SOUTHWEST CONNECTICUT RELIABILITY PROJECT

BY

THE CONNECTICUT LIGHT AND POWER COMPANY

DOING BUSINESS AS EVERSOURCE ENERGY

VOLUME 4: PLANNING

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EXHIBIT 1: ISO-NE, "SOUTHWEST CONNECTICUT AREA TRANSMISSION 2022 NEEDS ASSESSMENT," JUNE 2014, REDACTED TO SECURE CONFIDENTIAL ENERGY INFRASTRUCTURE INFORMATION (CEII)

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Southwest Connecticut Area Transmission 2022 Needs Assessment

REDACTED—PUBLIC VERSION

June 2014

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Section 1
Executive Summary

1.1 Study Objective

The objective of the Southwest Connecticut Needs Assessment study is to evaluate the reliability performance and identify reliability-based transmission needs in the Southwest Connecticut (SWCT) study area, while considering the following:

- Future load growth
- Reliability over a range of generation patterns and transfer levels
- All applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Corporation (NPCC) and ISO New England transmission planning reliability standards
- Regional and local reliability issues
- Existing and planned supply resources and demand resources
- Limited short circuit margin concerns in the Southwest Connecticut area

The scope of the Needs Assessment study performed for the SWCT area included evaluation of the reliability performance of the transmission system serving this area of New England for the year 2022 projected system conditions. The system was tested with all elements in-service (i.e. N-0) and under N-1 and N-1-1 contingency conditions for a number of possible operating conditions with respect to related interface transfer levels and generating unit availability conditions.

As described in this report, the Needs Assessment identified certain areas of the system that failed to meet North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), Independent System Operator of New England Inc. (ISO-NE), and Transmission Owner standards and criteria.

This Needs Assessment was the first step in the study process defined in accordance with the Regional Planning Process as outlined in Attachment K to the ISO-NE Open Access Transmission Tariff (OATT). In accordance with Attachment K, a Solutions Study will be conducted to develop and analyze potential transmission solutions for the needs identified in this analysis.

A working group led by ISO-NE and consisting of members from ISO-NE, Northeast Utilities (NU), and United Illuminating (UI), was formed to study the Southwest Connecticut transmission system. As part of the Planning Advisory Committee (PAC) process, stakeholders, which include generator owners, suppliers, load serving entities, energy efficiency entities, state regulators, and transmission owners, also provided input throughout the study process.

1.2 Method and Criteria

The Needs Assessment was performed in accordance with NERC TPL-001, TPL-002, TPL-003, and TPL-004 Transmission System Standards, Northeast Power Coordinating Council (NPCC) Directory #1, "Design and Operation of the Bulk Power System," ISO New England Planning Procedure 3, "Reliability Standards for the New England Area Bulk Power Supply System," and ISO New England Planning Procedure 5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses".

1.3 Study Assumptions

A long-term (ten-year) planning horizon was used for this study based on the most recently available Capacity, Energy, Loads, and Transmission (CELT) forecast data (2013) at the time the study began. This study was focused on the projected 2022 peak demand load levels for the ten-year horizon. The models reflected the following peak load conditions:

Loads:

The summer peak 90/10 load level forecast is 34,105 MW for all of New England and 8,825 MW (which represents 26% of the New England load) for the state of Connecticut

Transmission Topology:

All relevant transmission projects with Proposed Plan Application (PPA) approval have been included in the study base case except for the Central Connecticut Reliability Project (CCRP), which is under re-assessment in the Great Hartford Central Connecticut (GHCC) Study, and previously PPA approved SWCT projects which were presented at the June 18, 2012 PAC meeting[1], since they are being re-evaluated in this assessment. Section 3.1.3 includes a full listing and description of all projects included.

Generation:

All generation projects with a Capacity Supply Obligation as of Forward Capacity Auction 7 (FCA #7) were included in the study base case. Section 3.1.4 of this report includes a full listing and description of generation included in the base case. Due to the submission of Non-Price Retirement (NPR) Requests for the Bridgeport Harbor 2 and Norwalk Harbor units for FCA #8, these units have been taken out-of-service (OOS) in the base case. Generation dispatch scenarios testing included one or two relevant generation units Out Of Service (OOS). A detailed table of generation dispatches can be seen in Table 3-8.

Demand Resource Assumptions:

Demand Resources (active and passive) were modeled based on the Demand Resources (DR) cleared in FCA #7. In addition, any accepted NPR requests for DR and any DR terminations in Connecticut for FCA #8 were also taken into account. Finally, the energy efficiency forecast for the years corresponding to FCA #8 were also modeled based on the 2013 energy efficiency (EE) forecast. Section 3.1.6 includes the details of the demand resources considered for this study.

Error! Reference source not found. of this report contains more details of all assumptions used to complete this study.

The following types of analyses were performed as part of this study:

- **Steady-State Thermal and Voltage Analysis** – steady-state analysis was performed to determine the level of steady-state power flows on transmission circuits and voltage levels and performance on transmission buses for a variety of one and two-unit-out generation dispatches and inter-regional stresses, for N-0 (All-facilities-in) conditions as well as following contingency events for N-1 (all-facilities-in, first contingency) and N-1-1 (facility-out, first contingency) conditions.

[1] *SWCT Preferred Solution – New Haven and Bridgeport Areas*, (June 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/jun192012/swct_solution.pdf

- **Extreme Contingency Analysis** – limited steady-state analysis was performed to evaluate the severity of the impact of NERC Category D Transmission Planning System Standard 004 (TPL-004)[2] extreme contingencies on transmission system performance. A thermal or voltage violation arising from this analysis may not necessarily demonstrate a reliability need in the study area; as such, this analysis was performed for informational purposes only.
- **Short Circuit Analysis** – a study to determine the ability of substation equipment to withstand and interrupt fault current was also conducted.

1.4 Specific Areas of Concern

The SWCT study area was divided into the following five subareas for the purpose of this study:

1. Frost Bridge - Naugatuck Valley
2. Housatonic Valley / Norwalk - Plumtree
3. Bridgeport
4. New Haven -Southington
5. Glenbrook – Stamford

The results of the steady state thermal and voltage analysis indicated that many thermal and voltage issues exist on facilities in each of the subareas comprising the SWCT study area, with the exception of the Glenbrook – Stamford area. The results for each study subarea are summarized in the following Sections 1.4.1 to 1.4.5. Each section summarizes the number of thermal and voltage violations observed and provides the Connecticut load level at which these violations would be resolved. The Connecticut load numbers provided exclude transmission losses, and include the impact of demand resources.

Limited circuit breaker short circuit margins were observed at a few SWCT substations. A summary of the short circuit study result is provided in Section 1.4.6.

Results of generation re-dispatch are summarized in Section 1.4.7.

1.4.1 Frost Bridge – Naugatuck Valley Subarea Thermal and Voltage Needs

The Frost Bridge – Naugatuck Valley subarea net load for 2022 after demand resources being subtracted is about 652 MW. This subarea is a net importer of energy and relies on the surrounding areas to serve local load.

The Frost Bridge – Naugatuck Valley subarea had two transmission elements with N-1 thermal violations and ten 115 kV buses with N-1 low voltage violations. Under N-1-1 conditions, there were 10 elements with thermal violations and twelve 115 kV PTF buses with low voltage violations. There were no N-0 violations.

The contingencies leading to the violations are typically loss of import paths from either Frost Bridge or Devon into the subarea. See Sections 5.1.1 and 5.2.1 for a full discussion of this subarea.

The majority of the worst-case violations in the Frost Bridge – Naugatuck Valley subarea are expected to be seen at summer peak load levels before 2013. The net Connecticut load at which all

[2] Transmission Planning (TPL) System Standard 004: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), published February 2005; available at http://www.nerc.com/files/TPL-004-0.pdf.

thermal violations would be resolved is 2,687 MW and the net Connecticut load at which all voltage violations would be resolved is 1,703 MW. The details of the corresponding critical load level and year of need are available in Section 5.2.1.3.

1.4.2 Housatonic Valley / Norwalk – Plumree Subarea Thermal and Voltage Needs

The Housatonic Valley / Norwalk – Plumtree subarea net load for 2022 after demand resources being subtracted is about 860 MW. This subarea is a net importer of energy and relies on the surrounding areas to serve local load.

The Housatonic Valley / Norwalk – Plumtree subarea had three transmission elements with N-1 thermal violations and six 115 kV buses with N-1 low voltage violations. Under N-1-1 conditions, there were eight elements with thermal violations and twelve 115 kV PTF buses with low voltage violations. There were no N-0 violations.

The contingencies leading to the violations are typically loss of import paths into the subarea. Worst case violations are seen after loss of one or both of the Plumtree 345/115 kV autotransformers. See Sections 5.1.2 and 5.2.2 for a full discussion of this subarea.

The majority of the worst-case violations in the Housatonic Valley / Norwalk – Plumtree subarea are expected to be seen at summer peak load levels before 2013. The net Connecticut load at which all thermal violations would be resolved is 4,163 MW and the net Connecticut load at which all voltage violations would be resolved is 5,218 MW. The details of the corresponding critical load level and year of need are available in Section 5.2.2.3.

1.4.3 Bridgeport Subarea Thermal and Voltage Needs

The Bridgeport subarea net load for 2022 after demand resources being subtracted is about 511 MW. Unlike the two subareas described above, there is sufficient local generation to supply loads within the Bridgeport subarea.

The Bridgeport subarea had four transmission elements with N-1 thermal violations and two 115 kV buses with N-1 low voltage violations. Under N-1-1 conditions, there were seven elements with thermal violations and two 115 kV PTF buses with low voltage violations. There were no N-0 violations.

There are various contingencies leading to criteria violations in the subarea and the majority of those contingencies are due to the dispatch scenario with both Bridgeport Energy and Bridgeport Harbor 3 OOS. See Sections 5.1.3 and 5.2.3 for a full discussion of this subarea.

The majority of the worst-case violations in the Bridgeport subarea are expected to be seen at summer peak load levels before 2013. The net Connecticut load at which all thermal violations would be resolved is 234 MW[3] and the net Connecticut load at which all voltage violations would be resolved is 7,093 MW. The details of the corresponding critical load level and year of need are available in Section 5.2.3.3.

[3] The violation exists below the minimum load level.

1.4.4 New Haven - Southington Subarea Thermal and Voltage Needs

The New Haven - Southington subarea net load for 2022 after demand resources being subtracted is about 1044 MW. The New Haven –Southington subarea has about 950 MW in local generation to supply the subarea load when all units are available. The subarea is a net importer of energy and relies on the surrounding areas to serve local load when the New Haven Harbor is OOS.

The New Haven - Southington subarea had one transmission element with an N-1 thermal violation and one 115 kV bus with an N-1 low voltage violation. Under N-1-1 conditions, there were 14 elements with thermal violations and six 115 kV PTF buses with low voltage violations. There were no N-0 violations.

[redacted] See Sections 5.1.4 and 5.2.4 for a full discussion of this subarea.

The majority of the worst-case violations in the New Haven - Southington subarea are expected to be seen at summer peak load levels before 2013. The net Connecticut load at which all thermal violations would be resolved is 3,659 MW and the net Connecticut load at which all voltage violations would be resolved is 6,093 MW. The details of the corresponding critical load level and year of need are available in Section 5.2.4.3.

1.4.5 Glenbrook – Stamford Subarea Thermal and Voltage Needs

The Glenbrook - Stamford subarea net load for 2022 after demand resources being subtracted is about 908 MW. This subarea is a net importer of energy and relies on the surrounding areas to serve local load. See Sections 5.1.5 and 5.2.5 for a full discussion of this subarea.

There were no N-0, N-1 or N-1-1 violations observed in this subarea.

1.4.6 Short Circuit Test Results

Short circuit study results are summarized in Table 1-1 and show there are no over-dutied 115 kV circuit breakers in the SWCT study area. However, there are a few high duty circuit breakers with minimal remaining short circuit margin.

In addition, both the bus system and a number of disconnect switches at the Pequonnock 115kV Substation are over-dutied based on existing short circuit levels[4]. For further details refer to Section 5.4.

[4] PAC Presentation "Pequonnock Fault Duty Mitigation Solution Study Update", dated September 20, 2012, available at https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/sep202012/pequonnock.pdf.

Table 1-1 Circuit Breaker Short Circuit Duty

Substation	Voltage	Number of Circuit Breakers		
		Over Duty	High Duty	Marginal Duty
		(Above 100%)	(95-100%)	(90-95%)
Pequonnock 8J	115 kV	--	--	17 (65kA)
East Devon 8G	115 kV	--	4 (63kA)	--
Devon Ring 2 7R	115 kV	--	--	5 (63kA)
Mill River 38M	115 kV	--	2 (50 kA)	--

1.4.7 Results of Generation Re-Dispatch Analysis

Several thermal needs in the 2022 Needs Assessment were able to be eliminated through re-dispatch following the first contingency and prior to the second contingency. These include the thermal violations on the 1460 (Branford RR to East Shore), 1537 (Branford to Branford RR), and 1655 (Branford to New Haven) lines which were mitigated by backing down the New Haven Harbor units in the New Haven – Southington Subarea.

Details of the re-dispatch analysis can be seen in Appendix G: Generation Re-dispatch Results.

1.5 Statements of Need

All the criteria violations observed in the Southwest Connecticut (SWCT) area were based on steady state thermal and voltage testing. The following summarizes the needs for each subarea:

Frost Bridge – Naugatuck Valley Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the Frost Bridge – Naugatuck Valley area
- The worst-case thermal and voltage violations observed for the loss of two or three source paths serving the load pocket from Frost Bridge and Devon under various dispatches

Housatonic Valley – Plumtree – Norwalk Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the Housatonic Valley – Plumtree – Norwalk area
- [redacted]
- [redacted] There are no reported N-1 thermal or voltage violations in the Plumtree-Norwalk area

Bridgeport Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the Bridgeport area

- [redacted]
- The only voltage violations observed are for the loss of the path that connects Devon to Norwalk under various dispatches

New Haven Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the New Haven area
- [redacted]
- The worst-case voltage violations observed are for the loss of the paths that connect East Shore and Devon to North Haven under various dispatches

Glenbrook-Stamford Subarea

- No thermal or voltage violations observed

Short Circuit

High short-circuit current levels are identified as a concern in the study area, specifically with the capability of certain circuit breakers at several substations to successfully interrupt 115 kV faults.

1.6 NERC Compliance Statement

This report is the first part of a two part process used by ISO-NE to assess and address compliance with NERC TPL standards. This 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 Solutions 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 required to address all needs documented in this report. This Needs Assessment report and the Solutions Study report taken together provide the necessary evaluations and determinations required under the NERC TPL standards. (See Section 16 for the complete NERC compliance statement.)

