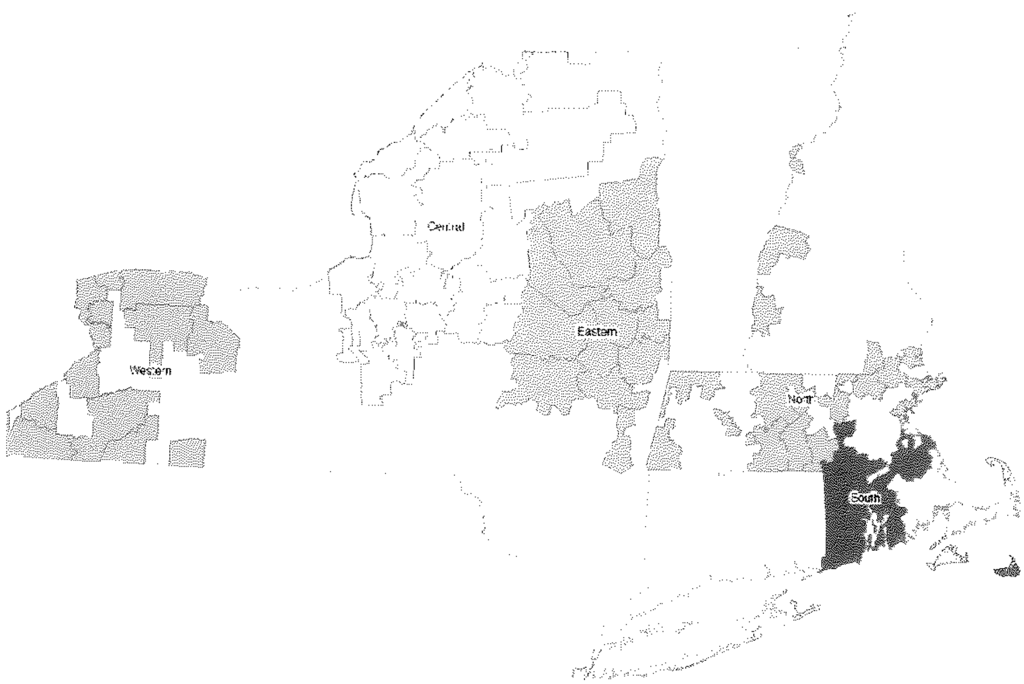
Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

