New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment

Southern New England Regional Working Group

(ISO New England, National Grid, Northeast Utilities, and NSTAR)

Redacted Public Version

April 2011

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Executive Summary

1.1 Objective

The objective of this study was to update the analysis of the reliability-based transmission needs identified in the Southern New England Transmission Reliability (SNETR) Report Needs Analysis, dated January 2008, specifically with respect to the Interstate Reliability Project component of the New England East-West Solution (NEEWS), to ensure that the area adheres to North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC) and ISO New England (ISO) standards and criteria.

The updated needs assessment study evaluated the reliability of the southern New England transmission system for 2015 and 2020 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[1] facilities in the states of Massachusetts, Rhode Island and Connecticut.[2]

An ISO led working group consisting of members from NU, NGRID, and NSTAR updated the analysis of system needs for the southern New England regional transmission system. 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 updated needs assessment is the first step in this study process. A second study will be conducted, to develop and analyze potential transmission solutions to meet the identified updated needs.

General areas of concern that this study addressed:

- Transmission planning standards and criteria: Multiple interrelated violations of NERC, NPCC and ISO transmission planning standards and criteria in eastern New England, western New England, Greater Rhode Island and Connecticut are projected within the 10-year planning horizon.
- Transmission Transfer Capability: The ability to serve load with existing and FCA cleared generation from western New England to eastern New England and from eastern New England to western New England resulting from transmission constraints along the 345-kilovolt transmission corridor from southeast Massachusetts through Rhode Island into eastern Connecticut.
- Salem Harbor Non-Price Retirement Requests: In February, 2011, Non-Price Retirement Requests were filed for the Salem Harbor Generating Station. With 750 MW less capacity in eastern New England, how will this retirement affect transmission system reliability?

[1] The working group was expanded to include NSTAR once interdependent needs were identified in their service territory.

[2] 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.

1.2 Method and Criteria

The updated needs assessment was performed in accordance with the NERC TPL[3]-001, TPL-002, TPL-003 and TPL-004 Transmission Planning System Standards, the NPCC Directory D-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 five-year and ten-year planning horizon was used for this study based on the most recently available Capacity, Energy, Loads, and Transmission (CELT) Report issued in April 2010 at the time the study began. This study was focused on the projected 2015 peak demand load levels for the five-year horizon and 2020[4] peak demand load levels for the ten-year horizon. The models reflected the following peak load conditions:

2015 system load level tested:

- The summer peak 90/10 demand forecast of 31,810 MW for New England

2020 system load level tested:

- The summer peak 90/10 demand forecast of 33,555 MW for New England

A total of 4 base cases were modeled for each 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 51 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]
- **Salem Harbor Retirement Scenario:** [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 final scenario stressed the New England West-East transfers with the additional retirement of Salem Harbor Generating Station along with [redacted].

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

[4] The 2010 CELT forecast only has projected peak demands for the years 2010 to 2019. To determine the 2020 peak demand forecasted load, the growth rate from years 2018 to 2019 was applied to the 2019 forecast.

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.

1.4.2 Results of N-1 Testing

N-1 testing indicated several thermal overloads and emerging issues[5] across the study area under several system conditions. Main areas of concern are the overloads on the 345-kilovolt path from West Medway to Sherman Road to West Farnum (336, 3361 and 328 lines), the 345-kilovolt path from Ludlow to Carpenter Hill to Millbury (301 and 302 lines) and the 115-kilovolt path along the CT/RI coast from Montville to Kent County (1280, 1410, 1465 and 1870S lines). A summary of the N-1 overloads and emerging issues (not including the Salem Harbor retirement scenario increase in overloads) can be seen in Figure 1-1 and is described in further detail in Section 5.2.2. In the N-1 Salem Harbor retirement scenario, overloads increased [redacted] compared to the west to east analysis and an additional voltage violation was found along the CT/RI coastal 115-kilovolt path.

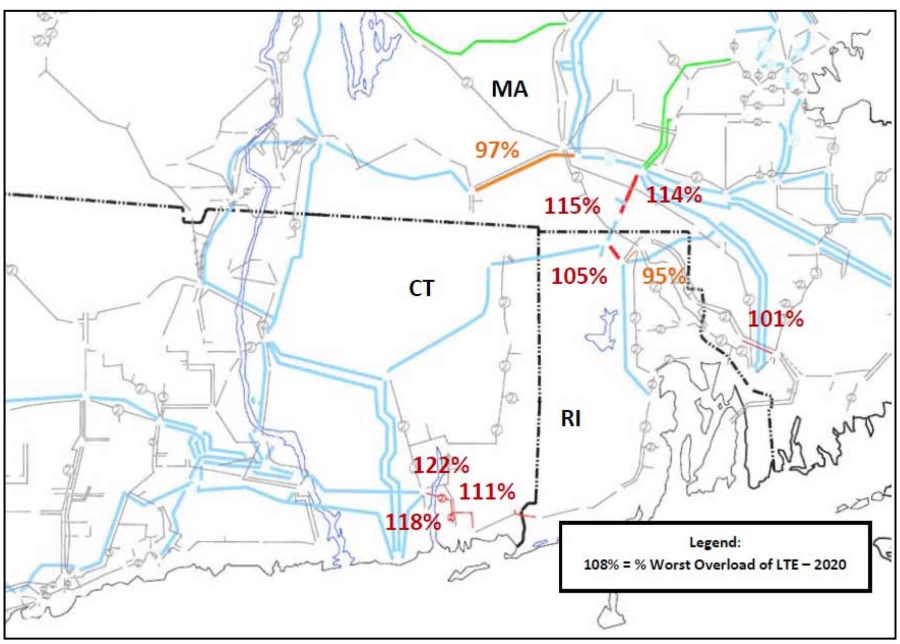

Figure 1-1: New England N-1 Thermal Overload Summary

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

1.4.3 Results of N-1-1 Testing

N-1-1 testing showed wide-spread thermal overloads across the study area under almost all system conditions. Most 345-kilovolt lines in Rhode Island and several 345-kilovolt lines in central and western Massachusetts and Connecticut overload under certain conditions. With only three major 345-kilovolt paths connecting Eastern to Western New England [redacted] networks experience large power flows while transferring power across the region.

Rhode Island experiences severe overloads [redacted] during an N-1-1 event. The [redacted] network cannot support the resulting power transfers into the state to serve the local area load.

A summary of the N-1-1 overloads can be seen in Figure 1-2 and is described in further detail in Section 5.2.3.

In the N-1-1 Salem Harbor retirement scenario, overloads increased [redacted] compared to the west to east analysis.

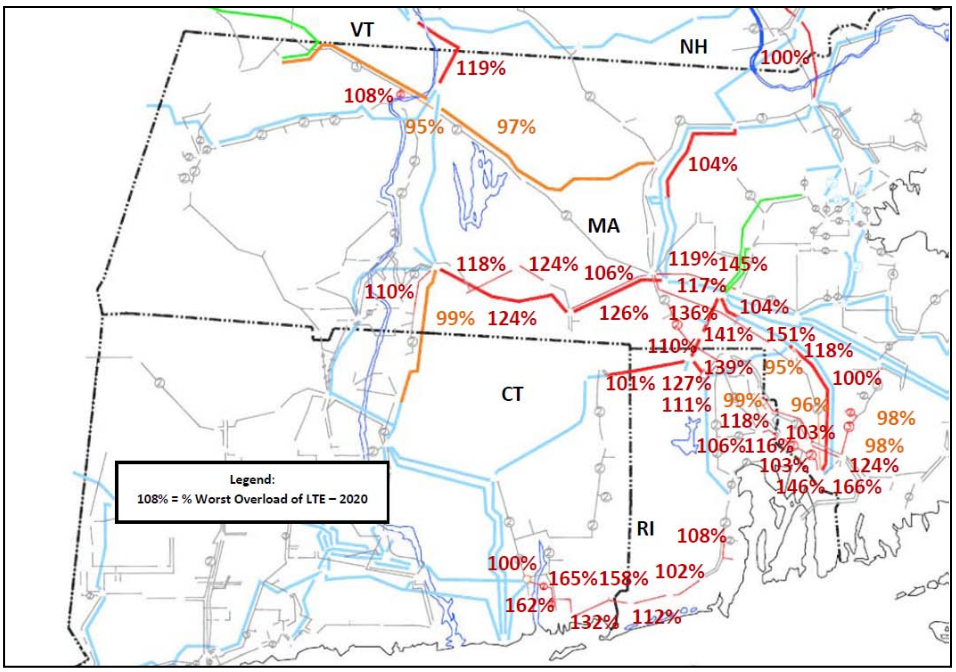

Figure 1-2: New England N-1-1 Thermal Overload Summary

1.4.4 Results of Transmission Transfer Capability

As stated in Section 4 of the ISO PP-3, "The New England bulk power supply system shall be designed with adequate inter-Area and intra-Area transmission transfer capability to minimize system reserve requirements, facilitate transfers, provide emergency backup of supply resources, permit economic interchange of power, and to assure [the system will remain reliable under contingency conditions]."

The ability of a region to serve its load reliably is a simple equation where the amount of resources in a region plus the amount of power that can be imported into the region must be equal to or greater than the amount of load in that region. As load grows and if no future generation resources are built in the region or no additional transmission capability is built to import more power, load cannot be served reliably. The eastern New England region will have insufficient transfer capability to deliver resources to serve its load under N-1-1 conditions starting in 2011, the western New England region in 2017-2018 and the Connecticut region in 2014-2015. Details of this analysis can be seen in Section 5.2.7.

1.5 Statements of Need

The results of these analyses indicated a need to:

- Reinforce the 345-kilovolt system into the [redacted] 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

Many of these issues were seen in the original SNETR study at today's load levels and the updated Interstate needs assessment continues to show overloads within the 10 year planning horizon.

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 E: 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 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 recently approved both of these components and NGRID and NU are now moving forward with the construction phase. This report summarizes the reaffirmation of the need for the Interstate component. 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.

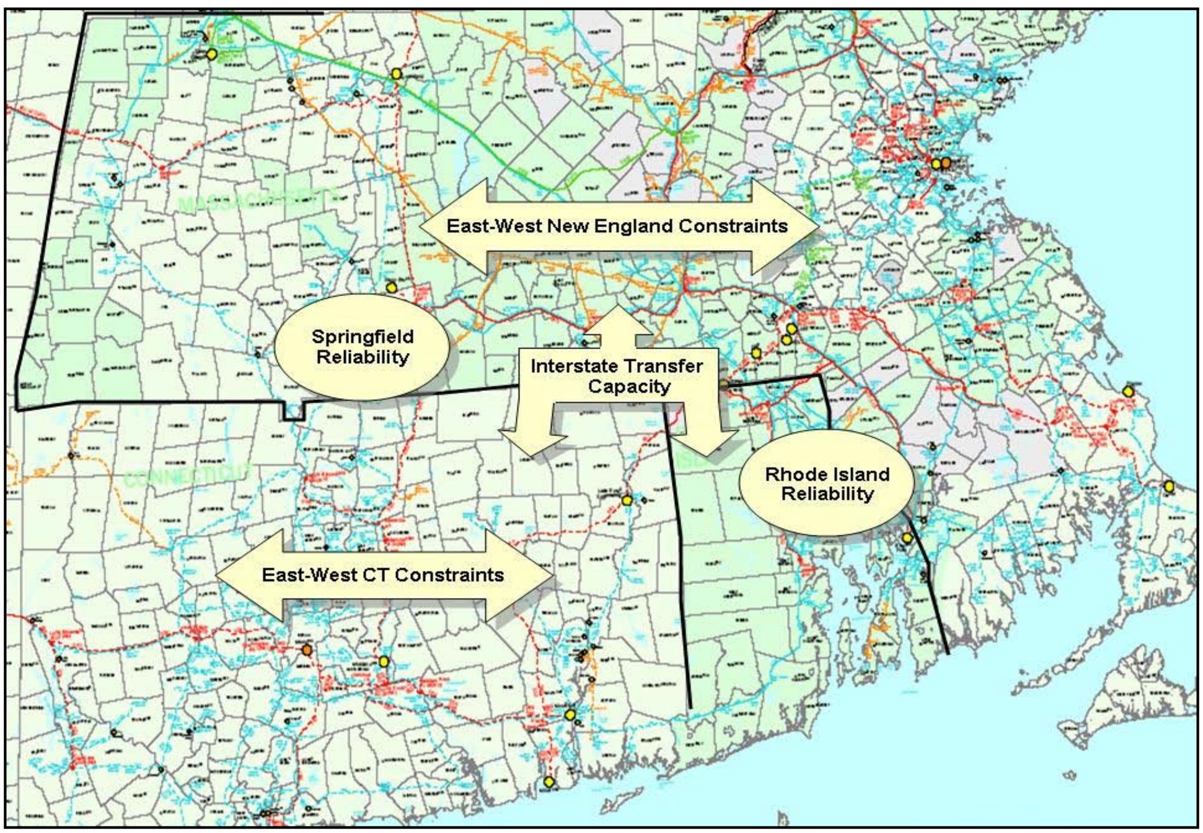

Figure 2-1: Original Southern New England Needs and Constraints

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-kilovolt transmission system in southern New England with the major substations highlighted.

[Figure 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 [redacted], 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]

[Figure redacted]

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

[Figure 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

[Table 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

[Table 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

[Table redacted]

[Figure redacted]

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

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

[Table redacted]

[Figure 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

[Table redacted]

[Figure redacted]

Figure 2-7: Load Serving Capability: Connecticut

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

[Table redacted]

2.3 Study Horizon

A five-year and ten-year planning horizon was used for this study based on the most recent load forecast from the 2010 Capacity, Energy, Loads, and Transmission (CELT) report at the time the study began. This study was focused on the projected 2015 peak demand load levels for the five-year horizon and 2020 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 circuits 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.
- **Extreme Contingency** – limited stability studies to examine how the transmission system could handle North American Electric Reliability Corporation (NERC) Category D (TPL-004) type contingencies and how severe the results would be for those events.
- **Delta P Analysis** – limited studies were done to determine the mechanical stress put on local machines in the area due to system contingency events.
- **Transmission Transfer Capability Analysis** – studies to determine if the transmission system could reliably serve load in a specific sub-area and at what time-frame there was a risk of not meeting that objective.

The following analyses will be performed during the solutions study phase:

- **Stability Analysis** – detailed studies to determine the dynamic performance of electric machines with respect to rotor angle displacement, system voltage stability and system frequency deviations following a fault.
- **Short Circuit Analysis** – studies to determine the ability of substation equipment to withstand and interrupt fault current.

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 5 and 10-year projections of the 90/10 summer peak system demand levels 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 2015 and 2020. 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 June 2010 Regional System Plan (RSP) Project Listing[6] have been included in the study base case. 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)[7]
- Vermont Southern Loop Project (RSP ID: 323, 1032-1035)

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)

[6] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2010/index.html

[7] 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)

Connecticut

- NEEWS – Greater Springfield Reliability Project (RSP ID: 816, 1054[8], 1092)

3.1.4 Generation

Generation Projects with a Forward Capacity Market (FCM) Capacity Supply Obligation as of the Forward Capacity Auction #4 (FCA-4) commitment period (June 1, 2013 – May 31, 2014) were included in the study base case. A listing of the recent major new FCA-1 through 4 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)
- Northfield Mountain Uprate 30 MW (FCA-4)

Rhode Island

- QP 233 – Ridgewood Landfill (FCA-2)

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)

[8] RSP 1054 – Meekville to Manchester Project was modified to reflect changes from the Connecticut Siting Council hearings for GSRP in 2009 to now separate the 345-kilovolt three-terminal 395 line (Manchester – N. Bloomfield – Barbour Hill) into two separate 345-kilovolt lines, 3557 line (Barbour Hill – Manchester) and 3642 line (N. Bloomfield – Manchester)

- QP 193 – Ansonia Generation (FCA-1)
- 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 recent issues concerning the operation of the Vermont Yankee Nuclear Station in Vernon, VT after March 2012, the unit (604 MW) was assumed out of service as a base case condition.

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. For the base west to east stressed cases the Salem Harbor Station will be assumed in-service as a base case condition. An additional retirement scenario with Salem Harbor OOS and an increase in New Brunswick imports to 700 MW was evaluated.

The ongoing Greater Boston analysis will be determining the specific, more local, upgrades needed in the north shore area. The capacity of Salem Harbor Station is roughly equal to five years of load growth in the eastern New England import area. In cases where Salem Harbor was in service, overloads seen in 2020 in this report will now approximately occur in 2015 if Salem Harbor Station is out of service and all additional capacity to replace Salem Harbor comes from western New England and New York imports.

This NEEWS study and other ongoing studies with their resultant transmission upgrades will likely improve the ability of new resources to interconnect to the system and deliver capacity and energy to serve load in eastern and western New England. This will become increasingly important as more of the region's older resources seek to retire.

Real Time Emergency Generation (RTEG) cleared in the FCM is not included in reliability analyses due to their emissions restrictions and use in only emergency situations.

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 June 2010 RSP Project Listing and generation projects that have not cleared in FCA-4 were not modeled in the study base case due to the uncertainty concerning their final development.

