Rhode Island Energy Facility Siting Board
Appendices – Volume IA

Interstate Reliability Project

North Smithfield and Burrillville, Rhode Island

Prepared For: The Narragansett Electric Company
d/b/a National Grid
40 Sylvan Road
Waltham, Massachusetts 02451

Prepared By: AECOM
10 Orms Street, Suite 405
Providence, Rhode Island 02904

July 2012 (Revision No. 1 - 11/20/12)

This document has been reviewed for Critical Energy Infrastructure Information (CEII).

TABLE OF CONTENTS (VOLUME 1A)

Appendix N

ISO-NE, New Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment (September 2012), [referred to as "2012 Follow-Up Needs Analysis"].

This page intentionally left blank

Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment

Public Version - CEII Material Redacted

September 2012

Table of Contents

[redacted]

[redacted]

List of Figures

List of Tables

[redacted]

[redacted]

[redacted]

Section 1
Executive Summary

1.1 Objective

The objective of this study was to follow up with the analysis of the reliability-based transmission needs identified in the New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment, dated April 2011, specifically with respect to the changes in load forecast and forecasted energy efficiency.

The needs follow up evaluated the reliability of the southern New England transmission system for 2022 projected system conditions. The system was tested with all-lines-in service (N-0) and under N-1 and N-1-1 contingency events for a number of possible operating conditions. The study area defined as southern New England includes Northeast Utilities (NU), National Grid USA (NGRID) and NSTAR facilities in the states of Massachusetts, Rhode Island and Connecticut.[1]

The study was conducted in accordance with the Regional Planning Process as outlined in Attachment K to the Independent System Operator – New England Open Access Transmission Tariff (OATT). This study identifies the areas of the system that fail to meet NERC, NPCC and ISO standards and criteria. This needs follow up is the confirmation of the transmission needs stated in the previous updated needs assessment. A second study follow up will be conducted, to confirm the transmission solutions outlined in the New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report, dated February 2012, continue to meet the identified needs.

Summary of changes that this follow up study addressed:

- Updated Capacity, Energy, Loads, and Transmission (CELT) Report for 2012. The 2010 CELT report was used for the last needs study.
- Study year of 2022 for 10-year horizon. The year 2020 was used in the last needs study.
- Results from the most recent Forward Capacity Auction (FCA) #6 (Capacity Period June 1, 2015 – May 31, 2016). FCA #4 results were used in the last study.
- Forecasted energy efficiency (EE) published in the 2012 CELT Report through the year 2022. No forecasted EE past the last FCA was used in the last study.
- Changes in generation dispatch assumptions:
    - Wind power output – On shore 5% of nameplate in the import area, 100% in the export area. The QC value was used in the last needs study.
    - Hydro power assumptions – Update based on the ongoing Vermont / New Hampshire, Pittsfield / Greenfield, and Greater Hartford / Central Connecticut reliability studies. The QC value was used in the last needs study.
    - Salem Harbor, AES Thames, Bridgeport Harbor 2, Somerset 6, Somerset Jet 2, Holyoke 6 & 8, Bio Energy, Potter Diesel, and Ansonia were assumed out of service in base case due to multiple delist bids / retirements / interconnection queue withdrawals. These units were all available in the last needs study.

[1] Note that there are other studies currently underway (within the same geographic area) that are being coordinated with this study effort. Such studies include the Greater Boston, the southwest Connecticut, the Greater Hartford-Central Connecticut, the southeastern Massachusetts/Rhode Island (SEMA/RI) and the Pittsfield/Greenfield studies.

[redacted]

- Lake Road generating station was in service for all stresses. These units were assumed out of service for the East to West stressed cases in the last needs study.

1.2 Method and Criteria

The updated needs assessment was performed in accordance with the NERC TPL[2]-001, TPL-002, TPL-003 and TPL-004 Transmission Planning System Standards, the NPCC Directory #1, "*Design and Operation of the Bulk Power System,*" and the ISO Planning Procedure 3, "*Reliability Standards for the New England Area Bulk Power Supply System.*"

1.3 Study Assumptions

A ten-year planning horizon was used for this study based on the most recently available Capacity, Energy, Loads, and Transmission (CELT) Report issued in May 2012 at the time the follow up study began. This study was focused on the projected 2022[3] peak demand load levels for the ten-year horizon. The model reflected the following peak load condition:

2022 system load level tested:

- The summer peak 90/10 demand forecast of 34,130 MW for New England

A total of 3 base cases and 2 sensitivity cases were modeled for the study year in all the N-0 and N-1 contingency testing which represented a number of possible generation dispatch and availability conditions. A total of 40 design cases and 30 sensitivity cases were modeled for each study year in all N-1-1 contingency testing to represent a number of possible situations resulting from an initial event followed by system adjustment within the 30 minute criteria prior to a second event. System adjustments allowed in power-flow simulations for analyzing needs are listed in ISO Planning Procedure 3 (PP-3).

Design Cases

Base cases for N-1 and N-1-1 conditions were created for five different areas of concern.

- **New England West to East Stress:** [redacted]
- **New England East to West Stress:** [redacted]
- **Rhode Island Reliability:** [redacted]
- **Connecticut Reliability:** [redacted]

Sensitivity Cases

Base cases for N-1 and N-1-1 conditions were created for two additional scenarios of concern.

- **New England West to East Stress:** [redacted]
- **New England East to West Stress:** [redacted]

[2] NERC standards are divided into a number of compliance areas. The TPL series applies to Transmission Planning.

[3] The 2012 CELT forecast only has projected peak demands for the years 2012 to 2021. To determine the 2022 peak demand forecasted load, the growth rate from years 2020 to 2021 was applied to the 2021 forecast.

[redacted]

The first two scenarios stressed the New England West-East and East-West transfers to determine the capability needed on the bulk transmission system to serve demand on either side. The next two scenarios stressed conditions in local areas to determine the capability needed on the transmission system to serve demand in the local area. The sensitivity scenarios tested the effect of [redacted]

1.4 Specific Areas of Concern

Each base case was subjected to contingencies defined by NERC, NPCC and ISO standards and criteria including: the loss of a generator, transmission circuit, transformer, or bus section and also the loss of multiple elements that might result from a single event such as a circuit breaker failure or loss of two circuits on a multiple-circuit tower.

1.4.1 Results of N-0 Testing

N-0 study indicated no thermal or voltage violations for all cases.

1.4.2 Results of N-1 Testing

N-1 study indicated thermal violations for Eastern New England reliability testing. Violations were found on the 328 line (Sherman Road to West Farnum) and the 115 kV path connecting Rhode Island and Connecticut along the Long Island Sound shoreline. N-1 study indicated no thermal or voltage violations for Western New England reliability, Rhode Island reliability, and Connecticut reliability testing. N-1 study indicated no voltage violations for all cases.

1.4.3 Results of N-1-1 Testing

N-1-1 study indicated several thermal and voltage violations, the most severe during the Rhode Island reliability testing where a potential voltage collapse could occur [redacted]. Eastern New England reliability testing indicated thermal violations on the central and southern 345 kV West-East paths and thermal and voltage violations on the 115 kV paths connecting Rhode Island to Connecticut and southeastern Massachusetts. Western New England and Connecticut reliability testing indicated thermal violations on the central 345 kV East-West path and 115 kV path connecting Rhode Island and Connecticut along the Long Island Sound shoreline.

1.5 Statements of Need

The results of these analyses indicated a need to:

- Reinforce the 345 kV system into the West Farnum Substation for Rhode Island reliability
- Increase the transmission transfer capability from eastern New England and Greater Rhode Island to western New England if additional resources are available in the exporting area
- Increase the transmission transfer capability from western New England and Greater Rhode Island to eastern New England. With the retirement of Salem Harbor, there is a need for additional transmission transfer capability to eastern New England.
- Increase the transmission transfer capability into the state of Connecticut

These issues were seen in the last needs reassessment study and the follow up study continues to show similar concerns within the 10 year planning horizon. The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. The western New England reliability analysis shows the first violation in the 2016-2017 timeframe. The Rhode Island reliability analysis shows the first violation at 2012 load levels or earlier. The Connecticut reliability analysis shows the first violation in the 2016-2017 timeframe.

1.6 NERC Compliance Statement

This report is the first part of a two part process used by ISO New England to assess and address compliance with NERC TPL standards. This updated needs assessment report provides documentation of an evaluation of the performance of the system as contemplated under the TPL standards to determine if the system meets compliance requirements. The solution study report is a complementary report that documents the study to determine which transmission upgrades should be implemented along with the in-service dates of proposed upgrades that are needed to address the needs documented in the updated needs assessment report. The needs assessment report and the Solution Study report taken together provide the necessary evaluations and determinations required under the TPL standards.

(See Appendix F: NERC Compliance Statement for the complete NERC compliance statement)

Section 2
Introduction and Background Information

2.1 Study Objective

The objective of this study was to determine if the need for the Interstate Reliability Project component of the New England East West Solutions (NEEWS) still exists under currently forecasted system conditions. If the need is found to still exist, then an updated solutions follow up study will be performed to determine if any changes to the original preferred transmission plan are necessary.

2.1.1 Study Background

In the 2004 to 2008 time frame, the Southern New England Regional Working Group, which included representatives from Independent System Operator New England (ISO), National Grid USA (NGRID), and Northeast Utilities (NU), performed a study that has been referred to as the Southern New England Transmission Reliability (SNETR) study. The proposed regional solution that was developed as a result of this study effort has been labeled NEEWS. This solution consisted of four components: the Rhode Island Reliability Project (RIRP), the Greater Springfield Reliability Project (GSRP), the Interstate Reliability Project (Interstate), and the Central Connecticut Reliability Project (CCRP), known collectively as the NEEWS projects. These four components were the direct result of a regional transmission planning effort which combined a comprehensive regional transmission study with a comprehensive four-component regional transmission solution.

In accordance with the Regional Planning Process as outlined in Attachment K of the Independent System Operator – New England Open Access Transmission Tariff (OATT), the ISO reaffirmed the need for the RIRP and the GSRP in 2009, using the latest network, load and resource data available. The siting agencies in Rhode Island, Massachusetts and Connecticut have approved both of these components and NGRID and NU are now moving forward with the construction phase. The ISO started a reassessment of the Interstate component in 2010 and reaffirmed the need for a modified Interstate component in February 2012. A follow-up study of the Greater Hartford and Central Connecticut area will update and document the results of the CCRP updated needs analysis.

As stated previously, the NEEWS projects emerged from a coordinated series of studies assessing the deficiencies in the southern New England electric supply system. The SNETR study initially focused on limitations on East to West power transfers across southern New England and transfers between Connecticut and southeast Massachusetts and Rhode Island. These limitations had been identified as interdependent beginning in the ISO's 2003 Regional Transmission Expansion Plan (RTEP03). In the course of studying these inter-state transfer limitations, the working group determined that previously identified reliability problems in Greater Springfield and Rhode Island were not simply local issues, but also affected inter-state transfer capabilities. In addition, constraints in transferring power from eastern Connecticut across central Connecticut to the concentrated load in southwest Connecticut were identified.

The needs at that time were summarized as follows and are depicted in Figure 2-1:

- **East–West New England Constraints**: Regional East to West power flows could be limited during summer peak periods across the southern New England region as a result of thermal and voltage violations on area transmission facilities under contingency conditions.
- **Springfield Reliability**: The Springfield, Massachusetts area could be exposed to significant thermal overloads and voltage problems under numerous contingencies and load levels. The severity of these problems would increase as the transmission system attempts to move power into Connecticut from the rest of New England.
- **Interstate Transfer Capacity**: Transmission transfer capability into Connecticut and Rhode Island during summer peak periods could be inadequate under existing generator availabilities for criteria contingency conditions.
- **East–West Connecticut Constraints**: East to West power flows in Connecticut could stress the existing system under N-1-1 contingency conditions during peak load levels.
- **Rhode Island Reliability**: The system depends heavily on limited transmission lines or autotransformers to serve its peak load demand, which could result in thermal overloads and voltage problems during contingency conditions.

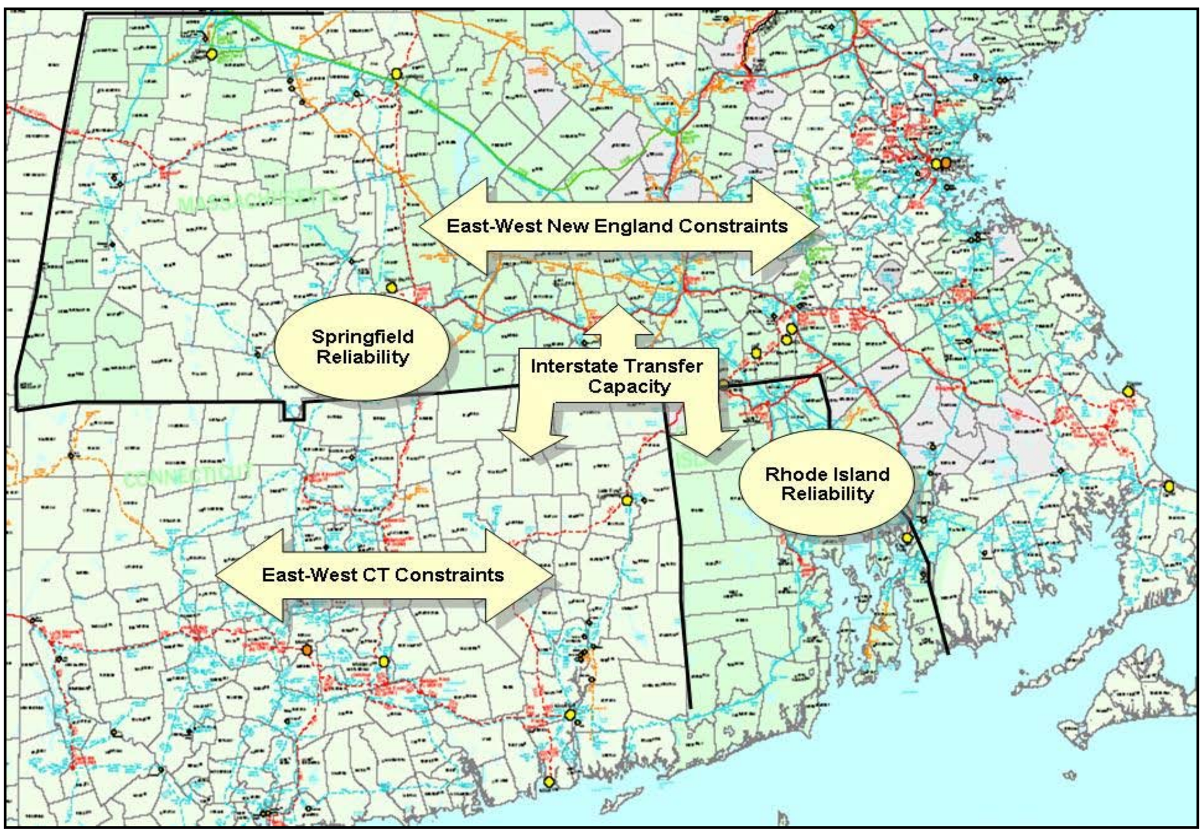

Figure 2-1: Original Southern New England Needs and Constraints

[redacted]

2.2 Area Studied

The study area consisted of the three southern New England states of Massachusetts, Rhode Island and Connecticut. Figure 2-2 is a geographic map of the 345/230 kV transmission system in southern New England with the major substations highlighted.

[redacted]

Figure 2-2: Southern New England Bulk Transmission System

For purposes of this study, the New England system was split into three sub-areas (eastern New England, western New England and Greater Rhode Island) based on weak transmission system connections to neighboring sub-areas. Figure 2-3 is a map that shows how the three sub-areas were divided geographically. For the eastern New England reliability study, Greater Rhode Island was considered as part of the western New England sub-area shown in Figure 2-4 (left). For the western New England reliability study, the Greater Rhode Island sub-area was considered as part of the eastern New England sub-area shown in Figure 2-4 (right).

The fact that the Greater Rhode Island area is part of the east when moving power westward and then becomes part of the west when moving power eastward is the direct result of where the transmission constraints develop under the two scenarios. A significant amount of generation enters the system via the 345 kV path between the West Medway and Card Street Substations, and constraints exist in moving power in both the westerly and easterly directions. With power flow from east to west (to cover for unavailable western resources), the Greater Rhode Island generation gets constrained to its west; hence, Greater Rhode Island is in the east and vice versa when you try to move power from west to east (to cover for unavailable eastern resources).

[redacted]

This is very similar to the Lake Road issue in Connecticut. Lake Road is currently considered outside of Connecticut under Connecticut Import conditions but, conversely, is considered within Connecticut when Connecticut Export is modeled.

[redacted]

Figure 2-3: Interstate Needs New England Sub-Areas

[redacted] [redacted]

Figure 2-4: Eastern and Western New England Sub-Areas by Direction of Power Flow

Electrically the western New England sub-area is defined with the following tie-lines in Table 2-1.

Table 2-1
Western NE Sub-Area Tie Lines

Element	kV	From	To
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[4] This new tie-line is part of RSP 941 – Central/Western Massachusetts Upgrades

[redacted]

The eastern New England sub-area is defined electrically with the following tie-lines in Table 2-2.

Table 2-2
Eastern NE Sub-Area Tie Lines

Element	kV	From	To
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

The Greater Rhode Island sub-area is shown geographically in Figure 2-5 and defined electrically with the following tie-lines in Table 2-3.

Table 2-3
Greater Rhode Island Sub-Area Tie Lines

Element	kV	From	To
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Figure 2-5: One Line Diagram of the Greater Rhode-Island Sub-Area

[redacted]

For the Rhode Island reliability portion of the study, the Rhode Island load zone was used as the region under study and is shown geographically in Figure 2-6 and defined electrically with the following tie-lines in Table 2-4.

Table 2-4
Rhode Island Load Zone Tie Lines

Element	kV	From	To
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Figure 2-6: Load Serving Capability: Rhode Island

For the Connecticut reliability portion of the study, the Connecticut load zone was used as the region under study and is shown geographically in Figure 2-7 and defined electrically with the following tie-lines in Table 2-5.

Table 2-5
Connecticut Load Zone Tie Lines

Element	kV	From	To
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Figure 2-7: Load Serving Capability: Connecticut

[redacted]

[redacted]

There are two key interfaces in New England under examination in the NEEWS study, the New England East to West and West to East interfaces. They are defined in Table 2-6.

Table 2-6
New England East to West and West to East Interface Definitions

Element	kV	From	To	East → West	West → East
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

2.3 Study Horizon

A ten-year planning horizon was used for this study based on the most recent load forecast from the 2012 Capacity, Energy, Loads, and Transmission (CELT) report at the time the study began. This study was focused on the projected 2022 peak demand load levels for the ten-year horizon.

2.4 Analysis Description

The working group performed the following studies for this analysis:

- **Thermal Analysis** – studies to determine the level of steady-state power flows on transmission elements under base case conditions and following contingency events.
- **Voltage Analysis** – studies to determine steady-state voltage levels and performance under base case conditions and following contingency events.

Section 3
Study Assumptions

3.1 Steady State Model

3.1.1 Study Assumptions

The regional steady state model was developed to be representative of the 10-year projections of the 90/10 summer peak system demand level to assess reliability performance under stressed system conditions. The model assumptions included consideration of area generation unit unavailability conditions as well as variations in surrounding area regional interface transfer levels. These study assumptions were consistent with ISO PP-3.

3.1.2 Source of Power Flow Models

The power flow study cases used in this study were obtained from the ISO Model on Demand system with selected upgrades to reflect the system conditions in 2022. A detailed description of the system upgrades included is described in later sections of this report.

3.1.3 Transmission Topology Changes

Transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff as of the March 2012 Regional System Plan (RSP) Project Listing[8] have been included in the study base case. The cases also included the most recent updates to the NEEWS projects after their May 2012 revised Proposed Plan Application approval. A listing of the major projects is included below.

Maine

- Maine Power Reliability Program (RSP ID: 905-909, 1025-1030, 1158)
- Down East Reliability Improvement (RSP ID: 143)

New Hampshire

- Second Deerfield 345/115kV Autotransformer Project (RSP ID: 277, 1137-1141)

Vermont

- Northwest Vermont Reliability Projects (RSP ID: 139)[9]
- Vermont Southern Loop Project (RSP ID: 323, 1032-1035)
- Vermont Shunt Reactive Devices (RSP ID: 1171-1172)

Massachusetts

- Auburn Area Transmission System Upgrades (RSP ID: 59, 887, 921, 919)
- Merrimack Valley / North Shore Reliability Project (RSP ID: 775-776, 782-783, 840)
- Long Term Lower SEMA Upgrades (RSP ID: 592, 1068, 1118)
- Central/Western Massachusetts Upgrades (RSP ID: 924- 929, 931-932, 934-935, 937- 950, 952- 955)

[8] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2012/index.html

[9] Majority of project is currently in service as of 2010 with the exception of new synchronous condensers at the Granite substation.

[redacted]

- NEEWS – Greater Springfield Reliability Project (RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105)
- Advanced NEEWS Interstate Projects (RSP ID: 1202, 1342)
- Salem Harbor Retirement Upgrades (RSP ID: 1257-1259)

Rhode Island

- Greater Rhode Island Transmission Reinforcements (RSP ID: 484, 786, 788, 790-793, 913-918, 1098)
- NEEWS – Rhode Island Reliability Project (RSP ID: 795, 798-800, 1096-1097, 1099, 1106, 1109, 1331)

Connecticut

- NEEWS – Greater Springfield Reliability Project (RSP ID: 816, 1054, 1092, 1369-1371, 1378)
- Advanced NEEWS Interstate Projects (RSP ID: 1235, 1245)

3.1.4 Generation

Generation Projects with a Forward Capacity Market (FCM) Capacity Supply Obligation as of the Forward Capacity Auction #6 (FCA-6) commitment period (June 1, 2015 – May 31, 2016) were included in the study base case. A listing of the recent major new FCA-1 through 6 cleared projects is included below.

Maine

- QP 138 – Kibby Wind Farm (FCA-2)
- QP 197 – Record Hill Wind (FCA-2)
- QP 215 – Longfellow Wind Project (FCA-2)
- QP 244 – Wind Project (FCA-4)

New Hampshire

- QP 166 – Granite Wind Farm (FCA-2)
- QP 220 – Indeck Energy Alexandria (FCA-2)
- QP 251 – Laidlaw Berlin Biomass Energy Plant (FCA-4)
- QP 256 – Granite Reliable Power (FCA-2)
- QP 307 – Biomass Project (FCA-4)

Vermont

- QP 172 – Sheffield Wind Farm (FCA-1)
- QP 224 – Swanton Gas Turbines (FCA-1)

Massachusetts

- QP 077 – Berkshire Wind (FCA-3)
- QP 171 – Thomas A Watson (FCA-1)
- QP 231 – Steam Turbine Capacity Uprate (FCA-3)
- QP 243 – Steam Turbine Capacity Uprate (FCA-3)
- QP 265 – MATEP Third CTG (FCA-6)
- Northfield Mountain Uprate 30 MW (FCA-4)
- Northfield Mountain Uprate 10 MW (FCA-6)

Rhode Island

- QP 233 – Ridgewood Landfill (FCA-2)
- QP 332 – RISEP Uprate (FCA-5)

Connecticut

- QP 095 – Kleen Energy (FCA-2)
- QP 125 – Cos Cob 13&14 (FCA-1)
- QP 140 – A.L. Pierce (FCA-1)
- QP 150 – Plainfield Renewable Energy Project (FCA-3)
- QP 161 – Devon 15-18 (FCA-2)
- QP 161 – Middletown 12-15 (FCA-2)
- QP 199 – Waterbury Generation (FCA-1)
- QP 206 – Kimberly Clark Energy (FCA-2)
- QP 248 – New Haven Harbor 2-4 (FCA-3)
- Fuel Cell Projects 18 MW (FCA-4)

Due to issues concerning the on-going operation of the Vermont Yankee Nuclear Station [redacted] the unit (604 MW) was assumed out of service as a base case condition for all East to West stressed cases. Vermont Yankee was assumed available if needed for West to East stressed cases.

In the fall of 2010, the Salem Harbor Station, located on the north shore area of Massachusetts, submitted a Permanent De-List Bid into the ISO Forward Capacity Market for FCA-5 and subsequently a Non-Price Retirement request in February, 2011. While the ISO accepted the retirement request for Salem 1 and 2, the ISO rejected the retirement request for Salem 3 and 4 on May 10, 2011 due to reliability concerns. The owners have elected to retire Salem 3 and 4 by June 1, 2014. Based on this decision, the Salem Harbor Station was assumed retired as a base case condition.

In addition the Salem Harbor, other resources also submitted Non-Price Retirement (NPR) requests. A summary is provided in Table 3-1.

Table 3-1
Summary of Non-Price Retirement Requests

Resource Name	Summer Qualified Capacity (MW)	NPR Request Date	NPR Determination Date
Salem Harbor 1	81.988	2/10/2011	5/10/2011
Salem Harbor 2	80.000	2/10/2011	5/10/2011
Salem Harbor 3	149.805	2/10/2011	5/10/2011
Salem Harbor 4	436.754	2/10/2011	5/10/2011
BIO ENERGY	0.000	8/4/2011	10/20/2011
Potter Diesel 1	2.250	8/1/2011	10/21/2011
Holyoke 6/ Cabot 6	9.611	10/19/2011	1/17/2012
Holyoke 8/ Cabot 8	9.965	10/19/2011	1/17/2012

All the NPR determinations accepted the NPR request except for Salem Harbor 3 and 4, which were discussed above.