Section 2
Introduction and Background Information

2.1 Study Objective

The objective of this Southwest Connecticut Needs Assessment study is to evaluate the reliability performance and identify reliability-based transmission needs in the Southwest Connecticut (SWCT) study area, while considering the following:

- Future load growth
- Reliability over a range of generation patterns and transfer levels
- All NERC, NPCC and ISO New England applicable transmission planning reliability standards
- Regional and local reliability issues
- Existing and planned supply resources and demand resources
- Limited short circuit margin concerns in the Southwest Connecticut area

The scope of the Needs Assessment study performed for the SWCT area included evaluation of the reliability performance of the transmission system serving this area of New England for the year 2022 projected system conditions. The system was tested with all elements in-service (i.e. N-0) and under N-1 and N-1-1 contingency conditions for a number of possible operating conditions with respect to related interface transfer levels and generating unit availability conditions.

This Needs Assessment was the first step in the study process defined in accordance with the Regional Planning Process as outlined in Attachment K to the ISO-NE Open Access Transmission Tariff (OATT). In accordance with Attachment K, a Solutions Study will be conducted to develop and analyze potential transmission solutions for the needs identified in this analysis.

A working group led by ISO-NE and consisting of members from ISO-NE, Northeast Utilities (NU), and United Illuminating (UI), was formed to study the Southwest Connecticut transmission system. As part of the Planning Advisory Committee (PAC) process, stakeholders, which include generator owners, suppliers, load serving entities, energy efficiency entities, state regulators, and transmission owners, also provided input throughout the study process.

2.2 Areas Studied

In this study, the SWCT area has been divided into five sub-areas:

1. Frost Bridge - Naugatuck Valley
2. Housatonic Valley / Norwalk - Plumtree
3. Bridgeport
4. New Haven -Southington
5. Glenbrook - Stamford

Table 2-1 summarizes the towns included in the Southwest Connecticut area.

Table 2-1 Towns Included in Study Area

Area	Towns in the Study Area

	(Note: Location of towns may not dictate where load is served)
Southwest Connecticut	Bridgeport, Darien, Easton, Fairfield, Greenwich, New Canaan, Norwalk, Redding, Ridgefield, Stamford, Weston, Westport, Wilton, Ansonia, Branford, Beacon Falls, Bethany, Bethel, Bridgewater, Brookfield, Cheshire, Danbury, Derby, East Haven, Hamden, Meriden, Middlebury, Milford, Monroe, Naugatuck, New Fairfield, New Milford, New Haven, Newtown, North Branford, North Haven, Orange, Oxford, Prospect, Roxbury, Seymour, Shelton, Sherman, Southbury, Southington, Stratford, Trumbull, Wallingford, Waterbury, Watertown, West Haven, Wolcott, Woodbridge, Woodbury.

Figure 2-1 shows the geographic map of the study area with the five subareas delineated and Figure 2-2 shows the one-line diagram for the SWCT study area.

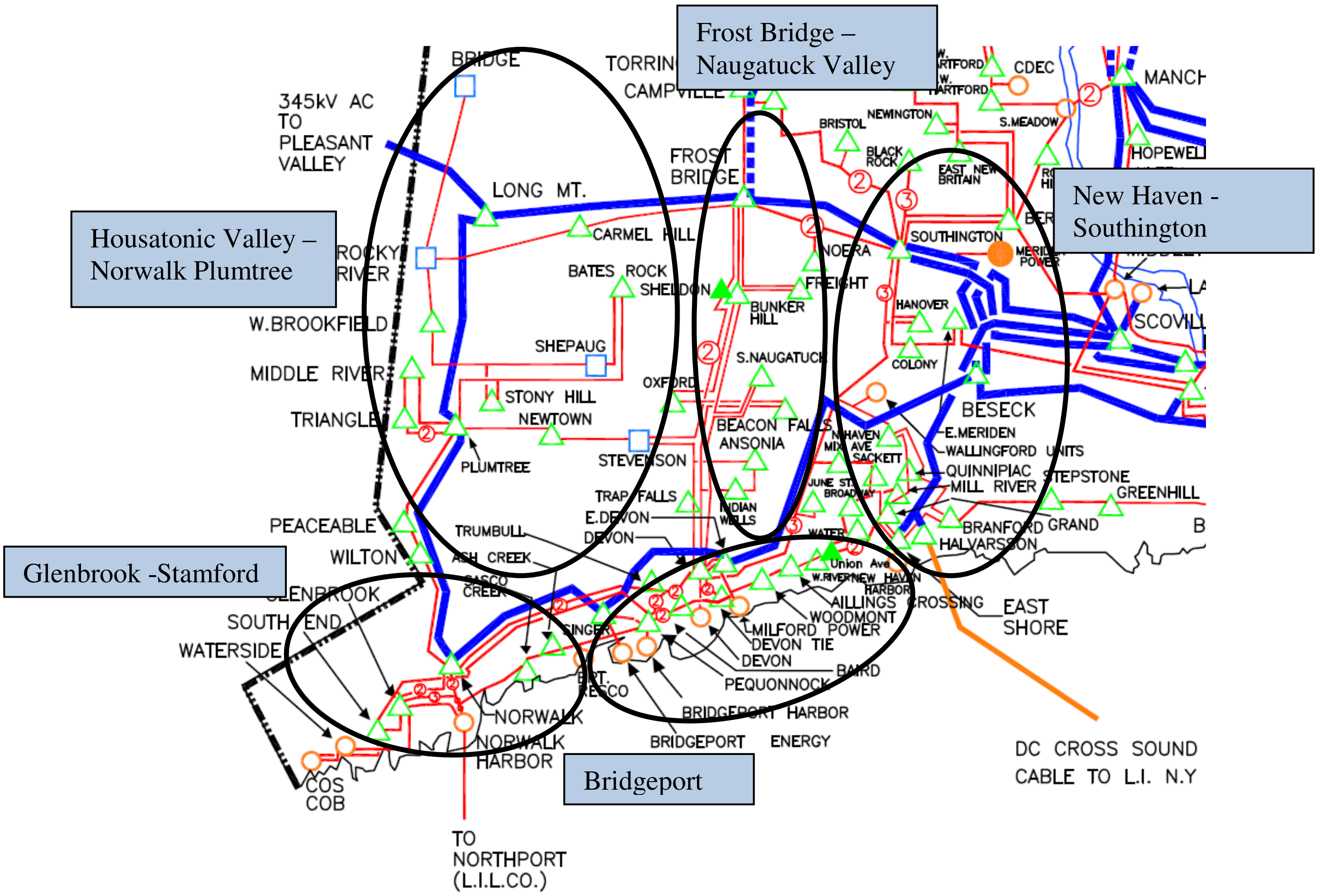

Figure 2-1: SWCT Study Area Map

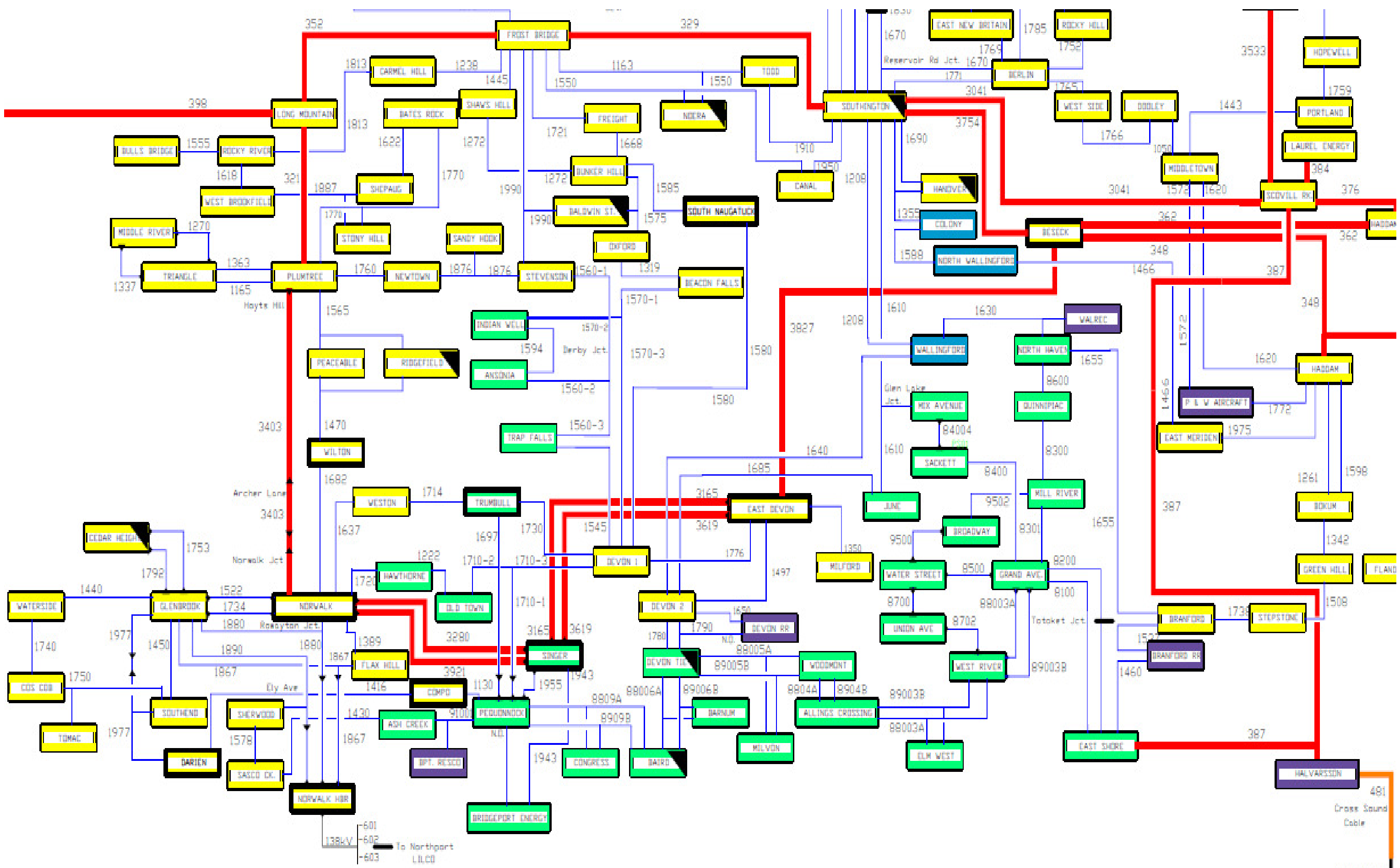

Figure 2-2: SWCT Study Area One Line Diagram[5]

[5] The diagram is for illustrative purposes to show the study area. It does not show any future projects in the area. These items were included in the base case models. I can't comment on a footnote, so I will do it like this. This says that it doesn't show future projects, but it seems like it is missing existing projects, like that new station that Bruce McKinnon asked about in the RSP listing.

The study area is located inside the Southwest Connecticut Import interface. It borders the New England to New York interface along the Connecticut state border. Various import levels from New York to New England through the AC ties, and export levels through the Cross Sound Cable (CSC) due to its FCM Administrative De-List bid were modeled and studied for this Needs Assessment[6]. The transfer across the Norwalk Northport Cable (NNC) was set at 0 MW in all base cases. Figure 2-3 shows the interfaces impacting the study area.

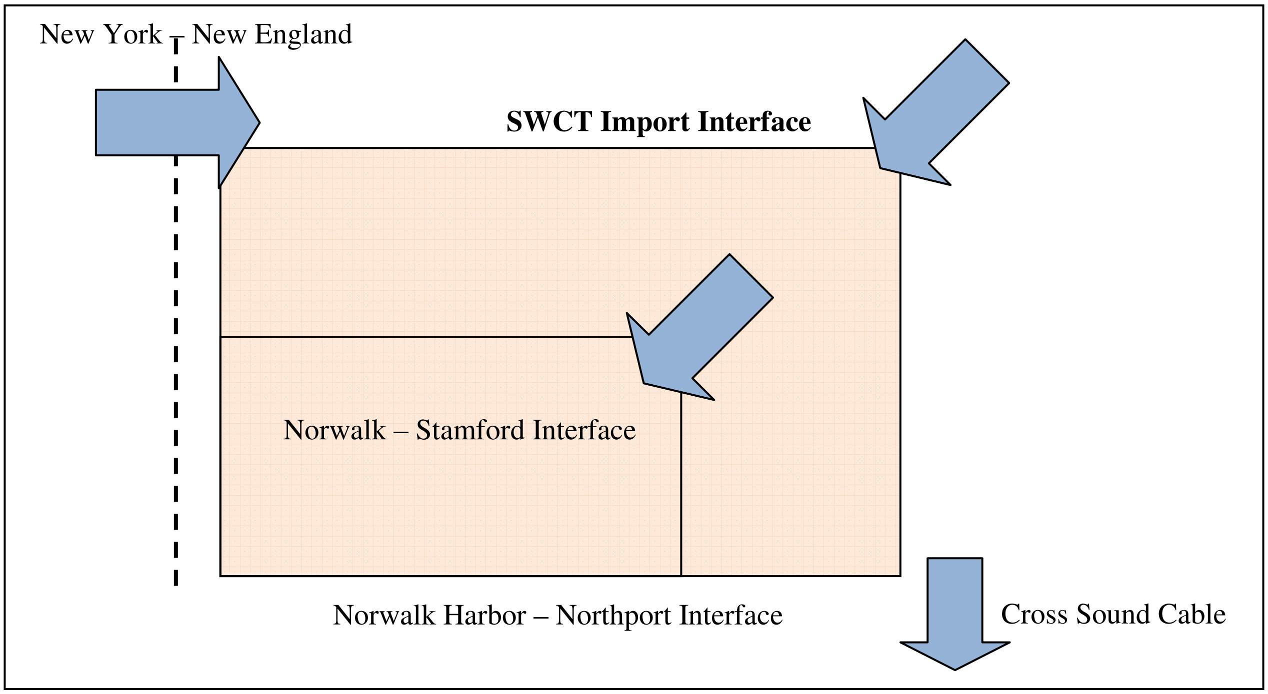

Figure 2-3: Interfaces Impacting the SWCT Study Area

2.3 Study Horizon

This study was initiated in late 2012 with a 10-year look ahead at the projected 2022 peak demand load level. The loads are based on the most recent CELT report, issued in May 2013[7].

2.4 Analysis Description

The study included the evaluation of the reliability of the transmission system serving the Southwest Connecticut study area for the projected system conditions in 2022. The system was tested under N-0 (all-facilities-in), N-1 (all-facilities-in, first contingency), and N-1-1 (facility-out, first contingency) conditions for a number of possible operating scenarios with respect to related interface transfer levels and generating unit unavailability conditions.

[6] For N-0 and N-1 testing, the ISO no longer supports reliability needs for export to other areas. See Section 3.1.9 for details.