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 five-year and ten-year planning horizon was used for this study based on the most recently available CELT report issued in April 2010 at the time the study began. This study was focused on the projected 2015 peak demand load levels for the five-year horizon and 2020[9] peak demand load levels for the ten-year horizon. The models reflected the following peak load conditions:

2015 system load level tested:

- The summer peak 90/10 demand forecast of 31,810 MW for New England

2020 system load level tested:

- The summer peak 90/10 demand forecast of 33,555 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 resources are modeled in the base case at the levels of the most recent Forward Capacity Auction. When this updated needs assessment was started, the values from FCA-4 were the most recently available values.

Starting in 2010, DR values are now published in the CELT report. 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 3-1 and Table 3-2 and detailed reports of can be seen in Appendix A: 2010 CELT Load Forecast in Table 7-4.

Table 3-1
FCA-4 Passive DR Values

Load Zone	CELT DRV[10] (MW)
Maine	152
New Hampshire	72
Vermont	97
Northeast Massachusetts & Boston	263
Southeast Massachusetts	140
West Central Massachusetts	150
Rhode Island	85
Connecticut	424

[9] The 2010 CELT forecast only has projected peak demands for the years 2010 to 2019. To determine the 2020 peak demand forecasted load, the growth rate from years 2018 to 2019 was applied to the 2019 forecast.

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

Table 3-2
FCA-4 Active DR Values

Dispatch Zone	CELT DRV (MW)	Dispatch Zone	CELT DRV (MW)
Bangor Hydro	76	**Springfield, MA**	36
Maine	203	**Western Massachusetts**	45
Portland, ME	135	**Lower Southeast Massachusetts**	64
New Hampshire	64	**Southeast Massachusetts**	106
New Hampshire Seacoast	10	**Rhode Island**	77
Northwest Vermont	35	**Eastern Connecticut**	48
Vermont	19	**Northern Connecticut**	63
Boston, MA	212	**Norwalk-Stamford, Connecticut**	70
North Shore Massachusetts	83	**Western Connecticut**	208
Central Massachusetts	86		

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 2015 and 2020 cases is shown in Table 3-3. 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 7-2 and Table 7-3.

Table 3-3
2010 90/10 CELT Load

State	2015 Load (MW)	2020 Load (MW)
Maine	2,275	2,400
New Hampshire	2,750	2,957
Vermont	1,138	1,205
Massachusetts	14,160	14,952
Rhode Island	2,098	2,208
Connecticut	8,112	8,486

A comparison of the load levels studied under previous NEEWS transmission planning studies was performed and is provided in graphic form in Figure 3-1. The original 2008 transmission planning studies identified needs in 2009, within cases that modeled a 90/10 summer peak load level of 29,910 MW for New England. This load level was based on the 2005 CELT report[11] and is depicted as the horizontal red line in Figure 3-1. The 2005 CELT report forecasted (blue bar) a 2015[12] load level of 32,405 MW and a 2020 load level of 34,230 MW.

Correspondingly the 2010 CELT report with a reduction of approximately 2-3% from the 2005 CELT peak load levels due to the economic downturn (orange bar) forecast a summer peak load level of

[11] http://www.iso-ne.com/trans/celt/report/2005/2005_celt_report.pdf

[12] Since the 2005 CELT only forecasts values up to the summer of 2014, 2015 and 2020 loads were found by taking the growth rate between 2013 and 2014 and applying that annually to get forecasted values out to 2020. The same method was used to find the 2020 load using the 2010 CELT forecast.

31,810 MW in 2015 and 33,560 MW for the end of its ten-year forecast period in 2020. As shown in Figure 3-1, the load levels studied in 2015 and 2020 are higher than the original 2008 NEEWS needs assessment load level of 29,910 MW.

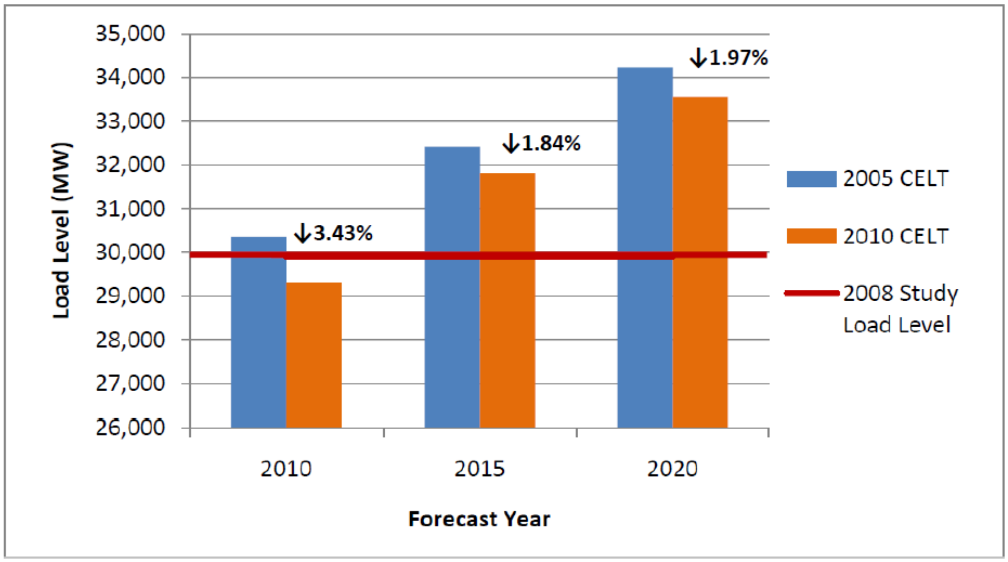

Figure 3-1: CELT 90/10 Load Forecast: 2005 & 2010 vs. 2008 Study Load Level

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 7-2 and Table 7-3.

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 and Generation Dispatches. The following external transfers were utilized for the study:

- N-1 Analysis
    - New York to New England (AC ties) – 0 MW export
    - Cross Sound Cable – 346 MW export to Long Island
    - Norwalk-Northport Cable – 100 MW export to Long Island
    - Highgate HVDC – 200 MW import to New England
    - Phase II HVDC – 2,000 MW import to New England
    - New Brunswick to New England – 0 MW import
        - Salem Harbor retirement scenario – 700 MW import

- N-1-1 Analysis
    - New York to New England (AC Ties) – 0 MW export
    - Cross Sound Cable – 0 MW export
    - Norwalk-Northport Cable – 0 MW export
    - Highgate HVDC – 200 MW import to New England
    - Phase II HVDC – 2,000 MW import to New England
    - New Brunswick to New England – 0 MW export
        - ➢ Salem Harbor retirement scenario – 700 MW import

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 updated needs assessment 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[13] generators that were qualified and new generators that cleared FCA-4. Figure 3-2 identifies resource additions by New England load zones in FCA 1-4. The figure shows that a significant amount of new resources (both new generation and demand response) have been added to the Connecticut load zone.

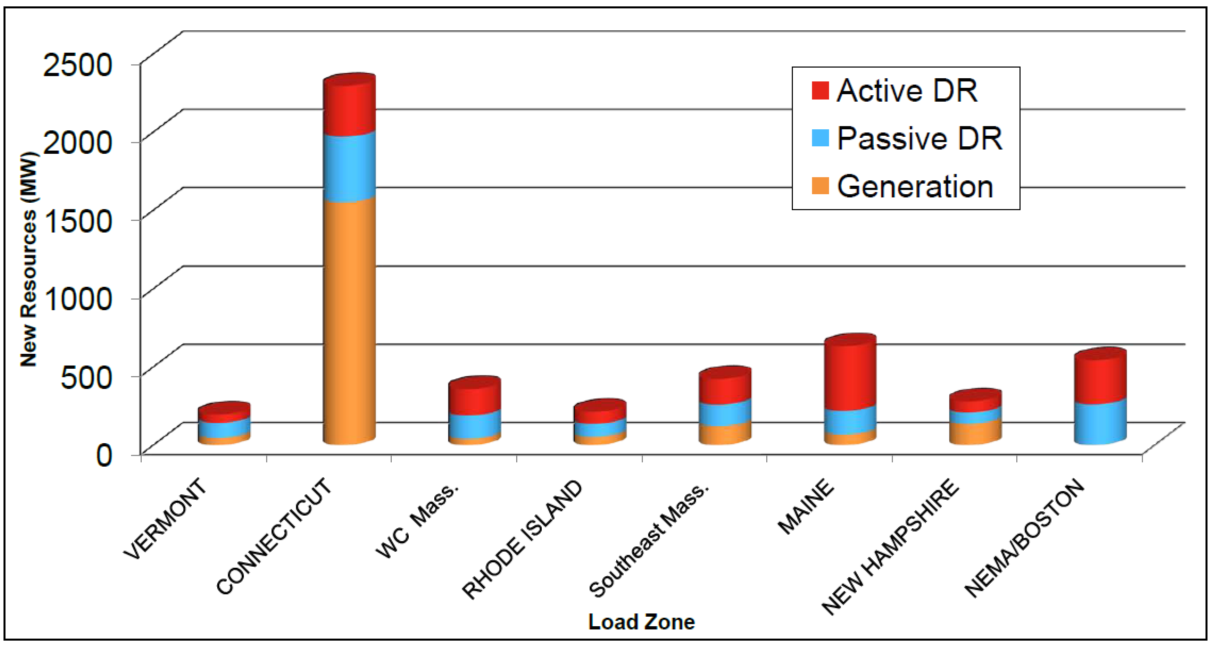

Figure 3-2: FCA 1-4 Resource Additions

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

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

detailed list of the dispatches for each sub-area stress is listed in the Sections 3.1.10.1 through 3.1.10.4.

Vermont Yankee is a 604 MW nuclear power generating station placed in service in 1972 located along the Connecticut River in Vernon, Vermont. There is significant uncertainty surrounding the continued operation of the plant after March 2012. 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.

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].

3.1.10.1 Eastern New England

[redacted]

[redacted] A summary table of resources for the eastern New England analysis is shown in Table 3-4.

Table 3-4
Eastern New England Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]		

3.1.10.2 Western New England and Connecticut

[redacted]

[redacted] A summary table of resources for the western New England analysis is shown in Table 3-5.

[redacted]

Table 3-5
Western New England and Connecticut Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]		

3.1.10.3 Rhode Island

[redacted]

[redacted]. A summary table of resources for the Rhode Island analysis is shown in Table 3-6.

Table 3-6
Rhode Island Reliability Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[redacted]		

3.1.10.4 Salem Harbor Retirement Scenario

[redacted]

[redacted] A summary table of resources for the eastern New England analysis is shown in Table 3-7.

Table 3-7
Salem Harbor Retirement Analysis Dispatch Assumptions

Resource	Capacity (MW)	Dispatch
[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. This included numerous new generation and demand resources from FCA-1 through 4 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 2010 FCA-4 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. 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. Many RTEGs are emissions restricted and cannot be counted as always being available. A summary of assumed DR performance is shown in Table 3-8.

Table 3-8
New England Demand Resource Performance Assumptions

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

Not applicable to this study.

3.2 Stability Model

3.2.1 Study Assumptions

For use in the extreme contingency analysis, the stability models were developed to be representative of the near term projection of a light load system demand level to assess the dynamic performance of the power system 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 are consistent with ISO PP-3.

The starting base case for the analysis was the 2013 light load case used in the original stability analysis conducted in support of the proposed plan application for NEEWS.

3.2.2 Load Levels Studied

The ISO light load stability model was used for this transient stability study. It includes a 2013 light load (45% of 50/50 peak load) New England load and losses representation of approximately 13,700 MW. The load flow case summary appears in Appendix B: Case Summaries and Generation Dispatches.

3.2.3 Load Models

The dynamic load models used when performing dynamic simulations for New England include 100% constant conductance for the real component and 100% constant susceptance for the imaginary component of the admittance.

3.2.4 Dynamic Models

The dynamic models are captured in the snapshot file from the ISO stability database. This snapshot file corresponds with the 2013 light load cases used in this analysis.

3.2.5 Transfer Levels

In this analysis, the southeast Massachusetts (SEMA) and SEMA/Rhode Island (SEMA/RI) exports were stressed. Power flows on other key interfaces are listed below. Further details on dispatches and transfers are provided in the power flow summary document in Appendix B: Case Summaries and Generation Dispatches.

Key interface transfer levels:

- 3300 MW export on SEMA/RI Export interface
- 3470 MW export on SEMA Export interface
- 2360 MW transfer on East - West interface
- 0 MW transfer on New York – New England interface
- 2500 MW import on Connecticut Import interface

3.2.6 Generation Dispatch Scenarios

The generation dispatch scenarios incorporate the common practice of turning on a significant amount of local area generation to stress the specific interface transfer levels. The objective of this dispatch was to represent a maximum unit commitment scenario to determine the deliverability of power resources across the region. Regional interface transfer levels are a function of generation dispatch scenarios. The transfer levels used in these analyses are contained in the case summary provided in Appendix B: Case Summaries and Generation Dispatches.

3.2.7 Reactive Resource and Dispatch

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. The base cases assume all reactive resources are available.

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-kilovolts 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-kilovolts 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

Transmission 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[14] 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[15]	[redacted]		
Pilgrim[15]	[redacted]		
Vermont Yankee[15]	[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

[14] Applies to non-Bulk Power System (BPS) designated substations. BPS stations must be > 0.95 post contingency.

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

4.2.2 Stability Performance Criteria

All stability testing was in accordance with Appendix C of the ISO Planning Procedure No. 3.

The criteria for normal contingencies are as follows:

- A loss of source is not acceptable.
- All generating units must remain transiently stable except for those units tripped as part of the fault clearing.

The criteria for extreme contingencies are as follows:

- A loss of source less than 1,400 MW is acceptable
- A loss of source between 1,400 MW and 2,200 MW may be acceptable depending upon the likelihood of occurrence.
- A loss of source above 2,200 MW is not acceptable.

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 Planning Procedure 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]					

4.3.3 Stability Contingencies / Faults Tested

Three-phase normally cleared faults (normal contingencies), single-line-to-ground faults with delayed clearing due to a circuit breaker failure (normal contingencies), and three-phase faults with delayed clearing (extreme contingencies) were tested. A summary of the stability contingencies tested is listed in Table 4-6.

Table 4-6
Summary of BPS, NC and EC Stability Contingencies

Fault #	ID	Fault Type	NERC CTG Cat	Stuck Breaker	Fault Description	Fault Clearing Time # cycles @ Substation
1	EC1	None	D	[redacted]		
2	EC2	None	D	[redacted]		
3	EC5	None	D	[redacted]		
4	EC6	3 Phase Bus	D	[redacted]		
5	NC8	Close in 3LG	C	[redacted]		
6	NC9	Close in 3LG	C	[redacted]		
7	NC10	Close in 3LG	C	[redacted]		

4.3.4 Short Circuit Faults Tested

Not applicable for this study.

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. Summaries of the N-1 and N-1-1 overloads and emerging issues are shown in Figure 5-1 and Figure 5-2 respectively. Detailed results from the analyses are in Appendix D: Contingency Results / Stability Plots.

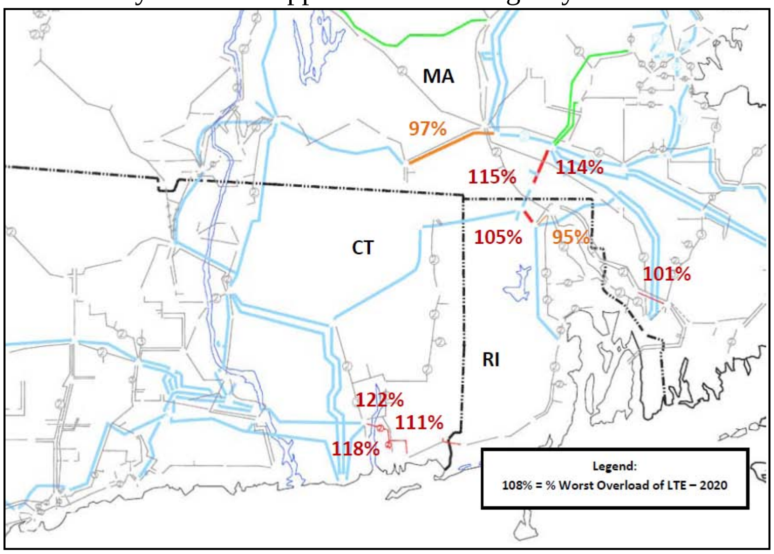

Figure 5-1: New England N-1 Thermal Overload Summary

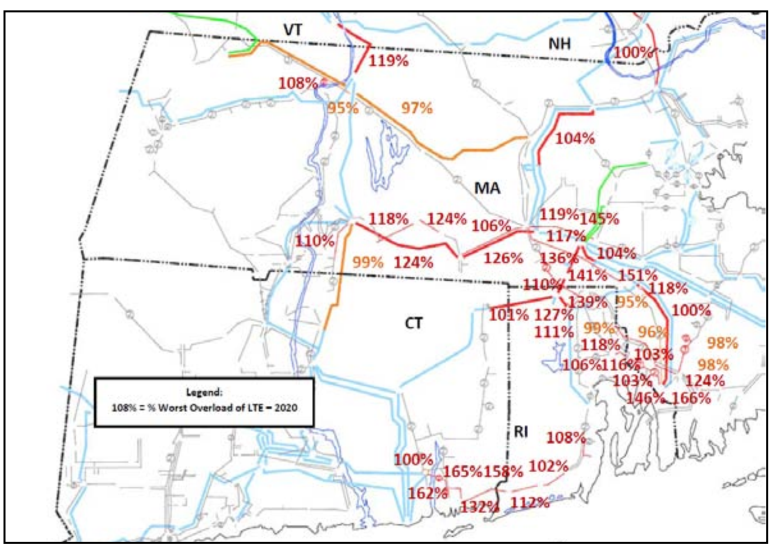

Figure 5-2: New England N-1-1 Thermal Overload Summary

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,[16] central/northeast Massachusetts, southeast Massachusetts, and Boston. The electrical tie-lines for this subarea are defined in Section 2.2. Figure 5-3 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. A summary of eastern New England overloads and emerging issues are shown in Figure 5-4.