In addition the Somerset Jet 2 (17.5 MW) retired as of April 20, 2012 and Somerset 6 (109.058 MW) retired as of 4/18/2012.

[redacted]

Two units in Connecticut, the Bridgeport Harbor 2 unit (130.495 MW) and the AES Thames unit (181 MW) submitted dynamic delist bids in multiple auctions and their bids were cleared. Bridgeport Harbor 2 dynamically delisted in FCA #4, 5 and 6, whereas AES Thames delisted in FCA #5 and 6. These units were assumed OOS for all the base cases.

The West Springfield 3 unit (94.276 MW) submitted a dynamic delist bid in FCA #5 and a static delist bid in FCA #6. Both these bids cleared. [redacted]

The Ansonia unit (60 MW) had cleared FCA #1, but have since withdrawn from the interconnection queue and withdrawn their approved PPAs. The unit was excluded from all the base cases.

Real Time Emergency Generation (RTEG) are distributed generation which have air permit restrictions that limit their operations to ISO Operating Procedure 4 (OP-4), Action 6 – an emergency action which also implements voltage reductions of five percent (5%) of normal operating voltage that require more than 10 minutes to implement. RTEG cleared in the FCM was not included in the reliability analyses because in general, long term analyses should not be performed such that the system must be in an emergency state as required for the implementation of OP-4, Action 6.

3.1.5 Explanation of Future Changes Not Included

Transmission projects that have not been fully developed and have not received PPA approval as of the March 2012 RSP Project Listing and generation projects that have not cleared in FCA-6 were not modeled in the study base case due to the uncertainty concerning their final development. One exception is the recently revised NEEWS – Greater Springfield Reliability Project and Rhode Island Reliability Project that received an updated PPA in May 2012.

Additionally, the NEEWS – Interstate Reliability Project component was not included in the base case since the scope of this study was to confirm the transmission reliability needs that were the justification for this component. The NEEWS – Central Connecticut Reliability Project component was also not included in the base case since the reliability needs that justified that component will be updated in conjunction with the Greater Hartford – Central Connecticut needs assessment.

3.1.6 Forecasted Load

A ten-year planning horizon was used for this study based on the most recently available CELT report issued in April 2012 at the time the study began. This study was focused on the projected 2022[10] peak demand load level for the ten-year horizon. The models reflected the following peak load conditions:

2022 system load level tested:

- The summer peak 90/10 demand forecast of 34,130 MW for New England

The CELT load forecast includes both system demand and losses (transmission & distribution) from the power system. Since power flow modeling programs calculate losses on the transmission system

[10] The 2012 CELT forecast only has projected peak demands for the years 2012 to 2021. To determine the 2022 peak demand forecasted load, the growth rate from years 2020 to 2021 was applied to the 2021 forecast.

(69-kV and above), the actual system load modeled in the case was reduced to account for transmission system losses which are explicitly calculated in the system model.

Demand resources (DR) are treated as capacity resources in the Forward Capacity Auctions. Demand resources are split into two major categories, passive and active DR. Passive demand resources are largely comprised of energy efficiency (EE) programs and are expected to lower the system demand during designated peak hours in the summer and winter. Active demand resources are commonly known as demand side management (DSM) and are dispatchable on a zonal basis if a forecasted or real-time capacity shortage occurs on the system. As per Attachment K of the OATT, demand resources are modeled in the base case at the levels of the most recent Forward Capacity Auction. When this needs follow-up was started, the values from FCA-6 were the most recently available values.

Because DR was modeled at the low-side of the distribution bus in the power-flow model, all DR values were increased to account for the reduction in losses on the local distribution network. Passive DR was modeled by load zone and Active DR was modeled by dispatch zone. Since Active DR is only reported by load zone, the Active DR load zones were split proportionally to dispatch zones using the percentage of CELT load modeled in the dispatch zone to the total CELT load modeled in the load zone. The amounts modeled in the cases are listed in Table 3-2 and Table 3-4 and detailed reports of can be seen in Appendix A: 2012 CELT Load Forecast in Table 8-3.

Table 3-2
FCA-6 Passive DR Values

Load Zone	CELT DRV[11] (MW)
Maine	146
New Hampshire	78
Vermont	115
Northeast Massachusetts & Boston	318
Southeast Massachusetts	176
West Central Massachusetts	210
Rhode Island	129
Connecticut	389

In addition to Passive DR, the ISO now forecasts energy efficiency past the last FCA through the 10-year horizon in the CELT report. The amounts modeled in the cases are listed in Table 3-3. These values were be added to the Passive DR totals cleared through FCA-6 to come up with a total Passive DR value for the year 2022.

[11] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter.

[redacted]

Table 3-3
Additional Forecasted EE Values through 2022[12]

Load Zone	EE DRV (MW)
Maine	47
New Hampshire	56
Vermont	100
Northeast Massachusetts & Boston	356
Southeast Massachusetts	182
West Central Massachusetts	208
Rhode Island	143
Connecticut	168

Table 3-4
FCA-6 Active DR Values

Dispatch Zone	CELT DRV (MW)	Dispatch Zone	CELT DRV (MW)
Bangor Hydro	44	**Springfield, MA**	39
Maine	151	**Western Massachusetts**	54
Portland, ME	100	**Lower Southeast Massachusetts**	48
New Hampshire	53	**Southeast Massachusetts**	110
New Hampshire Seacoast	8	**Rhode Island**	84
Northwest Vermont	41	**Eastern Connecticut**	42
Vermont	22	**Northern Connecticut**	55
Boston, MA	198	**Norwalk-Stamford, Connecticut**	63
North Shore Massachusetts	70	**Western Connecticut**	195
Central Massachusetts	80		

Demand Resources that are eligible for termination for satisfying the condition of MR 1 section III.13.3.4. (c) "… successfully covered its Capacity Supply Obligation for two Capacity Commitment Periods but has not yet achieved Commercial Operation." The "Reduction in Summer QC" column represents the amount that has been treated as Existing in subsequent auctions but has not been demonstrated in commercial operation audit. A list of the DR eligible for termination is listed in Table 3-5.

[12] The 2012 CELT only provides EE forecast values through 2021. The growth of EE forecast from 2021 to 2022 was assumed to be identical to the growth of EE from 2020 to 2021.

[redacted]

Table 3-5
Summary of DR Eligible for Termination

Load Zone	Active DR (MW)	Passive DR (MW)	Real Time EG (MW)	TOTAL (MW)
Connecticut	14	20	41	75
Maine	2	1	10	13
NEMA Boston	9	30	71	111
New Hampshire	2	0	8	11
Rhode Island	2	2	39	44
SEMA	5	4	40	49
Vermont	3	0	7	9
WCMASS	4	9	32	45
TOTAL	**42**	**65**	**249**	**356**

The majority of this DR is Real-Time Emergency Generation that is not modeled in long-term needs analysis so it will not affect the net load modeled. The amount of passive and active DR that is eligible for termination was removed from their respective zone totals.

3.1.7 Load Levels Studied

In accordance with ISO planning practices, transmission planning studies utilize the ISO extreme weather 90/10 forecast assumptions for modeling summer peak load profiles in New England. A summary of the load modeled in the 2022 case compared with the 2020 case from the last needs study is shown in Table 3-6. A more detailed report of the loads modeled and how the numbers were derived from the CELT values can be seen in Appendix A in Table 8-1 and Table 8-2.

Table 3-6
90/10 CELT Load Comparison (including losses)

State	2020 Load 2010 CELT (MW)	2022 Load 2012 CELT (MW)	Difference (MW)	Difference (%)
Maine	2,500	2,480	-20	-0.80%
New Hampshire	3080	3,120	+40	+1.30%
Vermont	1,255	1,230	-25	-1.99%
Massachusetts	15,575	16,060	+485	+3.11%
Rhode Island	2,300	2,430	+130	+5.65%
Connecticut	8,840	8,810	-30	-0.34%
ISO New England	33,555	34,130	+575	+1.71%

A comparison of the 2010 CELT report used in the Interstate updated needs assessment to the 2012 CELT used in this follow up study shows that the overall load was generally lower for the same year. For example the 2019 Summer 90/10 NE load was 33,225 MW in the 2010 CELT. The same year in the 2012 CELT was 33,040 MW a reduction of 185 MW or about ½ a year of overall NE load growth.

However the follow-up study used a higher overall NE load level due to looking at the year 2022 vs. 2020 in the updated needs assessment. The extra two years of load growth, even with a lower forecast, cause an overall increase of 575 MW system wide in the follow up study.

[redacted]

The following Table 3-7 provides a comparison of the net ISO New England load in the 2011 needs assessment and the 2012 follow-up needs assessment.

Table 3-7
Comparison of Net New England Load between 2011 and 2012 Needs Assessments

Assumption	2011		2012		Difference	
	Reference	(MW) Incl. T&D losses	Reference	(MW) Incl. T&D losses	(MW)	(%)
CELT Load	2020 90/10 2010 CELT	33,555	2022 90/10 2012 CELT	34,130	+575	+1.71%
Mfg. Load in ME		0		+364	+364	
Passive DR[13]	FCA #4	-1,494	FCA #6	-1,685	-191	+12.78%
Terminated Passive DR				+65	+65	
Forecasted EE	N/A	0	2022 2012 CELT	-1,362	-1,362	
Active DR[13]	FCA #4	-1,771	FCA #6	-1,574	+197	-11.12%
Terminated Active DR				+42	+42	
Active DR De-Rate		+443		+383	-60	
Net ISO-NE Load		**30,733**		**30,363**	**-370**	**-1.20%**

The 2011 needs assessment had overstated the amount of DR that was available as a result of FCA #4. An additional 164 MW of passive DR and 261 MW of active DR were assumed in those basecases.

The net effect of the revised load forecast, updated DR and the EE forecast was a decrease in New England load of 370 MW.

3.1.8 Load Power Factor

Load power factors consistent with the local transmission owner's planning practices were applied uniformly at each substation and consistent with the megawatt load level assumed at each power flow model substation bus. Demand resources' power factors were set to match the power factor of the load at that bus in the model. A list of overall power factors by company territory can be found in the detailed load report in Appendix A in Table 8-1 and Table 8-2.

3.1.9 Transfer Levels

In accordance with the reliability criteria of the Northeast Power Coordinating Council (NPCC) and the ISO, the regional transmission power grid must be designed for reliable operation during stressed system conditions. A detailed list of all transfer levels can be found in Appendix B: Case Summaries

[13] Following completion of the 2011 Needs Assessment, the DR values used were found to be overstated (Passive DR should have been 1,330 MW, Active DR 1,510 MW). The details are provided on Page 24 of the New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report, dated February 2012. https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/neews_interstate_solution.pdf

[redacted]

and Generation Dispatches. The following external transfers shown in Table 3-8 were utilized for the study.

Table 3-8
Interface Levels Tested

	N-1		N-1-1	
Interface	**E→W**	**W→E**	**E→W**	**W→E**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Internal transfer levels were monitored during the assessment. Due to the major changes to the system with the Maine Power Reliability Program and the two components of NEEWS, GSRP and RIRP, already approved, the existing transfer limits will change. During this needs follow-up the generation dispatch dictated the internal transfer levels and all elements were monitored on the system.

3.1.10 Generation Dispatch Scenarios

The power-flow models used in these analyses were adjusted to incorporate the capacity levels for existing[14] generators that were qualified and new generators that cleared FCA-6. The capacity levels for generating units in New England used in this study are contained in the power flow case summary files in Appendix B: Case Summaries and Generation Dispatches. In constructing dispatch conditions for the sub-area analyses, the working group considered a number of dispatch scenarios in New England that would have the greatest impact on power flows in the area of study. A detailed list of the dispatches for each sub-area stress is listed in the Sections 3.1.10.1 through 3.1.10.3.

Vermont Yankee is a 604 MW nuclear power generating station placed in service in 1972 [redacted]. There is significant uncertainty surrounding the continued operation of the plant. To ensure that the New England transmission system is sufficiently robust enough to operate reliably in the event of a permanent shutdown at the station, this unit was considered off-line in these analyses when the unit was in the importing area.

New England has two major pumped-storage hydroelectric stations and both are located in western Massachusetts. Northfield Station is a four unit 1,110 MW station on the Connecticut River in Northfield, Massachusetts. Bear Swamp Station is a two unit 580 MW station on the Deerfield River in Rowe, Massachusetts. The base case assumes a reduction of power output of approximately 50% for these two stations. De-rating these stations [redacted] recognizes acceptance of export delist bids for Bear Swamp to serve capacity obligations in New York, and recognizes run time limitations to effectively serve New England capacity needs over long-time emergency periods (12 hours for New England in the summer time), all during a summer heat wave.

[14] Existing refers to any generator that has cleared in the previous auction, FCA-3, held in October 2009.

[redacted]

On shore wind was dispatched at 5% of nameplate when in the import area. In the export area the units were ramped up to 100% of their qualified capacity.

Hydro assumptions were based on the VT/NH, Pittsfield/Greenfield and GHCC studies, when these units are in the import area. The details are provided in Table 3-9.

Table 3-9
Dispatch of Hydro Units when in Import Area

Name	Dispatch Level (Import Area)	Name Plate (50° rating)	Location
Western Mass Hydro Units			
Deerfield	9.0	33.5	Western NE
Harriman	14.0	41.1	Western NE
Vernon	5.0	32.0	Western NE
Sherman	6.0	6.5	Western NE
Cabot	10.0	68.2	Western NE
Searsburg	5.0	5.0	Western NE
Vermont / New Hampshire Hydro Units			
Moore	14.0	191.3	Eastern NE
Comerford	21.0	183.3	Eastern NE
Bellows Falls	18.8	49.0	Western NE
Wilder	10.0	42.9	Western NE
Amoskeag	14.7	17.5	Eastern NE
Lower Lamoille	5.4	15.8	Western NE
Sheldon Springs	3.4	14.8	Western NE
Great Lakes Berlin	1.3	25.0	Eastern NE
Garvins/Hooksett	0.0	14.8	Eastern NE
Smith	9.2	17.6	Eastern NE
Mcindoes	0.0	13.0	Western NE
Highgate Falls	0.0	9.6	Western NE
Ayers Island	0.0	9.1	Eastern NE
Pontook Hydro	3.8	9.6	Eastern NE
Winooski 1	1.0	7.5	Western NE
Proctor	0.0	6.7	Western NE
Middlebury	0.0	6.8	Western NE
Eastman Falls	0.0	6.5	Eastern NE
N Rutland Composite	2.0	5.2	Western NE
Dodge Falls - New	0.0	5.0	Western NE
Connecticut Hydro Units			
Rainbow Hydro	0.8	8.2	Western NE
Stevenson Hydro	2.8	28.9	Western NE
Falls Village	0.9	9.8	Western NE
Rocky River	2.9	29.4	Western NE
Shepaug	4.2	42.9	Western NE
Bulls Bridge	0.8	8.4	Western NE
Derby Dam	0.7	7.1	Western NE

[redacted]

The hydro resources in an export area were dispatched assuming that 100% of the output is available up to the qualified capacity of the unit. A low hydro scenario is assumed for the hydro resources in an import area. Table 3-9 captures the major hydro units in VT, NH, MA and CT. For the units excluded from the table, the units may be dispatched up to their qualified capacity.

Wind and hydro resources in the import area were dispatched to these reduced levels based on historical output seen during summer 90/10 weather conditions.

3.1.10.1 Eastern New England

To stress the eastern New England subarea, generation is reduced in the sub-area to require the system to deliver generation resources from outside the sub-area to reliably serve the load in the region. To model this condition, the two largest resources in the subarea are assumed out of service (OOS). [redacted]

The Comerford and Moore hydro stations were at 10% of their nameplate for the N-1 analysis. However, after the first contingency, both plants were ramped up to 100% of their qualified capacity in preparation for the second contingency. Thus, the N-1-1 analysis had both Comerford and Moore at 100% of their qualified capacity.

Under normal operating conditions, if a large resource were offline, the quick-start resources in the area would be dispatched in the area to compensate for lost generation. Due to the infrequent use of the units, they do not always respond when dispatched so an unavailability rate of 20% is assumed for all quick-start resources in the subarea of concern. A summary table of resources for the eastern New England analysis is shown in Table 3-10.

Table 3-10
Eastern New England Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

3.1.10.2 Western New England and Connecticut

To stress the western New England subarea, generation is reduced in the sub-area to require the system to deliver generation resources from outside the subarea to reliably serve the load in the region. To model this condition, the two largest units in the subarea are assumed out-of-service. [redacted] In addition, the [redacted] was assumed offline to reflect the

[15] All other resources in eastern New England were modeled at 100%. To meet load balance requirements and external transfer levels, some excess generation in western New England may have been turned off to not violate this requirement. For most cases, western New England was capacity deficient and additional imports from New York were needed to meet the load balance requirements.

equivalent demand forced outage rate[16] (EFORd) for western Massachusetts generation. Instead of reducing the electrical output of all western Massachusetts' units based on their individual EFORd values, the total generation reduction for the area is represented by turning off [redacted][17] A sensitivity was run with the [redacted]

Under normal operating conditions, if a large resource were offline, the quick-start resources in the area would be dispatched in the area to compensate for lost generation. Due to the infrequent use of the units, they do not always respond when dispatched so an unavailability rate of 20% is assumed for all quick-start resources in the subarea of concern. A summary table of resources for the western New England analysis is shown in Table 3-11.

For the 2022 cases, there are insufficient resources in eastern New England and Greater Rhode Island to both serve local load in the area and also export power to western New England. To meet this resource requirement, the Cape Wind Project connected to the NSTAR Barnstable substation and the Brockton Combined Cycle connected near the NSTAR Auburn substation were modeled as additional capacity.

Table 3-11
Western New England and Connecticut Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]	[redacted]	[redacted]

3.1.10.3 Rhode Island

To stress the Rhode Island load zone, generation is reduced in the subarea to require the system to deliver generation resources from outside the subarea to reliably serve the load in the region. To model this condition, the largest resources in the subarea were assumed out of service. [redacted]

---

[16] Equivalent demand forced outage rate represents the portion of time a unit is in demand, but is unavailable due to forced outages.

[17] Since the power flow model included the Greater Springfield Reliability Project, turning off [redacted] completely would not produce a significantly different result than reducing the output of all generating units by a quantity of MW equal to the [redacted] capacity.

[18] All other resources in western New England were modeled at 100%. To meet load balance requirements and external transfer levels, some excess generation in eastern New England in the 2015 cases may have been turned off to not violate this requirement. For most cases, eastern New England was capacity deficient and the Cape Wind and Brockton units needed to be turned on to meet the load balance requirements.

[redacted]

Under normal operating conditions, if a large resource were off-line, the quick-start resources in the area would be dispatched to compensate for lost generation. Due to the infrequent use of the units, they do not always respond when dispatched so an unavailability rate of 20% is assumed for all quick-start resources in the sub-area of concern. A summary table of resources for the Rhode Island analysis is shown in Table 3-12

Table 3-12
Rhode Island Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

3.1.11 Reactive Resource and Dispatch

All area shunt reactive resources were assumed available and dispatched when conditions warranted. Reactive output of generating units was modeled to reflect defined limits. A summary of the reactive output of units and shunt devices connected to the transmission system that play a significant role in the study area can be found in the power flow case summaries included in Appendix B: Case Summaries and Generation Dispatches.

3.1.12 Market Solution Consideration

In accordance with the Attachment K of the OATT, all resources that have cleared in the markets were assumed in the model for future planning reliability studies except for those described in Table 3-5 of Section 3.1.6. This included numerous new generation and demand resources from FCA-1 through 6 as listed in Section 3.1.4 and Section 3.1.6 respectively.

3.1.13 Demand Resources

As stated in Section 3.1.6, active and passive demand resources cleared as of the 2012 FCA-6 auction were modeled for this study. For all analyses, passive demand resources were assumed to be 100% available and are expected to perform to 100% of their cleared amount. Forecasted energy efficiency for the years 2016 through 2022 were expected to perform to 100% of their forecasted amount. For active demand resources, their performance was dependent on which subarea was being studied. The import area assumed that 75% of all active demand resources performed when dispatched and the export area assumed 100% of all active demand resources performed when dispatched, to model a more stressed system condition in the import area.

[19] All other Rhode Island resources were turned to 100%. To meet load balance requirements and external transfer levels, some excess generation in New England was turned off to not violate this requirement.

[redacted]

Real Time Emergency Generation (RTEG) was not modeled in any analysis. RTEGs cleared in the FCM was not included in the reliability analyses because in general, long term analyses should not be performed such that the system must be in an emergency state as required for the implementation of OP-4, Action 6. A summary of assumed DR performance is shown in Table 3-13.

Table 3-13
New England Demand Resource Performance Assumptions

Region	Passive DR	Forecasted EE	Active DR	RTEGs
Import Area	100%	100%	75%	0%
Export Area	100%	100%	100%	0%

3.1.14 Description of Protection and Control System Devices Included in the Study

All existing and planned special protection systems (SPS) and control system devices have been included in this analysis. Some of the relevant devices are listed below:

[redacted]

3.1.15 Explanation of Operating Procedures and Other Modeling Assumptions

[redacted]

[redacted]

[redacted]

[redacted]

3.2 Stability Model

3.2.1 Study Assumptions

Not applicable to this study.

3.2.2 Load Levels Studied

Not applicable to this study.

3.2.3 Load Models

Not applicable to this study.

3.2.4 Dynamic Models

Not applicable to this study.

3.2.5 Transfer Levels

Not applicable to this study.

3.2.6 Generation Dispatch Scenarios

Not applicable to this study.

3.2.7 Reactive Resource and Dispatch

Not applicable to this study.

3.2.8 Explanation of Operating Procedures and Other Modeling Assumptions

Not applicable for this study.

3.3 Short Circuit Model

3.3.1 Study Assumptions

Not applicable for this study.

3.3.2 Short Circuit Model

Not applicable for this study.

3.3.3 Contributing Generation

Not applicable for this study.

3.3.4 Generation and Transmission System Configurations

Not applicable for this study.

3.3.5 Boundaries

Not applicable for this study.

3.3.6 Other Relevant Modeling Assumptions

Not applicable for this study.

3.4 Other System Studies

Not applicable for this study.

3.5 Changes in Study Assumptions

Not applicable for this study.

Section 4
Analysis Methodology

4.1 Planning Standards and Criteria

The applicable NERC, NPCC and ISO standards and criteria were the basis of this evaluation. A description of each of the NERC, NPCC and ISO standard test that were included in all studies used to assess system performance are discussed later in this section.

4.2 Performance Criteria

4.2.1 Steady State Criteria

The needs assessment was performed in accordance with NERC TPL-001, TPL-002, TPL-003 and TPL-004 Transmission Planning System Standards, NPCC Directory #1 *"Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System"*, dated 12/01/09, and the ISO Planning Procedure No. 3, *"Reliability Standards for the New England Area Bulk Power Supply System"*, dated 06/11/09. The contingency analysis steady-state voltage and loading criteria, solution parameters and contingency specifications used in this analysis are consistent with these documents.

4.2.1.1 Steady State Thermal and Voltage Limits

Loadings on all transmission facilities rated at 69 kV and above in the study area were monitored. The thermal violation screening criteria defined in Table 4-1 were applied.

Table 4-1
Steady State Thermal Criteria

System Condition	Maximum Allowable Facility Loading
Normal (all lines-in) (Pre-Contingency)	Normal Rating
Emergency (Post-Contingency)	Long Time Emergency (LTE) Rating

Voltages were monitored at all buses with voltages 69 kV and above in the study area. System bus voltages outside of limits identified in Table 4-2 were identified for all normal (pre-contingency) and emergency (post-contingency) conditions.

Table 4-2
Steady State Voltage Criteria

Facility Owner	Voltage Level	Bus Voltage Limits (Per-Unit) Normal Conditions (Pre-Contingency)	Bus Voltage Limits (Per-Unit) Emergency Conditions (Post-Contingency)
Northeast Utilities	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
National Grid	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.90[20] to 1.05
NSTAR	230 kV and above	0.95 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
United Illuminating	230 kV and above	0.95 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
Millstone / Seabrook[21]	345 kV	[redacted]	[redacted]
Pilgrim[21]	345 kV	[redacted]	[redacted]
Vermont Yankee[21]	345 kV	[redacted]	[redacted]
Vermont Yankee[21]	115 kV	[redacted]	[redacted]

4.2.1.2 Steady State Solution Parameters

The steady state analysis was performed with pre-contingency solution parameters that allow adjustment of load tap-changing transformers (LTCs), static var devices (SVDs) including automatically-switched capacitors and phase angle regulators (PARs). Post-contingency solution parameters only allow adjustment of LTCs and SVDs. Table 4-3 displays these solution parameters.

Table 4-3
Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Base	Tie Lines Regulating	Stepping	Regulating or Statically Set	Regulating
Contingency	Disabled	Stepping	Disabled	Regulating

[20] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

[21] This in compliance with NUC-001-2, *"Nuclear Plant Interface Coordination Reliability Standard,"* adopted August 5, 2009.

[redacted]

4.2.2 Stability Performance Criteria

Not applicable for this study.

4.2.3 Short Circuit Performance Criteria

Not applicable for this study.

4.2.4 Other Performance Criteria

Not applicable for this study.

4.3 System Testing

4.3.1 System Conditions Tested

Testing of system conditions included evaluation of system performance under a number of resource outage scenarios, variation of related transfer levels, and an extensive number of transmission circuit contingency events.