[7] The 2013 CELT Report, published in May 1, 2013, is available at http://www.iso-ne.com/trans/celt/report/index.html.

The following type of analysis was performed:

- **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 steady-state studies to evaluate the severity of the impact of North American Electric Reliability Corporation (NERC) Category D Transmission Planning System Standard 004 (TPL-004)[8], extreme contingencies on transmission system performance. A thermal or voltage violation arising from this analysis may not necessarily demonstrate a reliability need in the study area.
- **Short Circuit Analysis** – studies to determine the ability of substation equipment to withstand and interrupt fault current.

For the various elements having thermal violations and for buses with voltage violations, a critical load level assessment was performed to determine the Connecticut load level at which these violations would be eliminated.

The following analyses may be performed during the Solutions Study phase:

- **Stability Analysis** – detailed studies to determine if any substations would be classified as BPS[9] (Bulk Power System) elements with the addition of the proposed solutions.

The Needs Assessment was performed in accordance with relevant NERC, NPCC, and ISO criteria as described in Section 4.2.1.

The thermal, voltage, and extreme contingency analysis was performed using Siemens PTI PSS/E v32.2.1 and PowerGEM TARA v7.02 software. The short circuit analysis was performed using ASPEN.

[8] Transmission Planning (TPL) System Standard 004: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), published February 2005; available at http://www.nerc.com/files/TPL-004-0.pdf.

[9] In accordance with NPCC document A-10: Classification of Bulk Power System Elements (https://www.npcc.org/Standards/Criteria/A-10-Revised%20Full%20Member%20Approved%20December%2001,%202009%20GJD.pdf)

Section 3 Study Assumptions

3.1 Steady State Model Assumptions

3.1.1 Study Assumptions

The regional steady-state model was developed to be representative of the 10-year projection of the 90/10 summer peak system demand levels to assess reliability performance under stressed system conditions. The 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-NE Planning Procedure No. 3(PP-3), "Reliability Standards for the New England Area Bulk Power Supply System".

3.1.2 Source of Power Flow Models

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

3.1.3 Transmission Topology Changes

Transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff, as of the October 2012 RSP Project Listing, have been included in the study base case. A comprehensive list of projects modeled in the base case can be seen in Appendix B: Future Projects Modeled and Case Summaries A listing of the major projects in Massachusetts, Rhode Island, and Connecticut is included below.

Massachusetts

- Auburn Area Transmission System Upgrades (RSP ID: 59, 887, 921, 919)
- Merrimack Valley / North Shore Reliability Project (RSP ID: 775-776, 782-783, 840)
- Long Term Lower SEMA Upgrades (RSP ID: 592, 1068, 1118)
- Central/Western Massachusetts Upgrades (RSP ID: 924- 929, 931-932, 934-935, 937- 950, 952- 955)
- NEEWS – Greater Springfield Reliability Project (RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105)
- Advanced NEEWS Interstate Projects (RSP ID: 1202, 1342)
- NEEWS – Interstate Reliability Project (RSP ID: 190, 1094, 1202, 1293, 1342)
- Salem Harbor Retirement Upgrades (RSP ID: 1257-1259)
- Pittsfield/Greenfield Project (RSP ID: 1208-1210, 1221-1226) [10]

Rhode Island

- Greater Rhode Island Transmission Reinforcements (RSP ID: 484, 786, 788, 790-793, 913-918, 1098)
- NEEWS – Rhode Island Reliability Project (RSP ID: 795, 798-800, 1096-1097, 1099, 1106, 1109, 1331)
- NEEWS – Interstate Reliability Project (RSP ID: 794, 1233-1234, 1252, 1294-1298)
- Chase Hill (Crandall Street) Substation (RSP ID: 1253)

[10] The Pittsfield/Greenfield Project received its PPA approval in December 2012 and is in Table A of March 2013 RSP Project Listing.

Connecticut

- NEEWS – Greater Springfield Reliability Project (RSP ID: 816, 1054, 1369-1371, 1378)
- NEEWS – Interstate Reliability Project (RSP ID: 191, 802, 810, 1085, 1090-1091, 1235, 1245)
- Northeast Simsbury Substation 115 kV Circuit Breaker Project (RSP ID: 1230)
- Millstone 345 kV Circuit Separation & SLOD SPS System Retirement (RSP ID: 1218)
- Advanced SWCT – Line 8300 Reconfiguration (RSP ID: 1246)
- Advanced SWCT – Glenbrook to South End 115 kV Cable (RSP ID: 1228)
- Line 1990 Asset Condition Replacement Project (RSP ID: 1229)
- SWCT Minimum Load Project – Haddam Neck 150 MVAR shunt reactor (RSP ID: 1400)

The Central Connecticut Reliability Project (CCRP) component of the NEEWS projects has received PPA approval, but was excluded since the needs for these upgrades are being reassessed as a part of the GHCC Needs Assessment.

Other PPA approved SWCT projects, which were presented at the June 18, 2012 PAC meeting, were also excluded since this study is reassessing the need for those upgrades.

In addition to the new transmission projects in Connecticut that were added during the Needs Assessment, any changes to element ratings or impedances as a part of the base case update process were captured on an ongoing basis. These upgrades may have varied some of the line ratings or impedances to reflect the most accurate future system condition. A significant change in this area was the cable rating updates made by the Transmission Owners as a result of their latest cable survey in July 2013. The Long Term Emergency (LTE) and Short Term Emergency (STE) ratings on portions of the 3921, 3280, 3165, and 3619 345 kV cables were slightly decreased.[11]

3.1.4 Generation Additions & Retirements

Generation projects with a FCM Capacity Supply Obligation as of Forward Capacity Auction 7 (FCA #7) were included in the study base case. All generation projects that cleared in FCA #1 through FCA #7 in Connecticut and Rhode Island are either withdrawn or are in operation by February 1, 2014. A listing of the recent major new future projects cleared in FCA #1 through FCA #7 and not yet in service in Massachusetts is included below.

Massachusetts

- QP 089 – Cape Wind Turbine Generators (FCA #7)
- QP 196 – Northfield Mountain Uprate 88 MW (FCA #4, #6, and #7)
- QP 387 – Combined Cycle Unit (FCA #7)

In March 2012, the Ansonia generation unit (QP-193) withdrew its PPA. As a result the Ansonia generation has been removed from the case. The generator had previously cleared in FCA #2.

During FCA #4, FCA #5, FCA #6, and FCA #7, a dynamic delist was submitted for Bridgeport Harbor 2 for the commitment periods of June 2013 – May 2014, June 2014 – May 2015, June 2015 – May 2016, and June 2016 – May 2017. Subsequently, on September 16, 2013 a Non-Price Retirement (NPR) Request for this resource was submitted for FCA #8. Following a reliability review

[11] *Southwest Connecticut 2022 Needs Assessment II, Slide 9,* (February 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/feb192014/a9_swct_needs_assessment_2.pdf

by ISO-NE, the NPR request was accepted on October 16, 2013. As a result, for this study, the Bridgeport Harbor 2 unit was assumed OOS as a base case condition.

Additionally, during FCA #5 and FCA #6 a dynamic delist bid was submitted for the AES Thames unit for the commitment periods of June 2014 – May 2015 and June 2015 – May 2016. Subsequently, on September 18, 2012, a Non-Price Retirement Request was submitted for this resource; following a reliability review by ISO-NE, the Non-Price Retirement Request was accepted on November 19, 2012. For this study, the AES Thames unit was assumed OOS as a base case condition.

On September 30, 2013 a Non-Price Retirement request for Norwalk Harbor Station (Norwalk Harbor 1, 2 and 10) was submitted for the FCA #8 commitment period. The NPR request was accepted on December 20, 2013. As a result, the Norwalk Harbor Station was assumed out–of-service as a base condition.

A summary of Non-Price Retirement (NPR) requests in CT is provided in Table 3-1.

Table 3-1 Summary of Non-Price Retirement Requests in CT

Resource Name	Summer Qualified Capacity (MW)	NPR Request Date	NPR Determination Date
AES Thames	182.653	9/18/2012	11/19/2012
Bridgeport Harbor 2	0.000	9/20/2013	10/16/2013
John Street 3	2.000	9/26/2013	10/16/2013
John Street 4	2.000	9/26/2013	10/16/2013
John Street 5	1.900	9/26/2013	10/16/2013
Norwalk Harbor 1	162.000	9/30/2013	12/20/2013
Norwalk Harbor 2	168.000	9/30/2013	12/20/2013
Norwalk Harbor 10	11.925	9/30/2013	12/20/2013

All other NPR requests across New England through FCA-8 were also modeled as OOS in the study base case.

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

3.1.5 Explanation of Future Changes Not Included

The following projects were not added:

- Transmission projects that have not been fully developed and have not received PPA approval as of the October 2012 RSP Project Listing. These projects were not modeled in the study base case due to the uncertainty concerning their final development or lack of an impact on the SWCT study area

- Transmission Projects that have been added to the project listing since the October 2012 project listing update, but do not have a significant impact on the study area
- Southwest Connecticut solution alternatives, which were proposed as a result of the SWCT Preferred Solution – New Haven and Bridgeport Areas presentation delivered to PAC in June 2012, were not included[12] because the need for these projects was revisited as part of this Needs Assessment
    - Four advanced SWCT projects (RSP ID: 1246, 1228, 1229, 1400) listed in Section 3.1.3 were included in the study
- Additionally, the NEEWS – Central Connecticut Reliability Project components (RSP ID: 576, 1114, 1372, 1373) have PPA approval but were not included in the base case since the need for these components are under re-assessment in the GHCC study

3.1.6 Forecasted Load

A ten-year planning horizon was used for this study based on the most recently available Capacity, Energy, Loads, and Transmission (CELT) Report issued in May 2013. This study was based on the forecasted 2022 peak demand load levels for the ten-year horizon.

The 2022 summer peak 90/10 demand forecast for New England is 34,105 MW.

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 system, the actual system load modeled in the case was reduced to account for system losses which are explicitly calculated in the system model. Therefore, the actual system load modeled in the case was reduced to account for transmission system losses which are explicitly calculated in the system model. Load distributions in the case are based on the most recent 2013 MMWG case library data.

Demand Resources (DR) are treated as capacity resources in the Forward Capacity Auctions (FCA). DR is split into two major categories, Passive and Active DR. Passive DR is largely comprised of energy efficiency and is expected to lower the system demand during designated peak hours in the summer and winter. Active DR is commonly known as Demand Side Management (DSM) and can be dispatched on a zonal basis if a forecasted or real-time capacity shortage occurs on the system. Starting in 2012, forecasting passive DR has become part of the annual load forecasting process. This forecast takes into account additional electrical efficiency (EE) savings beyond FCM results across the ten-year planning horizon. This forecast is primarily based on forecasted financial investment in state-sponsored EE programs and its correlation with historical data on reduction in peak demand per dollar spent. This EE forecast was published in the annual CELT Report beginning in spring 2012. Active DR are modeled in the base case at the levels of the most recent Forward Capacity Auction (FCA #7), multiplied by a Performance Factor of 75% based on historical performance of similar resources. Passive DR are modeled at 2022 levels based on the passive DR cleared through FCA #7 (2010-2016) and the aforementioned EE forecast for the years until 2022 (2017-2022). In addition, Active and Passive DR levels in Connecticut were scaled down to account for the submission of several Non-Price Retirement Requests for FCA #8 and DR terminations post-FCA #7.

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[12] *SWCT Preferred Solution –New Haven and Bridgeport Area*, (June 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/jun192012/swct_solution.pdf

Starting in 2010, DR values are now published in the CELT Report. Because DR is modeled at the low-side of the distribution bus in the power-flow model, all DR values were increased by 5.5% to account for the reduction in losses on the local distribution network. Passive DR is modeled by load zone and Active DR are modeled by dispatch zone. The amounts modeled in the cases are listed in Table 3-2 and Table 3-3and detailed reports can be seen in Table 7-3 in Appendix A: Load Forecast.

Table 3-2:
2022 Passive DR Values: DR through FCA #7 and EE Forecast

Load Zone	Passive DR (FCA-1-7) DRV[13] (MW)	Passive DR Terminations DRV[13] (MW)	Passive DR NPR DRV[13] (MW)	EE Forecast (2017-2022) DRV[13] (MW)	Total Passive DR DRV[13] (MW)
Maine	159	-5	-4	56	206
New Hampshire	80	-3	0	53	130
Vermont	125	-5	0	89	209
Northeast Massachusetts & Boston	341	-10	0	276	607
Southeast Massachusetts	194	-9	0	147	332
West Central Massachusetts	245	-10	0	165	400
Rhode Island	142	-5	0	114	251
Connecticut	417	-25	-8	139	523
New England Total	1,703	-72	-12	1,039	2,658

[13] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter; these totals are forecasted values for the commitment period beginning June 1, 2022. These values exclude transmission and distribution losses.

Table 3-3:
FCA #7: Active DR Values through FCA #7

Dispatch Zone	Active DR (FCA-1-7) DRV[14] (MW) (Includes DR terminations in CT)	Active DR NPR DRV[14] (MW)	Total Active DR DRV[14] (MW)
Bangor Hydro	56	-29	27
Maine	207	-64	143
Portland, ME	32	-5	27
New Hampshire	49	-27	22
New Hampshire Seacoast	12	-8	4
Northwest Vermont	38	-13	25
Vermont	25	-12	13
Boston, MA	81	-23	58
North Shore Massachusetts	36	-16	20
Central Massachusetts	51	-13	38
Springfield, MA	33	-14	19
Western Massachusetts	78	-44	34
Lower Southeast Massachusetts	20	-10	10
Southeast Massachusetts	121	-75	46
Rhode Island	74	-21	53
Eastern Connecticut	49	-12	37
Northern Connecticut	100	-16	84
Norwalk-Stamford, Connecticut	37	-3	34
Western Connecticut	117	-13	104
New England Total	1,216	-416[15]	800[15]

3.1.7 Load Levels Studied

Consistent 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 state-by-state summary of the load modeled in the 2022 cases, taking into account transmission and distribution losses, is shown in Table 3-4. A more detailed report of the loads modeled and how the numbers were derived from the CELT values can be seen in Appendix A: Load Forecast in Table 7-3.

[14] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter; these totals are forecasted values for the commitment period beginning June 1, 2022. These values exclude transmission and distribution losses.

[15] May not sum exactly due to rounding.

Table 3-4
Load Levels to be Studied (losses included)

State	2022 CELT 90/10 Load (MW)
Maine	2,450[16]
New Hampshire	3,150
Vermont	1,220
Massachusetts	16,055
Rhode Island	2,405
Connecticut	8,825
New England Total	34,105

After taking into account the aforementioned transmission losses, the contributions of demand resources and forecasted EE, and the addition of non-CELT and station service loads, the actual load level modeled in the base cases for this study is approximately 29,730 MW.