[Figure redacted]

Figure 5-3: Eastern New England Reliability Study Area

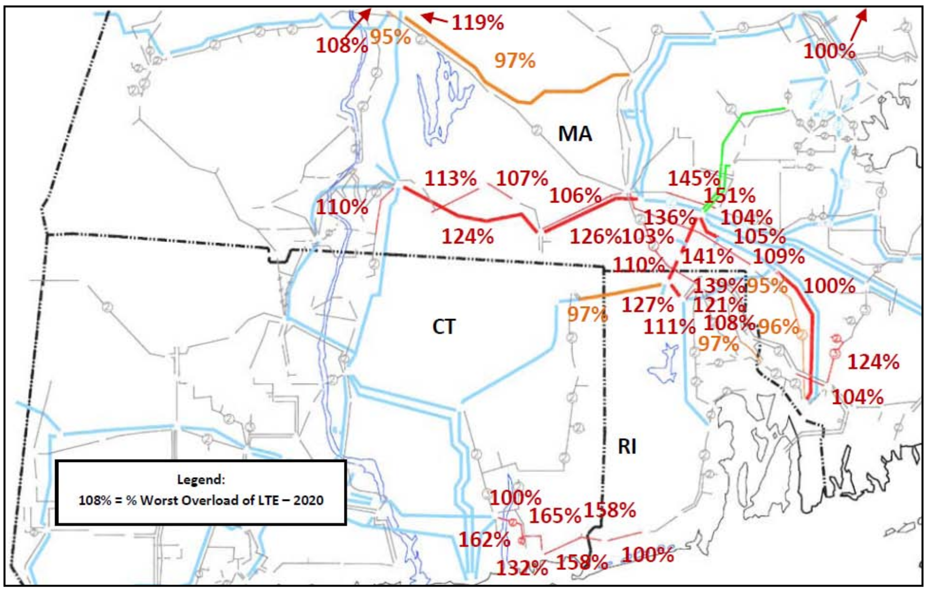

Figure 5-4: Eastern New England Thermal Overload Summary

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

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.[17] The electrical tie-lines for this subarea are defined in Section 2.2. Figure 5-5 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. A summary of western New England overloads and emerging issues are shown in Figure 5-6.

[Figure redacted]

Figure 5-5: Western New England Reliability Study Area

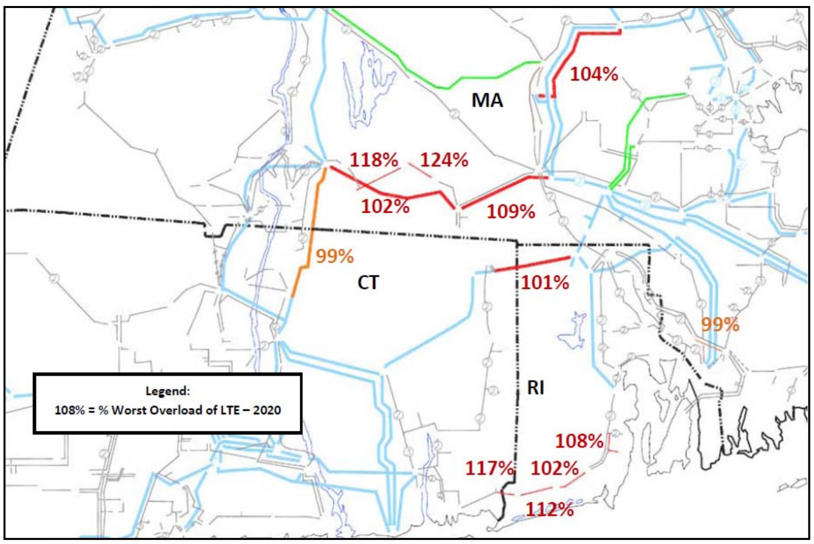

Figure 5-6: Western New England Thermal Overload Summary

[17] 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 5-7 is a geographic representation of the Rhode Island study area. A summary of Rhode Island overloads and emerging issues are shown in Figure 5-8.

[Figure redacted]

Figure 5-7: Rhode Island Reliability Study Area

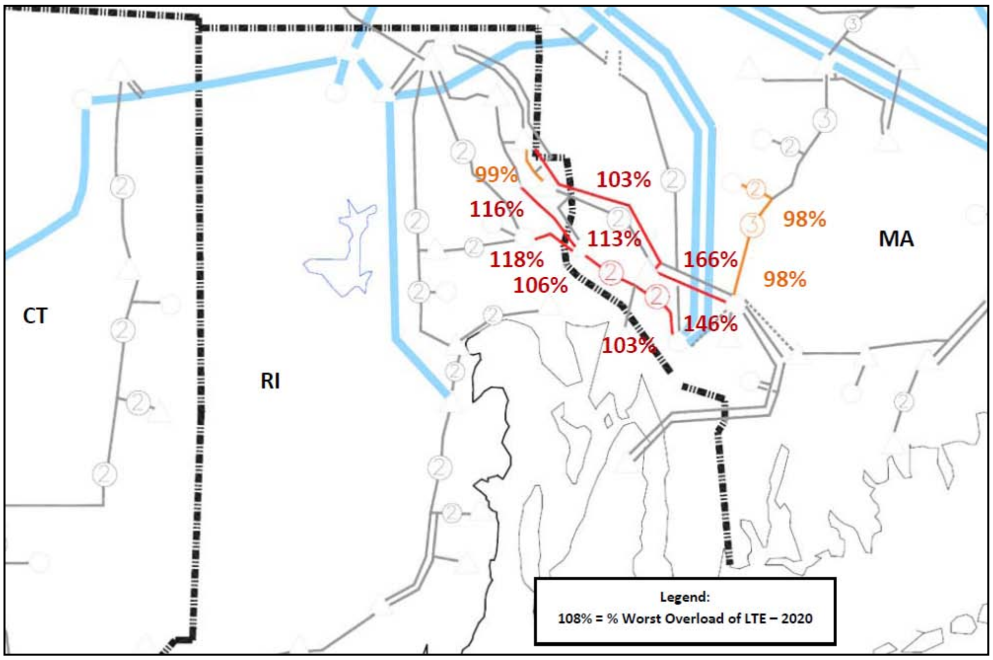

Figure 5-8: Rhode Island Thermal Overload Summary

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 5-9 is a geographic representation of the Connecticut study area. A summary of Connecticut overloads and emerging issues are shown in Figure 5-10.

[Figure redacted]

Figure 5-9: Connecticut Reliability Study Area

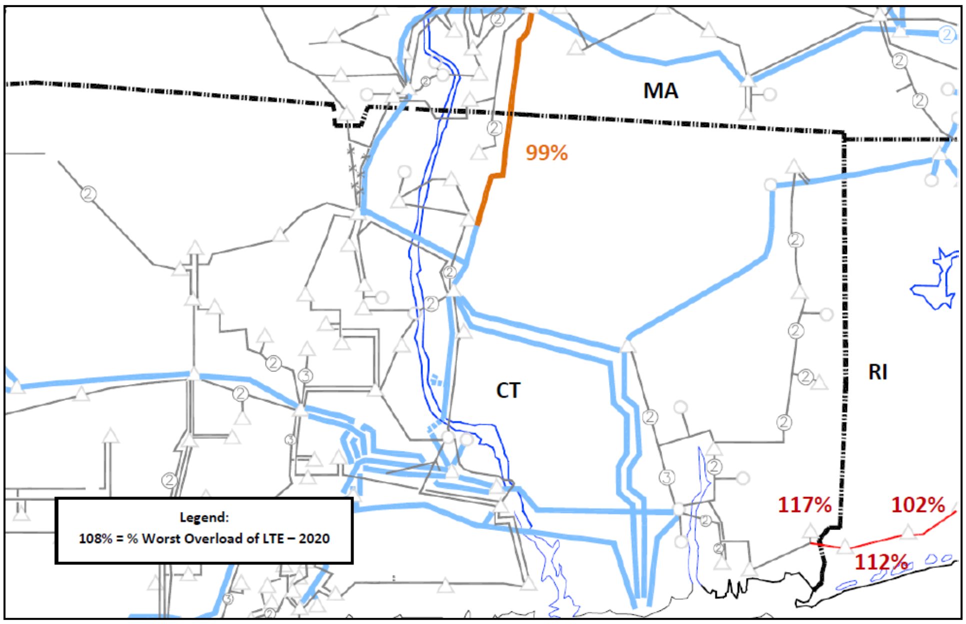

Figure 5-10: Connecticut Thermal Overload Summary

5.1.5 Salem Harbor Retirement Scenario

The results of the Salem Harbor retirement scenario with respect to eastern New England reliability and transmission transfer capability analyses indicate that there are violations of planning criteria under the assumptions and system conditions modeled within the 10 year planning horizon. With the Salem Harbor retirement, overloads compared to the west to east analysis showed an increase of 1% to 10% as shown in Sections 5.2.1.5, 5.2.2.5 and 5.2.3.5. If New Brunswick imports were replaced with generation in western New England, Greater Rhode Island or New York imports, these overloads would be even greater.

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.

5.2.1.2 Western New England

N-0 study indicated no thermal or voltage violations found.

5.2.1.3 Rhode Island

N-0 study indicated no thermal or voltage violations found.

5.2.1.4 Connecticut

N-0 study indicated no thermal or voltage violations found.

5.2.1.5 Salem Harbor Retirement

N-0 study indicated no thermal or voltage violations found.

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[18] following N-1 contingency events can be seen in Figure 5-11 and details found in Table 5-1.

[18] 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.

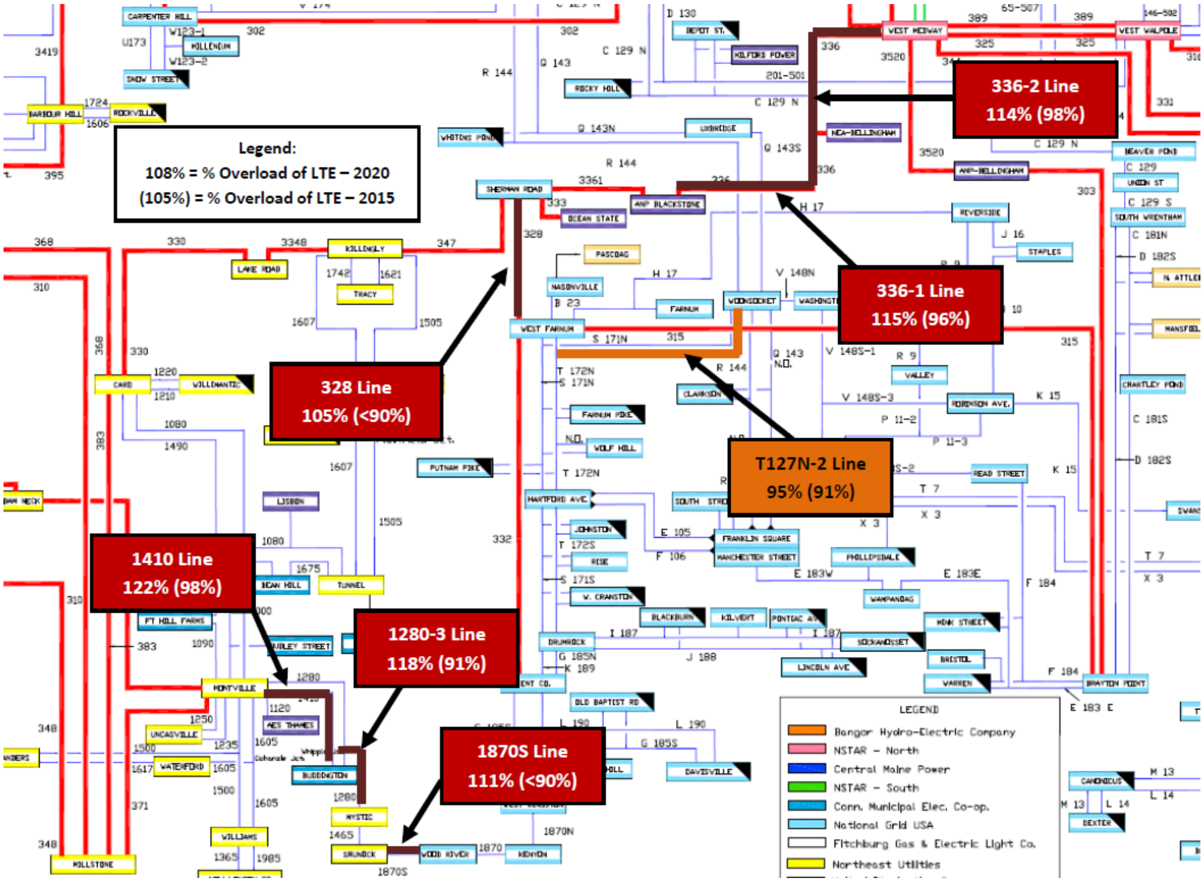

Figure 5-11: Eastern New England N-1 Thermal Violation Summary

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

Element ID	kV	Element Description	2015 Loading		2020 Loading	
			Worst Contingency	%LTE	Worst Contingency	%LTE
328	345	Sherman Rd. to W. Farnum	[redacted]	< 90	[redacted]	105
336-1	345	ANP Blackstone to NEA Bellingham Tap	[redacted]	96	[redacted]	115
336-2	345	West Medway to NEA Bellingham Tap	[redacted]	98	[redacted]	114
O215	230	N. Litchfield to Tewksbury	[redacted]	98	[redacted]	97
1280-3	115	Whipple Jct. to Mystic, CT	[redacted]	91	[redacted]	118
1410	115	Montville to Buddington	[redacted]	98	[redacted]	122
1870S	115	Wood River to Shunock	[redacted]	< 90	[redacted]	111
T172N-2	115	W. Farnum Tap to Woonsocket	[redacted]	91	[redacted]	95

N-1 study indicated no voltage violations found.

5.2.2.2 Western New England

N-1 testing was performed for all of the system condition models described in Section 3. The results of the N-1 contingency analysis can be seen in Figure 5-12 and details found in Table 5-2.

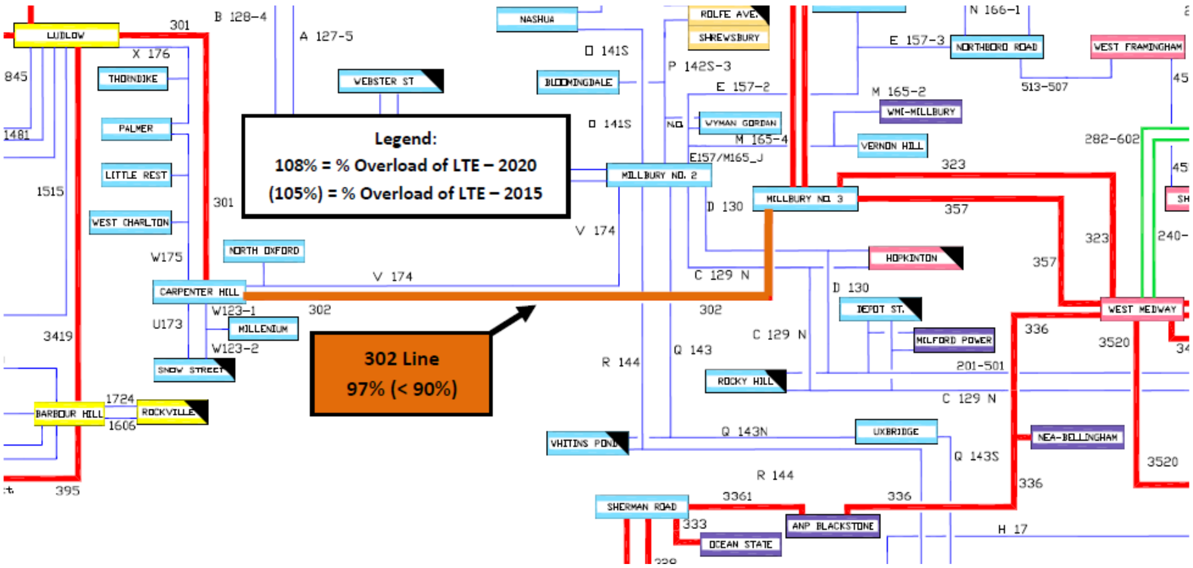

Figure 5-12: Western New England N-1 Thermal Violation Summary

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

Element ID	kV	Element Description	2015 Loading		2020 Loading	
			Worst Contingency	%LTE	Worst Contingency	%LTE
302	345	Millbury to Carpenter Hill	[redacted]	**< 90**	[redacted]	**97**

N-1 study indicated no voltage violations found.