4.3.2 Steady State Contingencies / Faults Tested

Each base case was subjected to single element contingencies such as the loss of a transmission circuit or an autotransformer and contingencies which may cause the loss of multiple transmission circuit facilities, such as those on a common set of tower line structures, circuit breaker failures and substation bus faults. A comprehensive set of contingency events, listed in Appendix C: Contingency List, was tested to monitor thermal and voltage performance of the New England transmission system.

Additional analyses evaluated N-1-1 conditions with an initial outage of a key transmission circuit followed by another contingency event. The N-1-1 analyses examined the summer peak load case with stressed conditions. For these N-1-1 cases, national and regional reliability standards, including ISO PP-3, allow specific manual system adjustments, such as quick start generation redispatch, phase-angle regulator adjustment or HVDC adjustments prior to the next single contingency event. A listing of all contingency types tested is shown in Table 4-4 and a listing of Line-out scenarios in Table 4-5.

Table 4-4
Summary of NERC, NPCC and/or ISO Category Contingencies Tested

Contingency Type	NERC Type	NPCC D-1 Section	ISO PP-3 Section	Tested
All Facilities in Service	A	5.4.2.b	3.2.b	Yes
Generator (Single Unit)	B1	5.4.1.a	3.1.a	Yes
Transmission Circuit	B2	5.4.1.a	3.1.a	Yes
Transformers	B3	5.4.1.a	3.1.a	Yes
Loss of an Element Without a Fault	B	5.4.1.d	3.1.d	Yes
Bus Section	C1	5.4.1.a	3.1.a	Yes
Breaker Failure	C2	5.4.1.e	3.1.e	Yes
Double Circuit Tower	C5	5.4.1.b	3.1.b	Yes
Extreme Contingencies	D	5.6	6	Yes

Table 4-5
N-1-1 Line-Out Scenarios

Element Name	kV	Description	E→W	W→E	RI
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	

4.3.3 Stability Contingencies / Faults Tested

Not applicable for this study.

4.3.4 Short Circuit Faults Tested

Not applicable for this study.

[redacted]

Section 5
Results of Analysis

5.1 Overview of Results

The objective of this analysis was to determine if New England load can be served reliably in accordance the NERC, NPCC and ISO planning standards and criteria in the ten-year planning horizon. With the assumptions discussed in Section 3 of this report, numerous thermal criteria violations were found in New England for N-1 and N-1-1 contingency events.

5.1.1 Eastern New England Reliability Analysis

The eastern New England area is defined as the Regional System Plan zones of Bangor Hydro, Maine, southern Maine, New Hampshire,[23] central/northeast Massachusetts, southeast Massachusetts, and Boston. The electrical tie-lines for this subarea are defined in Section 2.2. Figure 5-1 is a geographic representation of the conceptual performance of the transmission system across the eastern New England import interface in monitoring the amount of generation resources in western New England and Greater Rhode Island that can be delivered to loads in eastern New England.

[redacted]

Figure 5-1: Eastern New England Reliability Study Area

Several N-1 and N-1-1 criteria violations were seen in the Eastern New England reliability analysis. The 345 kV network had N-1 and N-1-1 thermal violations on the 301-302 lines (Millbury to Carpenter Hill to Ludlow) East-West path, the 328 line (Sherman Rd to West Farnum), and N-1-1 thermal violations for the southern paths connecting Connecticut to Rhode Island to Southeast Massachusetts. N-1 and N-1-1 thermal and voltage violations were seen on the 115 kV path

[23] Part of southwest New Hampshire is part of the western New England area.

connecting Connecticut to Rhode Island along the Long Island shoreline and N-1-1 thermal violations were seen on the 115 kV network connecting Rhode Island to Southeastern Massachusetts.

5.1.2 Western New England Reliability Analysis

The western New England area is defined as the Regional System Plan zones of Greater Connecticut (southwest Connecticut, northern and eastern Connecticut, and Norwalk/Stamford Connecticut), western Massachusetts, and the state of Vermont.[24] The electrical tie-lines for this subarea are defined in Section 2.2. Figure 5-2 is a geographic representation of the conceptual performance of the transmission system across the western New England import interface (identical to current New England East-West Interface) in monitoring the amount of generation resources in eastern New England and Greater Rhode Island that can be delivered to loads in western New England.

[redacted]

Figure 5-2: Western New England Reliability Study Area

N-1-1 criteria violations were seen in the Western New England reliability analysis. All violations involved the [redacted] followed by another criteria contingency. The central 345 kV East-West path connecting the Boston area to western Massachusetts (301-302 lines) were thermally overloaded as the other remaining East-West 345 kV path was lost under a N-1-1 contingency event. The 115 kV path from Rhode Island to Connecticut along the Long Island Sound shoreline also had N-1-1 thermal violations for [redacted] Voltage violations were also seen in the Springfield, MA area [redacted].

[24] The state of Vermont includes a small portion of southwest New Hampshire.

5.1.3 Rhode Island Reliability Analysis

The Rhode Island study area is defined as the Rhode Island load zone. Figure 5-3 is a geographic representation of the Rhode Island study area.

[redacted]

Figure 5-3: Rhode Island Reliability Study Area

N-1-1 analysis shows major concerns for the Rhode Island reliability study area including potential voltage collapse. [redacted]

5.1.4 Connecticut Reliability Analysis

The Connecticut study area is defined as the Regional System Plan zones of Greater Connecticut: northern and eastern Connecticut, southwest Connecticut, and Norwalk-Stamford. Figure 5-4 is a geographic representation of the Connecticut study area.

[redacted]

Figure 5-4: Connecticut Reliability Study Area

N-1-1 criteria violations were seen in the Connecticut reliability analysis. All violations involved the [redacted] followed by another criteria contingency. The 345 kV path connecting the Ludlow to northeastern Connecticut (3419 line from Ludlow to Barbour Hill) were near their thermal limits after another Connecticut 345 kV path was lost under a N-1-1 contingency event. The 115 kV path from Rhode Island to Connecticut along the Long Island Sound shoreline also had N-1-1 thermal violations for loss [redacted]

5.2 Steady State Performance Criteria Compliance

5.2.1 N-0 Thermal and Voltage Violation Summary

5.2.1.1 Eastern New England

N-0 study indicated no thermal or voltage violations found in the area under study.

5.2.1.2 Western New England

N-0 study indicated no thermal or voltage violations found in the area under study.

5.2.1.3 Rhode Island

N-0 study indicated no thermal or voltage violations found in the area under study.

5.2.1.4 Connecticut

N-0 study indicated no thermal or voltage violations found in the area under study.

5.2.2 N-1 Thermal and Voltage Violation Summary

5.2.2.1 Eastern New England

N-1 testing was performed for all of the system condition models described in Section 3. The results of overloaded lines and emerging issues[25] following N-1 contingency events can be found in Table 5-1.

Table 5-1
Eastern New England N-1 Thermal Violation Summary

Element ID	kV	Element Description	[redacted]		[redacted]	
			Worst Contingency	%LTE	Worst Contingency	%LTE
302	345	Carpenter Hill to Millbury	[redacted]	**< 90.0**	[redacted]	**95.0**
328	345	Sherman Rd. to W. Farnum	[redacted]	**97.3**	[redacted]	**105.3**
1280-3	115	Whipple Jct. to Mystic, CT	[redacted]	**111.7**	[redacted]	**122.5**
1465	115	Mystic, CT to Whipple Jct	[redacted]	**< 90.0**	[redacted]	**99.7**
1870S	115	Wood River to Shunock	[redacted]	**103.2**	[redacted]	**117.0**

N-1 study indicated no voltage violations found in the area under study.

5.2.2.2 Western New England

N-1 study indicated no thermal or voltage violations found in the area under study.

5.2.2.3 Rhode Island

N-1 study indicated no thermal or voltage violations found in the area under study.

5.2.2.4 Connecticut

N-1 study indicated no thermal or voltage violations found in the area under study.

[25] Although lines loaded between 95% and 100% are not technically overloaded, they are displayed in this and following tables because they are indicative of problems occurring with minimal load growth or system changes just beyond the study horizon.

5.2.3 N-1-1 Thermal and Voltage Violation Summary

5.2.3.1 Eastern New England

N-1-1 testing was performed for all of the system condition models described in Section 3. The results of N-1-1 contingency analysis can be found in Table 5-2.

Table 5-2
Eastern New England N-1-1 Thermal Violation Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
301	345	Ludlow to Carpenter Hill	[redacted]	[redacted]	97.2	[redacted]	[redacted]	118.9
302	345	Carpenter Hill to Millbury	[redacted]	[redacted]	97.4	[redacted]	[redacted]	119.1
328	345	Sherman Rd. to W. Farnum	[redacted]	[redacted]	115.5	[redacted]	[redacted]	126.7
336-2	345	W. Medway to NEA Bellingham Tap	[redacted]	[redacted]	98.4	[redacted]	[redacted]	105.5
347	345	Sherman Rd. to Killingly	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	101.0
3361	345	ANP Blackstone to Sherman Rd.	[redacted]	[redacted]	99.5	[redacted]	[redacted]	110.0
3520	345	W. Medway to ANP Bellingham	[redacted]	[redacted]	97.2	[redacted]	[redacted]	105.8
BP 5X		Brayton Point 345/115 kV Autotransformer	[redacted]	[redacted]	106.5	[redacted]	[redacted]	113.6
WM 345B		W. Medway 345/230 kV Autotransformer	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	107.0
O215	230	N. Litchfield to Tewksbury	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	99.5
1280	115	Whipple Jct to Mystic CT	[redacted]	[redacted]	150.2	[redacted]	[redacted]	141.2
1465	115	Mystic CT to Shunock	[redacted]	[redacted]	127.1	[redacted]	[redacted]	118.2
1870S	115	Shunock to Wood River	[redacted]	[redacted]	152.2	[redacted]	[redacted]	140.7
B128-6	115	Montague to Cabot Tap	[redacted]	[redacted]	98.0	[redacted]	[redacted]	102.0
C129N	115	Depot St Tap to Milford Power Tap	[redacted]	[redacted]	109.1	[redacted]	[redacted]	118.5
C129	115	Union Street to Beaver Pond	[redacted]	[redacted]	103.6	[redacted]	[redacted]	109.1
C129S	115	South Wrentham to Union Street	[redacted]	[redacted]	107.3	[redacted]	[redacted]	112.8
D130	115	Depot St Tap to Milford Power Tap	[redacted]	[redacted]	97.7	[redacted]	[redacted]	104.8
H17	115	Riverside to Farnum Tap	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	99.4
Q143S-1	115	Woonsocket to Uxbridge	[redacted]	[redacted]	99.4	[redacted]	[redacted]	105.1
R9	115	Riverside to Valley	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	98.7
S171N	115	West Farnum Tap to Woonsocket	[redacted]	[redacted]	110.8	[redacted]	[redacted]	116.7
T172N	115	West Farnum to West Farnum Tap	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	99.3
T172N	115	West Farnum Tap to Woonsocket	[redacted]	[redacted]	130.6	[redacted]	[redacted]	137.7
V174-2	115	N. Oxford to Millbury	[redacted]	[redacted]	98.5	[redacted]	[redacted]	110.3

It should be noted that the outage of the [redacted] did not converge in the [redacted] sensitivity power flow case due to voltage collapse. The next most limiting N-1-1contingency pair was entered in the tables.

The results of voltage violations following N-1-1 contingency events can be found in Table 5-3.

Table 5-3
Eastern New England N-1-1 Voltage Violation Summary

Substation	kV	[redacted]			[redacted]		
		L/O	Worst Contingency	Voltage (pu)	L/O	Worst Contingency	Voltage (pu)
Mystic CT	115	[redacted]	[redacted]	0.932	[redacted]	[redacted]	0.945
Shunock	115	[redacted]	[redacted]	0.912	[redacted]	[redacted]	0.926

5.2.3.2 Western New England

N-1-1 testing was performed for all of the system condition models described in Section 3. The results of contingency event analyses can be found in Table 5-4.

Table 5-4
Western New England N-1-1 Thermal Violation Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
301	345	Carpenter Hill to Ludlow	[redacted]	[redacted]	102.9	[redacted]	[redacted]	96.9
302	345	Millbury to Carpenter Hill	[redacted]	[redacted]	105.9	[redacted]	[redacted]	100.0
3419	345	Ludlow to Barbour Hill	[redacted]	[redacted]	96.5	[redacted]	[redacted]	97.4
1505	115	Plainfield Jct to Tunnel	[redacted]	[redacted]	93.4	[redacted]	[redacted]	< 90.0
1870N	115	West Kingston to Kenyon	[redacted]	[redacted]	105.5	[redacted]	[redacted]	99.9
1870	115	Wood River to Kenyon	[redacted]	[redacted]	117.5	[redacted]	[redacted]	110.7
1870S	115	Wood River to Shunock	[redacted]	[redacted]	121.9	[redacted]	[redacted]	113.3
L190-4	115	Tower Hill to West Kingston	[redacted]	[redacted]	101.2	[redacted]	[redacted]	96.6
L190-5	115	Tower Hill to Davisville Tap	[redacted]	[redacted]	113.3	[redacted]	[redacted]	108.7

N-1-1 study indicated no voltage violations found in the area under study.

5.2.3.3 Rhode Island

N-1-1 testing was performed for all of the system condition models described in Section 3. The results of contingency event analyses that were able to solve in the power flow program are found in Table 5-5.

Table 5-5
Rhode Island N-1-1 Thermal Violation Summary

Element ID	kV	Element Description	2022 Loading		
			L/O	Worst Contingency	%LTE
U6-1	115	Somerset to Dighton	[redacted]	[redacted]	104.6
U6-3	115	Dighton to Dighton Tap	[redacted]	[redacted]	104.6
W4	115	Somerset to Swansea	[redacted]	[redacted]	97.0

It should be strongly noted that the power flow case did not converge with the [redacted] This indicates a voltage collapse of the Rhode Island transmission network. The cause of the collapse is the combination of the [redacted]

[redacted] and voltage collapse occurs.

5.2.3.4 Connecticut

N-1-1 testing was performed for all of the system condition models described in Section 3. The results of contingency event analyses are found in Table 5-6.

Table 5-6
Connecticut N-1-1 Thermal Violation Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
3419	345	Ludlow to Barbour Hill	[redacted]	[redacted]	95.6	[redacted]	[redacted]	96.3
1505	115	Plainfield Jct to Tunnel	[redacted]	[redacted]	96.1	[redacted]	[redacted]	< 90.0
1870	115	Wood River to Kenyon	[redacted]	[redacted]	102.0	[redacted]	[redacted]	98.4
1870S	115	Wood River to Shunock	[redacted]	[redacted]	102.2	[redacted]	[redacted]	97.5
L190-4	115	Tower Hill to West Kingston	[redacted]	[redacted]	98.1	[redacted]	[redacted]	96.6
L190-5	115	Tower Hill to Davisville Tap	[redacted]	[redacted]	110.2	[redacted]	[redacted]	108.7

N-1-1 study indicated no voltage violations found in the area under study.

5.3 Stability Performance Criteria Compliance

Not applicable to this study.

5.3.1 Stability Fault Test Results

Not applicable to this study.

5.4 Short Circuit Performance Criteria Compliance

Not applicable to this study.

5.4.1 Short Circuit Test Results

Not applicable to this study.

[redacted]

Section 6
Critical Load Level Analysis

6.1 Methodology to determine Critical load level

The methodology used was to select the worst case contingency pairs and thermal violations in the 2022 results, and simulate those same contingency pairs at a 2017 load level. The two loadings at 2017 and 2022 load levels will then be utilized to do a linear extrapolation to determine the load level at which the overloads will be first seen.

No topology changes were assumed when reducing load from a 2022 load level to a 2017 load level.

Additionally, the CELT forecast, the forward capacity auction results and the EE forecast were utilized to determine the net load in eastern New England, western New England, Rhode Island and Connecticut. This table will provide the year of need for the different issues seen.

6.2 Equivalent Load in 2012-2022

The net load in the different load zones is determined by deducting the net DR from the CELT load forecast. The details of the calculations are provided in Appendix E: Net Loads in New England. Table 6-1 provides the net loads in New England and the 8 load zones for the 2012-2022 horizon.

Table 6-1
Net Loads (MW) : 2012-2022

Net Loads Includes T & D Losses	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Maine	1,926	1,869	1,870	1,893	1,919	1,941	1,963	1,976	1,994	2,013	2,032
NH	2,508	2,539	2,596	2,661	2,721	2,761	2,797	2,828	2,860	2,892	2,925
Vermont	1,020	995	986	980	971	968	962	957	953	950	947
NEMA_BOSTON	5,589	5,583	5,666	5,742	5,801	5,838	5,861	5,882	5,905	5,932	5,960
SEMA	3,643	3,678	3,738	3,810	3,878	3,931	3,976	4,018	4,063	4,108	4,154
WCMA	3,654	3,645	3,674	3,713	3,759	3,789	3,810	3,829	3,851	3,873	3,895
RI	1,992	1,984	2,004	1,992	2,001	2,016	2,028	2,036	2,046	2,057	2,069
CT	7,286	7,229	7,357	7,478	7,577	7,693	7,756	7,795	7,836	7,879	7,922
New England	**27,618**	**27,523**	**27,890**	**28,269**	**28,627**	**28,937**	**29,153**	**29,321**	**29,508**	**29,704**	**29,905**

Using the above table, the net load in the 4 subareas needs to be determined. Since Connecticut and Rhode Island are load zones these subarea loads are readily available. However, eastern New England and western New England loads are a combination of the different load zones. The western New England subarea consists of the Vermont load zone, the Connecticut load zone and parts of the WCMA load zone (56.5%) and parts of the NH load zone (7.8%).

The eastern New England subarea consists of the Maine and NEMA Boston load zones, the remainder of the WCMA load zone (43.5%) and a majority of the SEMA load zone (79.3%) and the NH load zone (92.2%).

A part of the SEMA load zone (20.7%) is in the Greater RI subarea in addition to the RI load zone load.

So using the above factors, the net load for the 2012-2022 forecast horizon, in the four subareas is calculated in Table 6-2.

Table 6-2
Net Subarea Loads (MW) : 2012-2022

Subarea Loads Includes T & D Losses	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Eastern NE	14,307	14,296	14,491	14,726	14,940	15,091	15,214	15,318	15,434	15,554	15,678
Western NE	10,565	10,482	10,620	10,763	10,884	11,017	11,088	11,135	11,187	11,242	11,298
RI	1,992	1,984	2,004	1,992	2,001	2,016	2,028	2,036	2,046	2,057	2,069
CT	7,286	7,229	7,357	7,478	7,577	7,693	7,756	7,795	7,836	7,879	7,922
Greater RI	2,746	2,745	2,778	2,781	2,804	2,830	2,851	2,868	2,887	2,908	2,929

6.3 Critical Load Level Analysis

For each subarea, the most critical elements that showed up under N-1-1 conditions were selected for the critical load level analysis. The N-1-1 conditions always demonstrated higher violations than the N-1 cases and hence the N-1 conditions were not considered.

6.3.1 Eastern New England

For the eastern New England area the following pairs were evaluated at 2017 load levels. The Table 6-3 below demonstrates the loadings seen in 2017 and 2022.

Table 6-3
Eastern New England N-1-1 Thermal Violations – 2017 and 2022

Element ID	kV	Element Description	[redacted] – 2017 Load Level			[redacted] – 2022 Load Level		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
1280	115	Whipple Jct to Mystic CT	[redacted]	[redacted]	149.4	[redacted]	[redacted]	Non-Convergent
1870-S	115	Mystic CT to Shunock	[redacted]	[redacted]	127.4	[redacted]	[redacted]	141.2

Since the contingency pair of [redacted] did not converge in 2022, the other overload will be used to determine the critical load level.

The net eastern New England load in 2017 is 15,091 MW and the load in 2022 is 15,678 MW. Using these two numbers and the respective overloads in Table 6-3, the eastern New England load at which the line will be loaded to 100% is 13,915 MW. When this load level is compared to the net subarea loads in Table 6-2, the year of need is determined to be prior to 2012.

6.3.2 Western New England

For the western New England area the following pair was evaluated at 2017 load levels. The Table 6-4 below demonstrates the loadings seen in 2017 and 2022.

Table 6-4
Western New England N-1-1 Thermal Violations – 2017 and 2022

Element ID	kV	Element Description	[redacted] – 2017 Load Level			[redacted] – 2022 Load Level		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
L190-5	115	Tower Hill to Davisville Tap	[redacted]	[redacted]	103.6	[redacted]	[redacted]	113.3
1870S	115	Wood River to Shunock	[redacted]	[redacted]	102.0	[redacted]	[redacted]	121.9

The net western New England load in 2017 is 11,017 MW and the load in 2022 is 11,298 MW.

For the L-190 line, the net western New England load level at which the loading is 100% is 10,914 MW. When this load level is compared to the net subarea loads in Table 6-2, the year of need is determined to be between 2016 and 2017.

For the 1870S line a similar analysis results in the critical load level being 10,988 MW, with a year of need again in the 2016-2017 timeframe.

6.3.3 Connecticut

The same overloads that drive a western New England need also drive the Connecticut import need. The Table 6-5 below demonstrates the loadings seen in 2017 and 2022.

Table 6-5
Connecticut N-1-1 Thermal Violations – 2017 and 2022

Element ID	kV	Element Description	[redacted] – 2017 Load Level			[redacted] – 2022 Load Level		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
L190-5	115	Tower Hill to Davisville Tap	[redacted]	[redacted]	103.6	[redacted]	[redacted]	113.3
1870S	115	Wood River to Shunock	[redacted]	[redacted]	102.0	[redacted]	[redacted]	121.9

The net Connecticut load in 2017 is 7,693 MW and the load in 2022 is 7,922 MW.

For the L-190 line, the net Connecticut load level at which the loading is 100% is 7,609 MW. When this load level is compared to the net subarea loads in Table 6-2, the year of need is determined to be between 2016 and 2017.

For the 1870S line a similar analysis results in the critical load level being 7,670 MW, with a year of need again in the 2016-2017 timeframe.

6.3.4 Rhode Island

The Rhode Island needs were driven by the [redacted] The following table has the worst case overloads in 2017 and 2022 under that condition.

Table 6-6
Rhode Island N-1-1 Thermal Violations – 2017 and 2022

Element ID	kV	Element Description	2017 Load Level			2022 Load Level		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
E-183W	115	Phillipsdale Tap to Franklin Square	[redacted]	[redacted]	111.0	[redacted]	[redacted]	Non-Convergent

Since the contingency pair did not converge in 2022, we cannot do a liner extrapolation to determine the critical load level. For this case, the loads were further reduced to 2012 levels and the same contingency pair was simulated. The loading on the E-183W line was a 108% of LTE. This indicates that the critical load level is a RI load level of 1,965 MW. The year of need is prior to 2012.

6.4 Summary

Based on the critical load level analysis, the following conclusions may be made:

- The need for a third 345 kV line into West Farnum exists in today's system.
- The need for additional eastern New England import capability exists in today's system.
- The need for additional western New England import capability is needed in the 2016-2017 time frame
- The need for additional Connecticut import capability is needed in the 2016-2017 time frame

Section 7 Conclusions on Needs Follow Up Assessment

7.1 Overview of Conclusions from Needs Follow Up Assessment

The results of these analyses continue to indicate a need to:

- Reinforce the 345 kV system into the West Farnum Substation for Rhode Island reliability
- Increase the transmission transfer capability from eastern New England and Greater Rhode Island to western New England if additional resources are available in the exporting area
- Increase the transmission transfer capability from western New England and Greater Rhode Island to eastern New England. With the retirement of Salem Harbor, there is a greater need for additional transmission transfer capability to eastern New England.
- Increase the transmission transfer capability into the state of Connecticut

7.1.1 Eastern New England Reliability

The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. With generation retirements, the need for additional eastern New England transmission transfer capability is greater.

7.1.2 Western New England Reliability

The results of the western New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen in the 2016-2017 timeframe. The need for additional transmission transfer capability is advanced if generation resources in western New England retire.

7.1.3 Rhode Island Reliability

The results of the Rhode Island reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier.

7.1.4 Connecticut Reliability

The results of the Connecticut reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen in the 2016-2017 timeframe. The need for additional transmission transfer capability is advanced if generation resources in Connecticut retire.