Companies

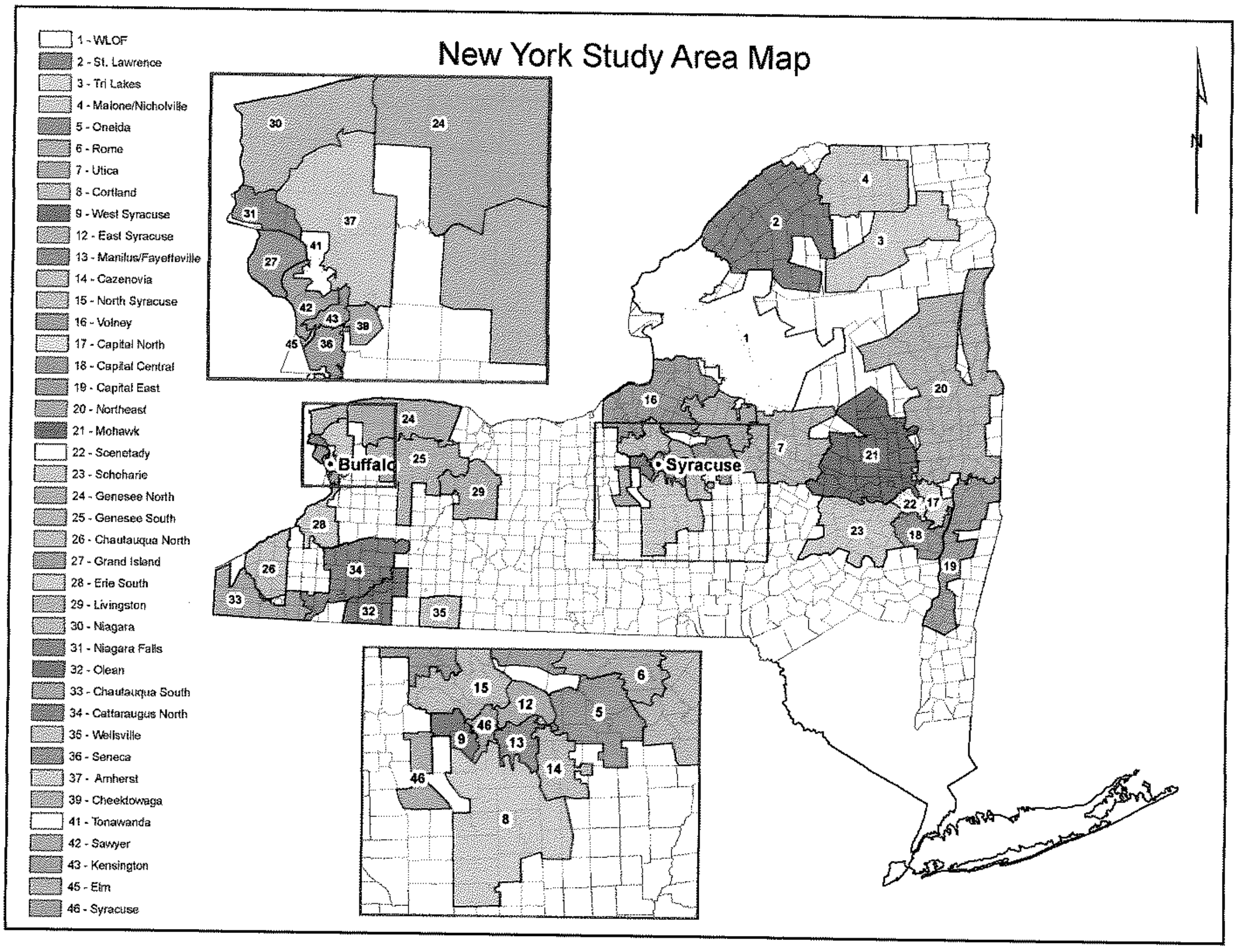


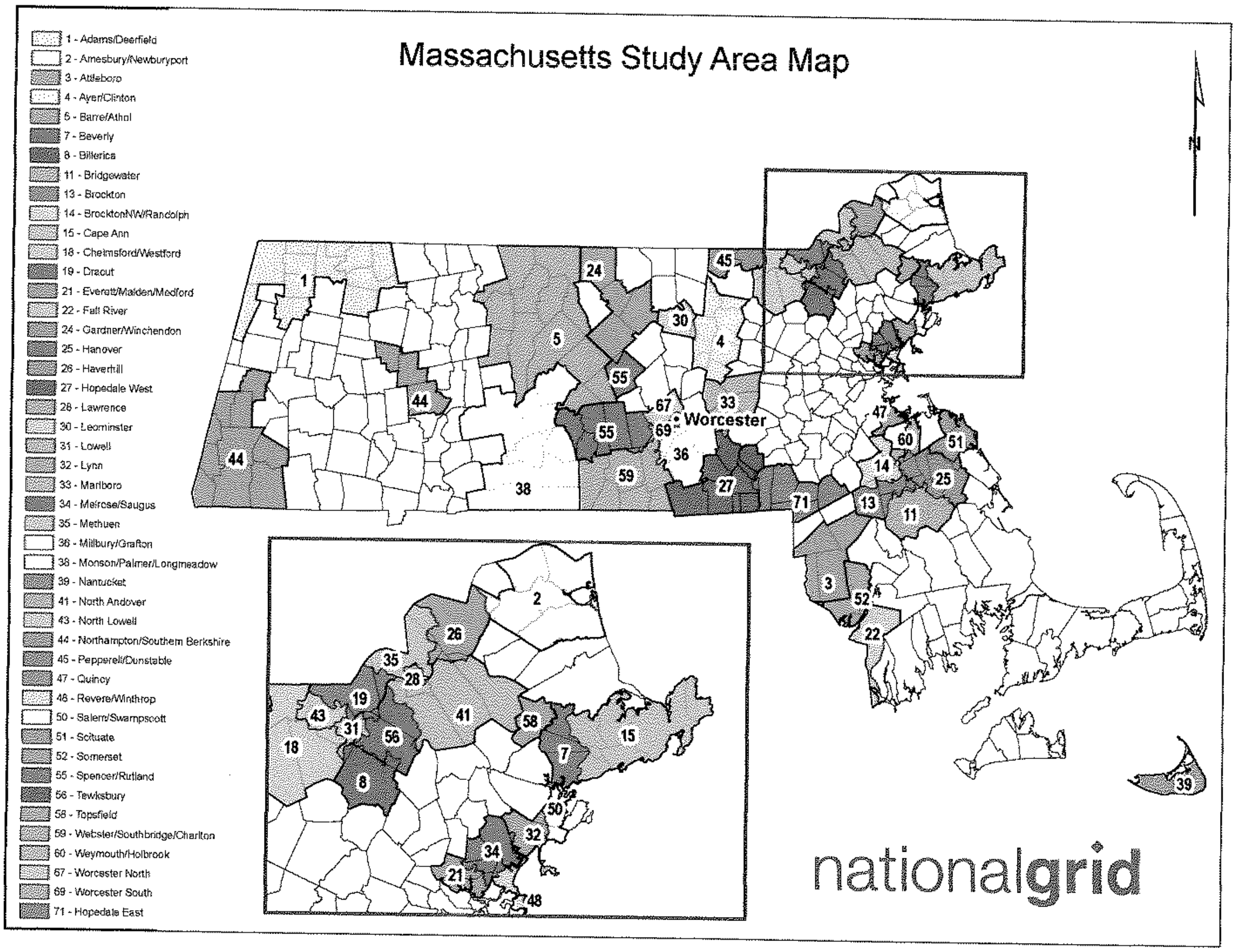
Divisions

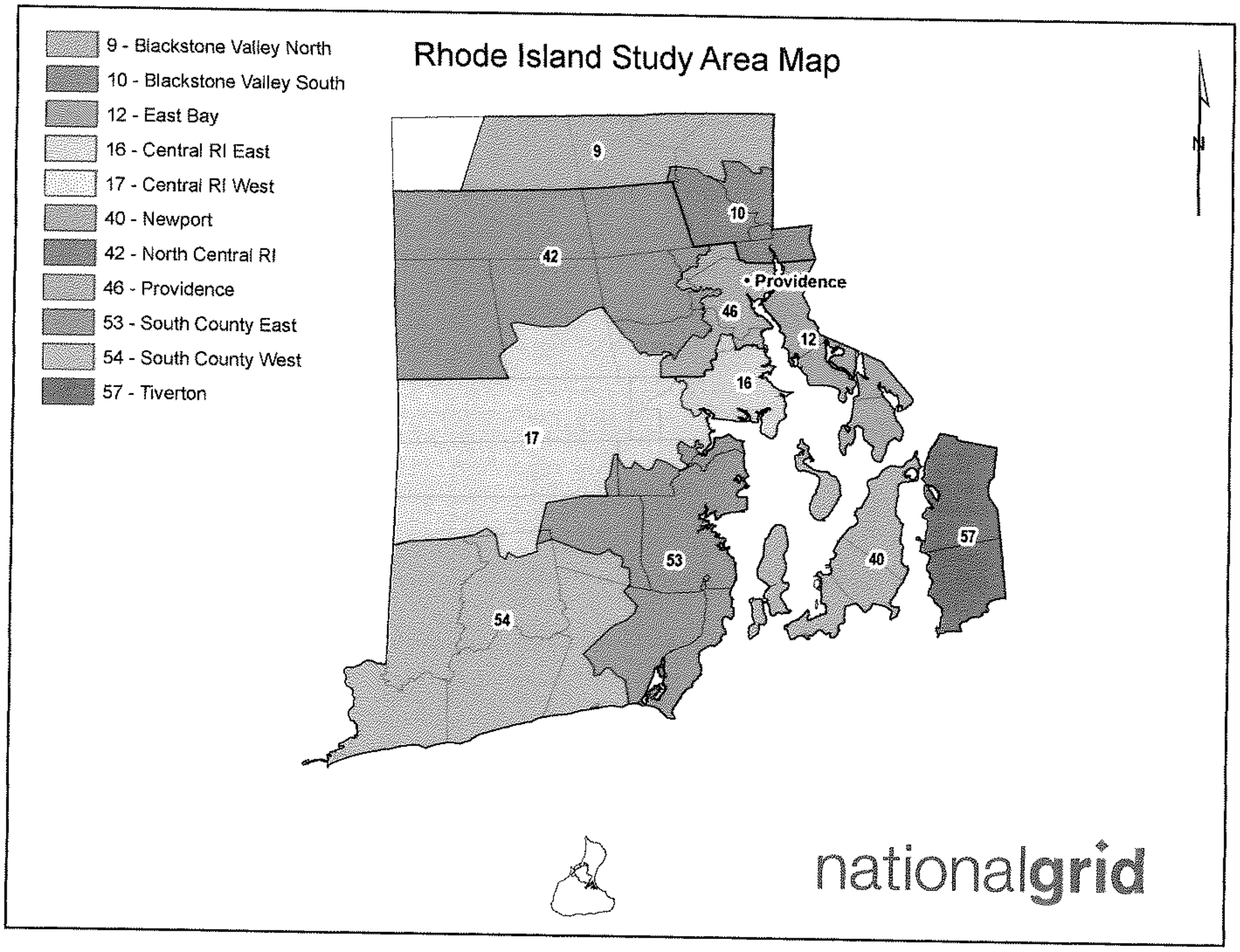


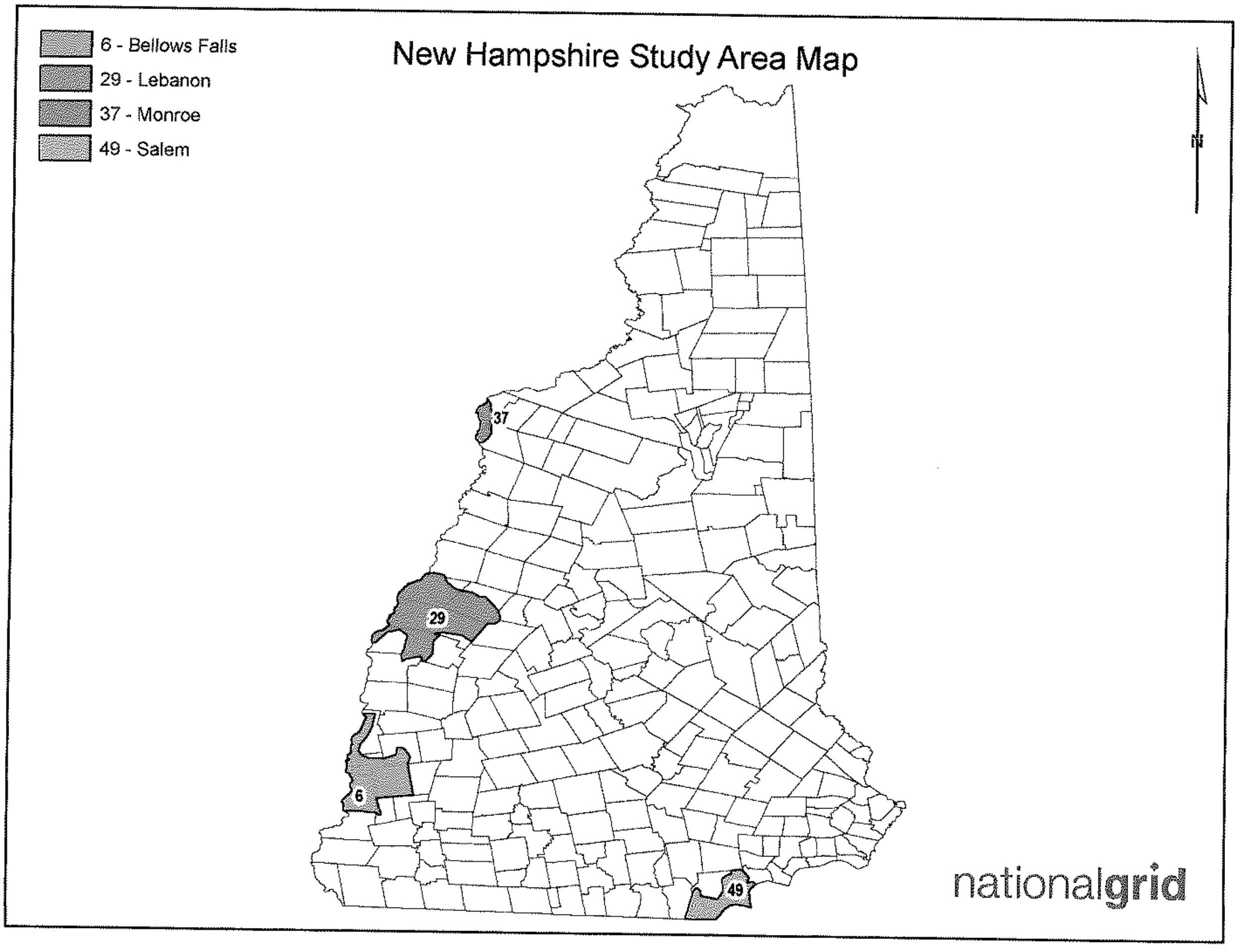
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
1 - Adams/Deerfield
2 - Amesbury/Newburyport
3 - Attleboro
4 - Ayer/Clinton
5 - Barre/Athol
7 - Beverly
8 - Billerica
11 - Bridgewater
13 - Brockton
14 - BrocktonNW/Randolph
15 - Cape Ann
18 - Chelmsford/Westford
19 - Dracut
21 - Everett/Malden/Medford
22 - Fall River
24 - Gardner/Winchendon
25 - Hanover
26 - Haverhill
27 - Hopedale West
28 - Lawrence
30 - Leominster
31 - Lowell
32 - Lynn
33 - Marlboro
34 - Melrose/Saugus
35 - Methuen
36 - Millbury/Grafton
38 - Monson/Palmer/Longmeadow
39 - Nantucket
41 - North Andover
43 - North Lowell
44 - Northampton/Southern Berkshire
45 - Pepperell/Dunstable
47 - Quincy
48 - Revere/Winthrop
50 - Salem/Swampscott
51 - Scituate
52 - Somerset
55 - Spencer/Rutland
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
69 - Worcester South
71 - Hopedale East
N
Worcester
nationalgrid