5.2.2.3 Rhode Island

N-1 testing was performed for all of the system condition models described in Section 3. The results of the N-1 contingency analysis can be seen in Figure 5-13 and details found in Table 5-3.

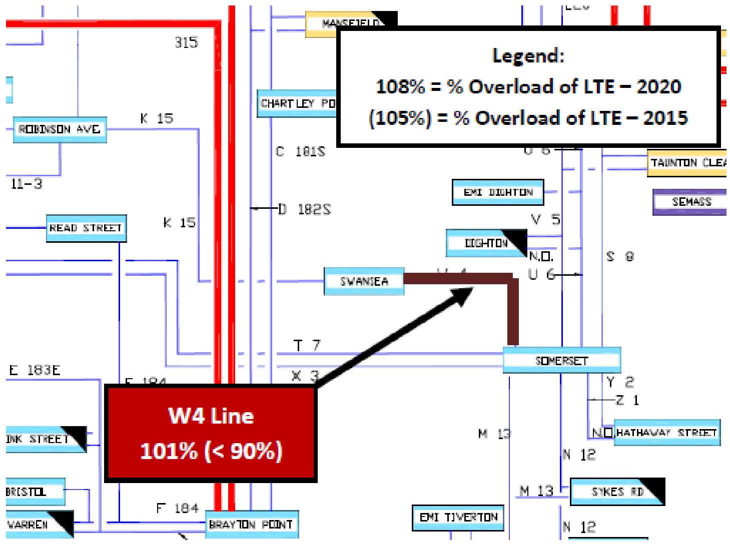

Figure 5-13: Rhode Island N-1 Thermal Violation Summary

Table 5-3
Rhode Island N-1 Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading		2020 Loading	
			Worst Contingency	%LTE	Worst Contingency	%LTE
W4	115	Somerset to Swansea	[redacted]	< 90	[redacted]	101

N-1 study indicated no voltage violations found.

5.2.2.4 Connecticut

N-1 study indicated no thermal or voltage violations found.

5.2.2.5 Salem Harbor Retirement

N-1 testing was performed for all of the system conditions described in Section 3. The results of the N-1 contingency analysis compared with the west to east N-1 analysis can be seen in Table 5-4.

Table 5-4
Salem Harbor Retirement N-1 Thermal Violation Summary

Element ID	kV	Element Description	Salem In-Service		Salem Out-of-Service	
			Worst Contingency	%LTE	Worst Contingency	%LTE
328	345	Sherman Rd. to W. Farnum	[redacted]			
336-1	345	ANP Blackstone to NEA Bellingham Tap	[redacted]			
336-2	345	West Medway to NEA Bellingham Tap	[redacted]			
O215	230	N. Litchfield to Tewksbury	[redacted]			
1280-3	115	Whipple Jct. to Mystic, CT	[redacted]			
1410	115	Montville to Buddington	[redacted]			
1465	115	Mysitc, CT to Shunock	[redacted]			
1870S	115	Wood River to Shunock	[redacted]			
T172N-2	115	W. Farnum Tap to Woonsocket	[redacted]			

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

Table 5-5
Salem Harbor Retirement N-1 Voltage Violation Summary

Substation	kV	Worst Contingency	Voltage (pu)
Seabrook	345	[redacted]	**0.994**
Shunock	115	[redacted]	**0.949**

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 involving 345 and 230-kilovolt transmission circuits can be seen in Figure 5-14 and details found in Table 5-6.

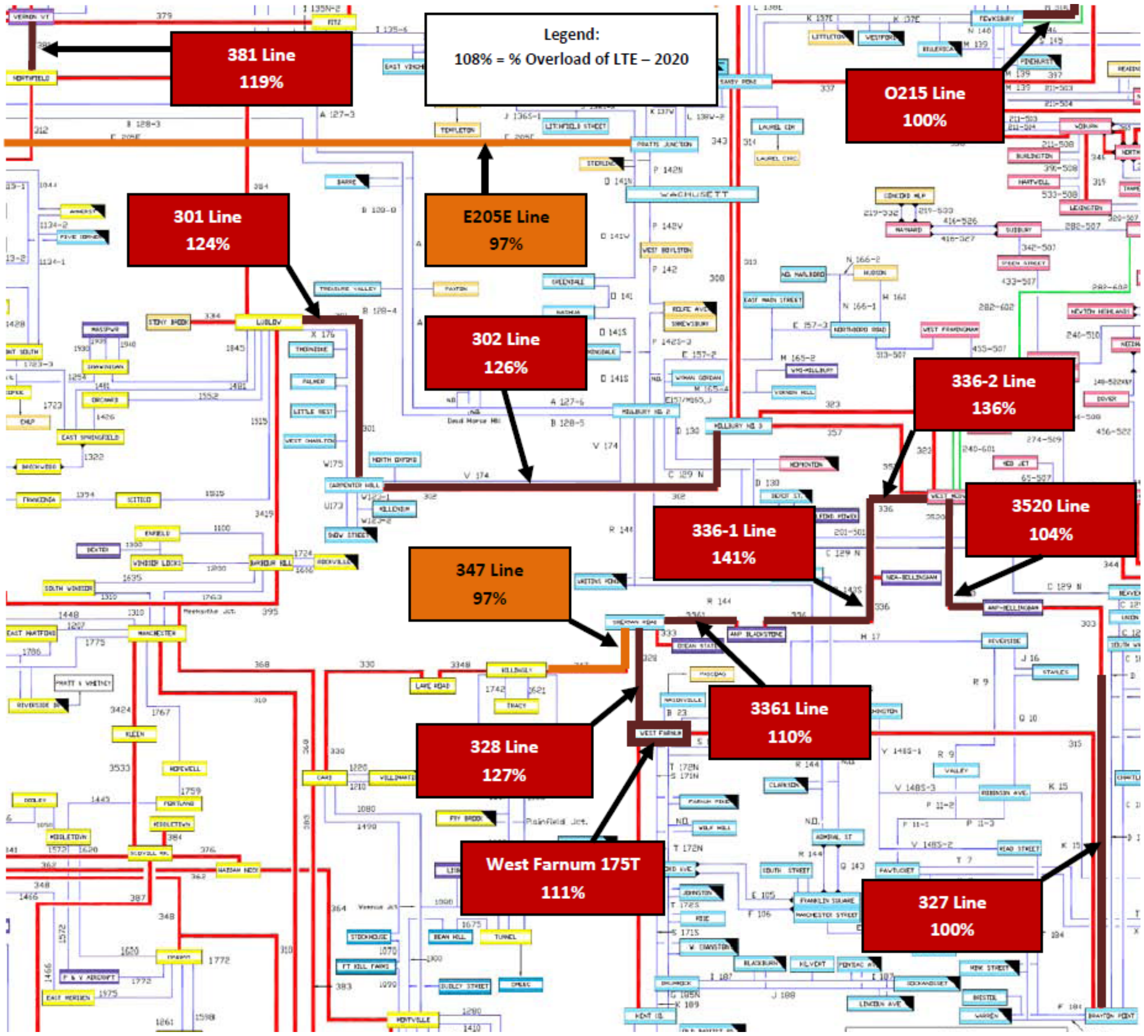

Figure 5-14: Eastern New England N-1-1 345 and 230 kV Thermal Violation Summary

Table 5-6
Eastern New England N-1-1 345 and 230 kV Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading L/O	2015 Loading Worst Contingency	2015 Loading %LTE	2020 Loading L/O	2020 Loading Worst Contingency	2020 Loading %LTE
301	345	Ludlow to Carpenter Hill	[redacted]		< 90	[redacted]		124
302	345	Carpenter Hill to Millbury	[redacted]		< 90	[redacted]		126
327	345	Brayton Pt. to Berry St.	[redacted]		< 90	[redacted]		100
328	345	Sherman Rd. to W. Farnum	[redacted]		110	[redacted]		127
336-1	345	NEA Bellingham Tap to ANP Blackstone	[redacted]		122	[redacted]		141
336-2	345	W. Medway to NEA Bellingham Tap	[redacted]		120	[redacted]		136
347	345	Sherman Rd. to Killingly	[redacted]		< 90	[redacted]		97
381	345	Northfield Mt. to Vernon	[redacted]		< 90	[redacted]		119
3361	345	ANP Blackstone to Sherman Rd.	[redacted]		< 90	[redacted]		110
3520	345	W. Medway to ANP Bellingham	[redacted]		100	[redacted]		104
E205E	230	Bear Swamp to Pratts Jct.	[redacted]		< 90	[redacted]		97
O215	230	N. Litchfield to Tewksbury	[redacted]		100	[redacted]		100
WF 175T		W. Farnum 345/115 kV Autotransformer	[redacted]		100	[redacted]		111

The results of the N-1-1 contingency analysis involving 115-kilovolt transmission circuits in western Massachusetts, New Hampshire, and Vermont can be seen in Figure 5-15 and details found in Table 5-7 and Connecticut, Rhode Island, and southeast Massachusetts in Figure 5-16 and Table 5-8.

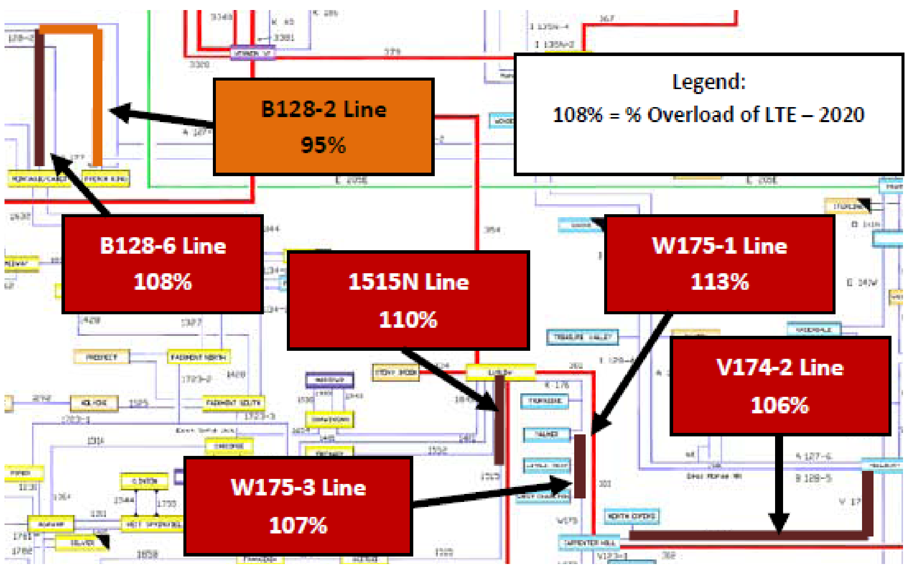

Figure 5-15: Eastern New England N-1-1 115 kV WMA, NH, and VT Thermal Violation Summary

Table 5-7
Eastern New England N-1-1 115 kV WMA, NH, and VT Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading			2020 Loading		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
1515N	115	Ludlow to W. Hampden	[redacted]		**< 90**	[redacted]		**110**
B128-2	115	Cabot Tap to French King	[redacted]		**< 90**	[redacted]		**95**
B128-6	115	Montague to Cabot Tap	[redacted]		**< 90**	[redacted]		**108**
V174-2	115	N. Oxford to Millbury	[redacted]		**< 90**	[redacted]		**106**
W175-1	115	Little Rest Rd. to Palmer	[redacted]		**< 90**	[redacted]		**113**
W175-3	115	Little Rest Rd. to W. Charlton	[redacted]		**< 90**	[redacted]		**107**

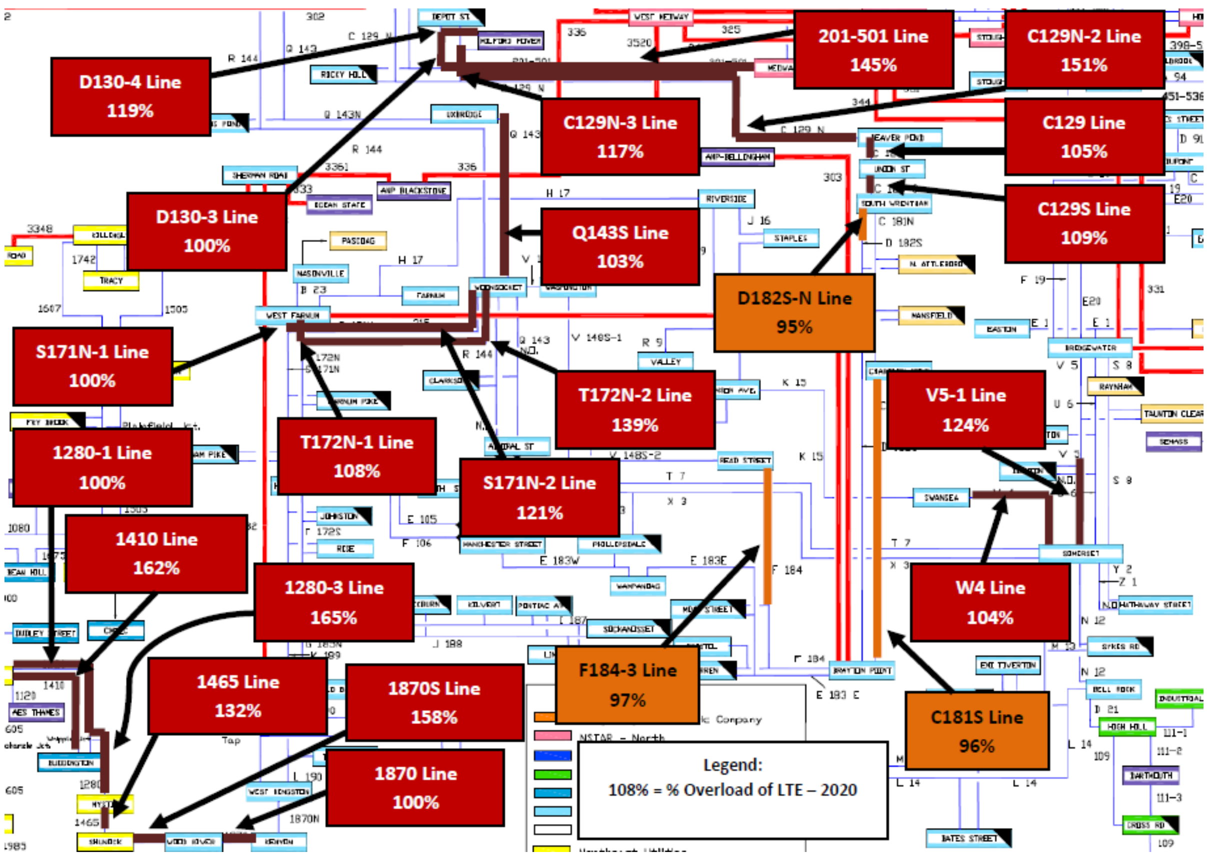

Figure 5-16: Eastern New England N-1-1 115 kV CT, RI, and SEMA Thermal Violation Summary

Table 5-8
Eastern New England N-1-1 115 kV CT, RI, and SEMA Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading L/O	2015 Loading Worst Contingency	2015 Loading %LTE	2020 Loading L/O	2020 Loading Worst Contingency	2020 Loading %LTE
1280-1	115	Montville to Whipple Jct.	[redacted]		**< 90**	[redacted]		**100**
1280-3	115	Whipple Jct. to Mystic, CT	[redacted]		**119**	[redacted]		**165**
1410	115	Montville to Buddington	[redacted]		**121**	[redacted]		**162**
1465	115	Mystic, CT to Shunock	[redacted]		**96**	[redacted]		**132**
1870	115	Kenyon to Wood River	[redacted]		**< 90**	[redacted]		**100**
1870S	115	Wood River to Shunock	[redacted]		**114**	[redacted]		**158**
201-501	115	Medway to Depot St. Tap	[redacted]		**134**	[redacted]		**145**
C129	115	Beaver Pond to Union St.	[redacted]		**103**	[redacted]		**105**
C129N-2	115	Depot St. Tap to Beaver Pond	[redacted]		**152**	[redacted]		**151**
C129N-3	115	Depot St. Tap to Milford Power Tap	[redacted]		**111**	[redacted]		**117**
C129S	115	Union St. to S. Wrentham	[redacted]		**107**	[redacted]		**109**
C181S	115	Brayton Pt. to Chartley Pond	[redacted]		**< 90**	[redacted]		**96**
D130-3	115	Depot St. Tap to Milford Power Tap	[redacted]		**98**	[redacted]		**100**
D130-4	115	Milford Power to Milford Power Tap	[redacted]		**116**	[redacted]		**119**
D182S-N	115	S. Wrentham to Berry St.	[redacted]		**< 90**	[redacted]		**95**
F184-3	115	Mink St. to Read St.	[redacted]		**< 90**	[redacted]		**97**
Q143S	115	Uxbridge to Woonsocket	[redacted]		**100**	[redacted]		**103**
S171N-1	115	W. Farnum to W. Farnum Tap	[redacted]		**< 90**	[redacted]		**100**
S171N-2	115	W. Farnum Tap to Woonsocket	[redacted]		**114**	[redacted]		**121**
T172N-1	115	W. Farnum to W. Farnum Tap	[redacted]		**97**	[redacted]		**108**
T172N-2	115	W. Farnum Tap to Woonsocket	[redacted]		**130**	[redacted]		**139**
V5-1	115	Somerset to Dighton	[redacted]		**116**	[redacted]		**124**
W4	115	Somerset to Swansea	[redacted]		**97**	[redacted]		**104**

The results of voltage violations following N-1-1 contingency events can be found in Table 5-9.