Section 8
Appendix A: 2012 CELT Load Forecast

Table 8-1
2012 CELT Seasonal Peak Load Forecast Distributions

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2012	26140	26370	26685	27045	27440	27865	28295	28910	29620	30245
	2013	26440	26675	26995	27360	27765	28190	28630	29260	29980	30615
	2014	26925	27165	27490	27865	28275	28710	29155	29795	30530	31170
	2015	27465	27710	28040	28420	28840	29280	29740	30395	31130	31785
	2016	27995	28245	28585	28970	29400	29850	30315	30985	31725	32390
	2017	28470	28720	29065	29460	29895	30355	30825	31505	32255	32930
	2018	28830	29085	29435	29835	30275	30740	31220	31905	32675	33360
	2019	29145	29405	29755	30160	30605	31075	31560	32255	33040	33735
	2020	29455	29715	30070	30480	30930	31405	31895	32595	33405	34110
	2021	29765	30030	30390	30800	31255	31735	32230	32940	33765	34480
WTHI (1)		**78.49**	**78.73**	**79.00**	**79.39**	**79.88**	**80.30**	**80.72**	**81.14**	**81.96**	**82.33**
Dry-Bulb Temperature (2)		**88.50**	**88.90**	**89.20**	**89.90**	**90.20**	**91.20**	**92.20**	**92.90**	**94.20**	**95.40**
Probability of Forecast Being Exceeded		**90%**	**80%**	**70%**	**60%**	**50%**	**40%**	**30%**	**20%**	**10%**	**5%**
Winter (MW)	2012/13	22060	22110	22155	22215	22355	22500	22720	22775	23095	23510
	2013/14	22215	22265	22310	22370	22510	22655	22880	22935	23160	23570
	2014/15	22370	22420	22465	22530	22670	22815	23040	23095	23315	23725
	2015/16	22525	22575	22620	22680	22825	22975	23200	23255	23475	23890
	2016/17	22655	22710	22755	22815	22960	23110	23335	23390	23630	24040
	2017/18	22785	22835	22885	22945	23090	23240	23465	23525	23765	24175
	2018/19	22905	22955	23000	23065	23210	23360	23590	23645	23890	24305
	2019/20	23020	23075	23120	23185	23330	23480	23710	23770	24015	24425
	2020/21	23135	23190	23235	23300	23445	23595	23830	23885	24130	24545
	2021/22	23255	23305	23355	23415	23565	23720	23950	24010	24250	24660
Dry-Bulb Temperature (3)		**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

FOOTNOTES:
(1) WTHI - a three-day weighted temperature-humidity index for eight New England weather stations. It is the weather variable used in producing the summer peak load forecast. For more information on the weather variables see http://www.iso-ne.com/trans/celt/fsct_detail/ .
(2) Dry-bulb temperature (in degrees Fahrenheit) shown in the summer season is for informational purposes only.
(3) Dry-bulb temperature (in degrees Fahrenheit) shown in the winter season is a weighted value from eight New England weather stations.

Table 8-2
2022 Detailed Load Distributions by State and Company

File Created :	2012-03-05	CELT Forecast :	2012	Forecast Year :	2022
Season :	Summer Peak	Weather :	90/10	Load Distribution :	N+10_SUM
ISO-NE CELT :	34130 MW	% of Peak :	100.00%	Tx Losses :	2.50%

State CELT L&L	-	2.50% Tx Losses	+	Non-CELT Load	+	Station Service	-	Area 104 NE Load	=	Area 101 Load
34130 MW		853.3 MW		364.4 MW		1059.4 MW		15.8 MW		34684.7 MW

1: State CELT L&L: This represents the sum of the 6 State CELT forecasts. This number can sometimes be 5-10 MW different than the ISO-NE CELT forecast number due to round-off error.
2: Non-CELT Load: This is the sum of all load modeled in the case that is not included in the CELT forecast. An example is the "behind the meter" paper mill load in Maine.
3: Station Service: This is the amount of generator station service modeled. If station service is off-line, the Area 101 report totals will be different since off-line load is not counted in totals.

Maine State Load = 2480 MW - 2.50% Tx Losses = 2418 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.17%	2059.43	648.73	0.954	332.06
BHE	14.83%	358.57	114.39	0.953	18.06

New Hampshire State Load = 3120 MW - 2.50% Tx Losses = 3042 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	78.91%	2400.35	342.03	0.990	
UNITIL	12.04%	366.10	52.17	0.990	
GSE	9.06%	275.54	8.64	1.000	1.85

Vermont State Load = 1230 MW - 2.50% Tx Losses = 1199.25 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	1199.25	319.51	0.966	98.39

Massachusetts State Load = 16060 MW - 2.50% Tx Losses = 15658.5 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	28.39%	4444.98	1117.12	0.970	37.79
COMEL	11.33%	1773.79	356.16	0.980	
MA-NGRID	39.47%	6180.57	363.67	0.998	38.49
WMECO	6.35%	994.47	141.70	0.990	
MUNI:BOST-NGR	3.34%	522.68	79.95	0.989	
MUNI:BOST-NST	1.24%	194.79	32.82	0.986	
MUNI:CNEMA-NGR	2.12%	332.43	52.30	0.988	
MUNI:RI-NGR	0.89%	139.67	17.23	0.992	
MUNI:SEMA-NGR	1.88%	293.60	33.50	0.994	
MUNI:SEMA-NST	1.75%	274.49	78.12	0.962	
MUNI:WMA-NGR	1.11%	173.81	14.84	0.996	
MUNI:WMA-NU	2.13%	333.06	47.46	0.990	

Rhode Island State Load = 2430 MW - 2.50% Tx Losses = 2369.25 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	2369.25	232.23	0.995	34.60

Connecticut State Load = 8810 MW - 2.50% Tx Losses = 8589.75 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	76.07%	6534.57	931.13	0.990	95.70
CMEEC	4.96%	426.40	60.76	0.990	
UI	18.96%	1628.79	162.88	0.995	10.00

Table 8-3
Detailed Demand Response Through FCA-6 Distributions by Zone

File Created : 2012-06-07 **CCP :** 2015/2016 **Load Season :** Summer Peak
Load Distrb : N+10_SUM **Distrb Losses :** 5.50% **DR Season :** SUM

	Demand Reduction Value (DRV)	X	Load Dependent Capability Assumption (LDCA)	X	Performance Assumption (PA)	+	Distribution Losses Gross-Up	-	Area 104 DR	=	Area 101 DR
Passive :	1560.41 MW		100.00%		100.00%		85.82 MW		3.75 MW		1642.48 MW
Active :	1457.33 MW		100.00%		75.00%		60.11 MW		1.54 MW		1151.57 MW

Demand Reduction Value (DRV): Amount of DR measured at the customer meter without any gross-up values for transmission or distribution losses.
Load Dependent Capability Assumption (LDCA): De-rate factor applied based on % of CELT load. (i.e. Light load is 45% of 50/50 load, so the LDCA would be 45%.)
Performance Assumption (PA): De-rate factor applied based on expected performance of DR after a dispatch signal from Operations.
Area 104 DR: This load is modeled in northern VT and is electrically served from Hydro Quebec. To make Area Interchange load independent, this load is assigned Area 104.

Passive Demand Resources - (On-Peak and Seasonal Peak)
DR Modeled = (DRV_SUM * 100.00% LDCA * 100.00% PA) + 5.50% Distrb Losses Gross-Up

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Load Zone - Maine	145.82	-153.84	-48.36
DR_P_NH	21	Load Zone - New Hampshire	78.03	-82.32	-11.43
DR_P_VT	22	Load Zone - Vermont	114.80	-121.11	-32.56
DR_P_NEMABOS	23	Load Zone - Northeast Massachusetts & Boston	317.53	-334.99	-72.10
DR_P_SEMA	24	Load Zone - Southeast Massachusetts	176.30	-186.00	-19.57
DR_P_WCMA	25	Load Zone - West Central Massachusetts	209.91	-221.46	-19.84
DR_P_RI	26	Load Zone - Rhode Island	129.07	-136.17	-13.41
DR_P_CT	27	Load Zone - Connecticut	388.95	-410.34	-55.16

Active Demand Resources - (Real-Time Demand Resource (RTDR), Excludes RTEG)
DR Modeled = (DRV_SUM * 100.00% LDCA * 75.00% PA) + 5.50% Losses Gross-Up

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_A_ME_BHE	30	Dispatch Zone - ME - Bangor Hydro	44.13	-34.92	-11.39
DR_A_ME_MAIN	31	Dispatch Zone - ME - Maine	151.25	-119.68	-36.00
DR_A_ME_PORT	32	Dispatch Zone - ME - Portland Maine	100.08	-79.19	-25.77
DR_A_NH_NEWH	33	Dispatch Zone - NH - New Hampshire	53.41	-42.26	-5.85
DR_A_NH_SEAC	34	Dispatch Zone - NH - Seacoast	7.60	-6.01	-0.86
DR_A_VT_NWVT	35	Dispatch Zone - VT - Northwest Vermont	40.80	-32.28	-9.22
DR_A_VT_VERM	36	Dispatch Zone - VT - Vermont	22.27	-17.62	-4.19
DR_A_MA_BOST	37	Dispatch Zone - MA - Boston	198.08	-156.73	-39.39
DR_A_MA_NSHR	38	Dispatch Zone - MA - North Shore	69.81	-55.24	-6.31
DR_A_MA_CMA	39	Dispatch Zone - MA - Central Massachusetts	79.81	-63.15	-3.75
DR_A_MA_SPFD	40	Dispatch Zone - MA - Springfield	38.89	-30.77	-4.39
DR_A_MA_WMA	41	Dispatch Zone - MA - Western Massachusetts	53.60	-42.41	-4.08
DR_A_MA_LSM	42	Dispatch Zone - MA - Lower Southeast Massachusetts	48.42	-38.31	-6.28
DR_A_MA_SEMA	43	Dispatch Zone - MA - Southeast Massachusetts	110.13	-87.14	-7.00
DR_A_RI_RHOD	44	Dispatch Zone - RI - Rhode Island	84.43	-66.81	-6.58
DR_A_CT_EAST	45	Dispatch Zone - CT - Eastern Connecticut	41.51	-32.84	-4.68
DR_A_CT_NRTH	46	Dispatch Zone - CT - Northern Connecticut	55.12	-43.61	-6.22
DR_A_CT_NRST	47	Dispatch Zone - CT - Norwalk-Stamford	63.46	-50.21	-6.85
DR_A_CT_WEST	48	Dispatch Zone - CT - Western Connecticut	194.53	-153.92	-19.97

[redacted]

Table 8-4
2012 CELT Forecasted Energy Efficiency (Including Losses)
by Load Zone 2016-2022[26]

PASSIVE Load Zone (MW including T & D Losses)	2016	2017	2018	2019	2020	2021	2022
MAINE	9.00	8.00	8.00	7.00	7.00	6.00	6.00
NEW HAMPSHIRE	10.00	9.00	10.00	8.00	8.00	8.00	8.00
VERMONT	19.00	17.00	16.00	16.00	14.00	13.00	13.00
NEMASSBOST	66.00	62.00	58.00	54.00	51.00	47.00	47.00
SEMASS	33.00	32.00	29.00	28.00	25.00	25.00	25.00
WCMASS	38.00	36.00	34.00	32.00	29.00	28.00	28.00
RHODE ISLAND	27.00	24.00	24.00	21.00	20.00	19.00	19.00
CONNECTICUT	31.00	29.00	27.00	26.00	24.00	22.00	22.00
NE Total	**233.00**	**217.00**	**206.00**	**192.00**	**178.00**	**168.00**	**168.00**

[26] The 2012 CELT report only forecasts energy efficiency until 2021. The growth of EE forecast from 2021 to 2022 was assumed to be identical to the growth of EE from 2020 to 2021.

[redacted]

Section 9
Appendix B: Case Summaries and Generation Dispatches

[redacted]

[redacted]

Section 10
Appendix C: Contingency List

[redacted]

Section 11
Appendix D: Contingency Results

[redacted]

[redacted]

Section 12
Appendix E: Net Loads in New England

12.1 CELT Load Forecast

The following Table 12-1 provides the 90/10 summer peak forecast based on the 2012 CELT. The table includes the individual forecasts for the 8 load zones.

Table 12-1
90/10 Summer Peak Forecast (MW) : 2012-2022

CELT Load Includes T & D Losses	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Maine	2,195	2,215	2,250	2,290	2,325	2,355	2,385	2,405	2,430	2,455	2,480
NH	2,605	2,655	2,720	2,795	2,865	2,915	2,960	3,000	3,040	3,080	3,121
Vermont	1,120	1,130	1,140	1,155	1,165	1,180	1,190	1,200	1,210	1,220	1,230
NEMA_BOSTON	5,991	6,063	6,176	6,302	6,427	6,526	6,607	6,682	6,756	6,830	6,905
SEMA	3,872	3,937	4,028	4,129	4,230	4,315	4,389	4,459	4,529	4,599	4,670
WCMA	3,872	3,920	3,996	4,079	4,163	4,229	4,284	4,335	4,386	4,436	4,487
RI	2,100	2,125	2,160	2,200	2,235	2,275	2,310	2,340	2,370	2,400	2,430
CT	7,870	7,940	8,060	8,185	8,315	8,460	8,550	8,615	8,680	8,745	8,810
New England	**29,625**	**29,985**	**30,530**	**31,135**	**31,725**	**32,255**	**32,675**	**33,036**	**33,401**	**33,765**	**34,133**

12.2 Passive DR and EE forecast

The following Table 12-2 has the total passive DR available for each year in the 2012-2022 forecast horizon. From 2012 to 2015, the passive DR values used correspond to the qualified capacities of the passive DR cleared in each successive forward capacity auction from FCA-3 to FCA-6. For the years beyond 2015, the EE forecast is added onto the passive DR at the end of FCA-6.

The numbers in the table correspond to the demand reduction value (DRV) and exclude the transmission and distribution losses.

Table 12-2
Qualified Capacities of Passive DR (FCA 1-6) and EE Forecast (MW) : 2012-2022

Passive DR (Excludes T & D losses)	QC's of FCA 1-6 DR				QC's of Cleared DR in FCA 1-6 + Forecasted EE						
	FCA3	FCA4	FCA5	FCA6	FCA7	FCA8	FCA9	FCA10	FCA11	FCA12	FCA13
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Maine	56	104	134	146	154	162	169	175	182	187	193
NH	59	66	72	78	87	97	105	113	121	128	135
Vermont	70	89	102	115	132	149	164	178	191	203	215
NEMA_BOSTON	193	240	273	318	379	436	490	540	587	630	674
SEMA	107	125	153	176	207	236	263	289	312	336	359
WCMA	107	136	177	210	245	278	310	340	366	392	418
RI	65	79	85	129	153	176	198	218	236	254	272
CT	338	393	399	389	418	445	470	494	516	536	557
New England	**993**	**1231**	**1396**	**1560**	**1775**	**1979**	**2168**	**2347**	**2511**	**2667**	**2822**

[redacted]

12.3 Active DR

The following Table 12-3 has the total active DR available for each year in the 2012-2022 forecast horizon. From 2012 to 2015, the active DR values used correspond to the qualified capacities of the active DR cleared in each successive forward capacity auction from FCA-3 to FCA-6. For the years beyond 2015, the active DR is assumed to stay constant.

The numbers in the table correspond to the demand reduction value (DRV) and exclude the transmission and distribution losses.

Table 12-3
Qualified Capacities of Active DR (FCA 1-6) (MW) : 2012-2022

Active DR (Excludes T & D losses)	QC's of FCA 1-6 DR				Constant Beyond FCA-6						
	FCA3	FCA4	FCA5	FCA6	FCA7	FCA8	FCA9	FCA10	FCA11	FCA12	FCA13
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Maine	258	288	291	295	295	295	295	295	295	295	295
NH	41	55	57	61	61	61	61	61	61	61	61
Vermont	31	47	55	63	63	63	63	63	63	63	63
NEMA_BOSTON	239	273	265	268	268	268	268	268	268	268	268
SEMA	140	153	154	159	159	159	159	159	159	159	159
WCMA	127	158	162	172	172	172	172	172	172	172	172
RI	46	69	79	84	84	84	84	84	84	84	84
CT	271	354	336	355	355	355	355	355	355	355	355
New England	**1153**	**1398**	**1399**	**1457**	**1457**	**1457**	**1457**	**1457**	**1457**	**1457**	**1457**

12.4 Net Demand Resources

This section determines the net DR which would be subtracted from the CELT load forecast to determine the net load in the different load zones. Two factors need to be applied to the DR values in Table 12-2 and Table 12-3:

- Availability of the DR
- Transmission and Distribution Losses

The passive DR and EE forecast are assumed to be available at 100% whereas the active DR is assumed to be available at 75%. The transmission and distribution losses correspond to about 8% and that amount is added to the values in the tables above.

For example to determine the net DR in 2018 in Maine, we add 100% of the passive DRV (169 MW) and 75% of the active DR (295 MW).

Net DRV = 1.00 * 169 + 0.75 * 295 = 390.25 MW

To obtain the net DR we add 8% to the net DRV Value.

Net DR = 1.08 * 390.25 = 421.47 MW

Table 12-4
Net Demand Resources (MW) : 2012-2022

Net DR (Includes DR unavailability and T&D losses)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Maine	269	346	380	397	406	414	422	429	436	442	448
NH	97	116	124	134	144	154	163	172	180	188	196
Vermont	100	135	154	175	194	212	228	243	257	270	283
NEMA_BOSTON	402	480	510	560	626	688	746	800	851	898	945
SEMA	229	259	290	319	352	384	413	441	466	491	516
WCMA	218	275	322	366	404	440	474	506	535	563	591
RI	108	141	156	208	234	259	282	304	324	343	362
CT	584	711	703	707	738	767	794	820	844	866	888
New England	**2,007**	**2,462**	**2,640**	**2,866**	**3,098**	**3,318**	**3,522**	**3,715**	**3,893**	**4,061**	**4,229**

12.5 Net Load

The net load in the different load zones is determined by deducting the net DR in Table 12-4 from the CELT load forecast in Table 12-1.

Table 12-5
Net Loads (MW) : 2012-2022

Net Loads Includes T & D Losses	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Maine	1,926	1,869	1,870	1,893	1,919	1,941	1,963	1,976	1,994	2,013	2,032
NH	2,508	2,539	2,596	2,661	2,721	2,761	2,797	2,828	2,860	2,892	2,925
Vermont	1,020	995	986	980	971	968	962	957	953	950	947
NEMA_BOSTON	5,589	5,583	5,666	5,742	5,801	5,838	5,861	5,882	5,905	5,932	5,960
SEMA	3,643	3,678	3,738	3,810	3,878	3,931	3,976	4,018	4,063	4,108	4,154
WCMA	3,654	3,645	3,674	3,713	3,759	3,789	3,810	3,829	3,851	3,873	3,895
RI	1,992	1,984	2,004	1,992	2,001	2,016	2,028	2,036	2,046	2,057	2,069
CT	7,286	7,229	7,357	7,478	7,577	7,693	7,756	7,795	7,836	7,879	7,922
New England	**27,618**	**27,523**	**27,890**	**28,269**	**28,627**	**28,937**	**29,153**	**29,321**	**29,508**	**29,704**	**29,905**

[redacted]

Section 13
Appendix F: NERC Compliance Statement

This report is the first part of a two part process used by ISO New England to assess and address compliance with NERC TPL standards. This updated needs assessment report provides documentation of an evaluation of the performance of the system as contemplated under the TPL standards to determine if the system meets compliance requirements. The solution study report is a complimentary report that documents the study to determine which, if any, upgrades should be implemented along with the in-service dates of proposed upgrades that are needed to address the needs documented in the needs assessment report. The needs assessment report and the solution study report taken together provide the necessary evaluations and determinations required under the NERC TPL standards.

This study provides a detailed assessment of southern New England's electric system performance for the 2011-2015 next five years and reviews system performance expected for 2016-2020, years six through ten. This study shows performance for NERC Category A conditions in Section 5.2.1 (Page 40) and performance was adequate. The study shows NERC Category B condition performance in Section 5.2.2 (Page 41) and performance was inadequate. NERC Category C review can be found in Section 5.2.2 and 5.2.3 (Pages 41-44) and performance was inadequate. For NERC Category B and C review all contingencies were studied. As shown in Section 6.4 (Page 48), the critical system condition is expected in year 2012 or earlier with a load of 29,620 MW. As shown in Section 3.1.7 (Page 22) the study includes a peak load of 34,130MW in 2022. These loads identify system conditions expected over the next five years and ensure that marginal conditions will be identified for years six through ten. Marginal conditions are expected after five years as reviewed in Section 5. This study uses normal operating procedures as illustrated by transfers, phase shifter settings and normal capacitor settings. Transfers are as shown in Section 3.1.9 (Page 23). Note that while firm transfers are not explicitly modeled or used in New England the system conditions used in this study are always sufficiently stressed to ensure transfer capability across interfaces are maintained. This study includes existing and planned Demand Resources, transmission and generation facilities as shown in Section 3.1.13 (Page 28). Demand Resources effects are included in load projections. The study includes reactive resources as shown in Section 3.1.11 (Page 28). Reactive resources will not provide adequate voltage support for the next five years and projections are that adequate support cannot be expected in years six through ten as shown in Section 5 (Page 36). Planned outages are addressed through generator dispatch as shown in Section 3.1.10 (Page 24). The effects of existing and planned protection systems can be found in Section 3.1.14 (Page 29). The effects of existing and planned control devices (Dynamic Control Systems) can be found in Section 3.1.14 (Page 29). ISO New England Operations coordinates and approves planned generator and transmission outages looking out one year. Long term planning studies look at 90/10 load, stressed dispatch and line out conditions that historically provide ample margin to perform maintenance.

Appendix O

ISO-NE, Follow-Up Analysis to the 2012 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report (September 2012), [referred to as "2012 Follow-Up Solution Report"].

This page intentionally left blank

Follow-Up Analysis to the 2012 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report

Public Version - CEII Material Redacted

September 2012

This page intentionally left blank

Table of Contents

[redacted]

List of Figures

[redacted]

List of Tables

Section 1
Executive Summary

1.1 Needs Assessment Results and Problem Statement

The objective of this analysis was to identify regulated transmission solutions that address the needs identified in the "*Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Need Assessment*," dated September 2012[1]. The objective of the follow up Needs Assessment was to update the needs identified in the "*New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment,*" dated April 2011[2], based on changes in assumptions, specifically with respect to the changes in load forecast and forecasted energy efficiency.

Summary of changes that the follow up Needs Assessment addressed:

- Updated Capacity, Energy, Loads, and Transmission (CELT) Report for 2012. The 2010 CELT report was used for the last needs study.
- Study year of 2022 for 10-year horizon. The year 2020 was used in the last needs study.
- Results from the most recent Forward Capacity Auction (FCA) #6 (Capacity Period June 1, 2015 – May 31, 2016). FCA #4 results were used in the last study.
- Forecasted energy efficiency (EE) published in the 2012 CELT Report through the year 2022. No forecasted EE past the last FCA was used in the last study.
- Changes in generation dispatch assumptions:
    - Wind power output – On shore 5% of nameplate in the import area, 100% in the export area. The QC value was used in the last needs study.
    - Hydro power assumptions – Update based on the ongoing Vermont / New Hampshire, Pittsfield / Greenfield, and Greater Hartford / Central Connecticut reliability studies. The QC value was used in the last needs study.
    - Salem Harbor, AES Thames, Bridgeport Harbor 2, Somerset 6, Somerset Jet 2, Holyoke 6 & 8, Bio Energy, Potter Diesel, and Ansonia were assumed out of service in base case due to multiple delist bids / retirements / interconnection queue withdrawals. These units were all available in the last needs study.
    - Lake Road generating station was in service for all stresses. These units were assumed out of service for the East to West stressed cases in the last needs study.

The needs follow up evaluated the reliability of the southern New England transmission system for 2022 projected system conditions. The system was tested with all-lines-in service (N-0) and under N-1 and N-1-1 contingency events for a number of possible operating conditions. The study area defined as southern New England includes Northeast Utilities (NU), National Grid USA (NGRID) and NSTAR facilities in the states of Massachusetts, Rhode Island and Connecticut.[3]

[1] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/index.html

[2] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2011/index.html

[3] Note that there are other studies currently underway (within the same geographic area) that are being coordinated with this study effort. Such studies include the Greater Boston, the southwest Connecticut, the Greater Hartford-Central Connecticut, the southeastern Massachusetts/Rhode Island (SEMA/RI) and the Pittsfield/Greenfield studies.

[redacted]

The following needs were identified in the follow-up needs analysis:

- Reinforce the 345 kV system into the West Farnum substation for Rhode Island reliability.
- Increase the transmission transfer capability from western New England and Greater Rhode Island to reliably serve load in eastern New England. With the retirement of Salem Harbor, there is an increased need for additional transmission transfer capability to eastern New England.
- Increase the transmission transfer capability from eastern New England and Greater Rhode Island to reliably serve load in western New England, if additional resources were available in the east.
- Increase the transmission transfer capability into the state of Connecticut to reliably serve load.

These issues were seen in the last needs reassessment study and the follow up study continues to show similar concerns within the 10 year planning horizon. The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. The western New England reliability analysis shows the first violation in the 2016-2017 timeframe. The Rhode Island reliability analysis shows the first violation at 2012 load levels or earlier. The Connecticut reliability analysis shows the first violation in the 2016-2017 timeframe.

1.2 Recommended Solution

1.2.1 Study Methodology

The needs that were seen in the 2011 updated Needs Assessment were again seen in the 2012 follow-up updated Needs Assessment. The five alternatives evaluated in the 2012 updated solutions study were options A-1, A-2, A-3, A-4 and C-2.1. A description of the five alternatives considered is provided in Appendix A: Description of Interstate Alternatives.

Of the five alternatives the four A-series alternatives provided very similar electrical performance and were all superior to the C-2.1 option. Moreover, the A-series options also had a significantly lower estimated cost compared to option C-2.1. Thus, for this assessment, the option C-2.1 was not considered.

Also, within the A-series options, option A-1 had the lowest estimated cost and the least environmental impact. Based on these factors option A-1 was selected as the preferred solution as documented in the in *"New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report,"* dated February 2012.

For the follow-up assessment only option A-1 was considered. Based on the previous analysis it was determined that the other A-series options would not provide a distinct advantage over option A-1. If the need was seen to modify A-1 to meet the updated needs then the necessary modifications would be made.