Recently, a minimum load levels (8,500 MW NE load level) study was completed which analyzed the entire state of Connecticut for potential high voltage violations. The study identified needs[17] and a preferred solution[18]. Since this study was recently completed, there is not a current need to perform a dedicated minimum load study for the Southwest Connecticut study area.

3.1.8 Load Power Factor Assumptions

Load power factors consistent with the local transmission owner's planning practices were applied uniformly at each substation. Demand resource 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 Table 7-2.

3.1.9 Transfer Levels

In accordance with the reliability criteria of the NERC, 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 Section 8. The following external transfers will be utilized for the study. For N-0 and N-1 testing, ISO no longer supports reliability needs for export to other areas[19].

Table 3-5
Interface Levels Tested

	N-1	N-1-1

[16] The value does not include 365 MW of paper mill load where the mills have on site generation located behind their meter.

[17] The Final SWCT Minimum Load Need Assessment Report, published in November 2012, is available at https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/swct_min_loads_needs.pdf

[18] The SWCT Minimum Load Analysis Solution Study Report has been posted to PAC on June 12, 2013 at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2013/a_swct_minimum_load_analysis_solutions_study_final_report.pdf

[19] Scenario 'A', which represents cases with New England exporting 1200 MW to New York, was no longer tested.

	B	C	D
New England to New York	0	-1200	0
Cross Sound Cable to NY	100	100	0
Norwalk-Northport Cable to NY	0	0	0
Highgate HVDC to NE	200	200	200
Phase II HVDC to NE	2000	1500	2000
New Brunswick to New England	1000	200	1000

For this Needs Assessment the generation dispatch dictated the internal transfer levels.

3.1.10 Generation Dispatch Scenarios

All generators in the base case are modeled with a maximum capacity corresponding to their qualified capacity as of FCA #7.

Table 3-6 shows the qualified capacities of the generating units in the study area, excluding hydro units.

Table 3-6
Qualified Generating Capacities of Study Area Units

Generating Unit	Qualified Capacity (MW)	Fast-Start[20] Unit
A. L. Pierce	77.5	No
Bridgeport Energy 10	162.2	No
Bridgeport Energy 11	160.8	No
Bridgeport Energy 12	160.8	No
Bridgeport Harbor 3	401.2	No
Bridgeport Harbor 4	18.0	Yes
Bridgeport Resco	65.7	No
Branford 10	16.2	Yes
Cos Cob 10	19.5	Yes
Cos Cob 11	21.8	Yes
Cos Cob 12	18.7	Yes
Cos Cob 13	18.0	Yes
Cos Cob 14	18.0	Yes
Devon 10	17.2	Yes
Devon 11	33.5	No
Devon 12	33.5	No
Devon 13	33.9	No
Devon 14	33.5	No
Devon 15	49.7	Yes

[20] "Fast-start" generators are those units that can go from being off-line to their full Seasonal Claimed Capability in 10 minutes. These units do not need to participate in the 10-minute reserve market to be considered a fast-start unit in planning studies.

Generating Unit	Qualified Capacity (MW)	Fast-Start[20] Unit
Devon 16	49.7	Yes
Devon 17	49.7	Yes
Devon 18	49.7	Yes
Kimberly Clark C1	6.0	No
Kimberly Clark C2	6.0	No
Kimberly Clark ST	2.0	No
Milford 1	272.8	No
Milford 2	272.8	No
New Haven Harbor 1	483.4	No
New Haven Harbor 2	51.0	Yes
New Haven Harbor 3	51.0	Yes
New Haven Harbor 4	51.0	Yes
Wallingford 1	43.1	Yes
Wallingford 2	43.6	Yes
Wallingford 3	43.8	Yes
Wallingford 4	43.5	Yes
Wallingford 5	43.6	Yes
Waterbury	103.8	Yes
Waterside 1	24	No
Waterside 2	24	No
Waterside 3	24	No

At all locations in the study area where a single fast-start unit was available, that unit was assumed OOS for each dispatch. For subareas where there were multiple fast-start units, one of the fast-start units was taken out of service and the rest were assumed online and available in that subarea. For example, if the Wallingford 5 unit was assumed OOS then the Wallingford 1-4 units were assumed to be in service.

The Connecticut fast-start units were dispatched such that approximately 80% of the fast-start capability in Connecticut was online. The most up-to-date voltage schedules obtained from the Operation Procedure 12 (OP-12) were utilized in this study. The fast-start dispatch assumptions detailed above were turned on in the base case and no adjustments were made to these fast start units post first contingency.

The performance of the hydroelectric units in the study area was examined and it was determined that an availability of 10% of its nameplate capacity at summer peak was a reasonable assumption. This assumption was extended to all the Connecticut hydro units. The exception to this assumption was the Rocky River and Shepaug hydro units. Historical output data has shown that Rocky River and Shepaug units should be considered out of service during peak load times.

Table 3-7 provides the outputs assumed for the hydro units in Connecticut for units above 5 MW.

Table 3-7
Dispatch of Hydro Units in Connecticut

Unit Name	Dispatched Amount (MW)	Name Plate (50 degree rating - MW)	Location
Stevenson Hydro	2.9	28.9	SWCT
Rocky River	OFF	29.4	SWCT
Shepaug	OFF	42.9	SWCT
Derby Dam	0.7	7.1	SWCT
Bulls Bridge	0.8	8.4	NWCT
Rainbow Hydro	0.8	8.2	Manchester/ Barbour Hill
Falls Village	1.0	9.8	NWCT

Previously, seventeen dispatches were set up for the study. Taking into consideration the retirement of the Norwalk Harbor 1 & 2 units, a total of eleven dispatches were studied in the SWCT Needs Assessment. The dispatches were set up by taking one or two critical units out of service. Table 3-8 lists the detailed dispatches for the study area, including four one-unit-out dispatches and seven two-units-out dispatches.

Table 3-8
Generation Dispatches

Unit	1	2	3	4	5	6	7	8	14	15	16
Bridgeport Energy	OFF	ON	ON	ON	OFF	ON	OFF	ON	ON	ON	OFF
Milford Power 1	ON	ON	ON	ON	ON	OFF	ON	ON	ON	ON	ON
Milford Power 2	ON	OFF	ON	ON	OFF	OFF	ON	OFF	ON	OFF	ON
Bridgeport Harbor 3	ON	ON	OFF	ON	ON	ON	OFF	OFF	OFF	ON	ON
New Haven Harbor 1	ON	ON	ON	OFF	ON	ON	ON	ON	OFF	OFF	OFF

All the non-RTEG units with the exception of fast start units not mentioned in Table 3-6 were assumed to be in service for all dispatches.

3.1.11 Reactive Dispatch Assumptions

All area shunt reactive resources were assumed available and dispatched when required. 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 played a significant role in the study area can be found in the power flow case summaries included in Section 8.

3.1.12 Demand Resources

As stated in Section 3.1.6, Passive DR as forecasted for the year 2022 and Active DR that cleared as of FCA-7 in 2013 were modeled for this study, minus demand resources that have accepted NPR Requests for FCA #8. Passive DR was assumed to perform to 100% of their qualified amount. The passive DR included the forecasted EE which was assumed to perform to 100% of the forecast. Active DR was assumed to perform to 75% of their qualified amount. A summary of assumed DR performance is shown in Table 3-9. Real Time Emergency Generation (RTEG) was not modeled, consistent with all needs and solutions planning analyses.

Table 3-9
New England Demand Resource Performance Assumptions

Region	Passive DR	Active DR	Forecasted EE	RTEGs
New England	100%	75%	100%	0%

3.1.13 Protection and Control System Devices Included in the Study Area

There are five relevant Special Protection Systems and two relevant control schemes in the study area:

- New Haven Harbor SPS
- Bridgeport Harbor # 3 SPS
- 1570 line section, Derby Junction to Indian Well (47P) SPS
- East Shore – Halvarsson – Scovill Rock 387 Line End Open (LEO) Scheme
- Southington 4C Substation Auto-Throwover Scheme
- Southington 4C Autotransformer Automatic Isolation and Reclosing Scheme
- New Haven Harbor Unit 1U Torsional Stress SPS

They are described in detail separately below.

The New Haven Harbor SPS is a Type III SPS. It reduces generation at New Haven Harbor station in order to prevent excessive flows on the cables from Grand Avenue to West River (88003A/89003B) and the cable from Grand Avenue to Water Street (8500). This SPS uses measurements on the Grand Avenue end of these lines. These measurements are used to activate either manual or automatic reduction of generation at New Haven Harbor, or trip off the unit.

Bridgeport Harbor #3 SPS is a Type III SPS, which reduces generation at the Bridgeport Harbor station to reduce flow on circuits carrying power away from the Pequonnock-8J substation. The specific objective of this SPS is to prevent excessive flows on the thermally limiting sections of the 1710/1697 and 8809A/8909B circuits. The thermally limiting sections of the 1710/1697 circuits are between Pequonnock and Seaview Tap and between the Congress and Baird sections of the 8809A/8909B circuits. Measurements for this SPS are taken by overcurrent relays at Pequonnock substation for the 1710/1697 circuits and at Baird substation for the 8809A/8909B circuits. These measurements are used to activate either manual or automatic reduction of generation at Bridgeport Harbor 3 to reduce flows on the 1710/1697 or 8809A/8909B circuits.

1570 line section, Derby Junction to Indian Well (47P) is also a Type III SPS. This SPS is in place to automatically relieve an overload on the 1570 line section from Derby Junction to Indian Well (47P). The SPS will monitor the 1570 line flow at Indian Well (47P), sense an overload condition, and send a signal to Ansonia (6R) by audio tone to open the 1560-6R-5. The operation of the 1560-6R-5 will redirect the flows on the transmission system and eliminate the overload on the 1570 line.

East Shore – Halvarsson – Scovill Rock 387 Line End Open (LEO) Scheme: Scovill Rock P22 is equipped with a Type III SPS. Operation of the Scovill Rock Halvarsson – Tomson 481 line SPS transmits a signal to the Halvarsson Converter Station 14P and will result in blocking the Cross Sound Cable HVDC facilities (0 MW and 0 MVAR) whether the flow is from Connecticut to Long Island or Long Island to Connecticut.

- [redacted]
- The SPS is used to prevent having an open ended 387 line at Scovill Rock, [redacted]
- The total operating time of the SPS, from sensing the line end open condition to blocking the Cross Sound Cable's converter is approximately 4.25 seconds.

Southington 4C Substation Auto-Throwover Scheme: The Southington 4C substation is equipped with an Automatic Ring Tie Breaker Closing Scheme [redacted]

- The 4C-19T-2 115 kV ring tie breaker is operated normally open. [redacted]
- The 4C-19T-2 breaker will remain closed until opened either manually or by SCADA.

Currently, ISO-NE operating procedures do not respect the Southington 4C Substation Auto-Throwover Scheme. However, as part of this analysis the performance of the system with and without the scheme in service was evaluated.

Southington 4C Autotransformer Automatic Isolation and Reclosing Scheme: At Southington 4C, upon detection of a fault within the protected zone the basic relaying of the transformer will immediately open its associated 345 kV and 115 kV circuit breakers, isolating the faulted transformer. After this, the disconnects on the faulted transformer also open isolating the transformer at the disconnect level. This allows the 345 kV and 115 kV breakers to safely automatically reclose to restore the 345 kV and 115 kV ring bus (the transformer remains isolated via its disconnects). The total elapsed time for these automatic control systems to operate is roughly tens of seconds. These automatic control systems are active whenever the protection and reclosing schemes are in service and all associated control switches are in their normal position. Currently, ISO-NE operating procedures do not respect the Southington 4C autotransformer automatic isolation and reclosing scheme. However, as part of this analysis the performance of the system with and without the scheme in service was evaluated.

New Haven Harbor Unit 1U Torsional Stress SPS: The 1U unit at New Haven Harbor is equipped with a Type III SPS. This SPS is activated by a torsional stress relay that monitors the sub-synchronous oscillations on the generator shaft. The primary action of this SPS will block the Cross Sound Cable HVDC facility. If oscillations persist following the primary action, a secondary action of the relay will trip the New Haven Harbor Unit 1U. This SPS is designed to protect the shaft of the New Haven Harbor unit from torsional stress by first removing the most likely cause of these oscillations and then, if the oscillations persist, tripping the unit itself.

3.1.14 Explanation of Operating Procedures and Other Modeling Assumptions

The SWCT area transmission power flows are managed on a daily basis through the use of generation dispatch, HVDC flows, and phase shifting transformers. The Halvarsson Converter station (Cross Sound Cable) typically is set to a fixed MW flow level from NE to NY. In addition, the automatically adjusting Northport Phase Angle Regulator (PAR) and manually adjustable Sackett Substation PAR provide further control of power flows within the SWCT area. These HVDC and PAR devices are set to balance power flows under normal conditions and are adjusted to mitigate power flows post contingency, as necessary. Adjustment of the Sackett Phase Shifter was not considered during this analysis. Each controlling device is described in the following sections.

Halvarsson Converter Station (Cross Sound Cable): the Cross Sound Cable (CSC) is a 330 MW, HVDC interconnection between the Shoreham Station on Long Island, New York and New Haven, Connecticut. The line connecting the two converter stations, the Halvarsson Converter Station 14P and the 8ZN Tomson Converter Station, has been designated the Halvarsson-Tomson 481 line. The Halvarsson converter station uses its reactive output capability to control the 345 kV bus to a target of 357 kV.

Sackett Phase Shifter: this phase shifter operates in a manual mode only and is normally set in the Raise 3 Tap (-1.875°) which tends to draw power flow from Grand Avenue through this phase shifter towards Mix Avenue substation. The tap may need adjustment for certain post contingency and planned outage operating conditions to either improve southern Connecticut transfers or alleviate potential N-1 and N-1-1 overload conditions. The tap is always returned to the Raise 3 position when the system is returned to the normal or pre-contingency configuration.

Northport Phase Shifter: The Phase Shifter is used to control the load flow on Norwalk Harbor-Northport 601, 602 and 603 Cables. The Phase Shifter is equipped for operation by automatic or supervisory control from the Long Island Power Authority (LIPA) System Operating Center and by local control from the Northport Control House. Normally, the control will be automatic. Normally, the loading of Norwalk Harbor-Northport 601, 602 and 603 Cables will be as agreed by ISO-NE System Operator and NYISO Shift Supervisor. In an emergency, the CONVEX System Operations Supervisor may request a change in loading on this line directly to the LIPA System Operator, and then notify the ISO-NE System Operator. Similarly, the LIPA System Operator may change the loading on this line and then notify the CONVEX System Operations Supervisor. The Phase Shifter is normally computer controlled, and will respond to changes in flow in the following manner:

- If the actual flow exceeds the scheduled flow by greater than the dead-band entered by the LIPA System Operator (usually +/- 20 MW) and lasts at least one minute, the regulator will change at the rate of one tap a minute. If another Long Island phase shifter is also changing taps, the regulator will change at the rate of one tap every two minutes.
- The phase shifter has a total of 65 taps available through two tap changers, one on the Load-side of the phase shifter and the other on the Source-side of the phase shifter. The two tap changers are operated alternately and are never more than one tap apart.
- At full load and at the extreme taps, Northport can lead Norwalk Harbor by 50.3 degrees or Northport can lag Norwalk Harbor by -65.7 degrees.
- The operator can manually change taps at one tap each 30 seconds.