Table 5-9
Eastern New England N-1-1 Voltage Violation Summary

Substation	kV	2015 Loading L/O	2015 Loading Worst Contingency	2015 Loading Voltage (pu)	2020 Loading L/O	2020 Loading Worst Contingency	2020 Loading Voltage (pu)
N. Bloomfield	345	[redacted]		**1.053**	[redacted]		**< 1.05**
VT Yankee	345	[redacted]		**0.945**	[redacted]		**0.932**
French King	115	[redacted]		**> 0.95**	[redacted]		**0.938**
Mystic CT	115	[redacted]		**> 0.95**	[redacted]		**0.886**
Podick	115	[redacted]		**> 0.95**	[redacted]		**0.946**
Shunock	115	[redacted]		**> 0.95**	[redacted]		**0.858**
VT Yankee	115	[redacted]		**0.954**	[redacted]		**0.947**

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 involving 345-kilovolt transmission circuits can be seen in Figure 5-17 and details found in Table 5-10.

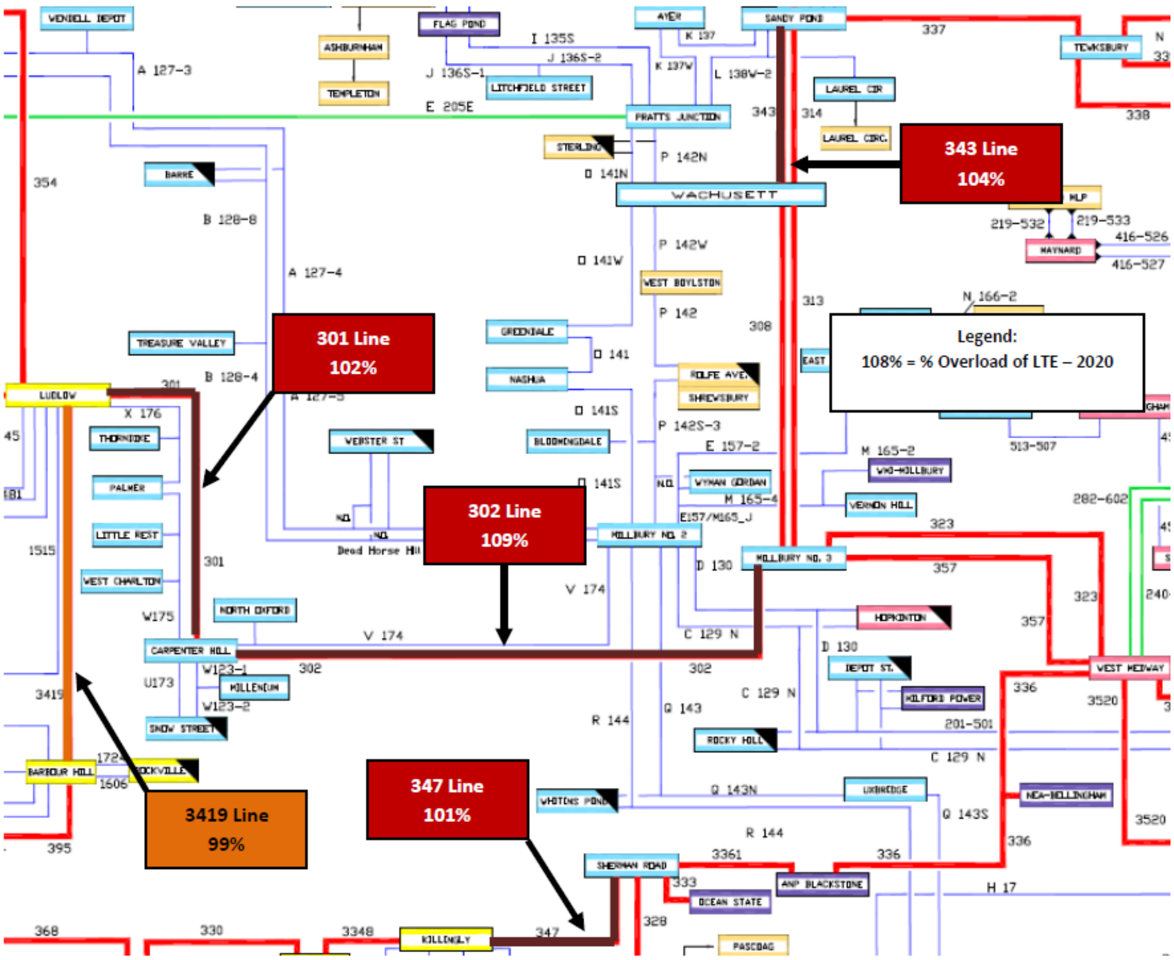

Figure 5-17: Western New England N-1-1 345 kV Thermal Violation Summary

Table 5-10
Western New England N-1-1 345 kV Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading			2020 Loading		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
301	345	Carpenter Hill to Ludlow	[redacted]	[redacted]	< 90	[redacted]	[redacted]	102
302	345	Millbury to Carpenter Hill	[redacted]	[redacted]	< 90	[redacted]	[redacted]	109
343	345	Wachusett to Sandy Pond	[redacted]	[redacted]	< 90	[redacted]	[redacted]	104
347	345	Sherman Rd. to Killingly	[redacted]	[redacted]	< 90	[redacted]	[redacted]	101
3419	345	Ludlow to Barbour Hill	[redacted]	[redacted]	< 90	[redacted]	[redacted]	99

The results of contingency event analyses involving 115-kilovolt transmission circuits are seen in Figure 5-18 and Figure 5-19 and details found in Table 5-11.

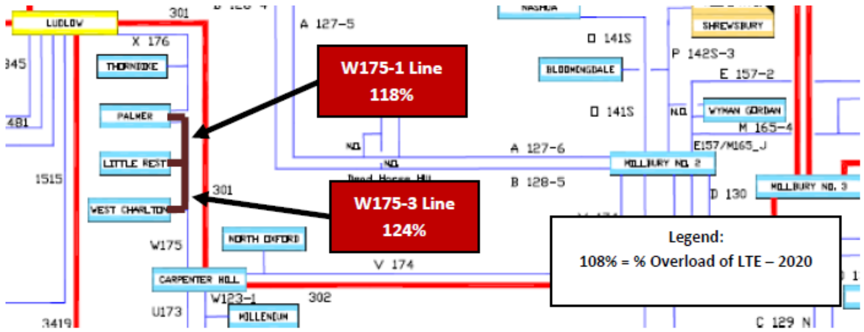

Figure 5-18: Western New England N-1-1 Northern 115 kV Thermal Violation Summary

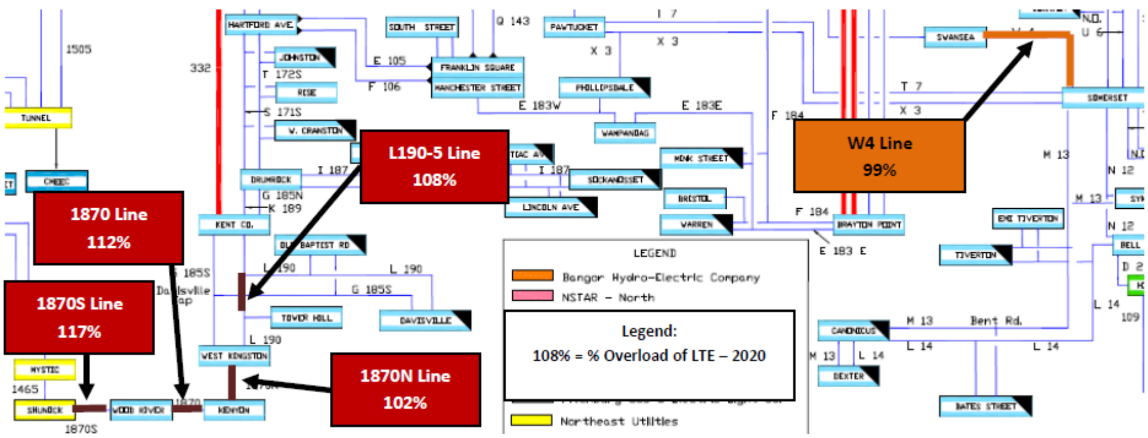

Figure 5-19: Western New England N-1-1 Southern 115 kV Thermal Violation Summary

Table 5-11
Western New England N-1-1 115 kV Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading			2020 Loading		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
1870	115	Wood River to Kenyon	[redacted]		96	[redacted]		112
1870N	115	Kenyon to W. Kingston	[redacted]		< 90	[redacted]		102
1870S	115	Wood River to Shunock	[redacted]		99	[redacted]		117
L190-5	115	Tower Hill to Davisville Tap	[redacted]		95	[redacted]		108
W4	115	Somerset to Swansea	[redacted]		< 90	[redacted]		99
W175-1	115	Little Rest Rd. to Palmer	[redacted]		102	[redacted]		118
W175-3	115	W. Charlton to Little Rest Rd.	[redacted]		107	[redacted]		124

The results of voltage violations following N-1-1 contingency events can be found in Table 5-12.

Table 5-12
Western New England N-1-1 Voltage Violation Summary

Substation	kV	2015 Loading			2020 Loading		
		L/O	Worst Contingency	Voltage (pu)	L/O	Worst Contingency	Voltage (pu)
Agawam	345	[redacted]		0.950	[redacted]		0.944
Millstone	345	[redacted]		> 1.00	[redacted]		0.991
Shunock	115	[redacted]		> 0.95	[redacted]		0.947
VT Yankee	115	[redacted]		> 0.99	[redacted]		0.975

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 are seen in Figure 5-20 and details are found in Table 5-13.

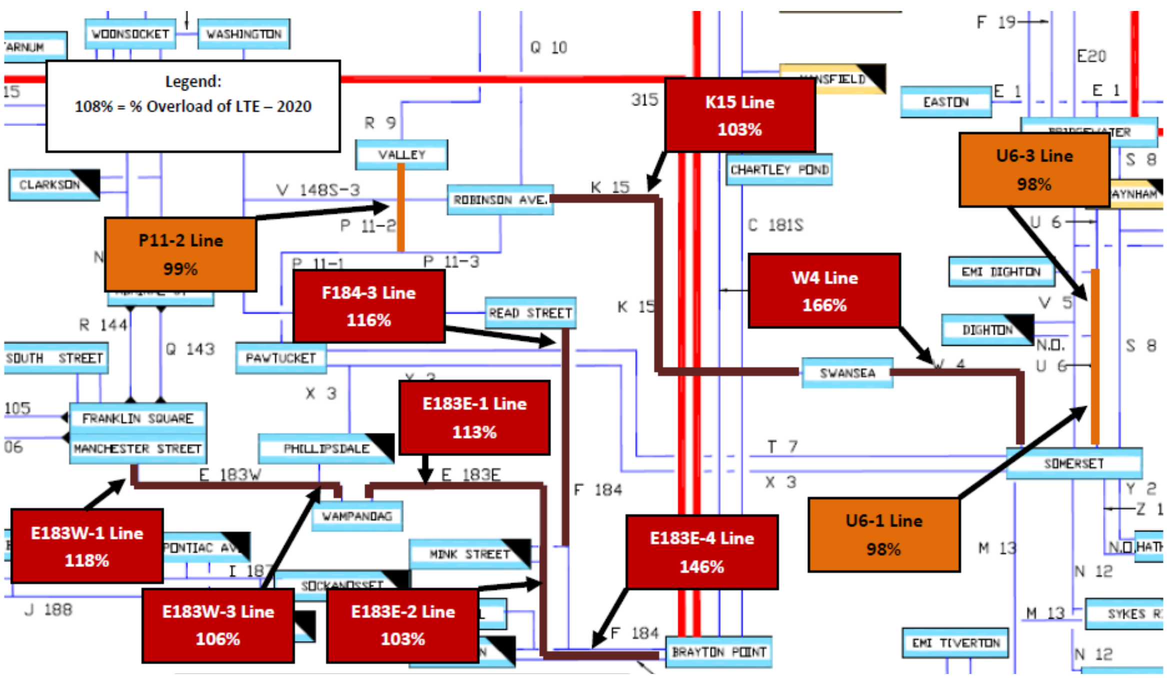

Figure 5-20: Rhode Island N-1-1 Thermal Violation Summary

Table 5-13
Rhode Island N-1-1 Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading			2020 Loading		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
E183E-1	115	Mink St. to Wampanoag	[redacted]		105	[redacted]		113
E183E-2	115	Merriman Jct. to Mink St.	[redacted]		96	[redacted]		103
E183E-4	115	Brayton Pt. to Merriman Jct.	[redacted]		134	[redacted]		146
E183W-1	115	Franklin Square to Phillipsdale Tap	[redacted]		109	[redacted]		118
E183W-3	115	Wampanoag to Phillipsdale Tap	[redacted]		98	[redacted]		106
F184-3	115	Mink St. to Read St.	[redacted]		110	[redacted]		116
K15	115	Swansea to Robinson Ave.	[redacted]		91	[redacted]		103
P11-2	115	Valley, RI to P11 Tap	[redacted]		91	[redacted]		99
U6-1	115	Somerset to Dighton	[redacted]		< 90	[redacted]		98
U6-3	115	Dighton to Dighton Tap	[redacted]		< 90	[redacted]		98
W4	115	Somerset to Swansea	[redacted]		148	[redacted]		166

[redacted]

Table 5-14
Rhode Island N-1-1 Thermal Violation Summary Excluding Breaker Failures

Element ID	kV	Element Description	2015 Loading			2020 Loading		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
E183E-1	115	Mink St. to Wampanoag	[redacted]		104	[redacted]		113
E183E-2	115	Merriman Jct. to Mink St.	[redacted]		95	[redacted]		103
E183E-4	115	Brayton Pt. to Merriman Jct.	[redacted]		133	[redacted]		145
E183W-1	115	Franklin Square to Phillipsdale Tap	[redacted]		108	[redacted]		117
E183W-3	115	Wampanoag to Phillipsdale Tap	[redacted]		98	[redacted]		106

N-1-1 study indicated no voltage violations found.

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 seen in Figure 5-21 and details found in Table 5-15.

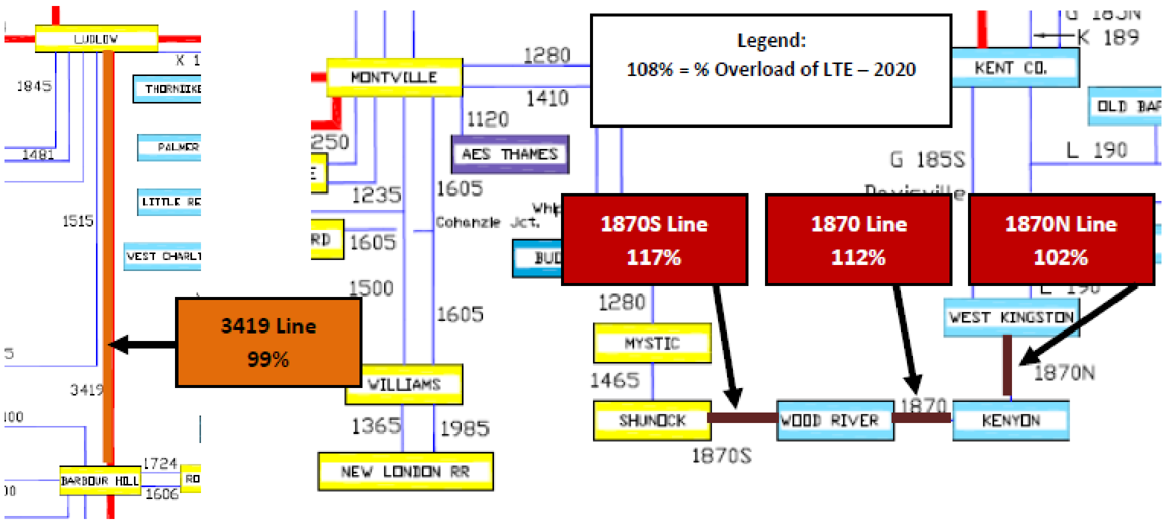

Figure 5-21: Connecticut N-1-1 Thermal Violation Summary

Table 5-15
Connecticut N-1-1 Thermal Violation Summary

Element ID	kV	Element Description	2015 Loading			2020 Loading		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
3419	345	Ludlow to Barbour Hill	[redacted]		**< 90**	[redacted]		**99**
1870	115	Wood River to Kenyon	[redacted]		**< 90**	[redacted]		**112**
1870N	115	Kenyon to W. Kingston	[redacted]		**< 90**	[redacted]		**102**
1870S	115	Wood River to Shunock	[redacted]		**< 90**	[redacted]		**117**

The results of voltage violations following N-1-1 contingency events can be found in Table 5-16.