In option A-1, a new 345 kV transmission line emanates from the Card substation in Lebanon, Connecticut and follows the existing transmission corridor (330 line) to the Lake Road switching station in Killingly, Connecticut. From the Lake Road switching station, a new 345 kV transmission line follows the existing transmission corridor (3348 and 347 lines) northeasterly to the vicinity of the Sherman Road switching station in Burrillville, Rhode Island. In option A-1, this new 345 kV transmission line does not connect to the Sherman Road switching station but goes by it and continues in a southeasterly direction on an existing transmission corridor (328 line) to terminate at

[redacted]

the West Farnum substation in North Smithfield, Rhode Island. A new 345 kV transmission line would also be constructed on the existing transmission corridor (Q-143 and R-144 lines) between the West Farnum substation and the Millbury switching station in Millbury, Massachusetts. The existing 345 kV 328 line (Sherman Road to West Farnum) must also be rebuilt with higher capacity conductors under this plan.

The one-line description of option A-1 is shown in Figure 1-1.

[redacted]

Figure 1-1: One-line Diagram of Option A-1

As a part of the follow up solutions study the different components of A-1 were tested in an incremental manner. This was done to determine if any component of A-1 might be deferred beyond the 10-year planning horizon.

The rebuild of Sherman Road was included as a common upgrade at all the incremental levels of option A-1 since this upgrade was needed to eliminate the critical breaker failure (breaker 142) at Sherman Road and would resolve other terminal equipment overloads at Sherman Road.

The most urgent need in the Needs Assessment was the addition of a new 345 kV line into West Farnum to resolve the voltage collapse seen for the [redacted] Additionally, N-1 thermal violations were seen in the eastern New England import analysis on the 345 kV and 115 kV network between Rhode Island and Massachusetts. Hence the first level

[redacted]

was the addition of the Millbury to West Farnum line that would simultaneously mitigate the RI non-convergence issue and the N-1-1 eastern NE import violations in MA and RI.

Subsequently the other major 345 kV components were added as discussed below in Table 1-1.

Table 1-1
Solution Study Component Level Descriptions

Level	Component Descriptions
1	• A new 345 kV line from the West Farnum substation in Rhode Island to the Millbury switching station in Massachusetts.
2	• All Level 1 components • A new 345 kV line from the Lake Road switching station in Connecticut to the West Farnum substation in Rhode Island
3	• All Level 2 components • A new 345 kV line from Card substation to the Lake Road switching station in eastern Connecticut
4	• All Level 3 components • Rebuild the existing 345 kV line (328) between the Sherman Road switching station in Rhode Island to the West Farnum substation in Rhode Island with higher capacity conductors

1.2.2 Study Results

The results of the analysis indicate that all 4 major 345 kV components of option A-1 were required to resolve the criteria violations identified in the follow-up Needs Assessment. In addition to the upgrades described in the Level 4 topology a new breaker was required at West Farnum in series with the existing 1713 breaker. This new breaker eliminates a critical breaker failure contingency. This series breaker was a part of the option A-1 that was selected as the preferred solution in the February 2012 updated solutions study.

In summary, all of the components of option A-1 that were identified as the preferred solution in the February 2012 solution study report were seen to be needed in the 10 year planning horizon.

1.2.3 Preferred Alternative

The major 345 kV components of the A-1 plan are:

- A new 345 kV line from Card substation to the Lake Road switching station
- A new 345 kV line from the Lake Road switching station in Connecticut to the West Farnum substation in Rhode Island
- A new 345 kV line from the West Farnum substation in Rhode Island to the Millbury switching station in Massachusetts.
- Rebuild existing 345 kV line (328) from Sherman Road to West Farnum substations

The new line into Millbury from West Farnum provides a new import line into eastern New England and allows for the movement of power from western New England and Greater Rhode Island to reliably serve load in eastern New England during resource outage conditions in eastern New England that require eastern New England to import power from the rest of New England.

Similarly the line into Card substation via Lake Road and West Farnum provides a new import path into Connecticut and western New England and allows for the movement of power from eastern New

England and Greater Rhode Island to reliably serve load in Connecticut and western New England during capacity deficiency conditions in the west.

The project also provides two new 345 kV lines into West Farnum which resolve the criteria violations in Rhode Island seen for the [redacted]

The other components of the plan are detailed in Appendix A: Description of Interstate Alternatives.

Thus, the preferred solution A-1 resolves all the needs identified in the follow-up Needs Assessment.

1.3 NERC Compliance Statement

In accordance with NERC TPL Standards, this assessment provides:

- A written summary of plans to address the system performance issues described in the "*Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment*," dated September 2012
- A schedule for implementation as shown in Section 7.3
- A discussion of lead times necessary to implement plans in Section 7.3

The results of these analyses continued to indicate a need for all the components of option A-1 in the 10 year planning horizon. The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. The western New England reliability analysis shows the first violation in the 2016-2017 timeframe. The Rhode Island reliability analysis shows the first violation at 2012 load levels or earlier. The Connecticut reliability analysis shows the first violation in the 2016-2017 timeframe.

The planned completion date of the preferred solution as described in Section 7.1 is December 2015.

[redacted]

Section 2
Needs Assessment Results Summary

2.1 Introduction

The objective of this analysis was to identify regulated transmission solutions that address the needs identified in the "*Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment*," dated September 2012[4]. The objective of the follow up Needs Assessment was to update the needs identified in the "*New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment,"* dated April 2011[5], based on system changes since then.

2.2 Background

In the 2004 to 2008 time frame, the Southern New England Regional Working Group, which included representatives from Independent System Operator New England (ISO), National Grid USA (NGRID), and Northeast Utilities (NU), performed a study that has been referred to as the Southern New England Transmission Reliability (SNETR) study. The proposed regional solution that was developed as a result of this study effort has been labeled NEEWS. This solution consisted of four components: the Rhode Island Reliability Project (RIRP), the Greater Springfield Reliability Project (GSRP), the Interstate Reliability Project (Interstate), and the Central Connecticut Reliability Project (CCRP), known collectively as the NEEWS projects. These four components were the direct result of a regional transmission planning effort which combined a comprehensive regional transmission study with a comprehensive four-component regional transmission solution.

The NEEWS projects emerged from a coordinated series of studies assessing the deficiencies in the southern New England electric supply system. The SNETR study initially focused on limitations on East to West power transfers across southern New England and transfers between Connecticut and southeast Massachusetts and Rhode Island. These limitations had been identified as interdependent beginning in the ISO's 2003 Regional Transmission Expansion Plan (RTEP03). In the course of studying these inter-state transfer limitations, the working group determined that previously identified reliability problems in Greater Springfield and Rhode Island were not simply local issues, but also affected inter-state transfer capabilities. In addition, constraints in transferring power from eastern Connecticut across central Connecticut to the concentrated load in southwest Connecticut were identified.

[4] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/index.html

[5] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2011/index.html

[redacted]

The needs at that time were summarized as follows and are depicted in Figure 2-1:

- **East–West New England Constraints**: Regional East to West power flows could be limited during summer peak periods across the southern New England region as a result of thermal and voltage violations on area transmission facilities under contingency conditions.
- **Springfield Reliability**: The Springfield, Massachusetts area could be exposed to significant thermal overloads and voltage problems under numerous contingencies and load levels. The severity of these problems would increase as the transmission system attempts to move power into Connecticut from the rest of New England.
- **Interstate Transfer Capacity**: Transmission transfer capability into Connecticut and Rhode Island during summer peak periods could be inadequate under existing generator availabilities for criteria contingency conditions.
- **East–West Connecticut Constraints**: East to West power flows in Connecticut could stress the existing system under N-1-1 contingency conditions during peak load levels.
- **Rhode Island Reliability**: The system depends heavily on limited transmission lines or autotransformers to serve its peak load demand, which could result in thermal overloads and voltage problems during contingency conditions.

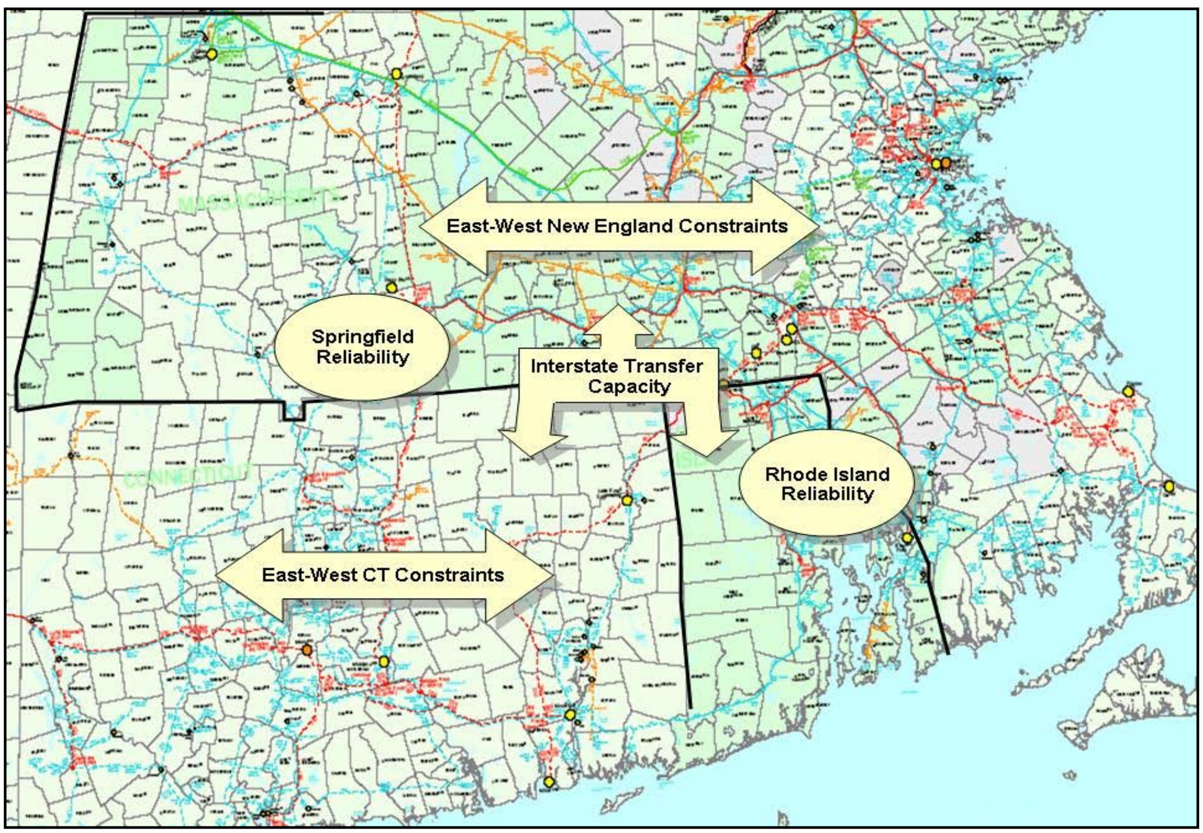

Figure 2-1: Original Southern New England Needs and Constraints

[redacted]

In accordance with the Regional Planning Process as outlined in Attachment K of the Independent System Operator – New England Open Access Transmission Tariff (OATT), the ISO reaffirmed the need for the RIRP and the GSRP in 2009, using the latest network, load and resource data available. The siting agencies in Rhode Island, Massachusetts and Connecticut have approved both of these components and NGRID and NU are now moving forward with the construction phase. The ISO started a reassessment of the Interstate component in 2010, reaffirmed the need for a modified Interstate component in April 2011, and finalized the solution study report in February 2012[6]. A follow-up study of the Greater Hartford and Central Connecticut area will update and document the results of the CCRP updated needs analysis.

The results of the 2011 updated Needs Assessment were identified in the "*New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment,*" dated April 2011[7]. The following needs were identified for the study area:

- Reinforce the 345 kV system into the West Farnum substation for Rhode Island reliability.
- Increase the transmission transfer capability from western New England and Greater Rhode Island to reliably serve load in eastern New England. With the retirement of Salem Harbor, there was a need for additional transmission transfer capability to eastern New England.
- Increase the transmission transfer capability from eastern New England and Greater Rhode Island to reliably serve load in western New England, if additional resources were available in the east.
- Increase the transmission transfer capability into the state of Connecticut to reliably serve load.

The Needs Assessment was followed by a solutions study that identified a modified version of the originally proposed Interstate Reliability Project as the preferred solution. The results of the solutions study were documented in "*New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report,*" dated February 2012. Five alternatives were evaluated that resolved all the criteria violation. The study concluded that option A-1 was the preferred solution. The major 345 kV components of option A-1 are:

- A new 345 kV line from Card substation to the Lake Road switching station in eastern Connecticut.
- A new 345 kV line from the Lake Road switching station in Connecticut to the West Farnum substation in Rhode Island.
- A new 345 kV line from the West Farnum substation in Rhode Island to the Millbury switching station in Massachusetts.
- Rebuild existing 345 kV line (328) from Sherman Road to West Farnum substations

The preferred solution option A-1 not only resolved all the needs identified in the updated needs analysis, but also stood out as the best option after a comparison of electrical performance factors, costs and natural/human environment impact factors.

---

6 https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/neews_interstate_solution.pdf

7 http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2011/index.html

[redacted]

Since April 2011, there were a number of system changes that required the ISO to reevaluate the need for the Interstate project. A summary of changes that the follow up Needs Assessment addressed:

- Updated Capacity, Energy, Loads, and Transmission (CELT) Report for 2012. The 2010 CELT report was used for the last needs study.
- Study year of 2022 for 10-year horizon. The year 2020 was used in the last needs study.
- Results from the most recent Forward Capacity Auction (FCA) #6 (Capacity Period June 1, 2015 – May 31, 2016). FCA #4 results were used in the last study.
- Forecasted energy efficiency (EE) published in the 2012 CELT Report through the year 2022. No forecasted EE past the last FCA was used in the last study.
- Changes in generation dispatch assumptions:
    - Wind power output – On shore 5% of nameplate in the import area, 100% in the export area. The QC value was used in the last needs study.
    - Hydro power assumptions – Update based on the ongoing Vermont / New Hampshire, Pittsfield / Greenfield, and Greater Hartford / Central Connecticut reliability studies. The QC value was used in the last needs study.
    - Salem Harbor, AES Thames, Bridgeport Harbor 2, Somerset 6, Somerset Jet 2, Holyoke 6 & 8, Bio Energy, Potter Diesel, and Ansonia were assumed out of service in base case due to multiple delist bids / retirements / interconnection queue withdrawals. These units were all available in the last needs study.
    - Lake Road generating station was in service for all stresses. These units were assumed out of service for the East to West stressed cases in the last needs study.

The needs follow up evaluated the reliability of the southern New England transmission system for 2022 projected system conditions. The system was tested with all-lines-in service (N-0) and under N-1 and N-1-1 contingency events for a number of possible operating conditions. The study area defined as southern New England includes Northeast Utilities (NU), National Grid USA (NGRID) and NSTAR facilities in the states of Massachusetts, Rhode Island and Connecticut.[8]

[8] Note that there are other studies currently underway (within the same geographic area) that are being coordinated with this study effort. Such studies include the Greater Boston, the southwest Connecticut, the Greater Hartford-Central Connecticut, the southeastern Massachusetts/Rhode Island (SEMA/RI) and the Pittsfield/Greenfield studies.

[redacted]

2.3 Area Studied

The study area consisted of the three southern New England states of Massachusetts, Rhode Island and Connecticut. Figure 2-2 is a geographic map of the 345/230 kV transmission system in southern New England with the major substations highlighted.

[redacted]

Figure 2-2: Southern New England Bulk Transmission System

For purposes of this study, the New England system was split into three sub-areas (eastern New England, western New England and Greater Rhode Island) based on weak transmission system connections to neighboring sub-areas. Figure 2-3 is a map that shows how the three sub-areas were divided geographically. For the eastern New England reliability study, Greater Rhode Island was considered as part of the western New England sub-area shown in Figure 2-4 (left). For the western New England reliability study, the Greater Rhode Island sub-area was considered as part of the eastern New England sub-area shown in Figure 2-4 (right).

The fact that the Greater Rhode Island area is part of the east when moving power westward and then becomes part of the west when moving power eastward is the direct result of where the transmission constraints develop under the two scenarios. A significant amount of generation enters the system via the 345 kV path between the West Medway and Card Street Substations, and constraints exist in moving power in both the westerly and easterly directions. With power flow from east to west (to cover for unavailable western resources), the Greater Rhode Island generation gets constrained to its west; hence, Greater Rhode Island is in the east and vice versa when you try to move power from west to east (to cover for unavailable eastern resources).

This is very similar to the Lake Road issue in Connecticut. Lake Road is currently considered outside of Connecticut under Connecticut Import conditions but, conversely, is considered within Connecticut when Connecticut Export is modeled.

[redacted]

Figure 2-3: Interstate Needs New England Sub-Areas

[redacted]

Figure 2-4: Eastern and Western New England Sub-Areas by Direction of Power Flow

[redacted]

A further detailed description of the subareas and the transmission lines defining the associated interfaces is provided in the "*Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment*," dated September 2012[9].

2.4 Needs Assessment Review

The follow-up Needs Assessment reaffirmed that all the needs identified in the 2011 Needs Assessment were seen in the 10 year planning horizon. The system changes since the 2011 analysis did reduce the severity of some of the criteria violations, but the following needs were identified:

- Reinforce the 345 kV system into the West Farnum substation for Rhode Island reliability.
- Increase the transmission transfer capability from western New England and Greater Rhode Island to reliably serve load in eastern New England. With the retirement of Salem Harbor, there was a need for additional transmission transfer capability to eastern New England.
- Increase the transmission transfer capability from eastern New England and Greater Rhode Island to reliably serve load in western New England, if additional resources were available in the east.
- Increase the transmission transfer capability into the state of Connecticut to reliably serve load.

2.5 Year of Need Analysis

The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. The western New England reliability analysis shows the first violation in the 2016-2017 timeframe. The Rhode Island reliability analysis shows the first violation at 2012 load levels or earlier. The Connecticut reliability analysis shows the first violation in the 2016-2017 timeframe.

[9] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/index.html

[redacted]

Section 3
Study Assumptions

3.1 Analysis Description

The needs that were seen in the 2011 updated Needs Assessment were again seen in the 2012 follow-up updated Needs Assessment. Thus, the first step in the solutions study was to revisit the five alternatives considered in the solutions study corresponding to the 2011 Needs Assessment. The five alternatives evaluated in that study were options A-1, A-2, A-3, A-4 and C-2.1. A description of the five alternatives considered is provided in Appendix A: Description of Interstate Alternatives.

Of the five alternatives the four A-series alternatives provided very similar electrical performance and were all superior to the C-2.1 option. Moreover, the A-series options also had a significantly lower estimated cost compared to option C-2.1. Thus for this assessment the option C-2.1 was not considered.

Also, within the A-series options, option A-1 had the lowest estimated cost and the least environmental impact. Based on these factors option A-1 was selected as the preferred solution. For this assessment only option A-1 was considered, and if the need was seen to modify A-1 to meet the need then the necessary modifications would be made. Based on the previous analysis it was determined that the other A-series options would not provide a distinct advantage over option A-1.

Additionally, as a part of the analysis the different components of A-1 were tested in an incremental manner. This analysis would determine if any component of A-1 might be deferred in the 10-year planning horizon.

In evaluating the different stages of option A-1, only thermal and voltage analysis was performed. If the final solution deviated from the complete option A-1 then additional transfer capability, stability analysis and delta P analysis may be performed.

A short description of the analysis performed is as follows:

- **Thermal analysis** – studies to determine the level of steady-state power flows on transmission facilities under base case conditions and following contingency events. These flows are compared to the applicable facility rating to determine if the equipment will be operated within its capabilities.
- **Voltage analysis** – studies to determine system voltage levels and performance under base case conditions and following contingency events. These voltages are then compared to applicable voltage criteria.

3.2 Steady State Model

3.2.1 Study Assumptions

The regional steady state model was developed to be representative of the 10-year projections of the 90/10 summer peak system demand level to assess reliability performance under stressed system conditions. The model assumptions included consideration of area generation unit unavailability conditions as well as variations in surrounding area regional interface transfer levels. These study assumptions were consistent with ISO PP-3.

3.2.2 Source of Power Flow Models

The power flow study cases used in this study were obtained from the ISO Model on Demand system with selected upgrades to reflect the system conditions in 2022. A detailed description of the system upgrades included is described in later sections of this report.

3.2.3 Transmission Topology Changes

Transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff as of the March 2012 Regional System Plan (RSP) Project Listing[10] have been included in the study base case. The cases also included the most recent updates to the NEEWS projects after their May 2012 revised Proposed Plan Application approval. A listing of the major projects is included below.

Maine

- Maine Power Reliability Program (RSP ID: 905-909, 1025-1030, 1158)
- Down East Reliability Improvement (RSP ID: 143)

New Hampshire

- Second Deerfield 345/115kV Autotransformer Project (RSP ID: 277, 1137-1141)

Vermont

- Northwest Vermont Reliability Projects (RSP ID: 139)[11]
- Vermont Southern Loop Project (RSP ID: 323, 1032-1035)
- Vermont Shunt Reactive Devices (RSP ID: 1171-1172)

Massachusetts

- Auburn Area Transmission System Upgrades (RSP ID: 59, 887, 921, 919)
- Merrimack Valley / North Shore Reliability Project (RSP ID: 775-776, 782-783, 840)
- Long Term Lower SEMA Upgrades (RSP ID: 592, 1068, 1118)
- Central/Western Massachusetts Upgrades (RSP ID: 924- 929, 931-932, 934-935, 937- 950, 952- 955)
- NEEWS – Greater Springfield Reliability Project (RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105)
- Advanced NEEWS Interstate Projects (RSP ID: 1202, 1342)
- Salem Harbor Retirement Upgrades (RSP ID: 1257-1259)

[10] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2012/index.html

[11] Majority of project is currently in service as of 2010 with the exception of new synchronous condensers at the Granite substation.

Rhode Island

- Greater Rhode Island Transmission Reinforcements (RSP ID: 484, 786, 788, 790-793, 913-918, 1098)
- NEEWS – Rhode Island Reliability Project (RSP ID: 795, 798-800, 1096-1097, 1099, 1106, 1109, 1331)

Connecticut

- NEEWS – Greater Springfield Reliability Project (RSP ID: 816, 1054, 1092, 1369-1371, 1378)
- Advanced NEEWS Interstate Projects (RSP ID: 1235, 1245)

3.2.4 Generation

Generation Projects with a Forward Capacity Market (FCM) Capacity Supply Obligation as of the Forward Capacity Auction #6 (FCA-6) commitment period (June 1, 2015 – May 31, 2016) were included in the study base case. A listing of the recent major new FCA-1 through 6 cleared projects is included below.

Maine

- QP 138 – Kibby Wind Farm (FCA-2)
- QP 197 – Record Hill Wind (FCA-2)
- QP 215 – Longfellow Wind Project (FCA-2)
- QP 244 – Wind Project (FCA-4)

New Hampshire

- QP 166 – Granite Wind Farm (FCA-2)
- QP 220 – Indeck Energy Alexandria (FCA-2)
- QP 251 – Laidlaw Berlin Biomass Energy Plant (FCA-4)
- QP 256 – Granite Reliable Power (FCA-2)
- QP 307 – Biomass Project (FCA-4)

Vermont

- QP 172 – Sheffield Wind Farm (FCA-1)
- QP 224 – Swanton Gas Turbines (FCA-1)

Massachusetts

- QP 077 – Berkshire Wind (FCA-3)
- QP 171 – Thomas A Watson (FCA-1)
- QP 231 – Steam Turbine Capacity Uprate (FCA-3)
- QP 243 – Steam Turbine Capacity Uprate (FCA-3)
- QP 265 – MATEP Third CTG (FCA-6)
- Northfield Mountain Uprate 30 MW (FCA-4)
- Northfield Mountain Uprate 10 MW (FCA-6)

Rhode Island

- QP 233 – Ridgewood Landfill (FCA-2)
- QP 332 – RISEP Uprate (FCA-5)

Connecticut

- QP 095 – Kleen Energy (FCA-2)
- QP 125 – Cos Cob 13&14 (FCA-1)
- QP 140 – A.L. Pierce (FCA-1)
- QP 150 – Plainfield Renewable Energy Project (FCA-3)
- QP 161 – Devon 15-18 (FCA-2)

[redacted]

- QP 161 – Middletown 12-15 (FCA-2)
- QP 199 – Waterbury Generation (FCA-1)
- QP 206 – Kimberly Clark Energy (FCA-2)
- QP 248 – New Haven Harbor 2-4 (FCA-3)
- Fuel Cell Projects 18 MW (FCA-4)

Due to issues concerning the on-going operation of the Vermont Yankee Nuclear Station [redacted] the unit (604 MW) was assumed out of service as a base case condition for all East to West stressed cases. Vermont Yankee was assumed available if needed for West to East stressed cases.

In the fall of 2010, the Salem Harbor Station, located on the north shore area of Massachusetts, submitted a Permanent De-List Bid into the ISO Forward Capacity Market for FCA-5 and subsequently a Non-Price Retirement request in February, 2011. While the ISO accepted the retirement request for Salem 1 and 2, the ISO rejected the retirement request for Salem 3 and 4 on May 10, 2011 due to reliability concerns. The owners have elected to retire Salem 3 and 4 by June 1, 2014. Based on this decision, the Salem Harbor Station was assumed retired as a base case condition.