The change in flow per degree is in the order of 25 MW per tap. Therefore, the flow on the cable may be changed as follows:

- Automatic 25 MW per minute, and

• Manual 50 MW per minute.

There is a one-minute delay before the automatic operation begins.

A change of 50 MW or more on any individual LIPA tie line will cause the Northport Phase Shifter to trip off "Automatic" control and will not be returned to "Automatic" control until both NYISO and ISO-NE agree to that return. The Northport Phase Shifter will not trip off "Automatic" control for any LIPA tie line deviation of less than 50 MW. Note also that the Northport Phase Shifter will trip off "Automatic" control for a tie line deviation of 50 MW or greater in either direction, in to, or out of, LIPA. Therefore, within 1 minute of a change of less than 50 MW on the 601, 602 and 603 Cables, the Phase Shifter will begin returning the 601, 602 and 603 Cables flow to the scheduled flow. If returning to schedule is not desired, communication with the LIPA system operator is required, requesting that the Phase Shifter be placed in "Manual" until system adjustments have been completed. If it is anticipated that such support may be required for an emergency, advance arrangements should be made with the LIPA system operator.

3.2 Stability Modeling Assumptions

Not applicable for this study.

3.3 Short Circuit Model

3.3.1 Study Assumptions

The short circuit study evaluated the projected 2022 available fault current levels around the SWCT area. It also included the effects of area reliability project upgrades as well as selected proposed generation interconnection projects as outlined in Sections 3.3.3 and 3.3.4 of this study document.

3.3.2 Short Circuit Model

The ASPEN Circuit Breaker Rating Module software was used to calculate all circuit breaker duties. The case for the short circuit study was obtained from the 2013 short circuit base case library and all PPA approved projects, as discussed in Section 3.1.3 of this scope document, were added to that model.

3.3.3 Generation Additions & Retirements

The model included proposed generation interconnection projects that have PPA approval as well as those generator projects that have FCA Capacity Supply Obligations (CSOs).

The following relevant proposed generation projects were modeled for this study:

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

The non-price retirements of Norwalk Harbor 1, 2, and 10 as well as Bridgeport Harbor 2 were reflected in the short circuit basecase.

3.3.4 Generation and Transmission System Configurations

NPCC Regional Reliability Reference Directory #1, "Design and Operation of the Bulk Power System" and PP 3 require short circuit testing to be conducted with all transmission and generation facilities in-service for all potential operating conditions.

3.3.5 Boundaries

This study included testing of all 115 kV and 345 kV substations and breakers in the Southwest Connecticut study area.

3.3.6 Other Relevant Modeling Assumptions

Not applicable to this document.

3.3.7 Other System Studies

Not applicable to this document.

Section 4
Analysis Methodology

4.1 Planning Standards and Criteria

The applicable NERC, NPCC and ISO-NE standards and criteria were tested as part of this evaluation. Descriptions of each of the NERC, NPCC and ISO-NE standard tests that were 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 "Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System", dated 04/30/12, and ISO Planning Procedure No. 3, "Reliability Standards for the New England Area Bulk Power Supply System", dated 03/01/13. The contingency analysis steady-state voltage and loading criteria, solution parameters and contingency specifications that were used in this analysis are consistent with these documents.

As a part of this needs analysis the robustness of the system with respect to limited extreme contingency events was evaluated.

4.2.1.1 Thermal and Voltage Limits

Loadings on all transmission facilities rated at 115 kV and above in the study area were monitored. The thermal violation screening criteria defined in Table 4-1 was applied.

Table 4-1
Steady-State Thermal Criteria

System Condition	Maximum Allowable Facility Loading
All Lines In	Normal Rating
Post-Contingency	Long Time Emergency (LTE) Rating

Voltages were monitored at all buses with voltages 115 kV and above in the study area. System bus voltages outside of limits identified in Table 4-2 were identified for all normal (pre-contingency) and post-contingency conditions.

Table 4-2
Steady-State Voltage Criteria

Facility Owner	Voltage Level	Bus Voltage Limits (Per-Unit) Normal Conditions (Pre-Contingency)	Emergency Conditions (Post-Contingency)
Northeast Utilities	69 kV and above	0.95 to 1.05	0.95 to 1.05
CMEEC	115 kV and below	0.95 to 1.05	0.95 to 1.05
United Illuminating	115 kV and above	0.95 to 1.05	0.95 to 1.05
Millstone / Seabrook[21]	345 kV	1.00 to 1.05	1.00 to 1.05
Pilgrim[21]	345 kV	0.995 to 1.05	0.99 to 1.05
Vermont Yankee[21]	345 kV	0.985 to 1.05	0.985 to 1.05
Vermont Yankee[21]	115 kV	1.00 to 1.05	1.00 to 1.05

4.2.1.2 Solution Parameters

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

Table 4-3
Study Solution Parameters

Case	Area Interchange Control	Tap Adjustments	Adjust Phase Shift	Switched Shunt Adjustments
Base	Tie Lines and Loads Enabled	Stepping	Enabled	Enabled
Contingency	Disabled	Stepping	Disabled[22]	Disabled

4.2.2 Stability Performance Criteria

Not applicable to this document.

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

[22] Results with NNC PARs 'Disabled' are being reported in this Needs Assessment report. To accurately model the operation of the NNC PARs as described in Section 3.1.15, the Adjust Phase Shift setting was also set to 'Enabled' for post-contingency analysis. Comparison of the PARs 'Enabled' vs. 'Disabled' results show that most of the time NNC PARs should be disabled since the change of flow post contingency was either greater than 50 MW causing NNC PARs loss of automatic control, or within its dead-band set by LIPA (usually at +/- 20 MW) so the automatic control feature of the PAR would not bring back the post contingency flows to pre-contingency flow (0 MW). So the worst violations remained the same, indicating that the post –contingency flows through NNC did not alleviate the violations.

4.2.3 Short Circuit Performance Criteria

This study was performed in accordance with appropriate IEEE C37 standards and specific design parameters of the circuit breakers. This includes specific considerations for total-current rated and symmetrical-current rated breakers as appropriate.

The circuit breakers were evaluated for short circuit adequacy based on the following criteria:

- *Acceptable-duty*: Circuit breaker fault interrupting duty less than 90% of the available fault current. No action required.
- *Marginal-duty*: Circuit Breaker Fault Interrupting Duty greater than or equal to 90% and less than 100%. This is an acceptable operating condition; however, potential solutions should begin to be developed to address solutions that would require a significant lead time to complete.
- *Over-duty Condition*: Circuit Breaker Fault Interrupting Duty greater than 100%. This is considered an unacceptable operating condition requiring a solution to be developed to eliminate the over-duty condition.

4.3 System Testing

4.3.1 System Conditions Tested

Testing of system conditions included the evaluation of system performance under a number of resource outage scenarios, variation of related transfer levels, and an extensive number of transmission equipment 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. In addition, single contingencies which may cause the loss of multiple transmission circuit facilities, such as those on a common set of tower line structures were simulated. The steady-state contingency events in this study also include circuit breaker failures and substation bus fault conditions that could result in removing multiple transmission elements from service. A comprehensive set of contingency events, listed in Section 9 were tested to monitor thermal and voltage performance of the Southwest Connecticut study area transmission network. A listing of all contingency types that were tested is included in Table 4-4.

Additional analyses evaluated N-1-1 conditions with an initial outage of a Pool Transmission Facility (PTF) transmission element 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, regional reliability standards, including ISO Planning Procedure 3, allow specific manual system adjustments, such as fast-start generation re-dispatch, phase-angle regulator adjustment or HVDC adjustments prior to the next single contingency event. The N-1-1[23] analysis also considered the operation of Line Switching Automation ("LSA") for the line out scenario, which is briefly explained as follows.

Line Switch Automation ("LSA") is a reclosing scheme designed to operate post-contingency to restore un-faulted elements that were tripped because it is included in the zone of protection of the faulted element, e.g. step-down transformers that are included in a transmission line's zone of

[23] LSA operation was tested in N-1 contingency analysis, but was not reported in the body of the report because the results are less severe than the results of N-1-1 contingency analysis.

protection. In most cases, the operation of the LSA scheme improves system conditions such that post-contingent violations are avoided and the system is postured to reduce exposure to reliability criteria violations that could result from the next contingency. For example, a permanent line fault will result in a sustained outage of an entire line after correct protection system operations and any unsuccessful reclose attempt(s). An LSA scheme would typically occur in less than a minute to automatically open a line disconnect at each terminal of the line that has a LSA scheme. The operation of the LSA scheme "sectionalizes" the system such that the unfaulted equipment that was isolated with the faulted equipment can be restored automatically while the faulted equipment remains out-of-service. The LSA scheme initiates an automatic restoration sequence which includes closing breakers at the associated terminal(s) to re-energize the un-faulted bus sections and associated transformers up to the previously opened line disconnect.

If there was a difference in loss of load with and without LSA (Line Switching Automation) action, then the line-out scenario was modeled with and without LSA action[24]. If there was no difference in loss of load with and without LSA action, then the line out scenario was modeled without the LSA action only.

A class of contingencies is the loss of elements without a fault. A distinction was made in this assessment based on the nature of a no-fault contingency as follows:

- Type 1: No-fault contingencies involving the opening of a terminal of a line independent of the design of the terminating facility
- Type 2: A subset of the above contingencies that involves the opening of a single breaker

For N-1 testing, all Type 1 contingencies above were simulated. However, for N-1-1 testing only the Type 2 contingencies were simulated as 2nd contingencies.

A listing of all contingency types that were tested is included in Table 4-4 and a summary of Element-out scenarios is provided in Table 4-5. A complete listing of the Element-out scenarios can be seen in Appendix C: Element Out for N-1-1 Analysis.

Table 4-4
Summary of NERC, NPCC and/or ISO-NE Category Contingencies to be Included

Contingency Type	NERC Type	NPCC D-1 Section	ISO PP-3 Section	Tested in This Study
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
Element w/o Fault	B5	5.4.1.d	3.1d	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 (Limited)

[24] Suffix 'LSA' to the line out scenario description in Table 4-5 indicates that line out scenario has been modeled with LSA action.

Table 4-5
Summary of N-1-1 First Element-Out Scenarios

Contingency Type	Number of Element Out Scenarios
Overhead 345 kV lines	12
Autotransformers	15
Generators	4
Underground 115 kV cables	12
Overhead 115 kV lines	106
Underground 345 kV cables	4
Reactive Devices	17
HVDC Line	1
Total Number of Scenarios	**171**

4.3.3 Generation Re-Dispatch Testing

As outlined in ISO Planning Procedure #3 (PP3), allowable actions after the first contingency event and prior to the second contingency event include re-dispatch of generation. To simulate these actions in power flow analysis, the Security Constrained Re-Dispatch (SCRD[25]) tool in the TARA software package was used.

During the analysis, all available generation within the study area was allowed to be reduced or turned off to mitigate a thermal violation. Proxy generation remote from the study area was used to replace the lost generation within the area of study to simulate the re-dispatch of fast-start units within New England to keep the load balanced. A maximum limit of 1200 MW of re-dispatch was considered acceptable. Anything higher than 1200 MW would not be considered acceptable due to the amount of reserves typically available on the system.

4.3.4 Critical Load Level (CLL) Analysis

For all violations that were not able to be resolved by the re-dispatch analysis, a critical load level analysis was performed to determine at what system load level the violation would first occur. This can then be used to determine the approximate year each violation could occur on the system.

For each criteria violation, the worst base case stress and contingency event pair were used to determine the CLL. The Connecticut load was scaled down, meanwhile generation far away in Maine, New Hampshire, Boston and southeastern Massachusetts was scaled down to maintain a balanced system.

For thermal criteria violations, the load was scaled down until the loading on the element was at or just below 100% of its LTE rating. For low voltage criteria violations, the load was scaled down until the substation voltage was above its applicable minimum limit (see Table 4-2 for limits). High voltage criteria violations were not tested because reducing area load would only increase the substation voltage making the violation worse.

[25] TARA's SCRD tool does not consider economics in the objective function to solve violation constraints. It solely uses the most effective generation that will resolve a particular constraint on the system.

After a study area critical load level was determined to resolve the violation, an approximate year of need was determined by comparing the study area CLL to the projected net load in Connecticut. Table 4-6 provides the net load expected in Connecticut for the 2013-2022 timeframe. The loads exclude the transmission losses. The details for the net load calculation are provided in Appendix I: Net Load in Connecticut Calculation.

Hence a critical load level of 7,400 MW indicates that the need is expected to be seen in 2016. For all loads below 7,055 MW, the year of need is prior to 2013. Note that that 2013 load in the table below is based on the 2013 summer peak load forecast in the 2013 CELT and is not the actual load for 2013.

Table 4-6: Projected Load in Connecticut 2013-2022 (Load – Available DR)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CT Load – DR (MW): Excluding Transmission Losses	7,055	7,165	7,292	7,456	7,568	7,620	7,677	7,721	7,777	7,819

4.3.5 Stability Contingencies / Faults Tested

Not applicable to this document.

4.3.6 Short Circuit Faults Tested

The ASPEN circuit breaker rating module software was used to calculate all circuit breaker duties. The pre-fault operating voltage for all the Southwest Connecticut study area buses was 1.04 per unit (p.u.). Figure 4-1shows the ASPEN options used in this study.