Table 5-16
Connecticut N-1-1 Voltage Violation Summary

Substation	kV	2015 Loading			2020 Loading		
		L/O	Worst Contingency	Voltage (pu)	L/O	Worst Contingency	Voltage (pu)
Agawam	345	[redacted]		**0.950**	[redacted]		**0.944**
Millstone	345	[redacted]		**> 1.00**	[redacted]		**0.991**
Shunock	115	[redacted]		**> 0.95**	[redacted]		**0.947**

5.2.3.5 Salem Harbor Retirement

N-1-1 testing was performed for all of the system conditions described in Section 3. The results following N-1-1 contingency events compared with the west to east N-1-1 analysis from Table 5-6 through Table 5-8 can be seen in Table 5-17 through Table 5-19.

Table 5-17
Salem Harbor Retirement N-1-1 345 and 230 kV Thermal Violation Summary

Element ID	kV	Element Description	Salem In-Service L/O	Salem In-Service Worst Contingency	Salem In-Service %LTE	Salem Out-of-Service L/O	Salem Out-of-Service Worst Contingency	Salem Out-of-Service %LTE
301	345	Ludlow to Carpenter Hill	[redacted]					
302	345	Carpenter Hill to Millbury	[redacted]					
327	345	Brayton Pt. to Berry St.	[redacted]					
328	345	Sherman Rd. to W. Farnum	[redacted]					
336-1	345	NEA Bellingham Tap to ANP Blackstone	[redacted]					
336-2	345	W. Medway to NEA Bellingham Tap	[redacted]					
347	345	Sherman Rd. to Killingly	[redacted]					
368	345	Card Street to Manchester	[redacted]					
381	345	Northfield Mt. to Vernon	[redacted]					
3361	345	ANP Blackstone to Sherman Rd.	[redacted]					
3520	345	W. Medway to ANP Bellingham	[redacted]					
E205E	230	Bear Swamp to Pratts Jct.	[redacted]					
O215	230	N. Litchfield to Tewksbury	[redacted]					
WF 175T		W. Farnum 345/115 kV Autotransformer	[redacted]					
BP 5X		Brayton Pt. 345/115 kV Autotransformer	[redacted]					

Table 5-18
Salem Harbor Retirement N-1-1 115 kV WMA, NH, & VT Thermal Violation Summary

Element ID	kV	Element Description	Salem In-Service L/O	Salem In-Service Worst Contingency	Salem In-Service %LTE	Salem Out-of-Service L/O	Salem Out-of-Service Worst Contingency	Salem Out-of-Service %LTE
1515N	115	Ludlow to W. Hampden	[redacted]					
B128-2	115	Cabot Tap to French King	[redacted]					
B128-3	115	Barre, MA to French King	[redacted]					
B128-6	115	Montague to Cabot Tap	[redacted]					
V174-2	115	N. Oxford to Millbury	[redacted]					
W175-1	115	Little Rest Rd. to Palmer	[redacted]					
W175-3	115	Little Rest Rd. to W. Charlton	[redacted]					

Table 5-19
Salem Harbor Retirement N-1-1 115 kV CT, RI, and SEMA Thermal Violation Summary

Element ID	kV	Element Description	Salem In-Service			Salem Out-of-Service		
			L/O	Worst Contingency	%LTE	L/O	Worst Contingency	%LTE
1280-1	115	Montville to Whipple Jct.	[redacted]					
1280-3	115	Whipple Jct. to Mystic, CT	[redacted]					
1410	115	Montville to Buddington	[redacted]					
1465	115	Mystic, CT to Shunock	[redacted]					
1870	115	Kenyon to Wood River	[redacted]					
1870S	115	Wood River to Shunock	[redacted]					
201-501	115	Medway to Depot St. Tap	[redacted]					
C129	115	Beaver Pond to Union St.	[redacted]					
C129N-2	115	Depot St. Tap to Beaver Pond	[redacted]					
C129N-3	115	Depot St. Tap to Milford Power Tap	[redacted]					
C129S	115	Union St. to S. Wrentham	[redacted]					
C181S	115	Brayton Pt. to Chartley Pond	[redacted]					
D130-3	115	Depot St. Tap to Milford Power Tap	[redacted]					
D130-4	115	Milford Power to Milford Power Tap	[redacted]					
D182S-N	115	S. Wrentham to Berry St.	[redacted]					
F184-3	115	Mink St. to Read St.	[redacted]					
H17-2	115	Riverside to Farnum Tap	[redacted]					
Q143S	115	Uxbridge to Woonsocket	[redacted]					
S171N-1	115	W. Farnum to W. Farnum Tap	[redacted]					
S171N-2	115	W. Farnum Tap to Woonsocket	[redacted]					
T172N-1	115	W. Farnum to W. Farnum Tap	[redacted]					
T172N-2	115	W. Farnum Tap to Woonsocket	[redacted]					
V5-1	115	Somerset to Dighton	[redacted]					
W4	115	Somerset to Swansea	[redacted]					

The results of voltage violations following N-1-1 contingency events compared with the west to east N-1-1 violations in Table 5-9 can be found in Table 5-20.

Table 5-20
Salem Harbor Retirement N-1-1 Voltage Violation Summary

Substation	kV	Salem In-Service			Salem Out-of-Service		
		L/O	Worst Contingency	Voltage (pu)	L/O	Worst Contingency	Voltage (pu)
Seabrook	345	[redacted]					
VT Yankee	345	[redacted]					
Pratts Jct.	230	[redacted]					
Amherst 1044[19]	115	[redacted]					
French King	115	[redacted]					
Mystic CT	115	[redacted]					
Podick[19]	115	[redacted]					
Shunock	115	[redacted]					
VT Yankee	115	[redacted]					

5.2.4 Results of Extreme Contingency Testing

5.2.4.1 Study Description

From previous New England area studies,[20] an extreme contingency of concern within the study region [redacted]. An updated analysis was performed in order to determine whether the loss of the [redacted] would result in a significant steady state problem possibly leading to cascading outages. The 2015 90/10 peak load case was used for the analysis. The Greater Springfield Reliability Project and the Rhode Island Reliability Project were assumed in service in the base case. Analysis performed many years ago indicated that this steady state problem could exist under conditions where there was power flowing into SEMA and heavy power flow into the Boston area. Therefore a base case was created with the following approximate interfaces:

- Boston import 4500 MW
- SEMA import 200 MW
- New England East to West 300 MW
- SEMA/RI Export of 2000 MW

Loss of the [redacted] was then simulated. The resulting flows on all circuits 115-kilovolts and above in New England were monitored as a result of this extreme contingency.

[19] Low voltages at the Amherst-1044 and Podick substations have been identified as criteria violations in the Pittsfield/Greenfield Area Transmission Assessment. A proposed solution for this area has been identified including the addition of reactive devices at these two substations.

[20] "*2004 Comprehensive Area Transmission Review of the New England Bulk Power Transmission System,*" dated September 9, 2005, pg.8.
https://www.iso-ne.com/trans/sys_studies/rsp_stud/region/2004_area_review_report_(rcc_final)_sep905.pdf

5.2.4.2 Study Results

While some power flows were above 100% of the long time emergency ratings, these are mostly local known problems or issues already seen in N-1 and N-1-1 testing.

The extreme contingency, [redacted], does not appear to be a concern for the conditions previously thought (high Boston import and SEMA import). This can be attributed to the recent projects, most notably the Stoughton cables, in the Boston area that have lessened the impact of this extreme contingency.

5.2.5 Results of Delta P Testing

5.2.5.1 Study Description

This section documents delta P analysis performed to investigate the torsional impact on the [redacted] generating machines' shafts.

The analysis was performed with all facilities in for three different Connecticut import levels: 2500 MW, 2900 MW & 3600 MW, with the New England East – West transfer levels maintained at 2630 MW, 3035 MW, and 3457 MW, respectively. The New York – New England interface was modeled at 0 MW transfer in this analysis. Further, the impact of reclosing of relevant lines on the [redacted] machine shaft was tested when [redacted]. Three contingencies were tested for all cases tested in this analysis. These contingencies are listed below.

- [redacted]
- [redacted]
- [redacted]

5.2.5.2 Study Results

Results of the analysis illustrate that even at a Connecticut import level of 1700 MW, the delta P as a per unit of machine MVA on [redacted]. Details of the results at the 1700 MW Connecticut import level can be seen in Table 5-21.

Table 5-21
Delta P Analysis Results post GSRP & RIRP

[Table redacted]

5.2.6 Results of Transfer Analysis

5.2.6.1 Study Description

To determine whether the import region meets the requirements of ISO Planning Procedure 3, Section 4, a simplified table called a Transmission Security Analysis (TSA) spreadsheet can be developed and used. This spreadsheet sums up the total resources available to an area (local generation plus demand response minus generation outages) and then subtracts the resource requirement of that area (area load minus imports). If there is a surplus (positive value) afterwards, then the import region has sufficient resources in a given year. If there is a deficit (negative value) afterwards, then the import region has insufficient resources in a given year.

To create a TSA sheet the import limit needs to be established for the region. Once the import limit is determined, the region can be evaluated as to when it will become resource deficient.

To determine a transfer limit, the Siemens PTI program Managing and Utilizing System Transmission (MUST) was used to increase transfers in the network model until a transmission element becomes overloaded in the base case or after a contingency event. To increase transfer levels in a case, a set of generators in the sending region of the transfer (the “source”) are increased and at the same time a set of generators in the receiving region of the transfer (the “sink”) are decreased. Testing was performed under all-lines-in and line out conditions. The transfer level at which an element becomes overloaded is determined to be the transfer limit. Since transfer limits can be dependent upon unique set of conditions for any given hour, a conservative and an optimistic transfer limit is established to create a transfer range. Detailed results from the transfer analysis can be seen in Appendix D: Contingency Results / Stability Plots.

5.2.6.2 Eastern New England Import Interface

In evaluating the ability to transfer power from western New England to eastern New England, transfer limits were determined from a set of sink/source pairs during transfer analysis. For the generation sink, generating units in eastern New England were chosen (Canal, Newington, Pilgrim, Salem, Seabrook and Yarmouth Stations). The generation source was made up of generating units in western New England and eastern New York (Altresco, Bear Swamp, Gilboa (NY), Ginna (NY), Mass Power, Millstone, Mount Tom, Northfield, and Waterbury Stations). To create two different sinks, one had Mystic Station OOS and the other sink had Phase II HVDC OOS as a base case condition. Lake Road was also tested In-Service and OOS since that station has a significant effect on west to east transfers.

The following element/contingency pairs were ignored in the transfer analysis due to local issues that will be addressed in on-going/future studies.

Table 5-22
Eastern New England Ignored Limiting Transfer Elements

Element ID	kV	Element Description	Contingency	L/O	Issue	ENE Import Level (MW)
D130-4	115	Milford Power to Milford Tap	[redacted]			876 (N-1-1)
WM 345B		W. Medway 345/230 kV Autotransformer	[redacted]			1111 (N-1-1)
D130-4	115	Milford Power to Milford Tap	[redacted]			1240 (N-1-1)

Table 5-23
Eastern New England N-1 Transfer Limits

Element ID	kV	Element Description	Contingency	Source	Lake Road	ENE Import Level (MW)
1410	115	Montville to Buddington	[redacted]			2733
			[redacted]			2610
			[redacted]			2693
			[redacted]			2693
336-2	345	W. Medway to NEA Bellingham Tap	[redacted]			3556
			[redacted]			3014
			[redacted]			3082
			[redacted]			3082

From the results shown in Table 5-23, the N-1 eastern New England import limit range is 2600-2700 MW based on the most limiting element contingency pair.

Table 5-24
Eastern New England N-1-1 Transfer Limits

Element ID	kV	Element Description	Contingency	L/O	Source	Lake Road	ENE Import Level (MW)
1410	115	Montville to Buddington	[redacted]				1285
			[redacted]				1263
T172-2	115	W. Farnum Tap to Woonsocket	[redacted]				1363
			[redacted]				1363
D130-4	115	Milford Power to Milford Tap	[redacted]				1618
			[redacted]				1519
1410	115	Montville to Buddington	[redacted]				1758
			[redacted]				1758
336-2	345	W. Medway to NEA Bellingham Tap	[redacted]				1785
			[redacted]				1615
			[redacted]				2082
			[redacted]				2082

From the results shown in Table 5-24, the N-1-1 eastern New England import limit range is 1250-1350 MW based on the most limiting element contingency pairs.

5.2.6.3 Western New England Import Interface

In evaluating the ability to transfer power from eastern New England to western New England, transfer limits were determined from two sets of sources and two sets of sinks during transfer analysis. For the sinks, units in Connecticut were chosen (Bridgeport Energy, Bridgeport Harbor, Devon 15-18, Kleen, Middletown, Milford, Montville, New Haven Harbor, and Norwalk Harbor Stations). To create the two different sinks, one had Lake Road OOS and the other sink had Millstone 2&3 OOS as a base condition.

The sources were made up of units in two eastern New England regions, southeast Massachusetts/ Boston and Maine/New Hampshire. The southeast Massachusetts/Boston source included units[21] from Brockton, Canal, Cape Wind, Edgar, Mystic, and Salem Harbor Stations. The Maine/New Hampshire source included units from Bucksport, Maine Independent, Newington, Seabrook, Westbrook, and Yarmouth Stations.

The following element/contingency pairs were ignored in the transfer analysis due to local issues that will be addressed in on-going/future studies.

Table 5-25
Western New England Ignored Limiting Transfer Elements

Element ID	kV	Element Description	Contingency	L/O	Issue	WNE Import Level (MW)
1207	115	Manchester to E. Hartford	[redacted]			3334 (N-1)
1704	115	S. Meadow to SW Hartford	[redacted]			< 0 (N-1-1)
343	345	Wachusett to Sandy Pond	[redacted]			562 (N-1-1)
Manch. 4X		Manchester 345/115 kV Autotransformer	[redacted]			1877 (N-1-1)
1773	115	S. Meadow to Rocky Hill	[redacted]			2186 (N-1-1)

A set of four transfer analyses were done using the combination of sinks and sources. The results of the N-1 analysis are shown in Table 5-26 and N-1-1 analysis are shown in Table 5-27.

Table 5-26
Western New England N-1 Transfer Limits

Element ID	kV	Element Description	Contingency	Source	Sink	WNE Import Level (MW)
302	345	Carpenter Hill to Millbury	[redacted]			3440
			[redacted]			3470
			[redacted]			3861
301	345	Carpenter Hill to Ludlow	[redacted]			3989

From the results shown above, the N-1 western New England import limit range is 3400-3950 MW based on the most limiting element contingency pair.

[21] Due to insufficient resources in 2020 to both serve eastern New England and Greater Rhode Island load and transfer power to serve western New England load, the Cape Wind and Brockton Stations were added as a proxy for future generation in eastern New England.

Table 5-27
Western New England N-1-1 Transfer Limits

Element ID	kV	Element Description	L/O	Contingency	Source	Sink	WNE Import Level (MW)
1870S	115	Wood River to Shunock	[redacted]				2437
W175-3	115	Little Rest Rd. to W. Charlton	[redacted]				2272
			[redacted]				3000
			[redacted]				2627
W175-3	115	Little Rest Rd. to W. Charlton	[redacted]				2477
			[redacted]				2285
			[redacted]				3013
			[redacted]				2640
302	345	Carpenter Hill to Millbury	[redacted]				2686
			[redacted]				2660
			[redacted]				3154
			[redacted]				3092
302	345	Carpenter Hill to Millbury	[redacted]				2690
			[redacted]				2664
			[redacted]				3158
			[redacted]				3096

From the results above, the N-1-1 western New England import limit range is 2250-3000 MW based on the most limiting element contingency pair.

5.2.6.4 Connecticut Import Interface

In evaluating the ability to transfer power from the rest of New England to Connecticut, transfer limits were determined from the same sets of sources and sinks used in the western New England transfer analysis. The results of the N-1 analysis are shown in Table 5-29 and N-1-1 analysis are shown in Table 5-30.

The following element/contingency pairs were ignored in the transfer analysis due to local issues that will be addressed in on-going/future studies.

Table 5-28
Connecticut Ignored Limiting Transfer Elements

Element ID	kV	Element Description	Contingency	L/O	Issue	CT Import Level (MW)
1207	115	Manchester to E. Hartford	[redacted]			2812 (N-1)
1704	115	S. Meadow to SW Hartford	[redacted]			< 0 (N-1-1)
343	345	Wachusett to Sandy Pond	[redacted]			68 (N-1-1)
Manch. 4X		Manchester 345/115 kV Autotransformer	[redacted]			1350 (N-1-1)

Table 5-29
Connecticut N-1 Transfer Limits

Element ID	kV	Element Description	Contingency	Source	Sink	CT Import Level (MW)
347	345	Sherman Road to Killingly	[redacted]			3066
			[redacted]			3122
1870S	115	Wood River to Shunock	[redacted]			3766
			[redacted]			3795
1870S	115	Wood River to Shunock	[redacted]			3201
			[redacted]			3292
			[redacted]			3856
			[redacted]			3840

From the results above, the N-1 Connecticut import limit range is 3050-3750 MW based on the most limiting element contingency pair.