In addition the Salem Harbor, other resources also submitted Non-Price Retirement (NPR) requests. A summary is provided in Table 3-1

Table 3-1
Summary of Non-Price Retirement Requests

Resource Name	Summer Qualified Capacity (MW)	NPR Request Date	NPR Determination Date
Salem Harbor 1	81.988	2/10/2011	5/10/2011
Salem Harbor 2	80.000	2/10/2011	5/10/2011
Salem Harbor 3	149.805	2/10/2011	5/10/2011
Salem Harbor 4	436.754	2/10/2011	5/10/2011
BIO ENERGY	0.000	8/4/2011	10/20/2011
Potter Diesel 1	2.250	8/1/2011	10/21/2011
Holyoke 6/ Cabot 6	9.611	10/19/2011	1/17/2012
Holyoke 8/ Cabot 8	9.965	10/19/2011	1/17/2012

All the NPR determinations accepted the NPR request except for Salem Harbor 3 and 4, which were discussed above.

In addition the Somerset Jet 2 (17.5 MW) retired as of April 20, 2012 and Somerset 6 (109.058 MW) retired as of 4/18/2012.

Two units in Connecticut, the Bridgeport Harbor 2 unit (130.495 MW) and the AES Thames unit (181 MW) submitted dynamic delist bids in multiple auctions and their bids were cleared. Bridgeport Harbor 2 dynamically delisted in FCA #4, 5 and 6, whereas AES Thames delisted in FCA #5 and 6. These units were assumed OOS for all the basecases.

The West Springfield 3 unit (94.276 MW) submitted a dynamic delist bid in FCA #5 and a static delist bid in FCA #6. Both these bids cleared. [redacted]

[redacted]

The Ansonia unit (60 MW) had cleared FCA #1, but have since withdrawn from the interconnection queue and withdrawn their approved PPAs. The unit was excluded from all the basecases.

Real Time Emergency Generation (RTEG) are distributed generation which have air permit restrictions that limit their operations to ISO Operating Procedure 4 (OP-4), Action 6 – an emergency action which also implements voltage reductions of five percent (5%) of normal operating voltage that require more than 10 minutes to implement. RTEG cleared in the FCM was not included in the reliability analyses because in general, long term analyses should not be performed such that the system must be in an emergency state as required for the implementation of OP-4, Action 6.

3.2.5 Explanation of Future Changes Not Included

Transmission projects that have not been fully developed and have not received PPA approval as of the March 2012 RSP Project Listing and generation projects that have not cleared in FCA-6 were not modeled in the study base case due to the uncertainty concerning their final development. One exception is the recently revised NEEWS – Greater Springfield Reliability Project and Rhode Island Reliability Project that received an updated PPA in May 2012.

Additionally, the NEEWS – Interstate Reliability Project component was not included in the base case since the scope of this study was to confirm the transmission reliability needs that were the justification for this component. The NEEWS – Central Connecticut Reliability Project component was also not included in the base case since the reliability needs that justified that component will be updated in conjunction with the Greater Hartford – Central Connecticut Needs Assessment.

3.2.6 Forecasted Load

A ten-year planning horizon was used for this study based on the most recently available CELT report issued in April 2012 at the time the study began. This study was focused on the projected 2022[12] peak demand load level for the ten-year horizon. The models reflected the following peak load conditions:

2022 system load level tested:

- The summer peak 90/10 demand forecast of 34,130 MW for New England

The CELT load forecast includes both system demand and losses (transmission & distribution) from the power system. Since power flow modeling programs calculate losses on the transmission system (69-kV and above), the actual system load modeled in the case was reduced to account for transmission system losses which are explicitly calculated in the system model.

Demand resources (DR) are treated as capacity resources in the Forward Capacity Auctions. Demand resources are split into two major categories, passive and active DR. Passive demand resources are largely comprised of energy efficiency (EE) programs and are expected to lower the system demand during designated peak hours in the summer and winter. Active demand resources are commonly known as demand side management (DSM) and are dispatchable on a zonal basis if a forecasted or real-time capacity shortage occurs on the system. As per Attachment K of the OATT, demand

[12] The 2012 CELT forecast only has projected peak demands for the years 2012 to 2021. To determine the 2022 peak demand forecasted load, the growth rate from years 2020 to 2021 was applied to the 2021 forecast.

resources are modeled in the base case at the levels of the most recent Forward Capacity Auction. When this needs follow-up was started, the values from FCA-6 were the most recently available values.

Because DR was modeled at the low-side of the distribution bus in the power-flow model, all DR values were increased to account for the reduction in losses on the local distribution network. Passive DR was modeled by load zone and Active DR was modeled by dispatch zone. Since Active DR is only reported by load zone, the Active DR load zones were split proportionally to dispatch zones using the percentage of CELT load modeled in the dispatch zone to the total CELT load modeled in the load zone. The amounts modeled in the cases are listed in Table 3-2 and Table 3-4 and detailed reports of can be seen in Appendix B: 2012 CELT Load Forecast in Table 9-3.

Table 3-2
FCA-6 Passive DR Values

Load Zone	CELT DRV[13] (MW)
Maine	146
New Hampshire	78
Vermont	115
Northeast Massachusetts & Boston	318
Southeast Massachusetts	176
West Central Massachusetts	210
Rhode Island	129
Connecticut	389

In addition to Passive DR, the ISO now forecasts energy efficiency past the last FCA through the 10-year horizon in the CELT report. The amounts modeled in the cases are listed in Table 3-3.

These values were be added to the Passive DR totals cleared through FCA-6 to come up with a total Passive DR value for the year 2022.

It should be noted that the EE forecast only provided values till 2021. The growth of EE from 2020 to 2021was used to determine the EE forecast for 2022.

[13] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter.

[redacted]

Table 3-3
Additional Forecasted EE Values through 2022

Load Zone	EE DRV (MW)
Maine	47
New Hampshire	56
Vermont	100
Northeast Massachusetts & Boston	356
Southeast Massachusetts	182
West Central Massachusetts	208
Rhode Island	143
Connecticut	168

Table 3-4
FCA-6 Active DR Values

Dispatch Zone	CELT DRV (MW)	Dispatch Zone	CELT DRV (MW)
Bangor Hydro	44	**Springfield, MA**	39
Maine	151	**Western Massachusetts**	54
Portland, ME	100	**Lower Southeast Massachusetts**	48
New Hampshire	53	**Southeast Massachusetts**	110
New Hampshire Seacoast	8	**Rhode Island**	84
Northwest Vermont	41	**Eastern Connecticut**	42
Vermont	22	**Northern Connecticut**	55
Boston, MA	198	**Norwalk-Stamford, Connecticut**	63
North Shore Massachusetts	70	**Western Connecticut**	195
Central Massachusetts	80		

Demand Resources that are eligible for termination for satisfying the condition of MR 1 section III.13.3.4. (c) "… successfully covered its Capacity Supply Obligation for two Capacity Commitment Periods but has not yet achieved Commercial Operation." The "Reduction in Summer QC" column represents the amount that has been treated as Existing in subsequent auctions but has not been demonstrated in commercial operation audit. A list of the DR eligible for termination is listed in Table 3-5.

Table 3-5
Summary of DR Eligible for Termination

Load Zone	Active DR (MW)	Passive DR (MW)	Real Time EG (MW)	TOTAL (MW)
Connecticut	14	20	41	75
Maine	2	1	10	13
NEMA Boston	9	30	71	111
New Hampshire	2	0	8	11
Rhode Island	2	2	39	44
SEMA	5	4	40	49
Vermont	3	0	7	9
WCMASS	4	9	32	45
TOTAL	**42**	**65**	**249**	**356**

[redacted]

The majority of this DR is Real-Time Emergency Generation that is not modeled in long-term needs analysis so it will not affect the net load modeled. The amount of passive and active DR that is eligible for termination was removed from their respective zone totals.

3.2.7 Load Levels Studied

In accordance with ISO planning practices, transmission planning studies utilize the ISO extreme weather 90/10 forecast assumptions for modeling summer peak load profiles in New England. A summary of the load modeled in the 2022 case compared with the 2020 case from the last needs study is shown in Table 3-6. A more detailed report of the loads modeled and how the numbers were derived from the CELT values can be seen in Appendix A in Table 9-1 and Table 9-2.

Table 3-6
90/10 CELT Load Comparison (including losses)

State	2020 Load 2010 CELT (MW)	2022 Load 2012 CELT (MW)	Difference (MW)	Difference (%)
Maine	2,500	2,480	-20	-0.80%
New Hampshire	3080	3,120	+40	+1.30%
Vermont	1,255	1,230	-25	-1.99%
Massachusetts	15,575	16,060	+485	+3.11%
Rhode Island	2,300	2,430	+130	+5.65%
Connecticut	8,840	8,810	-30	-0.34%
ISO New England	33,555	34,130	+575	+1.71%

A comparison of the 2010 CELT report used in the Interstate updated Needs Assessment to the 2012 CELT used in this follow up study shows that the overall load was generally lower for the same year. For example the 2019 Summer 90/10 NE load was 33,225 MW in the 2010 CELT. The same year in the 2012 CELT was 33,040 MW a reduction of 185 MW or about ½ a year of overall NE load growth.

However the follow-up study used a higher overall NE load level due to looking at the year 2022 vs. 2020 in the updated Needs Assessment. The extra two years of load growth, even with a lower forecast, cause an overall increase of 575 MW system wide in the follow up study.

The following Table 3-7 provides a comparison of the net ISO New England load in the 2011 needs assessment and the 2012 follow-up needs assessment.

[redacted]

Table 3-7
Comparison of Net New England Load between 2011 and 2012 Needs Assessments

Assumption	2011		2012		Difference	
	Reference	(MW) Incl. T&D losses	Reference	(MW) Incl. T&D losses	(MW)	(%)
CELT Load	2020 90/10 2010 CELT	33,555	2022 90/10 2012 CELT	34,130	+575	+1.71%
Mfg. Load in ME		0		+364	+364	
Passive DR[14]	FCA #4	-1,494	FCA #6	-1,685	-191	+12.78%
Terminated Passive DR				+65	+65	
Forecasted EE	N/A	0	2022 2012 CELT	-1,362	-1,362	
Active DR[14]	FCA #4	-1,771	FCA #6	-1,574	+197	-11.12%
Terminated Active DR				+42	+42	
Active DR De-Rate		+443		+383	-60	
Net ISO-NE Load		**30,733**		**30,363**	**-370**	**-1.20%**

The 2011 needs assessment had overstated the amount of DR that was available as a result of FCA #4. An additional 164 MW of passive DR and 261 MW of active DR were assumed in those basecases.

The net effect of the revised load forecast, updated DR and the EE forecast was a decrease in New England load of 370 MW.

3.2.8 Load Power Factor

Load power factors consistent with the local transmission owner's planning practices were applied uniformly at each substation and consistent with the megawatt load level assumed at each power flow model substation bus. Demand resources' power factors were set to match the power factor of the load at that bus in the model. A list of overall power factors by company territory can be found in the detailed load report in Appendix A in Table 9-1 and Table 9-2.

3.2.9 Transfer Levels

In accordance with the reliability criteria of the Northeast Power Coordinating Council (NPCC) and the ISO, the regional transmission power grid must be designed for reliable operation during stressed system conditions. A detailed list of all transfer levels can be found in Appendix C: Case Summaries and Generation Dispatches. The following external transfers shown in Table 3-8 were utilized for the study.

---

[14] Following completion of the 2011 Needs Assessment, the DR values used were found to be overstated (Passive DR should have been 1,330 MW, Active DR 1,510 MW). The details are provided on Page 24 of the New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report, dated February 2012. https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/neews_interstate_solution.pdf

[redacted]

Table 3-8
Interface Levels Tested

	N-1		N-1-1	
Interface	**E→W**	**W→E**	**E→W**	**W→E**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Internal transfer levels were monitored during the assessment. Due to the major changes to the system with the Maine Power Reliability Program and the two components of NEEWS, GSRP and RIRP, already approved, the existing transfer limits will change. During this needs follow-up the generation dispatch dictated the internal transfer levels and all elements were monitored on the system.

3.2.10 Generation Dispatch Scenarios

The power-flow models used in these analyses were adjusted to incorporate the capacity levels for existing[15] generators that were qualified and new generators that cleared FCA-6. The capacity levels for generating units in New England used in this study are contained in the power flow case summary files in Appendix C: Case Summaries and Generation Dispatches. In constructing dispatch conditions for the sub-area analyses, the working group considered a number of dispatch scenarios in New England that would have the greatest impact on power flows in the area of study. A detailed list of the dispatches for each sub-area stress is listed in the Sections 3.2.10.1 through 3.2.10.3.

Vermont Yankee is a 604 MW nuclear power generating station placed in service in 1972 [redacted]. There is significant uncertainty surrounding the continued operation of the plant. To ensure that the New England transmission system is sufficiently robust enough to operate reliably in the event of a permanent shutdown at the station, this unit was considered off-line in these analyses when the unit was in the importing area.

New England has two major pumped-storage hydroelectric stations and both are located in western Massachusetts. Northfield Station is a four unit 1,110 MW station on the Connecticut River in Northfield, Massachusetts. Bear Swamp Station is a two unit 580 MW station on the Deerfield River in Rowe, Massachusetts. The base case assumes a reduction of power output of approximately 50% for these two stations. De-rating these stations [redacted] recognizes acceptance of export delist bids for Bear Swamp to serve capacity obligations in New York, and recognizes run time limitations to effectively serve New England capacity needs over long-time emergency periods (12 hours for New England in the summer time), all during a summer heat wave.

[15] Existing refers to any generator that has cleared in the previous auction, FCA-3, held in October 2009.

[redacted]

On shore wind was dispatched at 5% of nameplate when in the import area. In the export area the units were ramped up to 100% of their qualified capacity.

Hydro assumptions will be based on the VT/NH, Pittsfield/Greenfield and GHCC studies, when these units are in the import area. The details are provided in Table 3-9.

The hydro resources in an export area were dispatched assuming that 100% of the output is available up to the qualified capacity of the unit. A low hydro scenario is assumed for the hydro resources in an import area. Table 3-9 captures the major hydro units in VT, NH, MA and CT. For the units excluded from the table, the units may be dispatched up to their qualified capacity.

Table 3-9
Dispatch of Hydro Units when in Import Area

Name	Dispatch Level (When in import Area)	Name Plate (50 deg rating)	Location
Western Mass Hydro Units			
Deerfield	9.0	33.5	Western NE
Harriman	14.0	41.1	Western NE
Vernon	5.0	32	Western NE
Sherman	6.0	6.5	Western NE
Cabot	10.0	68.2	Western NE
Searsburg	5.0	5.0	Western NE
Vermont/New Hampshire Hydro Units			
Moore	14.0	191.3	Eastern NE
Comerford	21.0	183.3	Eastern NE
Bellows Falls	18.8	49.0	Western NE
Wilder	10.0	42.9	Western NE
Amoskeag	14.7	17.5	Eastern NE
Lower Lamoille	5.4	15.8	Western NE
Sheldon Springs	3.4	14.8	Western NE
Great Lakes Berlin	1.3	25.0	Eastern NE
Garvins/Hooksett	0.0	14.8	Eastern NE
Smith	9.2	17.6	Eastern NE
Mcindoes	0.0	13.0	Western NE
Highgate Falls	0.0	9.6	Western NE
Ayers Island	0.0	9.1	Eastern NE
Pontook Hydro	3.8	9.6	Eastern NE
Winooski 1	1.0	7.5	Western NE
Proctor	0.0	6.7	Western NE
Middlebury	0.0	6.8	Western NE
Eastman Falls	0.0	6.5	Eastern NE
N Rutland Composite	2.0	5.2	Western NE
Dodge Falls - New	0.0	5.0	Western NE

Connecticut Hydro Units			
Rainbow Hydro	0.8	8.2	Western NE
Stevenson Hydro	2.8	28.9	Western NE
Falls Village	0.9	9.8	Western NE
Rocky River	2.9	29.4	Western NE
Shepaug	4.2	42.9	Western NE
Bulls Bridge	0.8	8.4	Western NE
Derby Dam	0.7	7.1	Western NE

Wind and hydro resources in the import area were dispatched to these reduced levels based on historical output seen during summer 90/10 weather conditions.

3.2.10.1 Eastern New England

To stress the eastern New England subarea, generation is reduced in the sub-area to require the system to deliver generation resources from outside the sub-area to reliably serve the load in the region. To model this condition, the two largest resources in the subarea are assumed out of service (OOS). [redacted]

The Comerford and Moore hydro stations were at 10% of their nameplate for the N-1 analysis. However, after the first contingency, both plants were ramped up to 100% of their qualified capacity in preparation for the second contingency. Thus, the N-1-1 analysis had both Comerford and Moore at 100% of their qualified capacity.

Under normal operating conditions, if a large resource were offline, the quick-start resources in the area would be dispatched in the area to compensate for lost generation. Due to the infrequent use of the units, they do not always respond when dispatched so an unavailability rate of 20% is assumed for all quick-start resources in the subarea of concern. A summary table of resources for the eastern New England analysis is shown in Table 3-10.

Table 3-10
Eastern New England Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[16] All other resources in eastern New England were modeled at 100%. To meet load balance requirements and external transfer levels, some excess generation in western New England may have been turned off to not violate this requirement. For most cases, western New England was capacity deficient and additional imports from New York were needed to meet the load balance requirements.

[redacted]

3.2.10.2 Western New England and Connecticut

To stress the western New England subarea, generation is reduced in the sub-area to require the system to deliver generation resources from outside the subarea to reliably serve the load in the region. To model this condition, the two largest units in the subarea are assumed out-of-service. [redacted] In addition, the [redacted] was assumed offline to reflect the equivalent demand forced outage rate[17] (EFORd) for western Massachusetts generation. Instead of reducing the electrical output of all western Massachusetts' units based on their individual EFORd values, the total generation reduction for the area is represented by turning off [redacted] completely.[18] A sensitivity was run with th [redacted]

Under normal operating conditions, if a large resource were offline, the quick-start resources in the area would be dispatched in the area to compensate for lost generation. Due to the infrequent use of the units, they do not always respond when dispatched so an unavailability rate of 20% is assumed for all quick-start resources in the subarea of concern. A summary table of resources for the western New England analysis is shown in Table 3-11.

For the 2022 cases, there are insufficient resources in eastern New England and Greater Rhode Island to both serve local load in the area and also export power to western New England. To meet this resource requirement, the Cape Wind Project connected to the NSTAR Barnstable substation and the Brockton Combined Cycle connected near the NSTAR Auburn substation were modeled as additional capacity.

Table 3-11
Western New England and Connecticut Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[17] Equivalent demand forced outage rate represents the portion of time a unit is in demand, but is unavailable due to forced outages.

[18] Since the power flow model included the Greater Springfield Reliability Project, turning off [redacted] completely would not produce a significantly different result than reducing the output of all generating units by a quantity of MW equal to the [redacted] capacity.

[19] All other resources in western New England were modeled at 100%. To meet load balance requirements and external transfer levels, some excess generation in eastern New England in the 2015 cases may have been turned off to not violate this requirement. For most cases, eastern New England was capacity deficient and the Cape Wind and Brockton units needed to be turned on to meet the load balance requirements.

[redacted]

3.2.10.3 Rhode Island

To stress the Rhode Island load zone, generation is reduced in the subarea to require the system to deliver generation resources from outside the subarea to reliably serve the load in the region. To model this condition, the largest resources in the subarea were assumed out of service. [redacted]

Under normal operating conditions, if a large resource were off-line, the quick-start resources in the area would be dispatched to compensate for lost generation. Due to the infrequent use of the units, they do not always respond when dispatched so an unavailability rate of 20% is assumed for all quick-start resources in the sub-area of concern. A summary table of resources for the Rhode Island analysis is shown in Table 3-12.

Table 3-12
Rhode Island Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

3.2.11 Reactive Resource and Dispatch

All area shunt reactive resources were assumed available and dispatched when conditions warranted. Reactive output of generating units was modeled to reflect defined limits. A summary of the reactive output of units and shunt devices connected to the transmission system that play a significant role in the study area can be found in the power flow case summaries included in Appendix C: Case Summaries and Generation Dispatches.

3.2.12 Market Solution Consideration

In accordance with the Attachment K of the OATT, all resources that have cleared in the markets were assumed in the model for future planning reliability studies except for those described in Table 3-5 of Section 3.2.6. This included numerous new generation and demand resources from FCA-1 through 6 as listed in Section 3.2.4 and Section 3.2.6 respectively.

3.2.13 Demand Resources

As stated in Section 3.2.6, active and passive demand resources cleared as of the 2012 FCA-6 auction were modeled for this study. For all analyses, passive demand resources were assumed to be 100% available and are expected to perform to 100% of their cleared amount. Forecasted energy efficiency

[20] All other Rhode Island resources were turned to 100%. To meet load balance requirements and external transfer levels, some excess generation in New England was turned off to not violate this requirement.

for the years 2016 through 2022 were expected to perform to 100% of their forecasted amount. For active demand resources, their performance was dependent on which subarea was being studied. The import area assumed that 75% of all active demand resources performed when dispatched and the export area assumed 100% of all active demand resources performed when dispatched, to model a more stressed system condition in the import area.

Real Time Emergency Generation (RTEG) was not modeled in any analysis. RTEGs cleared in the FCM was not included in the reliability analyses because in general, long term analyses should not be performed such that the system must be in an emergency state as required for the implementation of OP-4, Action 6. A summary of assumed DR performance is shown in Table 3-13.

Table 3-13
New England Demand Resource Performance Assumptions

Region	Passive DR	Forecasted EE	Active DR	RTEGs
Import Area	100%	100%	75%	0%
Export Area	100%	100%	100%	0%

3.2.14 Description of Protection and Control System Devices Included in the Study

All existing and planned special protection systems (SPS) and control system devices have been included in this analysis. Some of the relevant devices are listed below:

[redacted]

3.2.15 Explanation of Operating Procedures and Other Modeling Assumptions

[redacted]

[redacted]

[redacted]

[redacted]

3.3 Stability Model

3.3.1 Study Assumptions

Not applicable to this study.

3.3.2 Load Levels Studied

Not applicable to this study.

3.3.3 Load Models

Not applicable to this study.

3.3.4 Dynamic Models

Not applicable to this study.

3.3.5 Transfer Levels

Not applicable to this study.

3.3.6 Generation Dispatch Scenarios

Not applicable to this study.

3.3.7 Reactive Resource and Dispatch

Not applicable to this study.

3.3.8 Explanation of Operating Procedures and Other Modeling Assumptions

Not applicable for this study.

3.4 Short Circuit Model

3.4.1 Study Assumptions

Not applicable for this study.

3.4.2 Short Circuit Model

Not applicable for this study.

3.4.3 Contributing Generation

Not applicable for this study.

3.4.4 Generation and Transmission System Configurations

Not applicable for this study.

3.4.5 Boundaries

Not applicable for this study.

3.4.6 Other Relevant Modeling Assumptions

Not applicable for this study.

3.5 Other System Studies

Not applicable for this study.

3.6 Changes in Study Assumptions

Not applicable for this study.

Section 4
Analysis Methodology

4.1 Planning Standards and Criteria

The applicable NERC, NPCC and ISO standards and criteria were the basis of this evaluation. A description of each of the NERC, NPCC and ISO standard test that were included in all studies used to assess system performance are discussed later in this section.

4.2 Performance Criteria

4.2.1 Steady State Criteria

The Needs Assessment was performed in accordance with NERC TPL-001, TPL-002, TPL-003 and TPL-004 Transmission Planning System Standards, NPCC Directory #1 *"Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System"*, dated 12/01/09, and the ISO Planning Procedure No. 3, *"Reliability Standards for the New England Area Bulk Power Supply System"*, dated 06/11/09. The contingency analysis steady-state voltage and loading criteria, solution parameters and contingency specifications used in this analysis are consistent with these documents.

4.2.1.1 Steady State Thermal and Voltage Limits

Loadings on all transmission facilities rated at 69 kV and above in the study area were monitored. The thermal violation screening criteria defined in Table 4-1 were applied.

Table 4-1
Steady State Thermal Criteria

System Condition	Maximum Allowable Facility Loading
Normal (all lines-in) (Pre-Contingency)	Normal Rating
Emergency (Post-Contingency)	Long Time Emergency (LTE) Rating

Voltages were monitored at all buses with voltages 69 kV and above in the study area. System bus voltages outside of limits identified in Table 4-2 were identified for all normal (pre-contingency) and emergency (post-contingency) conditions.

Table 4-2
Steady State Voltage Criteria

Facility Owner	Voltage Level	Bus Voltage Limits (Per-Unit) Normal Conditions (Pre-Contingency)	Emergency Conditions (Post-Contingency)
Northeast Utilities	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
National Grid	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.90[21] to 1.05
NSTAR	230 kV and above	0.95 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
United Illuminating	230 kV and above	0.95 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
Millstone / Seabrook[22]	345 kV	[redacted]	[redacted]
Pilgrim[22]	345 kV	[redacted]	[redacted]
Vermont Yankee[22]	345 kV	[redacted]	[redacted]
Vermont Yankee[22]	115 kV	[redacted]	[redacted]

4.2.1.2 Steady State Solution Parameters

The steady state analysis was performed with pre-contingency solution parameters that allow adjustment of load tap-changing transformers (LTCs), static var devices (SVDs) including automatically-switched capacitors and phase angle regulators (PARs). Post-contingency solution parameters only allow adjustment of LTCs and SVDs. Table 4-3 displays these solution parameters.