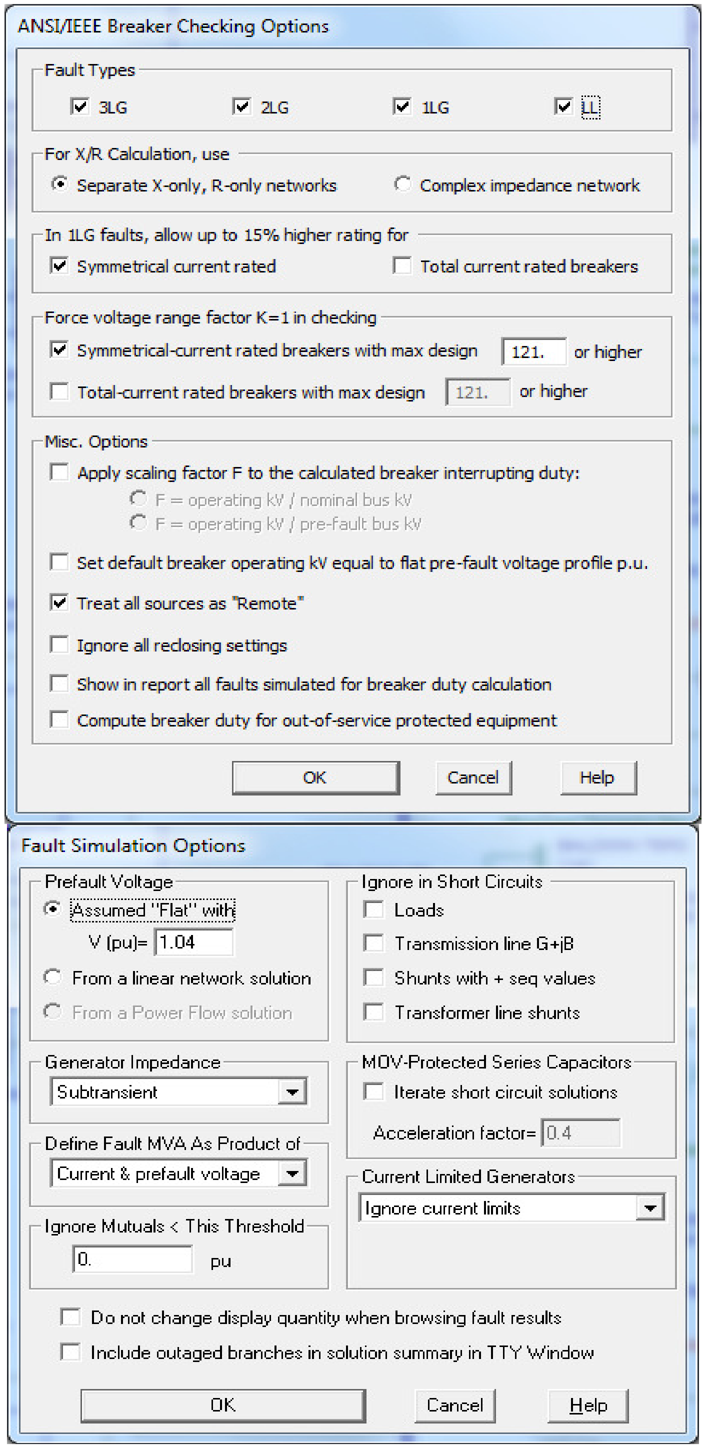

Figure 4-1: Circuit Breaker Testing Parameters

Section 5
Results of Analysis

5.1 Overview of Results

The 2022 SWCT study area load was 4361 MW after demand resources are subtracted. The total generation in the area is less than 3050 MW. The SWCT area is primarily an import area and depends on the transmission lines connecting the area to the rest of the system to serve load. A majority of the issues seen in the study area are load serving issues caused by the loss of key transmission elements OOS under N-1 and N-1-1 contingency conditions.

The criteria violations observed in the Needs Assessment indicate thermal and voltage violations in the four subareas seen mostly under generation deficiency conditions in each subarea. A number of issues are also seen when all the generation in a subarea is available thereby indicating that the issues are independent of generation dispatch.

As a part of the thermal and voltage analysis it was observed that criteria violations were seen to exist in both the one unit OOS and the two units OOS cases. In most cases there was very little difference in the extent of violation between the one unit OOS and the two units OOS cases. These results indicate that the violations are more a result of the local load and the contingencies applied rather than the specific generation dispatches.

The following section provides a description of each subarea in terms of total load in the subarea and some of the general characteristics that were seen for each subarea. The sections intend to provide a high level overview of the thermal and voltage concerns in each subarea.

5.1.1 Frost Bridge – Naugatuck Valley Subarea Overview

The Frost Bridge – Naugatuck Valley subarea net load for 2022 after demand resources being subtracted is about 652 MW. There are two hydro generation stations (Stevenson Hydro and Derby Dam) and one fast start unit (Waterbury) in this subarea. However, Waterbury is modeled OOS as a single fast start unit in the subarea, and Stevenson and Derby Dam are modeled to produce 10% of its nameplate capacity at summer peak based on historical performance of these hydroelectric units. As a result, the available generation totals about 3.6 MW in the Frost Bridge – Naugatuck Valley subarea.

Looking at the load and generation, it can be observed that the Frost Bridge – Naugatuck Valley subarea mainly rely on importing energy from the surrounding areas to serve local load. The major 115 kV lines that feed into the subarea are:

- Three 115 kV lines from Frost Bridge (Lines 1445, 1990, and 1721)
  - 1445: Frost Bridge – Shaws Hill
  - 1990: Frost Bridge – Baldwin St. – Stevenson
  - 1721: Frost Bridge – Freight
- Three 115 kV lines from Devon Ring 1 (Lines 1545, 1570, and 1580)
  - 1545: Devon 1 – Trap Falls
  - 1570: Devon 1 – Indian Well – Beacon Falls
  - 1580: Devon 1 – South Naugatuck
- Two 115 kV lines from Southington (Lines 1910 and 1950)

- 1910: Southington – Todd
- 1950: Southington – Canal

- One 115 kV line from Plumtree (Line 1876)
  - 1876: Newtown – Sandy Hook – Stevenson

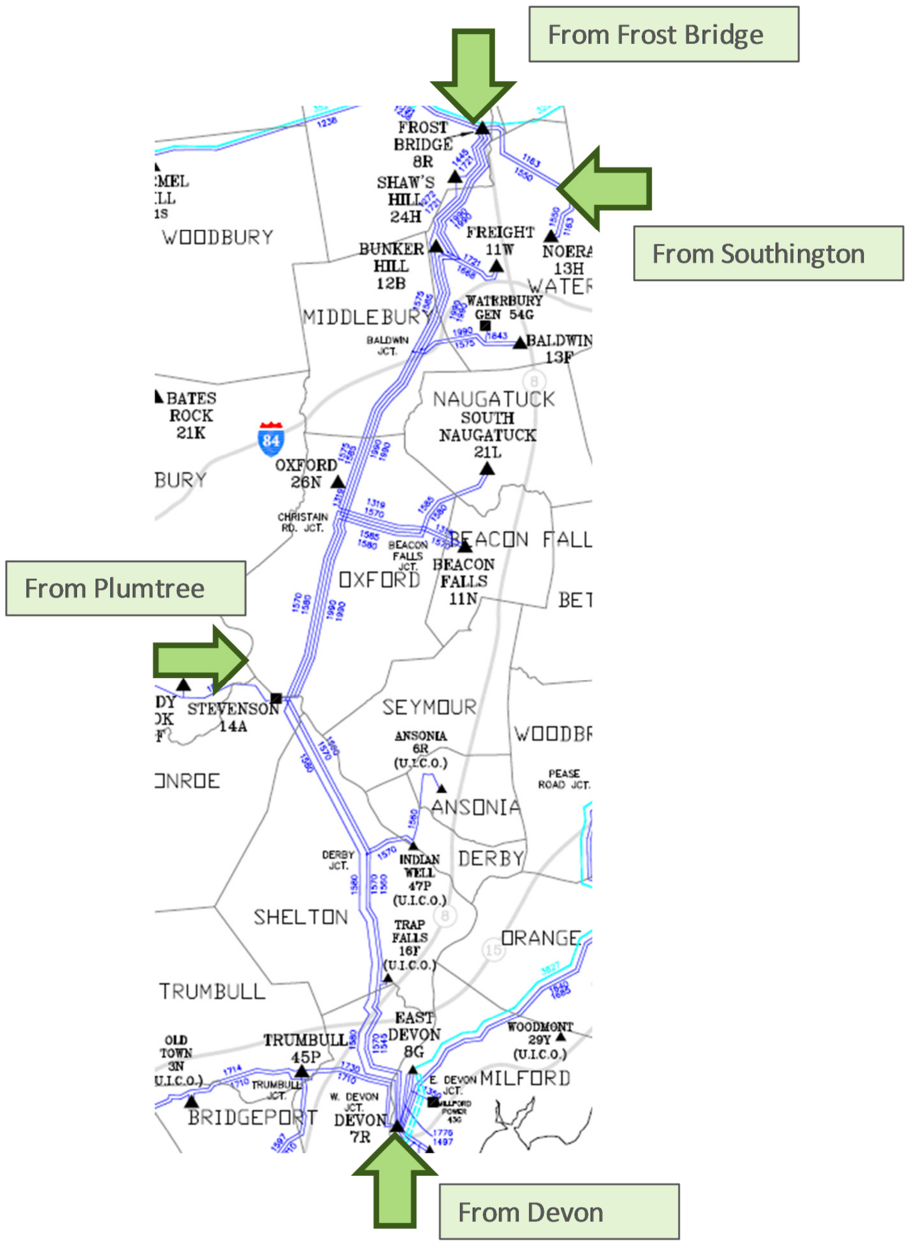

Figure 5-1: Frost Bridge – Naugatuck Valley Subarea

A couple N-1 thermal violations are seen in the Frost Bridge – Naugatuck Valley subarea. The majority are N-1-1 violations are caused by load pocket issues. [redacted] The remaining sources are insufficient to serve the entire connected load in the pocket.

Both N-1 and N-1-1 low voltage violations are seen in this subarea. The low voltage aggravates some thermal violations in this subarea.

5.1.2 Housatonic Valley / Norwalk – Plumtree Subarea Overview

The Housatonic Valley / Norwalk – Plumtree subarea net load for 2022 after demand resources being subtracted is about of 860 MW. There are three hydro units (Rocky River, Bulls Bridge, and Shepaug) and one conventional generation station (Kimberly Clark) in this subarea. Kimberly Clark is modeled to produce 28 MW to respect its Qualified Capacity. Rocky River and Shepaug are modeled OOS based on their historical performance, and Bulls Bridge is modeled at 0.8 MW which is 10% of its nameplate rating. The available generation is totaling about 28.8 MW in the Housatonic Valley / Norwalk – Plumtree subarea.

Since there is insufficient generation within, the Housatonic Valley / Norwalk – Plumtree subarea, the subarea is a net importer of energy and relies on importing energy from the surrounding areas to supply local loads. The major transmission elements that feed into the subarea are:

- Two Plumtree 345 / 115 kV autotransformers (Plumtree 1X and 2X)
- One 115 kV line from Norwalk (Line 1682)
  - 1682: Norwalk – Wilton
- One 115 kV line from Stevenson (Line 1876)
  - 1876: Stevenson – Sandy Hook – Newton
- One 115 kV line from Frost Bridge (Line 1238)
  - 1238: Frost Bridge – Carmel Hill

When one of the sources serving the subarea is lost due to an N-1 or N-1-1 contingency, the result is a thermal and/or voltage violation. [redacted]

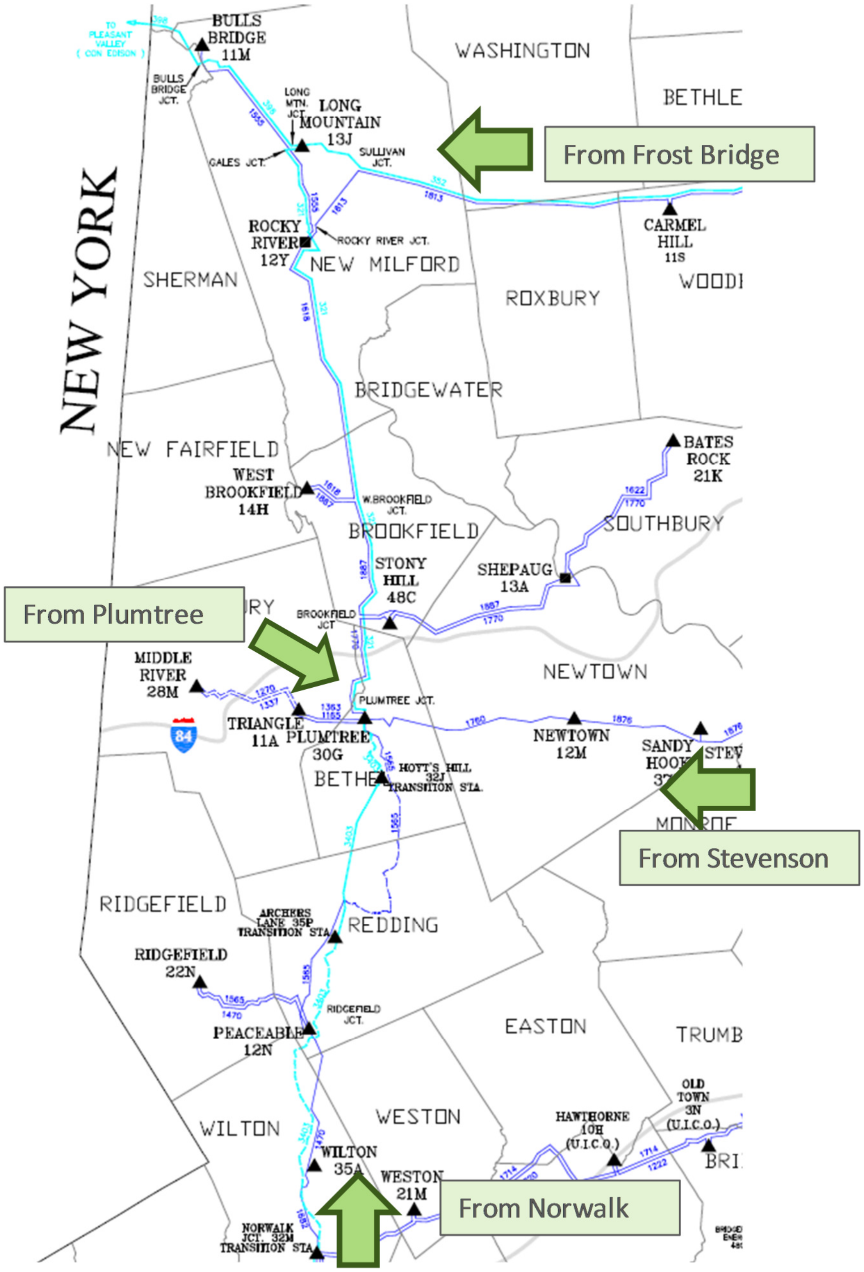

Figure 5-2: Housatonic Valley / Norwalk - Plumtree Subarea

5.1.3 Bridgeport Subarea Overview

The Bridgeport subarea net load for 2022 after demand resources being subtracted is about 511 MW. There are five conventional generation stations (Bridgeport Energy, Bridgeport Harbor 3, Bridgeport Resco, Milford 1 & 2, and Devon 11-14) and six fast start units (Bridgeport Harbor 4, Devon 10 and 15-18) in this subarea. The available on line generation capacity in the Bridgeport subarea varies from 815 MW to 1840 MW depending on the generation dispatches.