Table 5-30
Connecticut N-1-1 Transfer Limits

Element ID	kV	Element Description	L/O	Contingency	Source	Sink	CT Import Level (MW)
1870S	115	Wood River to Shunock	[redacted]				1914
			[redacted]				1757
L190-4	115	Tower Hill to W. Kingston	[redacted]				2431
			[redacted]				2117
L190-4	115	Tower Hill to W. Kingston	[redacted]				2006
			[redacted]				1849
			[redacted]				2461
			[redacted]				2154
3419	345	Ludlow to Barbour Hill	[redacted]				2064
			[redacted]				2073
			[redacted]				2500
			[redacted]				2512

From the results above, the N-1-1 Connecticut import limit range is 1750-2400 MW based on the most limiting element contingency pair.

5.2.7 Results of Transmission Transfer Capability Study

5.2.7.1 Study Description

As stated in Section 4 of the ISO Planning Procedure 3, "The New England bulk power supply system shall be designed with adequate inter-Area and intra-Area transmission transfer capability to minimize system reserve requirements, facilitate transfers, provide emergency backup of supply resources, permit economic interchange of power, and to assure [the system will remain reliable under contingency conditions]."

The ability of the transmission system within a defined area to reliably serve customer demands is predicated on the amount of local generation available and the capability of the transmission network to import power from surrounding areas. Within a defined import area, the minimum resource requirement is defined as peak load minus the minimum or maximum N-1-1 interface import capability. The available resources to serve customer demands are the in-service generation within the defined area plus demand resources. Reliability analyses also should consider certain outages of generating plants based on a variety of potential reasons for unavailability.

When the generation resource level falls below the minimum resource level then there are insufficient transmission transfer capability and generation resources to serve the load requirements. The following sections describe when there are insufficient resources for each of the regions under study.

5.2.7.2 Explanation of Common Terms Used in TSA Sheets

Some common terms are used in every TSA sheet in the following sections. Detailed explanations of these terms are in the list below with equations in bold. The letters in the equations correspond to the row of the TSA sheet.

- **Demand Resources (Active or Passive)**: FCA cleared values for Demand Resources are scaled up by 8% to account for Transmission and Distribution losses.
- **Available Demand Resources:** 100% of Passive Demand Resources and 75% of Active Demand Resources are assumed available.
- **Available Quick-Start Gens:** 80% of Quick-Start generation is assumed available **[0.8 * (C + D)]**
- **Available Regular Gens:** Available Regular Generation = All Regular Generation minus two largest resources OOS **(A + B) – J**.
- **Total Available Resources:** Available Resources = Available Regular Generation plus Available Quick-Start Gens plus Available Demand Resources minus Retirements **(E + H + I + K – L)**.
- **Max N-1-1 Import Limit:** Determined in Section 5.2.6 for each of the three areas
- **Min N-1-1 Import Limit:** Determined in Section 5.2.6 for each of the three areas
- **Min Resource Requirement:** Summer Peak 90/10 Load minus Max N-1-1 Import Limit **(N – O)**.
- **Max Resource Requirement:** Summer Peak 90/10 Load minus Min N-1-1 Import Limit **(N – P)**.
- **Best Case Surplus(+)/Deficiency(-):** Total Available Resources minus Max N-1-1 Import Limit **(M – O)**.
- **Worst Case Surplus(+)/Deficiency(-):** Total Available Resources minus Min N-1-1 Import Limit **(M – P)**.

5.2.7.3 Eastern New England

A representative eastern New England TSA sheet using resources cleared through FCA-4 is shown below in Table 5-31.

Table 5-31
Eastern New England Resource Requirement

	ENE[22] Resources	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
A	Regular Gens Pre FCM	13572	13572	13572	13572	13572	13572	13572	13572	13572	13572
B	FCM Cleared Regular Gens	96	96	122	122	122	122	122	122	122	122
C	Quick-Start Gens Pre FCM	529	529	529	529	529	529	529	529	529	529
D	FCM Cleared Quick-Start Gens	193	193	258	258	258	258	258	258	258	258
E	External Area Imports[23]	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
F	Passive Demand Resources	338	505	702	702	702	702	702	702	702	702
G	Active Demand Resources	588	772	1034	1034	1034	1034	1034	1034	1034	1034
H	Available Demand Resources	779	1084	1477	1477	1477	1477	1477	1477	1477	1477
I	Available Quick-Start Gens	577	577	630	630	630	630	630	630	630	630
J	Resource Outages[24]	3245	3245	3245	3245	3245	3245	3245	3245	3245	3245
K	Available Regular Gens	11023	11023	11049	11049	11049	11049	11049	11049	11049	11049
M	**Total Available Resources**	**13779**	**14084**	**14555**	**14555**	**14555**	**14555**	**14555**	**14555**	**14555**	**14555**
N	90/10 Peak Load Forecast	15575	15900	16150	16430	16690	16900	17105	17305	17485	17667
O	Max N-1-1 ENE Import Limit	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
P	Min N-1-1 ENE Import Limit	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Q	**Min Resource Requirement**	**14225**	**14550**	**14800**	**15080**	**15340**	**15550**	**15755**	**15955**	**16135**	**16317**
R	**Max Resource Requirement**	**14325**	**14650**	**14900**	**15180**	**15440**	**15650**	**15855**	**16055**	**16235**	**16417**
S	**Best Case Surplus(+)/Deficiency(-)**	**-446**	**-466**	**-245**	**-525**	**-785**	**-995**	**-1200**	**-1400**	**-1580**	**-1762**
T	**Worst Case Surplus(+)/Deficiency(-)**	**-546**	**-566**	**-345**	**-625**	**-885**	**-1095**	**-1300**	**-1500**	**-1680**	**-1862**

[22] Eastern New England ("ENE") consists of RSP sub-areas of New Hampshire (NH), Central / Northeast Massachusetts (CMA/NEMA), Boston (BOS), Southeast Massachusetts (SEMA), Maine (ME), Southern Maine (SME), and Bangor Hydro (BHE).

[23] Phase II HVDC assumed to be 2000 MW, New Brunswick Import at 0 MW.

[24] Two largest resources are assumed OOS: [redacted].

Using the information shown in Table 5-31, Figure 5-22 shows graphically the resource requirements with two resources OOS for the entire planning horizon.

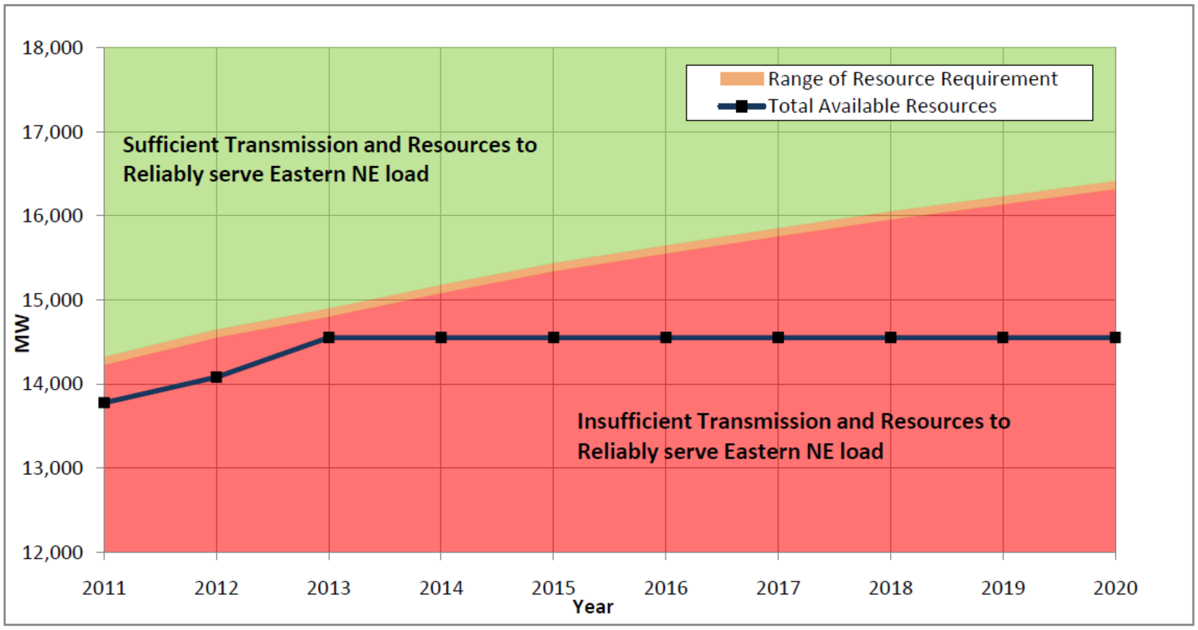

Figure 5-22: Eastern New England Resource Requirements

5.2.7.4 Western New England

A representative western New England TSA sheet using resources cleared through FCA-4 is shown below in Table 5-32.

Table 5-32
Western New England Resource Requirement

	WNE[25] Resources	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
A	Regular Gens Pre FCM	10524	10524	10524	10524	10524	10524	10524	10524	10524	10524
B	FCM Cleared Reg Gens	655	697	727	727	727	727	727	727	727	727
C	Quick-Start Gens Pre FCM	1142	1142	1142	1142	1142	1142	1142	1142	1142	1142
D	FCM Cleared Quick-Start Gens	646	779	803	803	803	803	803	803	803	803
E	External Area Imports[26]	200	200	200	200	200	200	200	200	200	200
F	Passive Demand Resources	394	498	596	596	596	596	596	596	596	596
G	Active Demand Resources	327	373	528	528	528	528	528	528	528	528
H	Available Demand Resources	639	777	992	992	992	992	992	992	992	992
I	Available Quick-Start Gens	1430	1537	1556	1556	1556	1556	1556	1556	1556	1556
J	Resource Outages[27]	3160	3160	3160	3160	3160	3160	3160	3160	3160	3160
K	Available Regular Gens	11023	11023	11023	11023	11023	11023	11023	11023	11023	11023
L	Possible Gen Retirements[28]	0	0	604	604	604	604	604	604	604	604
M	**Total Available Resources**	**10289**	**10575**	**10235**	**10235**	**10235**	**10235**	**10235**	**10235**	**10235**	**10235**
N	90/10 Peak Load Forecast	11455	11630	11800	11960	12145	12270	12395	12495	12625	12756
O	Max N-1-1 WNE Import Limit	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
P	Min N-1-1 WNE Import Limit	2250	2250	2250	2250	2250	2250	2250	2250	2250	2250
Q	**Min Resource Requirement**	**8455**	**8630**	**8800**	**8960**	**9145**	**9270**	**9395**	**9495**	**9625**	**9756**
R	**Max Resource Requirement**	**9205**	**9380**	**9550**	**9710**	**9895**	**10020**	**10145**	**10245**	**10375**	**10506**
S	**Best Case Surplus(+)/Deficiency(-)**	**1834**	**1945**	**1435**	**1275**	**1090**	**965**	**840**	**740**	**610**	**478**
T	**Worst Case Surplus(+)/Deficiency(-)**	**1084**	**1195**	**685**	**525**	**340**	**215**	**90**	**-10**	**-140**	**-272**

[25] Western New England ("WNE") consists of RSP sub-areas of Vermont (VT), Western Massachusetts (WMASS), northern and eastern Connecticut (CT), Southwest Connecticut (SWCT), and Norwalk / Stamford (NOR).

[26] Highgate HVDC assumed to be 200 MW, New York Import at 0 MW.

[27] Two largest resources are assumed OOS: [redacted].

[28] Vermont Yankee is assumed to be OOS starting 2013.

Using the information shown in Table 5-32, Figure 5-23 shows graphically the resource requirements with two resources OOS for the entire planning horizon.

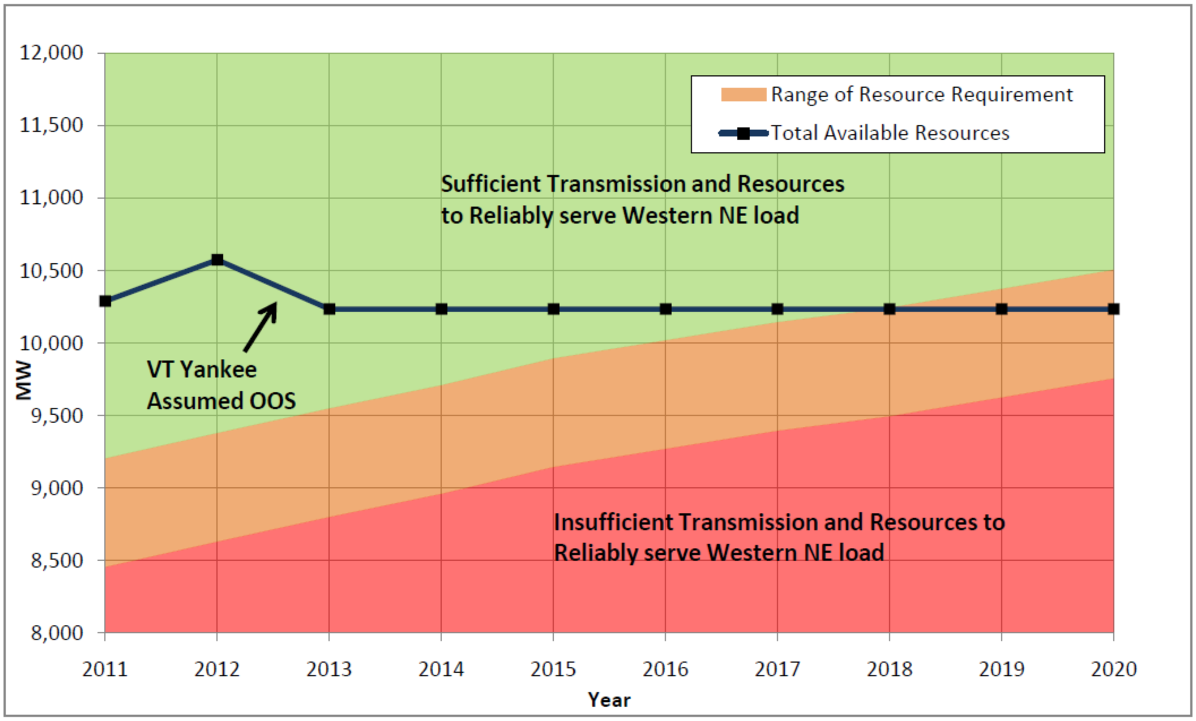

Figure 5-23: Western New England Resource Requirements

5.2.7.5 Connecticut

A representative Connecticut TSA sheet using resources cleared through FCA-4 is shown below in Table 5-33.

Table 5-33
Connecticut Resource Requirement

	CT[29] Resources	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
A	Regular Gens Pre FCM	6174	6174	6174	6174	6174	6174	6174	6174	6174	6174
B	FCM Cleared Reg Gens	642	679	679	679	679	679	679	679	679	679
C	Quick-Start Gens Pre FCM	788	788	788	788	788	788	788	788	788	788
D	FCM Cleared Quick-Start Gens	606	738	762	762	762	762	762	762	762	762
E	External Area Imports[30]	0	0	0	0	0	0	0	0	0	0
F	Passive Demand Resources	295	365	424	424	424	424	424	424	424	424
G	Active Demand Resources	250	273	388	388	388	388	388	388	388	388
H	Available Demand Resources	482	569	715	715	715	715	715	715	715	715
I	Available Quick-Start Gens	1115	1221	1240	1240	1240	1240	1240	1240	1240	1240
J	Resource Outages[31]	2102	2012	2012	2012	2012	2012	2012	2012	2012	2012
K	Available Regular Gens	4714	4752	4752	4752	4752	4752	4752	4752	4752	4752
M	**Total Available Resources**	**6312**	**6542**	**6707**	**6707**	**6707**	**6707**	**6707**	**6707**	**6707**	**6707**
N	90/10 Peak Load Forecast	7985	8105	8220	8330	8450	8530	8610	8680	8760	8840
O	Max N-1-1 CT Import Limit	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400
P	Min N-1-1 CT Import Limit	1750	1750	1750	1750	1750	1750	1750	1750	1750	1750
Q	**Min Resource Requirement**	**5585**	**5705**	**5820**	**5930**	**6050**	**6130**	**6210**	**6280**	**6360**	**6440**
R	**Max Resource Requirement**	**6235**	**6355**	**6470**	**6580**	**6700**	**6780**	**6860**	**6930**	**7010**	**7090**
S	**Best Case Surplus(+)/Deficiency(-)**	**727**	**837**	**887**	**777**	**657**	**577**	**497**	**427**	**347**	**267**
T	**Worst Case Surplus(+)/Deficiency(-)**	**77**	**187**	**237**	**127**	**7**	**-73**	**-153**	**-223**	**-303**	**-383**

[29] Connecticut consists of RSP sub-areas of Greater Connecticut: Northern and eastern Connecticut (CT), Southwest Connecticut (SWCT), and Norwalk / Stamford (NOR).

[30] New York AC Import, Norwalk-Northport Cable, and Cross Sound Cable at 0MW

[31] Two largest resources are assumed OOS: [redacted].

Using the information shown in Table 5-33, Figure 5-24 shows graphically the resource requirements with two resources OOS for the entire planning horizon.