Table 4-3
Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Base	Tie Lines Regulating	Stepping	Regulating or Statically Set	Regulating
Contingency	Disabled	Stepping	Disabled	Regulating

[21] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

[22] This is in compliance with NUC-001-2, *"Nuclear Plant Interface Coordination Reliability Standard,"* adopted August 5, 2009.

[redacted]

4.2.2 Stability Performance Criteria

Not applicable for this study.

4.2.3 Short Circuit Performance Criteria

Not applicable for this study.

4.2.4 Other Performance Criteria

Not applicable for this study.

4.3 System Testing

4.3.1 System Conditions Tested

Testing of system conditions included evaluation of system performance under a number of resource outage scenarios, variation of related transfer levels, and an extensive number of transmission circuit contingency events.

4.3.2 Steady State Contingencies / Faults Tested

Each base case was subjected to single element contingencies such as the loss of a transmission circuit or an autotransformer and contingencies which may cause the loss of multiple transmission circuit facilities, such as those on a common set of tower line structures, circuit breaker failures and substation bus faults. A comprehensive set of contingency events, listed in Appendix D: Contingency List, was tested to monitor thermal and voltage performance of the New England transmission system.

Additional analyses evaluated N-1-1 conditions with an initial outage of a key transmission circuit followed by another contingency event. The N-1-1 analyses examined the summer peak load case with stressed conditions. For these N-1-1 cases, national and regional reliability standards, including ISO PP-3, allow specific manual system adjustments, such as quick start generation redispatch, phase-angle regulator adjustment or HVDC adjustments prior to the next single contingency event. A listing of all contingency types tested is shown in Table 4-4 and a listing of Line-out scenarios in Table 4-5.

Table 4-4
Summary of NERC, NPCC and/or ISO Category Contingencies Tested

Contingency Type	NERC Type	NPCC D-1 Section	ISO PP-3 Section	Tested
All Facilities in Service	A	5.4.2.b	3.2.b	Yes
Generator (Single Unit)	B1	5.4.1.a	3.1.a	Yes
Transmission Circuit	B2	5.4.1.a	3.1.a	Yes
Transformers	B3	5.4.1.a	3.1.a	Yes
Loss of an Element Without a Fault	B	5.4.1.d	3.1.d	Yes
Bus Section	C1	5.4.1.a	3.1.a	Yes
Breaker Failure	C2	5.4.1.e	3.1.e	Yes
Double Circuit Tower	C5	5.4.1.b	3.1.b	Yes
Extreme Contingencies	D	5.6	6	Yes

[redacted]

Table 4-5
N-1-1 Line-Out Scenarios

Element Name	kV	Description	E→W	W→E	RI
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]		
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]		[redacted]	

4.3.3 Stability Contingencies / Faults Tested

Not applicable for this study.

4.3.4 Short Circuit Faults Tested

Not applicable for this study.

[redacted]

Section 5
Development of Alternative Solutions

5.1 Description of Option A-1

In option A-1, a new 345 kV transmission line emanates from the Card substation in Lebanon, Connecticut and follows the existing transmission corridor (330 line) to the Lake Road switching station in Killingly, Connecticut. From the Lake Road switching station, a new 345 kV transmission line follows the existing transmission corridor (3348 and 347 lines) northeasterly to the vicinity of the Sherman Road switching station in Burrillville, Rhode Island. In option A-1, this new 345 kV transmission line does not connect to the Sherman Road switching station but goes by it and continues in a southeasterly direction on an existing transmission corridor (328 line) to terminate at the West Farnum substation in North Smithfield, Rhode Island. A new 345 kV transmission line would also be constructed on the existing transmission corridor (Q-143 and R-144 lines) between the West Farnum substation and the Millbury switching station in Millbury, Massachusetts. The existing 345 kV 328 line (Sherman Road to West Farnum) must also be rebuilt with higher capacity conductors under this plan. Figure 5-1 is a geographic representation of option A-1.

The West Farnum 1713 circuit breaker failure, a 115 kV breaker failure contingency was eliminated due to the addition of a series breaker for the option A-1 analysis.

Option A-1 also required substantial work at Sherman Road switching station. The failure of [redacted] showed up as a limiting element in the thermal and voltage analysis and needed to be [redacted] work was required at Sherman Road to increase short circuit capability, resolve thermal overloads, upgrade the station to current BPS standards and replace antiquated equipment.

To resolve these issues the preferred alternative at Sherman Road as a part of option A-1 was to build a new 2-bay Air-Insulated Station (AIS) station adjacent to the existing station. This was determined to be the cost-effective solution based on cost, equipment outage requirements, construction sequencing, opportunity for future expansion, and environmental impact.

[redacted]

[redacted]

Figure 5-1: Option A-1 Geographic Layout

The new 345 kV lines being added as a part of this project are:

- Card to Lake Road
- Lake Road to West Farnum
- West Farnum to Millbury

The one-line description of the option A-1is provided in Figure 5-2

[redacted]

Figure 5-2: Option A-1 One-Line Diagram

The following upgrades of NSTAR, NU and Connecticut Municipal Electric Cooperative (CMEEC) facilities are already in progress and were included as in-service in the Needs Assessment:

- NSTAR – Reconductor a 1.2-mile section of the 345 kV 336 line (ANP Blackstone to NEA Bellingham Tap) and upgrade terminal equipment at the West Medway substation to 3000 A rated equipment.
- NSTAR - Add a new breaker in series with the 106 breaker at West Medway 345 kV substation
- NU/CMEEC – Eliminate the sag limit on the thermal rating of the 115 kV 1410 line (Montville to Buddington) in Connecticut.

5.2 Incremental Levels of Option A-1

The rebuild of Sherman Road was included as a common upgrade at all the incremental levels of option A-1. This would eliminate the critical breaker failure [redacted] that showed N-1 violations in the follow-up Needs Assessment. With [redacted] the associated BPS upgrades would be required. The high transfers through Sherman Road for the eastern New England import analysis would still need an upgrade of the equipment at Sherman Road to resolve thermal overloads. With the rebuild of the Sherman Road substation, the breaker limitation on the [redacted] would be eliminated.

The most urgent need in the Needs Assessment was the addition of a new 345 kV line into West Farnum to resolve the non-convergence seen for the [redacted] Also, the only N-1 violations were seen in the eastern New England import analysis.

The new line to Millbury from West Farnum provides a new import line into eastern New England and allows for the movement of power from western New England and Greater Rhode Island to reliably serve load in eastern New England during capacity deficiency conditions in eastern New England. The new line also provides the additional 345 kV feed into Rhode Island.

Thus, the first level of the analysis included the addition of the new 345 kV line from Millbury to West Farnum.

For the next level of analysis the 345 kV line from Lake Road to West Farnum was added. [redacted]

For the third level of analysis the new 345 kV line from Card to Lake Road was added to the solution. This helped resolve the N-1-1 violations seen in moving power into western New England and Connecticut.

For the final level of analysis the 345 kV line from Sherman Road to West Farnum was rebuilt. This line was seen to be overloading for [redacted]

In summary the four levels of option A-1 are described in Table 5-1.

Table 5-1
Solution Study Component Level Descriptions

Level	Component Descriptions
1	• A new 345 kV line from the West Farnum substation in Rhode Island to the Millbury switching station in Massachusetts.
2	• All Level 1 components • A new 345 kV line from the Lake Road switching station in Connecticut to the West Farnum substation in Rhode Island
3	• All Level 2 components • A new 345 kV line from Card substation to the Lake Road switching station in eastern Connecticut
4	• All Level 3 components • Rebuild the existing 345 kV line (328) between the Sherman Road switching station in Rhode Island to the West Farnum substation in Rhode Island with higher capacity conductors

[redacted]

Section 6
Results of Analysis

6.1 Steady State Performance Results

This section summarizes the steady-state analysis performed on each of the four levels of option A-1. The four topologies were tested against the three regional stresses described in section 3.2.10. The results of the analysis are documented in Appendix E: Contingency Results .

The following sections include a summary of the thermal and voltage violations for each stress. For each stress the number of highly loaded transmission lines within the study area was also recorded. A line was deemed to be highly-loaded when the flow on it was over 90% of its LTE rating after a contingency.

6.1.1 N-0 Thermal and Voltage Violation Summary

6.1.1.1 Eastern New England

No N-0 thermal or voltage violations were found in 2022 for the eastern New England import stress for any of the four topologies tested.

There were no highly loaded lines under N-0 conditions.

6.1.1.2 Western New England and Connecticut

No N-0 thermal or voltage violations were found in 2022 for the western New England and Connecticut import stress for any of the four topologies tested.

There were no highly loaded lines under N-0 conditions.

6.1.1.3 Rhode Island

No N-0 thermal or voltage violations were found in 2022 for the Rhode Island import stress for any of the four topologies tested.

There were no highly loaded lines under N-0 conditions.

6.1.2 N-1 Thermal and Voltage Violation Summary

6.1.2.1 Eastern New England

N-1 testing was performed for all of the system conditions described in Section 3. The results of overloaded lines and emerging issues[24] following N-1 contingency events were recorded. Of the four topologies tested only the level 1 topology showed any lines over 90% loading in the study area. The results for level 1 analysis can be found in Table 6-1.

Table 6-1
Option A-1 Level 1 - Eastern New England N-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]		[redacted]	
			Worst Contingency	%LTE	Worst Contingency	%LTE
328	345	Sherman Rd. to W. Farnum	[redacted]	98.0	[redacted]	106.7
1280-3	115	Whipple Jct. to Mystic, CT	[redacted]	<90.0	[redacted]	99.1

There were no N-1 voltage violations for any of the four topologies evaluated.

6.1.2.2 Western New England and Connecticut

No N-1 thermal or voltage violations were found in 2022 for the western New England and Connecticut import stress for any of the four topologies tested. However the 302 line showed up as highly loaded in 2022 for the level 1 and level 2 topologies.

Table 6-2 indicates the results for option A-1 level 1 and Table 6-3 indicates the results for option A-1 level 2.

Table 6-2
Option A-1 Level 1 - Western NE and Connecticut N-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]		[redacted]	
			Worst Contingency	%LTE	Worst Contingency	%LTE
301	345	Millbury to Carpenter Hill	[redacted]	92.4	[redacted]	<90.0

Table 6-3
Option A-1 Level 2 - Western NE and Connecticut N-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]		[redacted]	
			Worst Contingency	%LTE	Worst Contingency	%LTE
301	345	Millbury to Carpenter Hill	[redacted]	92.8	[redacted]	<90.0

6.1.2.3 Rhode Island

No N-1 thermal or voltage violations were found in 2022 for the Rhode Island import stress for any of the four topologies tested. There were no highly loaded lines under N-1 conditions.

[24] Although lines loaded between 90% and 100% are not technically overloaded, they are displayed in this and following tables because they are indicative of problems occurring with minimal load growth or system changes just beyond the study horizon.

6.1.3 N-1-1 Thermal and Voltage Violation Summary

6.1.3.1 Eastern New England

N-1-1 testing for the four topologies indicated that all 4 topologies had thermal violations. The option A-1 level 4 results had no 345 kV violations, but had one 115 kV violation.

The results are summarized for the 4 topologies below.

Table 6-4
Option A-1 Level 1 - Eastern New England N-1-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
301	345	Ludlow to Carpenter Hill	[redacted]	[redacted]	97.8	[redacted]	[redacted]	117.6
302	345	Carpenter Hill to Millbury	[redacted]	[redacted]	98.5	[redacted]	[redacted]	118.6
328	345	Sherman Rd. to W. Farnum	[redacted]	[redacted]	117.2	[redacted]	[redacted]	127.2
336-2	345	W. Medway to NEA Bellingham Tap	[redacted]	[redacted]	98.4	[redacted]	[redacted]	105.5
347	345	Sherman Rd. to Killingly	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	103.8
3361	345	ANP Blackstone to Sherman Rd.	[redacted]	[redacted]	99.1	[redacted]	[redacted]	109.5
WM 345B		W. Medway 345/230 kV Autotransformer	[redacted]	[redacted]	< 90.3	[redacted]	[redacted]	92.9
O215	230	N. Litchfield to Tewksbury	[redacted]	[redacted]	96.6	[redacted]	[redacted]	99.3
1280	115	Whipple Jct to Mystic CT	[redacted]	[redacted]	123.5	[redacted]	[redacted]	138.8
1465	115	Mystic CT to Shunock	[redacted]	[redacted]	100.7	[redacted]	[redacted]	115.8
1870S	115	Shunock to Wood River	[redacted]	[redacted]	135.0	[redacted]	[redacted]	137.7
B128-6	115	Montague to Cabot Tap	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	102.3
T172N	115	West Farnum Tap to Woonsocket	[redacted]	[redacted]	96.6	[redacted]	[redacted]	98.9
V174-2	115	N. Oxford to Millbury	[redacted]	[redacted]	92.5	[redacted]	[redacted]	110.6

Table 6-5
Option A-1 Level 2 - Eastern New England N-1-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
328	345	Sherman Rd. to W. Farnum	[redacted]	[redacted]	94.5	[redacted]	[redacted]	103.2
3520	345	ANP Bellingham to West Medway	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	90.9
WM 345B		W. Medway 345/230 kV Autotransformer	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	92.9
O215	230	N. Litchfield to Tewksbury	[redacted]	[redacted]	97.7	[redacted]	[redacted]	98.8
1280	115	Whipple Jct to Mystic CT	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	96.4
B128-6	115	Montague to Cabot Tap	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	98.1
T172N	115	West Farnum Tap to Woonsocket	[redacted]	[redacted]	98.7	[redacted]	[redacted]	101.3

Table 6-6
Option A-1 Level 3 - Eastern New England N-1-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
328	345	Sherman Rd. to W. Farnum	[redacted]	[redacted]	94.1	[redacted]	[redacted]	103.9
3520	345	ANP Bellingham to West Medway	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	90.4
WM 345B		W. Medway 345/230 kV Autotransformer	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	92.7
0215	230	N. Litchfield to Tewksbury	[redacted]	[redacted]	97.6	[redacted]	[redacted]	98.5
1280	115	Whipple Jct to Mystic CT	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	96.0
B128-6	115	Montague to Cabot Tap	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	96.8
T172N	115	West Farnum Tap to Woonsocket	[redacted]	[redacted]	98.7	[redacted]	[redacted]	101.6

Table 6-7
Option A-1 Level 4 - Eastern New England N-1-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst CTG	%LTE	L/O	Worst CTG	%LTE
3520	345	ANP Bellingham to West Medway	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	90.5
WM 345B		W. Medway 345/230 kV Autotransformer	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	92.6
0215	230	N. Litchfield to Tewksbury	[redacted]	[redacted]	97.6	[redacted]	[redacted]	98.5
1280	115	Whipple Jct to Mystic CT	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	95.9
B128-6	115	Montague to Cabot Tap	[redacted]	[redacted]	< 90.0	[redacted]	[redacted]	96.8
T172N	115	West Farnum Tap to Woonsocket	[redacted]	[redacted]	98.8	[redacted]	[redacted]	101.7

The results indicate that for each incremental addition from option A-1, the number of thermal violations decreases. For level 4, the only thermal violation is on the T172N line is for [redacted]

N-1-1 voltage violations were only seen for the level 1 topology. The results of voltage violations following N-1-1 contingency events can be found in Table 6-8.

Table 6-8
Option A-1 Level 1 - Eastern New England N-1-1 Voltage Violation Summary

Substation	kV	[redacted]			[redacted]		
		L/O	Worst Contingency	Voltage (pu)	L/O	Worst Contingency	Voltage (pu)
Mystic CT	115	[redacted]	[redacted]	>0.95	[redacted]	[redacted]	0.949
Shunock	115	[redacted]	[redacted]	>0.95	[redacted]	[redacted]	0.932

With the addition of a breaker in series with [redacted] the non-convergent case seen in the follow-up Needs Assessment was no longer seen.

[redacted]

6.1.3.2 Western New England

N-1-1 testing for the four topologies indicated that level 1 and level 2 topologies had thermal violations. These cases did not have the new line from Lake Road to Card. The thermal results are summarized below.

Table 6-9
Option A-1 Level 1 – Western NE and Connecticut N-1-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
301	345	Carpenter Hill to Ludlow	[redacted]	[redacted]	103.4	[redacted]	[redacted]	97.3
302	345	Millbury to Carpenter Hill	[redacted]	[redacted]	106.4	[redacted]	[redacted]	100.5
3419	345	Ludlow to Barbour Hill	[redacted]	[redacted]	96.7	[redacted]	[redacted]	97.5
1505	115	Plainfield Jct to Tunnel	[redacted]	[redacted]	94.0	[redacted]	[redacted]	90.2
1870N	115	W Kingston to Kenyon	[redacted]	[redacted]	106.1	[redacted]	[redacted]	101.7
1870	115	Wood River to Kenyon	[redacted]	[redacted]	118.2	[redacted]	[redacted]	112.9
1870S	115	Wood River to Shunock	[redacted]	[redacted]	122.8	[redacted]	[redacted]	116.1
L190-4	115	Tower Hill to West Kingston	[redacted]	[redacted]	99.5	[redacted]	[redacted]	97.7
L190-5	115	Tower Hill to Davisville Tap	[redacted]	[redacted]	111.7	[redacted]	[redacted]	109.8

Table 6-10
Option A-1 Level 2 – Western NE and Connecticut N-1-1 Thermal Results Summary

Element ID	kV	Element Description	[redacted]			[redacted]		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
301	345	Carpenter Hill to Ludlow	[redacted]	[redacted]	103.2	[redacted]	[redacted]	97.2
302	345	Millbury to Carpenter Hill	[redacted]	[redacted]	106.2	[redacted]	[redacted]	100.4
3419	345	Ludlow to Barbour Hill	[redacted]	[redacted]	96.3	[redacted]	[redacted]	97.1
1505	115	Plainfield Jct to Tunnel	[redacted]	[redacted]	95.1	[redacted]	[redacted]	91.7
1870N	115	W Kingston to Kenyon	[redacted]	[redacted]	93.7	[redacted]	[redacted]	90.6
1870	115	Wood River to Kenyon	[redacted]	[redacted]	103.6	[redacted]	[redacted]	99.4
1870S	115	Wood River to Shunock	[redacted]	[redacted]	102.6	[redacted]	[redacted]	98.8
L190-4	115	Tower Hill to West Kingston	[redacted]	[redacted]	96.9	[redacted]	[redacted]	95.3
L190-5	115	Tower Hill to Davisville Tap	[redacted]	[redacted]	108.9	[redacted]	[redacted]	107.3

The level 3 and level 4 cases did not show any lines in the study area over 90% of their LTE.

There were no voltage violations in the study area for all the four topologies.

6.1.3.3 Rhode Island

No N-1 thermal or voltage violations were found in 2022 for the Rhode Island import stress for any of the four topologies tested. There were no highly loaded lines under N-1 conditions.

The non-convergence that was seen with the outage of the [redacted] was not seen in any of the four topologies tested.

[redacted]

6.1.4 Conclusions

The thermal and voltage results indicate that the level 4 topology with all the components of A-1 resolves all the 345 kV violations and all but one 115 kV violation. The remaining 115 kV violation is resolved by the addition of a series breaker at West Farnum 115 kV switchyard.

Thus, all the components of option A-1 are required to resolve the criteria violations identified in the 10 year planning horizon.

Since stability, short-circuit and delta P analyses were conducted for the option A-1 in the previous analysis, these analyses were not repeated in this solutions study.

6.2 Stability Performance Criteria Compliance

Not required since preferred alternative identical to the alternative tested in previous analysis.

6.2.1 Stability Fault Test Results

Not applicable to this study.

6.3 Short Circuit Performance Criteria Compliance

Not required since preferred alternative identical to the alternative tested in previous analysis.

6.3.1 Short Circuit Test Results

Not applicable to this study.

[redacted]

Section 7
Conclusions on Follow up Solutions Study

7.1 Recommended Solution Description

The needs identified in the follow-up Needs Assessment were similar to the needs identified in the previous analysis. Hence, the preferred alternative from the previous solutions study, option A-1 was revisited. The different components of A-1 were evaluated incrementally in four different levels.

The major 345 kV components of the A-1 plan are:

- A new 345 kV line from Card substation to the Lake Road switching station
- A new 345 kV line from the Lake Road switching station in Connecticut to the West Farnum substation in Rhode Island
- A new 345 kV line from the West Farnum substation in Rhode Island to the Millbury switching station in Massachusetts.
- Rebuild existing 345 kV line (328) from Sherman Road to West Farnum substations

The new line into Millbury from West Farnum provides a new import line into eastern New England and allows for the movement of power from western New England and Greater Rhode Island to reliably serve load in eastern New England during capacity deficiency conditions in eastern New England.

Similarly the line into Card substation via Lake Road and West Farnum provides a new import path into Connecticut and western New England and allows for the movement of power from eastern New England and Greater Rhode Island to reliably serve load in Connecticut and western New England during capacity deficiency conditions in the west.

The project also provides two new 345 kV lines into West Farnum which resolve the criteria violations in Rhode Island seen for the [redacted]

The other components of the plan are detailed in Appendix A: Description of Interstate Alternatives.

Thus, the preferred solution A-1 resolves all the needs identified in the updated needs analysis.

[redacted]

7.2 Solution Component Year of Need

The results of these analyses continued to indicate a need for all the components of option A-1 in the 10 year planning horizon. The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. The western New England reliability analysis shows the first violation in the 2016-2017 timeframe. The Rhode Island reliability analysis shows the first violation at 2012 load levels or earlier. The Connecticut reliability analysis shows the first violation in the 2016-2017 timeframe.

The projected in-service date of all the components of A-1 is December 2015. This is based on the siting and permitting required in three states (MA, CT and RI) for the new 345 kV construction.

7.3 Schedule for Implementation and Lead Times

In accordance with NERC TPL Standards, this assessment provides:

- A written summary of plans to address the system performance issues described in the "*Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment,*" dated September 2012
- A schedule for implementation as described below
- A discussion of lead times necessary to implement plans described below

The major components of option A-1 include a significant amount of new 345 kV construction and have a 3-4 year lead time before they will be in-service.

NU and National Grid have received ISO approval for the Proposed Plan Applications, in accordance with section I.3.9 of the ISO tariff in May 2012. NU and National Grid will also pursue all required state (MA, CT and RI) siting approvals by late 2012 to early 2013.

Construction of the project is tentatively scheduled (based on receipt of all approvals of applications) in late 2013/early 2014, with a projected in-service date of all components of option A-1 of December 2015.

The planned completion date of the preferred solution as described in Section 7.1 is December 2015.

[redacted]

Section 8
Appendix A: Description of Interstate Alternatives

[Appendix A1 - Description of Interstate Option A-1 Components.pdf]

[Appendix A2 - Description of Interstate Option A-2 Components.pdf]

[Appendix A3 - Description of Interstate Option A-3 Components.pdf]

[Appendix A4 - Description of Interstate Option A-4 Components.pdf]

[Appendix A5 - Description of Interstate Option C-2.1 Components.pdf]

Section 9
Appendix B: 2012 CELT Load Forecast

Table 9-1
2012 CELT Seasonal Peak Load Forecast Distributions

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2012	26140	26370	26685	27045	27440	27865	28295	28910	29620	30245
	2013	26440	26675	26995	27360	27765	28190	28630	29260	29980	30615
	2014	26925	27165	27490	27865	28275	28710	29155	29795	30530	31170
	2015	27465	27710	28040	28420	28840	29280	29740	30395	31130	31785
	2016	27995	28245	28585	28970	29400	29850	30315	30985	31725	32390
	2017	28470	28720	29065	29460	29895	30355	30825	31505	32255	32930
	2018	28830	29085	29435	29835	30275	30740	31220	31905	32675	33360
	2019	29145	29405	29755	30160	30605	31075	31560	32255	33040	33735
	2020	29455	29715	30070	30480	30930	31405	31895	32595	33405	34110
	2021	29765	30030	30390	30800	31255	31735	32230	32940	33765	34480
WTHI (1)		**78.49**	**78.73**	**79.00**	**79.39**	**79.88**	**80.30**	**80.72**	**81.14**	**81.96**	**82.33**
Dry-Bulb Temperature (2)		**88.50**	**88.90**	**89.20**	**89.90**	**90.20**	**91.20**	**92.20**	**92.90**	**94.20**	**95.40**
Probability of Forecast Being Exceeded		**90%**	**80%**	**70%**	**60%**	**50%**	**40%**	**30%**	**20%**	**10%**	**5%**
Winter (MW)	2012/13	22060	22110	22155	22215	22355	22500	22720	22775	23095	23510
	2013/14	22215	22265	22310	22370	22510	22655	22880	22935	23160	23570
	2014/15	22370	22420	22465	22530	22670	22815	23040	23095	23315	23725
	2015/16	22525	22575	22620	22680	22825	22975	23200	23255	23475	23890
	2016/17	22655	22710	22755	22815	22960	23110	23335	23390	23630	24040
	2017/18	22785	22835	22885	22945	23090	23240	23465	23525	23765	24175
	2018/19	22905	22955	23000	23065	23210	23360	23590	23645	23890	24305
	2019/20	23020	23075	23120	23185	23330	23480	23710	23770	24015	24425
	2020/21	23135	23190	23235	23300	23445	23595	23830	23885	24130	24545
	2021/22	23255	23305	23355	23415	23565	23720	23950	24010	24250	24660
Dry-Bulb Temperature (3)		**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

FOOTNOTES:
(1) WTHI - a three-day weighted temperature-humidity index for eight New England weather stations. It is the weather variable used in producing the summer peak load forecast. For more information on the weather variables see http://www.iso-ne.com/trans/celt/fsct_detail/.
(2) Dry-bulb temperature (in degrees Fahrenheit) shown in the summer season is for informational purposes only.
(3) Dry-bulb temperature (in degrees Fahrenheit) shown in the winter season is a weighted value from eight New England weather stations.