9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
Rhode Island Study Area Map
9
10
42
Providence
46
12
16
17
57
53
40
54
N
nationalgrid


6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
New Hampshire Study Area Map
N
37
29
6
49
nationalgrid

Commission 2-2

Request:

Please provide updated copies of the Charts mentioned on pages 27 through 31 by including data for CY 2012.

Response:

Please see Attachment COMM 2-2.

Prepared by or under the supervision of: Jennifer L. Grimsley

Chart 1: Reliability Performance 2001-1012

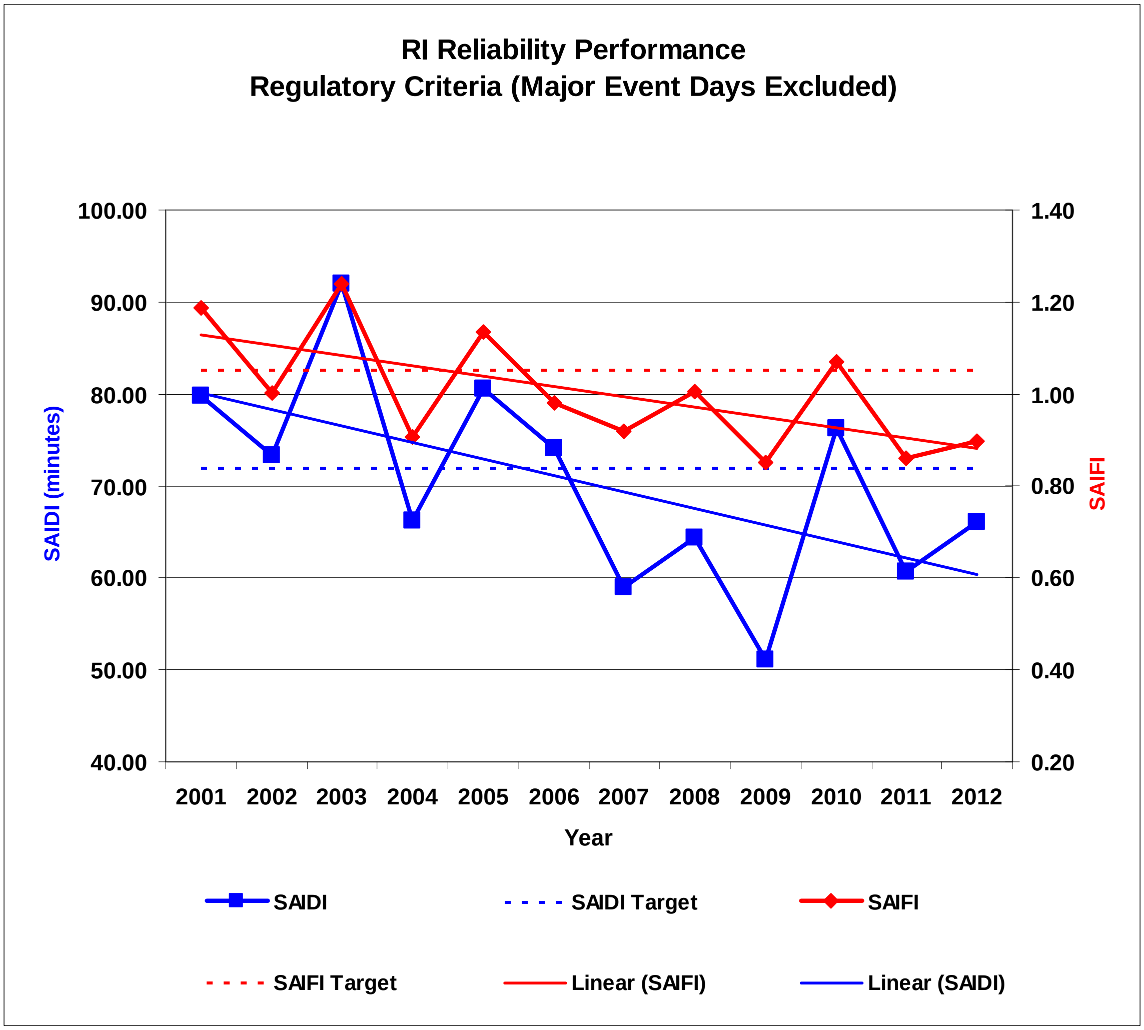


Chart 2: Customer Interruptions by Cause (excluding Major Event Days)

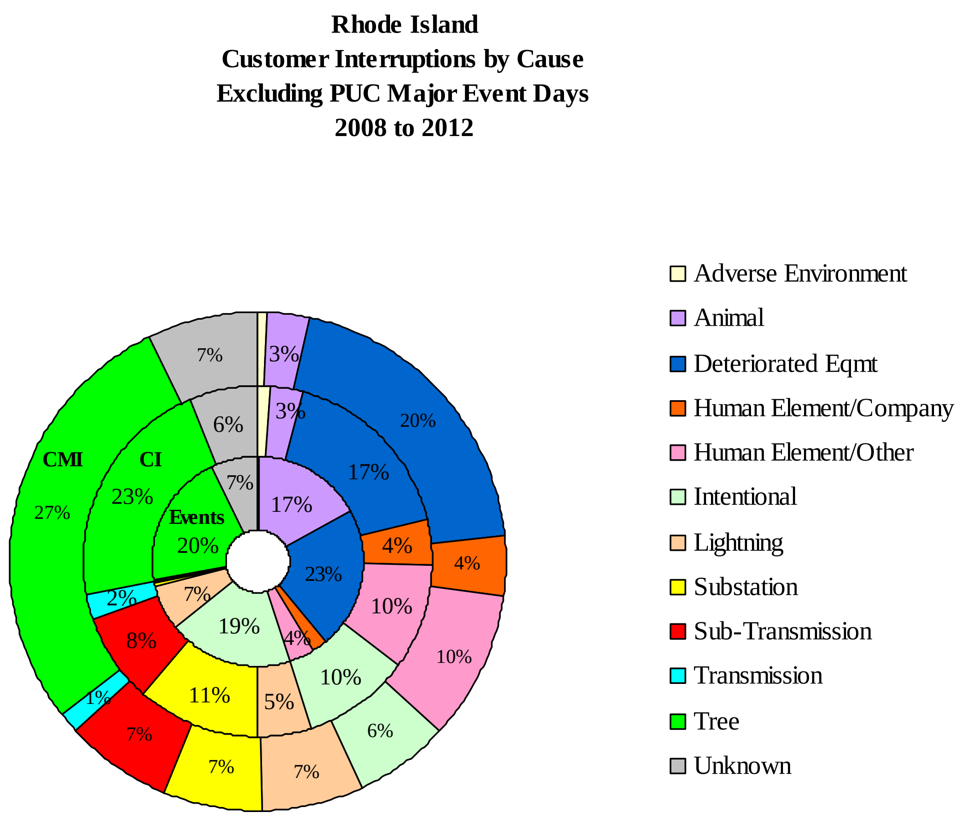


Chart 3: Customer Interruptions by Cause (including Major Event Days)