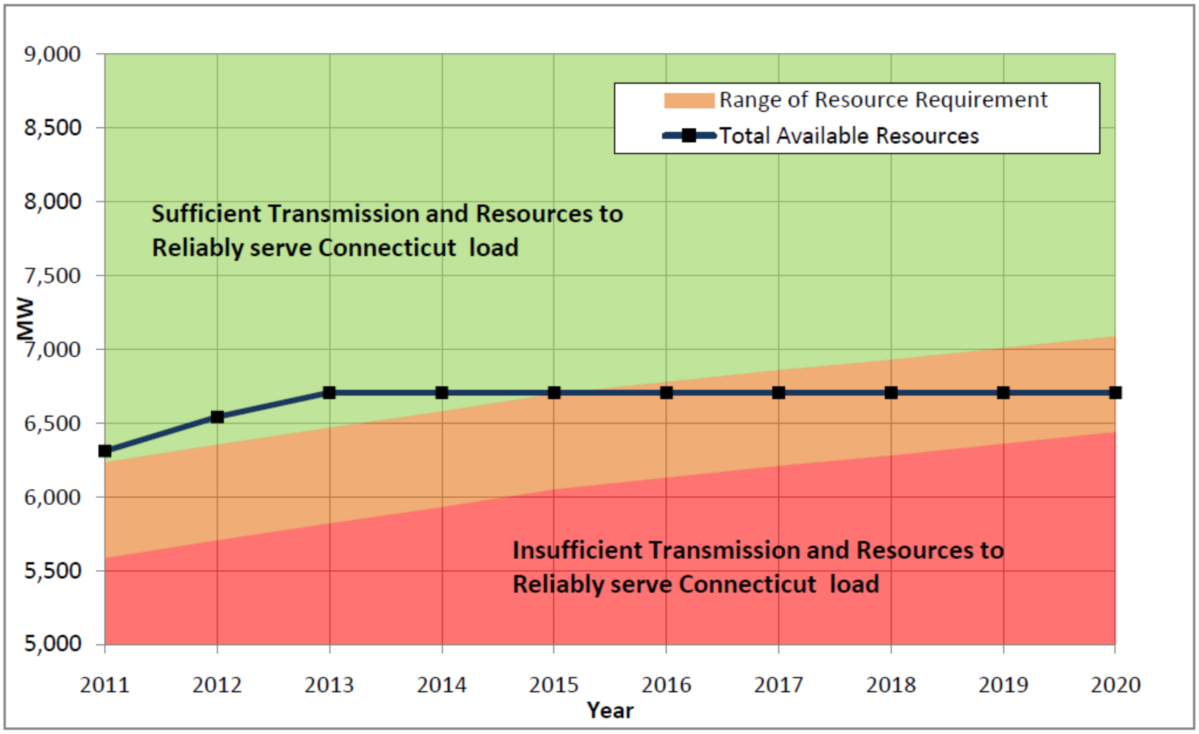

Figure 5-24: Connecticut Resource Requirements

5.3 Stability Performance Criteria Compliance

5.3.1 Stability Test Results

The loss of [redacted] as a result of a three-phase fault resulted in unsatisfactory stability performance with several generators losing synchronism. The total loss of source in New England for this contingency was over 2000 MW. While this contingency caused an unsatisfactory system stability condition, it is imperative to note that this specific contingency is more extreme than the NERC criteria listed for an extreme contingency evaluation. The criteria only require the testing of loss of substation ***without*** a fault, unlike this contingency which simulated the loss of [redacted] as a result of a three-phase fault. For further details, please refer to the stability plots provided in Appendix D: Contingency Results / Stability Plots.

All other contingencies simulated in this analysis including the extreme contingency of loss of [redacted] without a fault resulted in dynamic stability performance for the system that meets the criteria for an extreme contingency. All stability plots pertaining to these contingencies are provided in Appendix D: Contingency Results / Stability Plots.

The only unsatisfactory stability performance observed in the [redacted] area was for a disturbance more severe than the established criteria for extreme contingency simulations. Therefore, it is concluded that system dynamic stability performance for disturbances in the [redacted] area is satisfactory and meets all established criteria.

A summary of the results of stability tests are shown in Table 5-34 below. Detailed results tables and dynamic response plots are included in Section 10.

Table 5-34
Stability Study Result Summary

Fault #	ID	Fault Type	NERC CTG Cat	Fault Description	Fault Clearing Time	Stable (Y/N)	Loss of Source (MW)
1	EC1	None	D	[redacted]			
2	EC2	None	D	[redacted]			
3	EC5	None	D	[redacted]			
4	EC6	3 Phase Bus	D	[redacted]			
5	NC8	Close in 3LG	C	[redacted]			
6	NC9	Close in 3LG	C	[redacted]			
7	NC-10	Close in 3LG	C	[redacted]			

5.4 Short Circuit Performance Criteria Compliance

Not applicable to this study.

5.4.1 Short Circuit Test Results

Not applicable to this study.

Section 6
Conclusions on Needs Assessment

6.1 Overview of Conclusions from Needs Assessment

The results of these analyses indicate a need to:

- Reinforce the 345-kilovolt system [redacted] 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

6.1.1 Eastern New England Reliability

The results of the eastern New England reliability and transmission transfer capability analyses indicate that there are violations of planning criteria under the assumptions and system conditions modeled within the 10 year planning horizon. The need for additional transmission transfer capability in eastern New England is 2011. With generation retirements, the need for additional eastern New England transmission transfer capability is greater. With a New Brunswick import of 1000 MW, the need for additional transmission transfer capability in eastern New England is between 2015 and 2016.

6.1.2 Western New England Reliability

The results of the western New England reliability and transmission transfer capability analyses indicate that there are violations of planning criteria under the assumptions and system conditions modeled within the 10 year planning horizon. The need for additional transmission transfer capability can be reasonably forecasted between 2017 and 2018. The need for additional transmission transfer capability is advanced if generation resources in western New England retire. With Berkshire Power assumed in service, the need for additional transmission transfer capability in western New England is between 2019 and 2020. The 2020 study cases also indicated an insufficient resource condition in eastern New England and Greater Rhode Island to serve both local load in those areas and export power to western New England under the system conditions studied.

6.1.3 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 within the 10 year planning horizon.

6.1.4 Connecticut Reliability

The results of the Connecticut reliability and transmission transfer capability analyses indicate that there are violations of planning criteria under the assumptions and system conditions modeled within the 10 year planning horizon. The need for additional transmission transfer capability can be reasonably forecasted between 2014 and 2015. The need for additional transmission transfer capability is advanced if generation resources in Connecticut retire.

6.1.5 Salem Harbor Retirement

The results of the Salem Harbor retirement scenario with respect to eastern New England reliability and transmission transfer capability analyses indicate that there are violations of planning criteria under the assumptions and system conditions modeled within the 10 year planning horizon. The need for additional transmission transfer capability in eastern New England with the Salem Harbor retirement is 2011. With the Salem Harbor generation retirement, overloads compared to the west to east analysis showed an increase [redacted]. If New Brunswick imports were replaced with generation in western New England, Greater Rhode Island or New York imports, these overloads would be even greater.

Section 7
Appendix A: 2010 CELT Load Forecast

Table 7-1
2010 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)	2010	25925	26150	26455	26805	27190	27600	28020	28620	29310	29915
	2011	26365	26595	26910	27265	27660	28080	28510	29125	29835	30455
	2012	26845	27080	27400	27765	28165	28595	29030	29655	30390	31025
	2013	27230	27470	27795	28160	28570	29005	29450	30085	30840	31490
	2014	27665	27905	28240	28610	29025	29465	29915	30560	31340	32000
	2015	28070	28315	28650	29030	29450	29895	30355	31010	31810	32480
	2016	28390	28640	28975	29360	29785	30235	30700	31365	32180	32865
	2017	28700	28950	29295	29680	30110	30565	31035	31705	32545	33240
	2018	29005	29260	29605	29995	30430	30890	31365	32040	32895	33600
	2019	29290	29545	29895	30290	30730	31195	31675	32360	33225	33940
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)	2010/11	21655	21775	21870	21935	22085	22240	22405	22510	22765	23140
	2011/12	21790	21915	22010	22075	22225	22380	22545	22655	22905	23280
	2012/13	21845	21965	22065	22130	22280	22435	22605	22710	22960	23335
	2013/14	21965	22085	22180	22250	22400	22555	22725	22830	23080	23455
	2014/15	22065	22190	22285	22350	22505	22665	22830	22940	23185	23560
	2015/16	22170	22295	22390	22455	22610	22770	22940	23045	23290	23660
	2016/17	22280	22400	22500	22565	22720	22880	23050	23155	23400	23775
	2017/18	22390	22515	22615	22680	22835	22995	23165	23275	23520	23890
	2018/19	22505	22630	22725	22795	22950	23110	23285	23390	23635	24005
	2019/20	22620	22745	22845	22915	23070	23230	23405	23515	23750	24120
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 7-2
2015 Detailed Load Distributions by State and Company

Study Date :	8/1/2015	**CELT Forecast :**	2010	**Forecast Year :**	2015
Season :	Summer Peak	**Weather :**	90/10	**Load Distribution :**	N+6_SUM
CELT Load :	31810 MW	**% of Peak :**	100.00%	**Tx Losses :**	4.00%

Maine **State Load = 2370 MW - 4.00% Losses = 2275.2 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.33%	1941.46	767.46	0.930	704.56
BHE	14.67%	333.76	116.59	0.944	91.57

New Hampshire **State Load = 2865 MW - 4.00% Losses = 2750.4 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	79.00%	2172.81	309.49	0.990	
UNITIL	11.99%	329.76	47.00	0.990	
GSE	9.01%	247.82	9.18	0.999	1.60

Vermont **State Load = 1185 MW - 4.00% Losses = 1137.6 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	1137.58	290.15	0.969	104.80

Massachusetts **State Load = 14750 MW - 4.00% Losses = 14160 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	27.97%	3960.55	1080.97	0.965	38.13
COMEL	11.37%	1610.00	282.09	0.985	
MA-NGRID	40.32%	5701.85	347.08	0.998	38.79
WMECO	6.55%	927.46	132.18	0.990	
MUNI:BOST	4.21%	596.12	86.17	0.990	
MUNI:CNEMA	2.07%	293.08	60.26	0.980	
MUNI:RI	0.88%	124.60	23.80	0.982	
MUNI:SEMA	3.56%	504.09	86.26	0.986	
MUNI:WMA	3.06%	433.31	62.88	0.990	

Rhode Island **State Load = 2185 MW - 4.00% Losses = 2097.6 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	2097.62	204.12	0.995	34.60

Connecticut **State Load = 8450 MW - 4.00% Losses = 8112 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	75.72%	6142.45	875.28	0.990	75.10
CMEEC	5.34%	433.19	61.73	0.990	
UI	18.95%	1537.22	153.80	0.995	

Table 7-3
2020 Detailed Load Distributions by State and Company

Study Date :	8/1/2020	**CELT Forecast :**	2010	**Forecast Year :**	2020
Season :	Summer Peak	**Weather :**	90/10	**Load Distribution :**	N+11_SUM
CELT Load :	33555 MW	**% of Peak :**	100.00%	**Tx Losses :**	4.00%

Maine **State Load = 2500 MW - 4.00% Losses = 2400 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.33%	2047.99	799.64	0.932	704.56
BHE	14.67%	352.09	122.84	0.944	91.57

New Hampshire **State Load = 3080 MW - 4.00% Losses = 2956.8 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	79.00%	2335.87	332.74	0.990	
UNITIL	11.99%	354.53	50.52	0.990	
GSE	9.01%	266.40	9.80	0.999	1.60

Vermont **State Load = 1255 MW - 4.00% Losses = 1204.8 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	1204.82	306.34	0.969	104.80

Massachusetts **State Load = 15575 MW - 4.00% Losses = 14952 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	27.97%	4182.06	1135.77	0.965	38.13
COMEL	11.37%	1700.04	298.03	0.985	
MA-NGRID	40.32%	6021.18	366.25	0.998	38.79
WMECO	6.55%	979.34	139.58	0.990	
MUNI:BOST	4.21%	629.49	91.63	0.990	
MUNI:CNEMA	2.07%	309.51	63.68	0.979	
MUNI:RI	0.88%	131.56	24.70	0.983	
MUNI:SEMA	3.56%	532.28	90.33	0.986	
MUNI:WMA	3.06%	457.52	66.43	0.990	

Rhode Island **State Load = 2300 MW - 4.00% Losses = 2208 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	2207.96	216.09	0.995	34.60

Connecticut **State Load = 8840 MW - 4.00% Losses = 8486.4 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	75.72%	6425.84	915.72	0.990	75.10
CMEEC	5.34%	453.18	64.58	0.990	
UI	18.95%	1608.18	160.91	0.995	

Table 7-4
Detailed Demand Response Distributions by Zone

Study Date : 8/1/2015 **CCP :** 2012/2013 **Load Season :** Summer Peak

Load Distrb : N+6_SUM **Distrb Losses :** 4.00% **DR Season :** SUM

Passive DR Availability : 100.00% **Active DR Availability :** 100.00%

Passive DR Performance : 100.00% **Active DR Performance :** 75.00%

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

DR Modeled = (DRV_SUM * 100.00% Availability * 100.00% Performance) + 4.00% Losses Gross-Up

Zone	ID	Description	CELT DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Maine	60.04	-62.42	-23.24
DR_P_NH	21	New Hampshire	63.32	-65.84	-9.17
DR_P_VT	22	Vermont	75.32	-78.34	-20.03
DR_P_NEMABOS	23	Northeast Massachusetts & Boston	208.03	-216.39	-47.15
DR_P_SEMA	24	Southeast Massachusetts	115.55	-120.21	-13.66
DR_P_WCMA	25	West Central Massachusetts	115.35	-119.96	-11.52
DR_P_RI	26	Rhode Island	70.39	-73.25	-7.06
DR_P_CT	27	Connecticut	364.87	-379.51	-51.03

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

DR Modeled = (DRV_SUM * 100.00% Availability * 75.00% Performance) + 4.00% Losses Gross-Up

Zone	ID	Description	CELT DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_A_ME_BHE	30	ME - Bangor Hydro	49.88	-38.90	-15.82
DR_A_ME_MAIN	31	ME - Maine	133.33	-104.00	-37.15
DR_A_ME_PORT	32	ME - Portland Maine	88.96	-69.39	-26.01
DR_A_NH_NEWH	33	NH - New Hampshire	35.31	-27.53	-3.83
DR_A_NH_SEAC	34	NH - Seacoast	5.36	-4.17	-0.59
DR_A_VT_NWVT	35	VT - Northwest Vermont	21.27	-16.56	-4.14
DR_A_VT_VERM	36	VT - Vermont	11.88	-9.28	-2.45
DR_A_MA_BOST	37	MA - Boston	168.64	-131.54	-35.29
DR_A_MA_NSHR	38	MA - North Shore	65.89	-51.40	-5.60
DR_A_MA_CMA	39	MA - Central Massachusetts	71.64	-55.87	-3.92
DR_A_MA_SPFD	40	MA - Springfield	30.33	-23.66	-3.39
DR_A_MA_WMA	41	MA - Western Massachusetts	36.65	-28.60	-2.85
DR_A_MA_LSM	42	MA - Lower Southeast Massachusetts	56.44	-43.99	-7.35
DR_A_MA_SEMA	43	MA - Southeast Massachusetts	93.22	-72.76	-5.90
DR_A_RI_RHOD	44	RI - Rhode Island	49.42	-38.55	-3.70
DR_A_CT_EAST	45	CT - Eastern Connecticut	33.61	-26.20	-3.72
DR_A_CT_NRTH	46	CT - Northern Connecticut	44.49	-34.67	-4.96
DR_A_CT_NRST	47	CT - Norwalk-Stamford	48.96	-38.18	-5.21
DR_A_CT_WEST	48	CT - Western Connecticut	145.72	-113.65	-14.78

Section 8
Appendix B: Case Summaries and Generation Dispatches

[redacted]

Section 9
Appendix C: Contingency List

9.1 New England West to East

9.1.1 NERC Category B Contingencies

[redacted]

9.1.2 NERC Category C Contingencies

[redacted]

9.1.3 Special Protection System Contingencies

[redacted]

9.2 New England East to West

9.2.1 NERC Category B Contingencies

[redacted]

9.2.2 NERC Category C Contingencies

[redacted]

9.2.3 Special Protection System Contingencies

[redacted]

9.3 Rhode Island

9.3.1 NERC Category B Contingencies

[redacted]

9.3.2 NERC Category C Contingencies

[redacted]

9.3.3 Special Protection System Contingencies

[redacted]

Section 10
Appendix D: Contingency Results / Stability Plots

[redacted]

Section 11
Appendix E: 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 41) and performance was adequate. The study shows NERC Category B condition performance in Section 5.2.2 (Pages 41-44) and performance was inadequate. NERC Category C review can be found in Section 5.2.2 and 5.2.3 (Pages 41-54) and performance was inadequate. For NERC Category B and C review all contingencies were studied. As shown in Section 5.2.7 (Pages 65) the critical system condition is expected in year 2011 with a load of 29,835 MW. As shown in Section 3.1.7 (Page 21) the study includes a peak load of 33,555 MW in 2020. 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 22). 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 (Pages 27). Demand Resources effects are included in load projections. The study includes reactive resources as shown in Section 3.1.10.4 (Pages 26). 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 23). The effects of existing and planned protection systems can be found in Section 3.1.14 (Pages 28). The effects of existing and planned control devices (Dynamic Control Systems) can be found in Section 3.1.14 (Pages 28). 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.