Compared to local load, the Bridgeport subarea is a generation rich area. It has surplus generation after supplying the local load. The surplus generation flows through the 115 kV or 345 kV lines to feed loads in the surrounding areas. The major transmission elements that connect the Bridgeport to the rest of New England transmissions system are:

- The 345/115 kV autotransformer at East Devon (East Devon 2X)
- The 345/115 kV autotransformer at Singer (Singer 2X)
- Four 115 kV lines from New Haven (Lines 1640, 1685, 88005A and 89005B)
    - 1640: Devon 2 – Wallingford
    - 1685: Devon 2 – June
    - 88005A: Devon Tie – Milvon – Woodmont
    - 89005B: Devon Tie – Milvon – Woodmont
- Two 115 kV lines from Norwalk (Lines 1130 and 91001)
    - 1130: Pequonnock – Compo
    - 91001: Pequonnock – Ash Creek

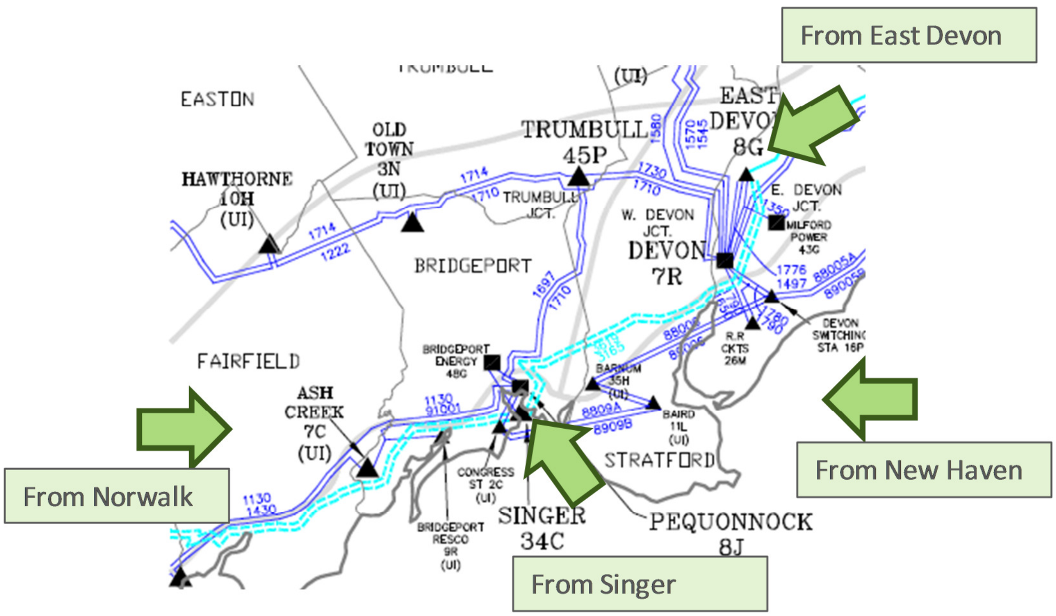

Figure 5-3: Bridgeport Subarea

[redacted]

[redacted]

5.1.4 New Haven – Southington Subarea Overview

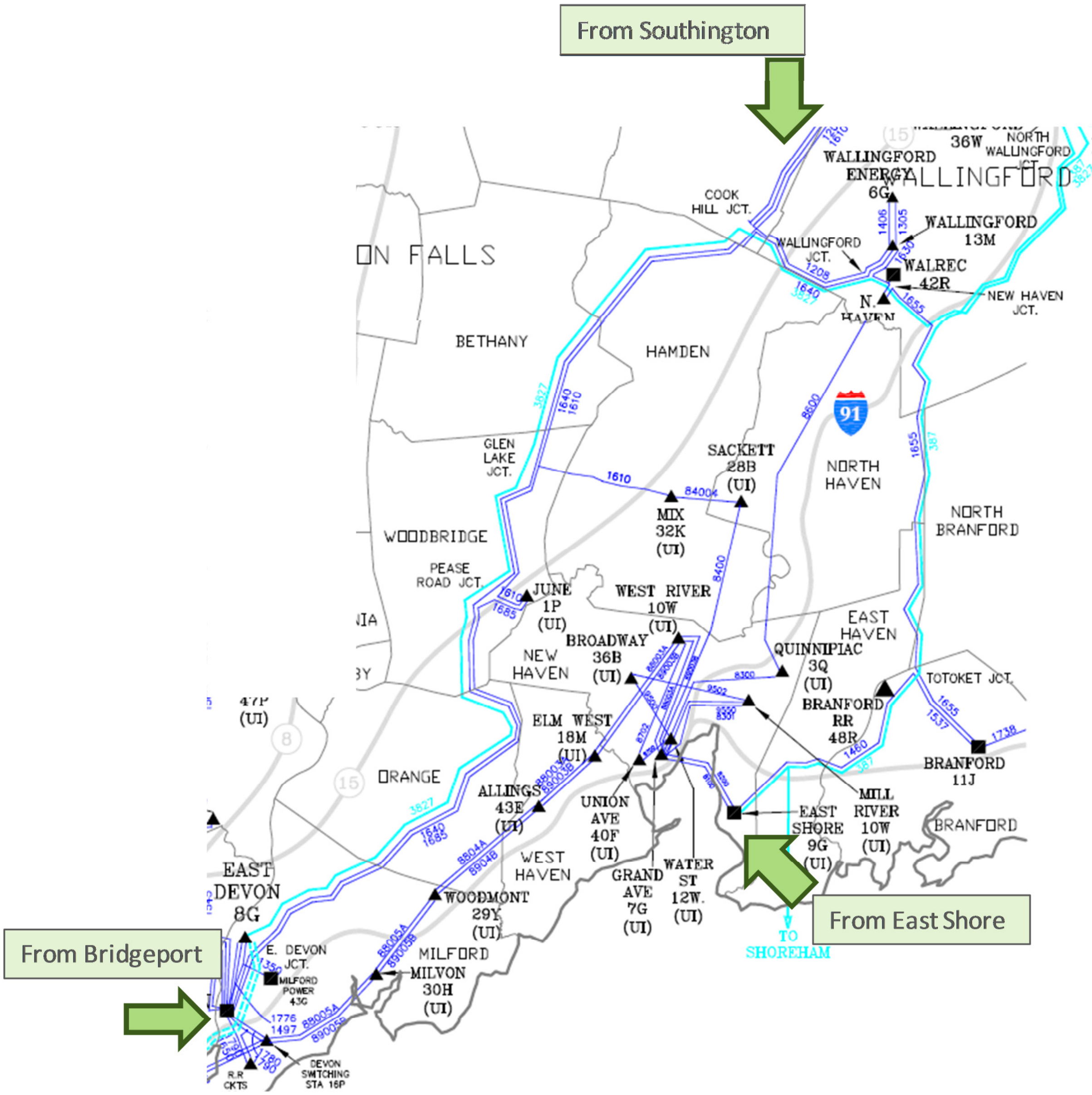

Figure 5-4: New Haven - Southington Subarea

The New Haven - Southington subarea net load for 2022 after demand resources being subtracted is about 1044 MW. There are three conventional generation stations (New Haven Harbor, A.L. Pierce, and Wallingford Refuse) and nine fast start units (New Haven Harbor Peakers 2-4, Branford 10, and Wallingford 1-5) in this subarea. Total available generation is 949 MW. The major transmission elements that feed into the subarea include:

- Two 345/115 kV autotransformers at East Shore (East Shore 8X and 9X)
- Two 115 kV lines from Southington (Lines 1208 and 1610)
  - 1208: Southington – Wallingford
  - 1610: Southington – Mix Avenue – June

- Four 115 kV lines from Devon and Devon Tie (Lines 88005A, 89005B, 1640, and 1685)
  - 1640: Devon 2 – Wallingford
  - 1685: Devon 2 – June
  - 88005A: Devon Tie – Milvon – Woodmont
  - 89005B: Devon Tie – Milvon – Woodmont

A majority of the criteria violations are seen under N-1-1 conditions in the New Haven - Southington subarea. [redacted]

5.1.5 Glenbrook – Stamford Subarea

The Glenbrook - Stamford subarea net load for 2022 after demand resources are subtracted is about 908 MW. There is one conventional generation station (Waterside) and five fast start units (Cos Cob 10-14) in this subarea. Total available generation is 167 MW.

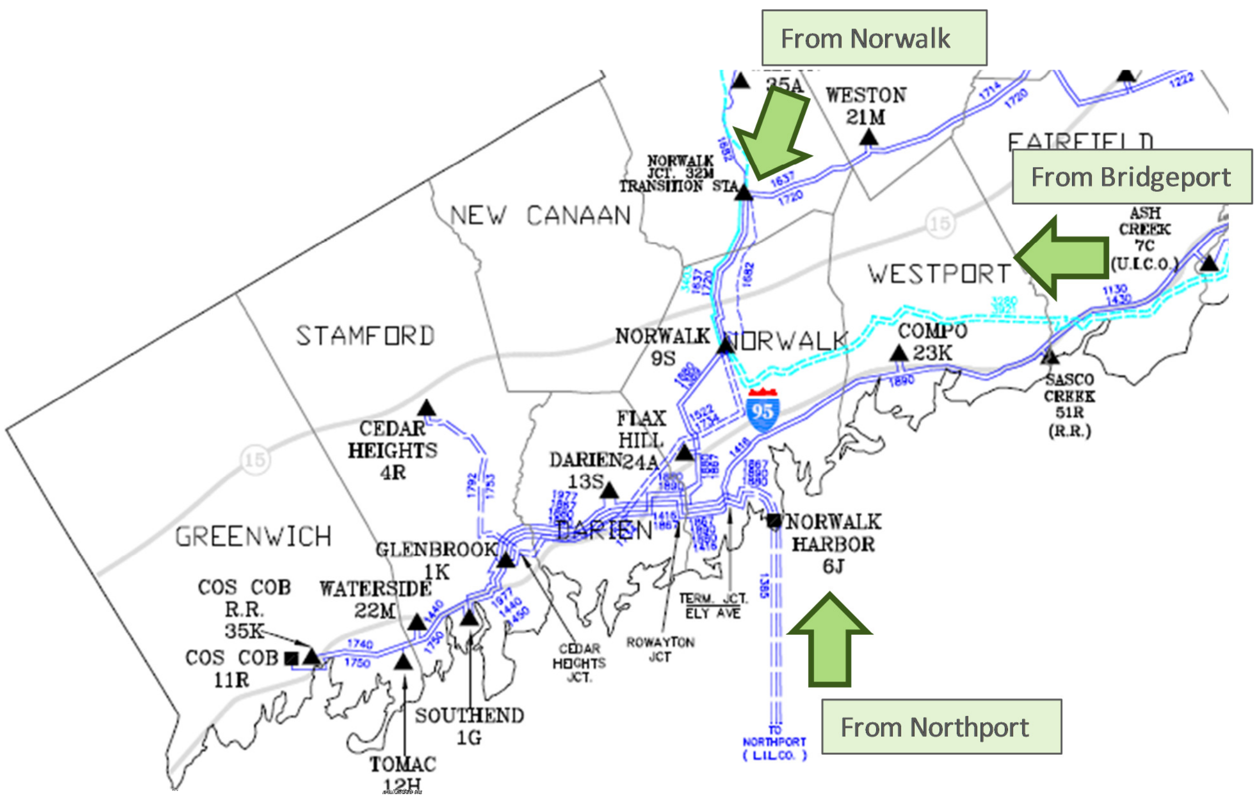

Figure 5-5: –Glenbrook – Stamford Subarea

The Glenbrook – Stamford subarea is a net energy importer. The major transmission elements that feed into the subarea include:

- One 138 kV path comprised of three underwater cables from Northport, Long Island
- Two 115 kV lines from Southington (Lines 1130 and 91001)
  - 1130: Pequonnock – Compo

- 91001: Pequonnock – Ash Creek

- Four 115 kV lines from Devon and Devon Tie (Lines 1389, 1522, 1734, and 1880)
  - 1389: Norwalk – Flax Hill
  - 1522: Norwalk – Glenbrook
  - 1734: Norwalk – Glenbrook
  - 1880: Norwalk – Glenbrook – Norwalk Harbor

Since the Glenbrook to South End 115 kV Cable project has been modeled in the base cases as described in Section 3.1.3, there are no thermal or voltage violations identified in the Glenbrook – Stamford subarea in this study.

5.1.6 Generation Re-Dispatch Analysis

Several thermal needs seen in this Needs Assessment were able to be eliminated through re-dispatch post first contingency prior to the second contingency. Details of the re-dispatch analysis can be seen in Appendix G: Generation Re-dispatch Results.

5.1.7 Critical Load Level Analysis

The critical load level for the majority of criteria violations in this study are prior to the projected 2013 summer peak with some violations occurring in 2014, 2015, 2016, and 2017. Detailed results for each violation can be seen in Section 5.2**.**

5.1.8 Short Circuit Test

Short circuit study results show that the study area has limited short circuit margins available at multiple substations. For further details refer to Section 5.4.

5.2 Steady State Performance Criteria Compliance

Results of the steady state testing are reported in this section by each subarea as below.