Table 9-2
2022 Detailed Load Distributions by State and Company

File Created :	2012-03-05	CELT Forecast :	2012	Forecast Year :	2022
Season :	Summer Peak	Weather :	90/10	Load Distribution :	N+10_SUM
ISO-NE CELT :	34130 MW	% of Peak :	100.00%	Tx Losses :	2.50%

State CELT L&L		2.50% Tx Losses		Non-CELT Load		Station Service		Area 104 NE Load		Area 101 Load
34130 MW	-	853.3 MW	+	364.4 MW	+	1059.4 MW	-	15.8 MW	=	34684.7 MW

1: State CELT L&L: This represents the sum of the 6 State CELT forecasts. This number can sometimes be 5-10 MW different than the ISO-NE CELT forecast number due to round-off error.
2: Non-CELT Load: This is the sum of all load modeled in the case that is not included in the CELT forecast. An example is the "behind the meter" paper mill load in Maine.
3: Station Service: This is the amount of generator station service modeled. If station service is off-line, the Area 101 report totals will be different since off-line load is not counted in totals.

Maine State Load = 2480 MW - 2.50% Tx Losses = 2418 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.17%	2059.43	648.73	0.954	332.06
BHE	14.83%	358.57	114.39	0.953	18.06

New Hampshire State Load = 3120 MW - 2.50% Tx Losses = 3042 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	78.91%	2400.35	342.03	0.990	
UNITIL	12.04%	366.10	52.17	0.990	
GSE	9.06%	275.54	8.64	1.000	1.85

Vermont State Load = 1230 MW - 2.50% Tx Losses = 1199.25 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	1199.25	319.51	0.966	98.39

Massachusetts State Load = 16060 MW - 2.50% Tx Losses = 15658.5 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	28.39%	4444.98	1117.12	0.970	37.79
COMEL	11.33%	1773.79	356.16	0.980	
MA-NGRID	39.47%	6180.57	363.67	0.998	38.49
WMECO	6.35%	994.47	141.70	0.990	
MUNI:BOST-NGR	3.34%	522.68	79.95	0.989	
MUNI:BOST-NST	1.24%	194.79	32.82	0.986	
MUNI:CNEMA-NGR	2.12%	332.43	52.30	0.988	
MUNI:RI-NGR	0.89%	139.67	17.23	0.992	
MUNI:SEMA-NGR	1.88%	293.60	33.50	0.994	
MUNI:SEMA-NST	1.75%	274.49	78.12	0.962	
MUNI:WMA-NGR	1.11%	173.81	14.84	0.996	
MUNI:WMA-NU	2.13%	333.06	47.46	0.990	

Rhode Island State Load = 2430 MW - 2.50% Tx Losses = 2369.25 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	2369.25	232.23	0.995	34.60

Connecticut State Load = 8810 MW - 2.50% Tx Losses = 8589.75 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	76.07%	6534.57	931.13	0.990	95.70
CMEEC	4.96%	426.40	60.76	0.990	
UI	18.96%	1628.79	162.88	0.995	10.00

[redacted]

Table 9-3
Detailed Demand Response Through FCA-6 Distributions by Zone

File Created : 2012-06-07 **CCP :** 2015/2016 **Load Season :** Summer Peak
Load Distrb : N+10_SUM **Distrb Losses :** 5.50% **DR Season :** SUM

	Demand Reduction Value (DRV)		Load Dependent Capability Assumption (LDCA)		Performance Assumption (PA)		Distribution Losses Gross-Up		Area 104 DR		Area 101 DR
Passive :	1560.41 MW	x	100.00%	x	100.00%	+	85.82 MW	-	3.75 MW	=	1642.48 MW
Active :	1457.33 MW		100.00%		75.00%		60.11 MW		1.54 MW		1151.57 MW

Demand Reduction Value (DRV): Amount of DR measured at the customer meter without any gross-up values for transmission or distribution losses.
Load Dependent Capability Assumption (LDCA): De-rate factor applied based on % of CELT load. (i.e. Light load is 45% of 50/50 load, so the LDCA would be 45%.)
Performance Assumption (PA): De-rate factor applied based on expected performance of DR after a dispatch signal from Operations.
Area 104 DR: This load is modeled in northern VT and is electrically served from Hydro Quebec. To make Area Interchange load independent, this load is assigned Area 104.

Passive Demand Resources - (On-Peak and Seasonal Peak)

DR Modeled = (DRV_SUM * 100.00% LDCA * 100.00% PA) + 5.50% Distrb Losses Gross-Up

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Load Zone - Maine	145.82	-153.84	-48.36
DR_P_NH	21	Load Zone - New Hampshire	78.03	-82.32	-11.43
DR_P_VT	22	Load Zone - Vermont	114.80	-121.11	-32.56
DR_P_NEMABOS	23	Load Zone - Northeast Massachusetts & Boston	317.53	-334.99	-72.10
DR_P_SEMA	24	Load Zone - Southeast Massachusetts	176.30	-186.00	-19.57
DR_P_WCMA	25	Load Zone - West Central Massachusetts	209.91	-221.46	-19.84
DR_P_RI	26	Load Zone - Rhode Island	129.07	-136.17	-13.41
DR_P_CT	27	Load Zone - Connecticut	388.95	-410.34	-55.16

Active Demand Resources - (Real-Time Demand Resource (RTDR), Excludes RTEG)

DR Modeled = (DRV_SUM * 100.00% LDCA * 75.00% PA) + 5.50% Losses Gross-Up

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_A_ME_BHE	30	Dispatch Zone - ME - Bangor Hydro	44.13	-34.92	-11.39
DR_A_ME_MAIN	31	Dispatch Zone - ME - Maine	151.25	-119.68	-36.00
DR_A_ME_PORT	32	Dispatch Zone - ME - Portland Maine	100.08	-79.19	-25.77
DR_A_NH_NEWH	33	Dispatch Zone - NH - New Hampshire	53.41	-42.26	-5.85
DR_A_NH_SEAC	34	Dispatch Zone - NH - Seacoast	7.60	-6.01	-0.86
DR_A_VT_NWVT	35	Dispatch Zone - VT - Northwest Vermont	40.80	-32.28	-9.22
DR_A_VT_VERM	36	Dispatch Zone - VT - Vermont	22.27	-17.62	-4.19
DR_A_MA_BOST	37	Dispatch Zone - MA - Boston	198.08	-156.73	-39.39
DR_A_MA_NSHR	38	Dispatch Zone - MA - North Shore	69.81	-55.24	-6.31
DR_A_MA_CMA	39	Dispatch Zone - MA - Central Massachusetts	79.81	-63.15	-3.75
DR_A_MA_SPFD	40	Dispatch Zone - MA - Springfield	38.89	-30.77	-4.39
DR_A_MA_WMA	41	Dispatch Zone - MA - Western Massachusetts	53.60	-42.41	-4.08
DR_A_MA_LSM	42	Dispatch Zone - MA - Lower Southeast Massachusetts	48.42	-38.31	-6.28
DR_A_MA_SEMA	43	Dispatch Zone - MA - Southeast Massachusetts	110.13	-87.14	-7.00
DR_A_RI_RHOD	44	Dispatch Zone - RI - Rhode Island	84.43	-66.81	-6.58
DR_A_CT_EAST	45	Dispatch Zone - CT - Eastern Connecticut	41.51	-32.84	-4.68
DR_A_CT_NRTH	46	Dispatch Zone - CT - Northern Connecticut	55.12	-43.61	-6.22
DR_A_CT_NRST	47	Dispatch Zone - CT - Norwalk-Stamford	63.46	-50.21	-6.85
DR_A_CT_WEST	48	Dispatch Zone - CT - Western Connecticut	194.53	-153.92	-19.97

[redacted]

Table 9-4
2012 CELT Forecasted Energy Efficiency by Load Zone 2016-2022[25]

PASSIVE Load Zone (MW including T & D losses)	2016	2017	2018	2019	2020	2021	2022
MAINE	9.00	8.00	8.00	7.00	7.00	6.00	6.00
NEW HAMPSHIRE	10.00	9.00	10.00	8.00	8.00	8.00	8.00
VERMONT	19.00	17.00	16.00	16.00	14.00	13.00	13.00
NEMASSBOST	66.00	62.00	58.00	54.00	51.00	47.00	47.00
SEMASS	33.00	32.00	29.00	28.00	25.00	25.00	25.00
WCMASS	38.00	36.00	34.00	32.00	29.00	28.00	28.00
RHODE ISLAND	27.00	24.00	24.00	21.00	20.00	19.00	19.00
CONNECTICUT	31.00	29.00	27.00	26.00	24.00	22.00	22.00
NE Total	**233.00**	**217.00**	**206.00**	**192.00**	**178.00**	**168.00**	**168.00**

[25] The 2012 CELT report only forecasts energy efficiency until 2021. The growth of EE forecast from 2021 to 2022 was assumed to be identical to the growth of EE from 2020 to 2021

[redacted]

Section 10
Appendix C: Case Summaries and Generation Dispatches

[redacted]

[redacted]

Section 11
Appendix D: Contingency List

[redacted]

[redacted]

[redacted]

Section 12
Appendix E: Contingency Results

[redacted]

[redacted]

Interstate Option A-1 Components

345 kV Transmission line facilities:

1. **Card – Lake Road (NU):** Build a 29.3 mile 345 kV transmission line (#3271) from the Card Substation in Lebanon, Connecticut to the Lake Road Switching Station in Killingly, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

2. **Lake Road – CT/RI Border (NU):** Build a 7.5 mile 345 kV transmission line (#341) from the Lake Road Switching Station in Killingly, Connecticut to the Rhode Island border in Thompson, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

3. **CT/RI Border – West Farnum (National Grid):** Build a 17.7 mile 345 kV transmission line (#341) from the Connecticut border in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

4. **West Farnum – MA/RI Border (National Grid):** Build a 4.8 mile 345 kV transmission line (#366) from the West Farnum Substation in North Smithfield, Rhode Island to the Massachusetts border in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

5. **MA/RI Border – Millbury (National Grid):** Build a 15.4 mile 345 kV transmission line (#366) from the Rhode Island border in Millville, Massachusetts to the Millbury Switching Station in Millbury, Massachusetts. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

6. **Sherman Road – West Farnum (National Grid):** Reconductor and rebuild the existing 9.0 mile 345 kV 328 transmission line from the Sherman Road Switching Station in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

345 kV Substation or Switching Station facilities:

1. **Card Substation (NU):** Expand the existing 345 kV ring-bus configuration by installing three new 345 kV circuit breakers. [redacted]

2. **Lake Road Switching Station (NU):** Expand the existing three bay 345 kV breaker-and-a-half scheme bus configuration by installing three new 345 kV breakers and associated bus work. [redacted] Also, add a new fourth 345 kV bay [redacted]

[redacted]

3. **West Farnum Substation (National Grid):** Install two additional 345 kV circuit breakers [redacted]

4. **Millbury Switching Station (National Grid):** Expand the existing two bay 345 kV breaker-and-a-half scheme bus configuration by installing four new 345 kV circuit breakers and associated bus work and upgrading three existing 345 kV circuit breakers. [redacted]

5. **Sherman Road Switching Station (National Grid):** Replace the existing ring bus with a new two bay breaker and a half open air switching station [redacted].

6. **Carpenter Hill Substation National Grid):** Upgrade the 345 kV protection system.

7. **Killingly Substation (NU)**: Install two terminal structures to support the new 345-kV line conductors that traverse the existing Killingly 345-kV bus work.

115 kV Substation or Switching Station facilities:

1. **West Farnum (National Grid):** [redacted]

2. **Riverside (National Grid):** Upgrade protection system for the 115 kV H-17 transmission line.

3. **Woonsocket (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

4. **Hartford Avenue (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

Interstate Option A-2 Components

345 kV Transmission line facilities:

1. **Card – Lake Road (NU):** Build a 29.3 mile 345 kV transmission line (#3271) from the Card Substation in Lebanon, Connecticut to the Lake Road Switching Station in Killingly, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

2. **Lake Road – CT/RI Border (NU):** Build a 7.5 mile 345 kV transmission line (#341) from the Lake Road Switching Station in Killingly, Connecticut to the Rhode Island border in Thompson, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

3. **CT/RI Border – Sherman Road (National Grid):** Build a 8.7 mile 345 kV transmission line from the Connecticut border in Burrillville, Rhode Island to the Sherman Road Switching Station in Burrillville, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

4. **Sherman Road – West Farnum (National Grid):** Build a 9.0 mile 345 kV transmission line from the Sherman Road Switching Station in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

5. **Sherman Road – MA/RI Border (National Grid):** Build a 0.2 mile 345 kV transmission line from the Sherman Road Switching Station in Burriville, Rhode Island to the Massachusetts border in Burriville, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

6. **MA /RI Border – Millbury (National Grid):** Build a 17.5 mile 345 kV transmission line from the Rhode Island border in Uxbridge, Massachusetts to the Millbury Switching Station in Millbury, Massachusetts. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

7. **Sherman Road – Ocean State Power:** Rebuild the 0.2 mile 333 345 kV transmission line from Sherman Road Switching Station in Burriville, Rhode Island to Ocean State Power in Burriville, Rhode Island.

345 kV Substation or Switching Station facilities:

1. **Card Substation (NU):** Expand the existing 345 kV ring-bus configuration by installing three new 345 kV circuit breakers. [redacted]

2. **Lake Road Switching Station (NU):** Expand the existing three bay 345 kV breaker-and-a-half scheme bus configuration by installing three new 345 kV breakers and associated bus work. [redacted] Also, add a new fourth 345 kV bay [redacted]

3. **Sherman Road Switching Substation (National Grid):** Replace the existing ring bus with a new four bay breaker and a half open air switching station [redacted]

4. **West Farnum Substation (National Grid):** Install an additional 345 kV circuit breaker in order to terminate the new 345 kV line to Sherman Road.

5. **Millbury Switching Station (National Grid):** Expand the existing two bay 345 kV breaker-and-a-half scheme bus configuration by installing four new 345 kV circuit breakers and associated bus work and upgrading three existing 345 kV circuit breakers. [redacted]

6. **Carpenter Hill Substation (National Grid):** Upgrade the 345 kV protection system.

7. **Killingly Substation (NU)**: Install two terminal structures to support the new 345-kV line conductors that traverse the existing Killingly 345 kV bus work.

115 kV Substation or Switching Station facilities:

1. **West Farnum (National Grid):** [redacted]

2. **Riverside (National Grid):** Upgrade protection system for the 115 kV H-17 transmission line.

3. **Woonsocket (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

4. **Hartford Avenue National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

Interstate Option A-3 Components

345 kV Transmission line facilities:

1. **Card – Lake Road (NU):** Build a 29.3 mile 345 kV transmission line (#3271) from the Card Substation in Lebanon, Connecticut to the Lake Road Switching Station in Killingly, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

2. **Lake Road – CT/RI Border (NU):** Build a 7.5 mile 345 kV transmission line (#341) from the Lake Road Switching Station in Killingly, Connecticut to the Rhode Island border in Thompson, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

3. **CT/RI Border – West Farnum (National Grid):** Build a 17.7 mile 345 kV transmission line (#341) from the Connecticut border in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

4. **West Farnum – MA/RI Border (National Grid):** Build a 4.8 mile 345 kV transmission line from the West Farnum Substation in North Smithfield, Rhode Island to the MA border in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

5. **MA/RI Border – Uxbridge (National Grid):** Build a 1.9 mile 345 kV transmission line from the MA border in Uxbridge, Massachusetts to a new Uxbridge Switching Station in Uxbridge Massachusetts. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

6. **Uxbridge – Millbury (National Grid):** Build a 13.5 mile 345 kV transmission line from the Uxbridge Switching Station in Uxbridge Massachusetts to the Millbury Switching Station Millbury Massachusetts. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

7. **Sherman Road – Uxbridge (National Grid/NSTAR):** Increase conductor height on 4.1 mile 345 kV line, from Sherman Road Switching Station in Burrillville, Rhode Island to Uxbridge Switching Station in Uxbridge, Massachusetts.

8. **Uxbridge – ANP Blackstone (NSTAR):** Increase conductor height on the 4.6 mile 345 kV line, from Uxbridge Switching Station in Uxbridge Massachusetts to ANP Blackstone Station in Blackstone, Massachusetts.

345 kV Substation or Switching Station facilities:

1. **Card Substation (NU):** Expand the existing 345 kV ring-bus configuration by installing three new 345 kV circuit breakers. [redacted]

2. **Lake Road Switching Station (NU):** Expand the existing three bay 345 kV breaker-and-a-half scheme bus configuration by installing three new 345 kV breakers and associated bus work. [redacted] Also, add a new fourth 345 kV bay [redacted]

3. **West Farnum Substation (National Grid):** Install two additional 345 kV circuit breakers [redacted]

4. **Uxbridge Switching Station (National Grid):** Build a new 345 kV switching station in a breaker-and-a-half configuration by installing six new 345 kV circuit breakers in two new bays. [redacted]

5. **Millbury Switching Station (National Grid):** Expand the existing two bay 345 kV breaker-and-a-half scheme bus configuration by installing four new 345 kV circuit breakers and associated bus work and upgrading three existing 345 kV circuit breakers. [redacted]

6. **Sherman Road Switching Station (National Grid):** Replace the existing ring bus with a new two bay breaker and a half open air switching station [redacted].

7. **Carpenter Hill Substation (National Grid):** Upgrade the 345 kV protection system.

8. **Killingly Substation (NU)** : Install two terminal structures to support the new 345-kV line conductors that traverse the existing Killingly 345 kV bus work.

115 kV Substation or Switching Station facilities:

1. **West Farnum (National Grid):** [redacted]

2. **Riverside (National Grid):** Upgrade protection system for the 115 kV H-17 transmission line.

3. **Woonsocket (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

4. **Hartford Avenue (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

Interstate Option A-4 Components

345 kV Transmission line facilities:

1. **Card – Lake Road (NU):** Build a 29.3 mile 345 kV transmission line (#3271) from the Card Substation in Lebanon, Connecticut to the Lake Road Switching Station in Killingly, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

2. **Lake Road – CT/RI Border (NU):** Build a 7.5 mile 345 kV transmission line (#341) from the Lake Road Switching Station in Killingly, Connecticut to the Rhode Island border in Thompson, Connecticut. The line will be constructed using steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase. In some places the line will be built in a delta steel pole configuration.

3. **CT/RI Border – West Farnum (National Grid):** Build a 17.7 mile 345 kV transmission line (#341) from the Connecticut border in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

4. **West Farnum – MA/RI Border (National Grid):** Build a 4.8 mile 345 kV transmission line from the West Farnum Substation in North Smithfield, Rhode Island to the MA border in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

5. **MA/RI Border – Millbury (National Grid):** Build a 15.4 mile 345 kV transmission line from the Rhode Island border in Millville, Massachusetts to the Millbury Switching Station in Millbury, Massachusetts. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase

6. **Sherman Road – West Farnum (National Grid):** Build a 9.0 mile 345 kV transmission line from the Sherman Road Switching Station in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frames structures with two (bundled) 1590 kcmil ACSR conductors per phase.

345 kV Substation or Switching Station facilities:

1. **Card Substation (NU):** Expand the existing 345 kV ring-bus configuration by installing three new 345 kV circuit breakers. [redacted]

2. **Lake Road Switching Station (NU):** Expand the existing three bay 345 kV breaker-and-a-half scheme bus configuration by installing three new 345 kV breakers and associated bus work. [redacted] Also, add a new fourth 345 kV bay [redacted]

[redacted]

3. **West Farnum Substation (National Grid):** Expand the existing four bay 345 kV breaker-and-a-half scheme bus configuration to five bays. [redacted]

4. **Millbury Switching Station (National Grid):** Expand the existing two bay 345 kV breaker-and-a-half scheme bus configuration by installing four new 345 kV circuit breakers and associated bus work and upgrading three existing 345 kV circuit breakers. [redacted]

5. **Sherman Road Switching Station (National Grid):** Replace the existing ring bus with a new three bay open air breaker and a half switching station [redacted]

6. **Carpenter Hill Substation (National Grid):** Upgrade the 345 kV protection system.

7. **Killingly Substation (NU)** : Install two terminal structures to support the new 345-kV line conductors that traverse the existing Killingly 345 kV bus work.

115 kV Substation or Switching Station facilities:

1. **West Farnum (National Grid):** [redacted]

2. **Riverside (National Grid):** Upgrade protection system for the 115 kV H-17 transmission line.

3. **Woonsocket (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

4. **Hartford Avenue (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.

Interstate Option C-2.1 Components

345kV Transmission line facilities:

1. **Manchester – CT/MA Border (NU):** Build a 33.4 mile 345 kV transmission line from the Manchester Substation in Manchester, Connecticut to the CT/MA border in Somers, Connecticut. The line will be constructed using vertical steel monopole and steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase.
2. **CT/MA Border –Belchertown/Ludlow Town Line (NU/National Grid (NU):** Build a 14.3 mile 345 kV transmission line from the CT/MA border in Hampden, Massachusetts to the Belchertown/Ludlow town line in Massachusetts. The line will be constructed using vertical steel monopole and steel (or wood) H-frame structures with two (bundled) 1590 kcmil ACSS conductors per phase

3. **Belchertown/Ludlow Town Line (NU/National Grid) – Carpenter Hill (National Grid):** Build a 23.1 mile 345 kV transmission line from the Belchertown/Ludlow town line to the Carpenter Hill substation in Charlton, Massachusetts. The line will be constructed using steel H-frame structures with two (bundled) 1590 kcmil ACSR conductors per phase. Note: National Grid also to relocate 2.6 miles of the 345kV 301 in the ROW, in Massachusetts.

4. **Carpenter Hill – Millbury (National Grid):** Build a 16.0 mile 345 kV transmission line from the Carpenter Hill Substation in Charlton, Massachusetts to the Millbury Switching Station in Millbury, Massachusetts. The line will be constructed using steel H-frame structures with two (bundled) 1590 kcmil ACSR conductors per phase.

5. **Sherman Road – West Farnum (National Grid):** Build a 9.0 mile 345 kV transmission line from the Sherman Road Switching Station in Burrillville, Rhode Island to the West Farnum Substation in North Smithfield, Rhode Island. The line will be constructed using steel H-frame structures with two (bundled) 1590 kcmil ACSR conductors per phase.

345 kV Substation or Switching Station facilities:

1. **Manchester Substation (NU):** Expand the existing 345 kV three bay 345 kV breaker-and-a-half scheme bus configuration by adding a new bay and installing two new 345 kV circuit breakers. [redacted] Upgrade substation equipment.

2. **Carpenter Hill Substation (National Grid):** Expand the existing 345 kV substation by adding two new 345 kV bays and installing six new 345 kV circuit breakers and a 345/115 kV autotransformer. [redacted] The project also involves the upgrade of the 345 kV protection system.

3. **Millbury Switching Station (National Grid):** Expand the existing two bay 345 kV breaker-and-a-half scheme bus configuration by installing four new 345 kV circuit breakers and associated buswork and upgrading three existing 345 kV circuit breakers. [redacted]

[redacted]

4. **West Farnum Substation (National Grid):** Install an additional 345 kV circuit breaker [redacted]

5. **Sherman Road Switching Station (National Grid):** Replace the existing ring bus with a new three bay open air breaker and a half switching station [redacted]

115 kV Transmission line facilities:

1. **Wood River – CT/MA Border (National Grid):** Uprate [redacted] the 7.2 mile 115 kV 1870S transmission line from the Wood River Substation in Charleston, Rhode Island to the CT/MA border in Westerly, Rhode Island.

2. **West Farnum Tap – Woonsocket (National Grid):** Reconductor the 1.1 mile 115 kV S-171N transmission line from the West Farnum Substation in North Smithfield, Rhode Island to the Woonsocket Substation in Smithfield, Rhode Island with 1590 ACSS.

3. **West Farnum Tap – Woonsocket (National Grid):** Reconductor the 1.1 mile 115 kV T-172N transmission line from the West Farnum Substation in North Smithfield, Rhode Island to the Woonsocket Substation in Smithfield, Rhode Island with 1590 ACSS.

4. **South Wrentham – Union Street (National Grid):** Uprate [redacted] the 3.3 mile 115 kV C-129S transmission line from the South Wrentham Substation in Wrentham, Massachusetts to the Union Street Substation in Franklin, Massachusetts.

5. **Depot Street Tap – Milford Power and Light Plant Tap (National Grid):** Reconductor the 2.65 mile 115 kV C-129N transmission line from the Depot Street Tap in Milford, Massachusetts to the Milford Power and Light Plant Tap in Milford, Massachusetts with 795 ACSR.

115 kV Substation or Switching Station facilities:

1. **West Farnum (National Grid):** [redacted]

2. **Riverside (National Grid):** Upgrade protection system for the 115 kV H-17 transmission line.

3. **Woonsocket (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines and upgrade 115 kV terminal equipment.

4. **Hartford Avenue (National Grid):** Upgrade protection systems for the 115 kV S-171N and T-172N transmission lines.