5.2.1 Frost Bridge – Naugatuck Valley Subarea

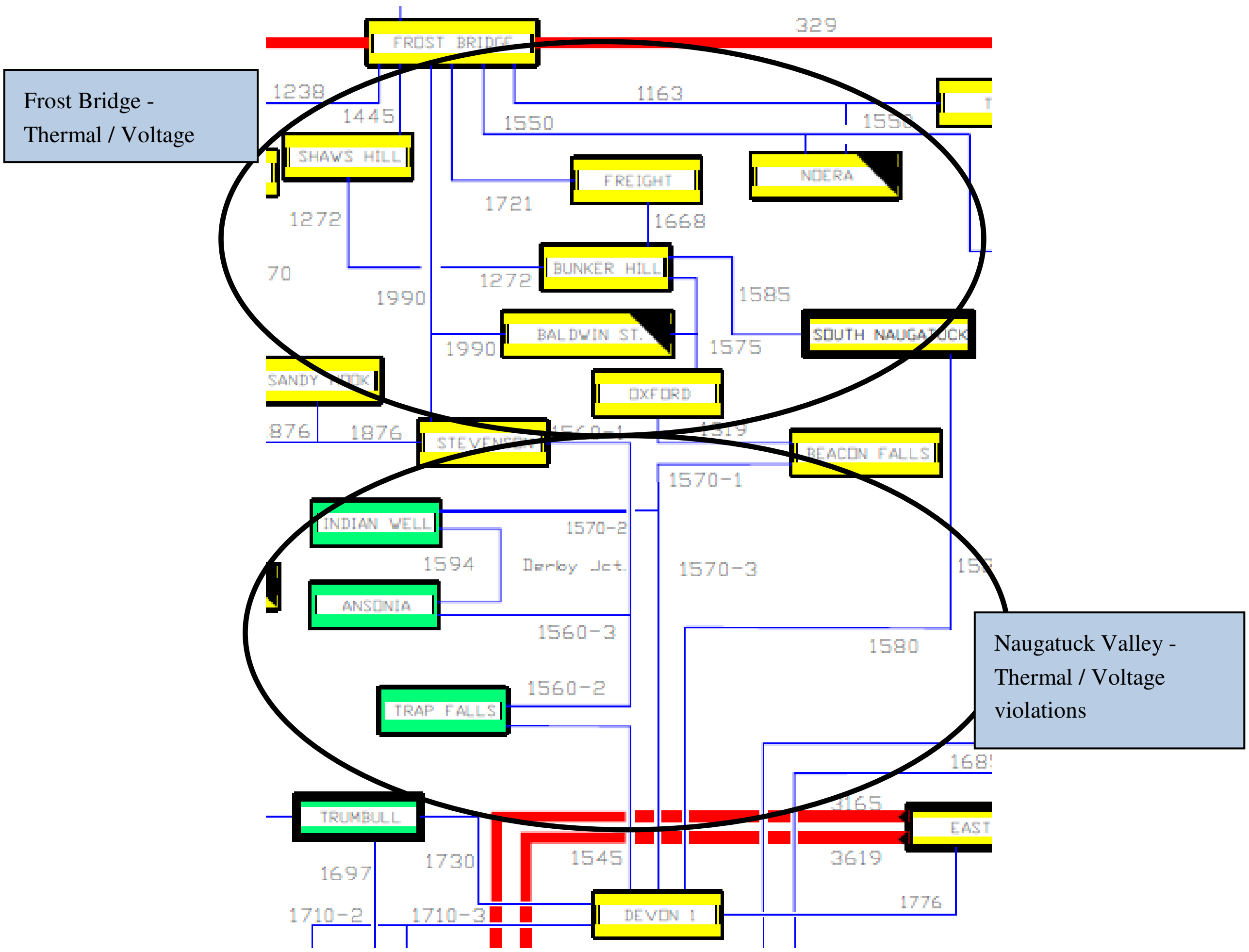

Figure 5-6: Frost Bridge – Naugatuck Valley Thermal and Voltage Violations

5.2.1.1 Results of N-0 Testing

There were no N-0 thermal or voltage violations found in the Frost Bridge – Naugatuck Valley subarea.

5.2.1.2 Results of N-1 Testing

N-1 testing indicated there were two LTE thermal violations in the Frost Bridge – Naugatuck Valley subarea, seen on the 1570-2 line (Derby Junction to Indian Well) and the 1580 line (Devon to South Naugatuck). Both were also STE thermal violations.

[redacted] The thermal overloading was aggravated by low voltage.

Table 5-1 summarizes the worst-case N-1 thermal violations in the Frost Bridge – Naugatuck Valley subarea. In this report, the worst dispatch is reported as a number corresponding to a specific generation dispatch defined in Table 3-8 and a letter corresponding to the transfer levels as discussed in Table 3-5. A diagram showing these N-1 thermal violations can be found in Section 5.2.1.3.

Table 5-1
N-1 Thermal Violations in Frost Bridge - Naugatuck Valley

[redacted]

N-1 testing also indicated there were 10 PTF buses and one non-PTF bus having low voltage violations in the Frost Bridge – Naugatuck Valley subarea. All the lowest N-1 voltage violations were caused by a DCT or a breaker failure contingency [redacted].

Table 5-2 and Table 5-3 summarize the worst-case 115 kV voltage violations for PTF and non-PTF buses in the Frost Bridge – Naugatuck Valley subarea. The corresponding diagram showing these N-1 voltage violations can be found in Section 5.2.1.3.

Table 5-2
N-1 PTF Low Voltage Violations in Frost Bridge - Naugatuck Valley

Element	kV	Worst Contingency	Worst Dispatch	Post Contingency Voltage (p.u.)
Shaws Hill	115	DC_1445_1721	8B	0.802
Freight				0.802
Bunker Hill	115	BF_BUNK_2-68	6B	0.743
Oxford				0.784
Beacon Falls				0.815
S-Naugatuck	115	BF_BUNK_2-72	6B	0.845
Trap Falls	115	DC_1545_1570	7B	0.926
Indian Well				0.911
Ansonia				0.917
Shelton				0.931

Table 5-3
N-1 non-PTF Low Voltage Violations in Frost Bridge - Naugatuck Valley

Element	kV	Worst Contingency	Worst Dispatch	Post Contingency Voltage (p.u.)
Baldwin St. 1975	115	BF_BUNK_2-68	6B	0.753

5.2.1.3 Results of N-1-1 Testing

The N-1-1 testing that was performed indicated there were 10 elements having thermal violations following N-1-1 contingency events in the Frost Bridge – Naugatuck Valley subarea. [redacted] The details of these thermal violations, including the corresponding critical load levels in terms of equivalent CT loads and the year of need, can be found in Table 5-4.

Table 5-4
N-1-1 Thermal Violations in Frost Bridge - Naugatuck Valley

[redacted]

The N-1 and N-1-1 thermal violations in the Frost Bridge – Naugatuck Valley subarea are illustrated in Figure 5-7, Figure 5-8, and Figure 5-9.

[redacted]

Figure 5-7: Thermal Violations in Upper Frost Bridge – Naugatuck Valley

[redacted]

Figure 5-8: Thermal Violations in Upper Frost Bridge – Naugatuck Valley

[redacted]

Figure 5-9: Thermal Violations in Lower Frost Bridge – Naugatuck Valley

Results of N-1-1 testing also indicated 12 PTF and three non-PTF buses having low voltage violations following N-1-1 contingency events in the Frost Bridge – Naugatuck Valley subarea. [redacted] Table 5-5 and Table 5-6 summarize the worst case dispatch and contingency pair of these voltage violations, including the corresponding critical load level in terms of equivalent CT load and the year of need.

Table 5-5
N-1-1 PTF Low Voltage Violations in Frost Bridge - Naugatuck Valley

[redacted]

[redacted]

** Violation exists below the Minimum Load Level

Table 5-6
N-1-1 non-PTF Low Voltage Violations in Frost Bridge - Naugatuck Valley

Element	kV	Initial Element OOS	Worst Contingency	Worst Dispatch	Post Contingency Voltage (p.u.)	CLL (MW)	Year of need
Baldwin 1575	115	LN_1319	DC_1272_1721	6D	0.227	1288**	Prior to 2013
Baldwin 1990	115	LN_1760	DC_1545_1570	14D	0.927	7005	Prior to
Waterbury				8D	0.927	7004	2013

** Violation exists below the Minimum Load Level

Figure 5-10 and Figure 5-11 illustrate the worst case N-1 and N-1-1 voltage violations in the Frost Bridge – Naugatuck Valley subarea.

[redacted]

Figure 5-10: Voltage Violations in Upper Frost Bridge – Naugatuck Valley

[redacted]

Figure 5-11: Voltage Violations in Lower Frost Bridge – Naugatuck Valley

5.2.2 Housatonic Valley / Norwalk – Plumtree

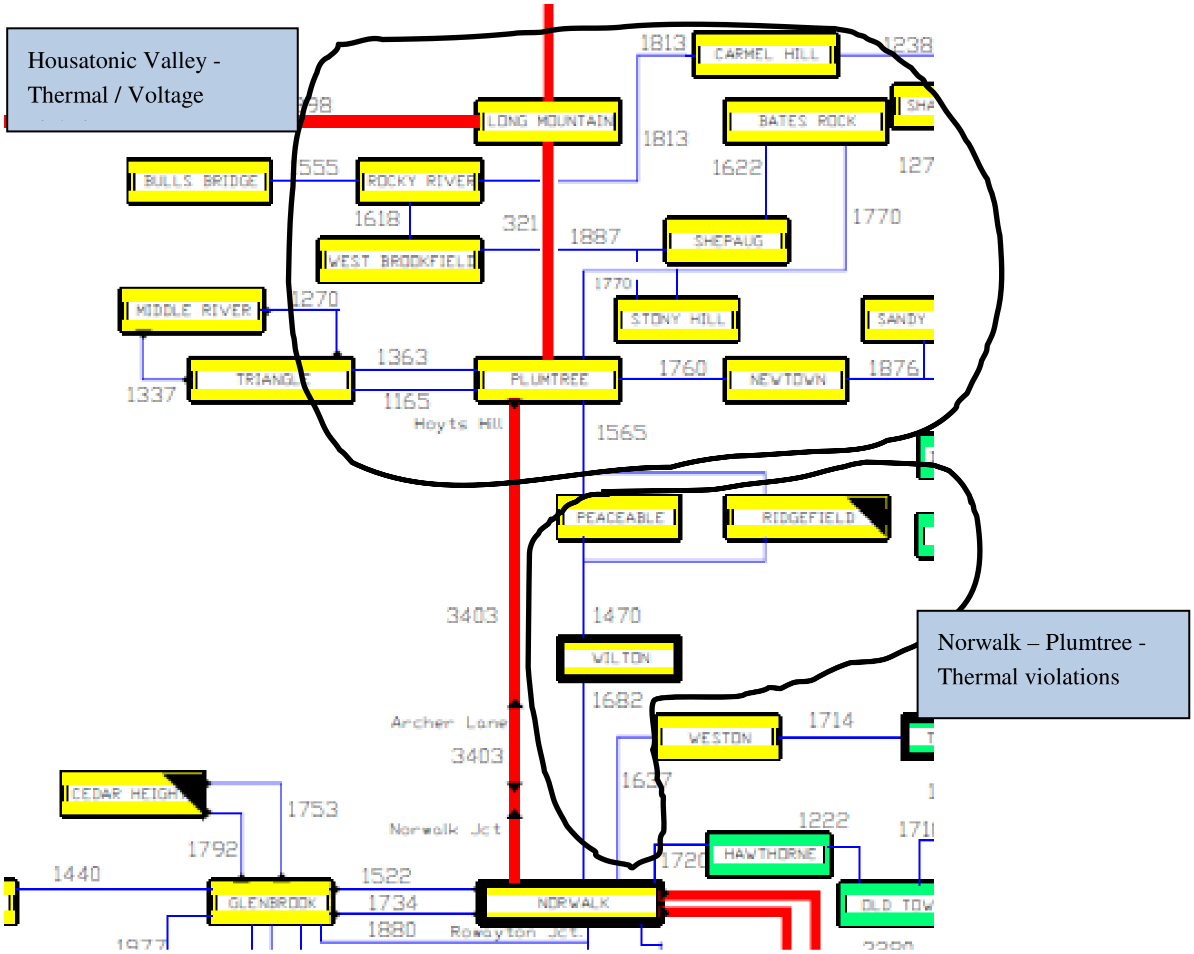

Figure 5-12: Housatonic Valley / Norwalk - Plumtree Thermal and Voltage Violations

5.2.2.1 Results of N-0 Testing

There were no N-0 thermal or voltage violations in the Housatonic Valley / Norwalk – Plumtree subarea.

5.2.2.2 Results of N-1 Testing

N-1 testing indicated there were three LTE thermal violations in the Housatonic Valley / Norwalk Plumtree subarea. Two of them were also STE thermal violations, as shown in Table 5-7.

All three N-1 thermal violations in the Housatonic Valley were caused by loss of the 1770 line (Plumtree to Stony Hill to Bates Rock), [redacted]. Wide spread low voltage violations were observed along the corridor after the contingency. The thermal overloading was aggravated by low voltage.

A diagram showing these N-1 thermal violations can be found in Section 5.2.1.3.

Table 5-7
N-1 Thermal Violations in Housatonic Valley / Norwalk Plumtree

[redacted]

N-1 voltage testing indicated there were six PTF buses and two non-PTF bus having low voltage violations in the Housatonic Valley / Norwalk Plumtree subarea. [redacted]

Table 5-8 and Table 5-9 summarize the lowest voltage violations for PTF and non-PTF buses in this subarea. The corresponding diagram illustrating these N-1 voltage violations can be found in Section 5.2.2.3.

Table 5-8
N-1 PTF Low Voltage Violations in Housatonic Valley / Norwalk Plumtree

[redacted]

Table 5-9
N-1 non-PTF Low Voltage Violations in Housatonic Valley / Norwalk Plumtree

[redacted]

5.2.2.3 Results of N-1-1 Testing

The results of N-1-1 testing indicated there were eight elements having thermal violations following N-1-1 contingency events in the Housatonic Valley / Norwalk Plumtree subarea. Table 5-10 summarizes the worst case dispatch and contingency pair of these thermal violations, including the corresponding critical load levels in terms of equivalent CT loads and the year of need.

Table 5-10
N-1-1 Thermal Violations in Housatonic Valley / Norwalk Plumtree

[redacted]

Figure 5-13 and Figure 5-14 illustrate the worst case N-1 & N-1-1 thermal violations in the Housatonic Valley / Norwalk Plumtree subarea.

[redacted]

Figure 5-13: Thermal Violations in Upper Housatonic Valley / Norwalk Plumtree

[redacted]

Figure 5-14: Thermal Violations in Lower Housatonic Valley / Norwalk Plumtree

The results of N-1-1 testing indicated 12 PTF and four non-PTF buses having low voltage violations following N-1-1 contingency events in the Housatonic Valley / Norwalk Plumtree subarea. [redacted] Table 5-11 and Table 5-12 summarize the details of the worst case voltage violations, including the corresponding critical load level in terms of equivalent CT load and the year of need,

Table 5-11
N-1-1 PTF Low Voltage Violations in Housatonic Valley / Norwalk Plumtree

[redacted]

[redacted]

Table 5-12
N-1-1 non-PTF Low Voltage Violations in Housatonic Valley / Norwalk Plumtree

Element	kV	Initial Element OOS	Worst Contingency	Worst Dispatch	Post Contingency Voltage (p.u.)	CLL (MW)	Year of need
Bulls Bridge	115	LN_1770	BF_FRSTB_1X2	8D	0.706	6366	Prior to 2013
Shepaug	69				0.623	6672	
Middle River	115	TF_PLUMTR_1X	BF_PLUMT_32T	4D	0.911	7005	Prior to 2013
Triangle					0.913	7004	

Figure 5-15 and Figure 5-16 illustrate the worst case N-1 & N-1-1 voltage violations in the Housatonic Valley / Norwalk Plumtree subarea.

[redacted]

Figure 5-15: Voltage Violations in Upper Housatonic Valley / Norwalk Plumtree

[redacted]

Figure 5-16: Voltage Violations in Lower Housatonic Valley / Norwalk Plumtree

5.2.3 Bridgeport

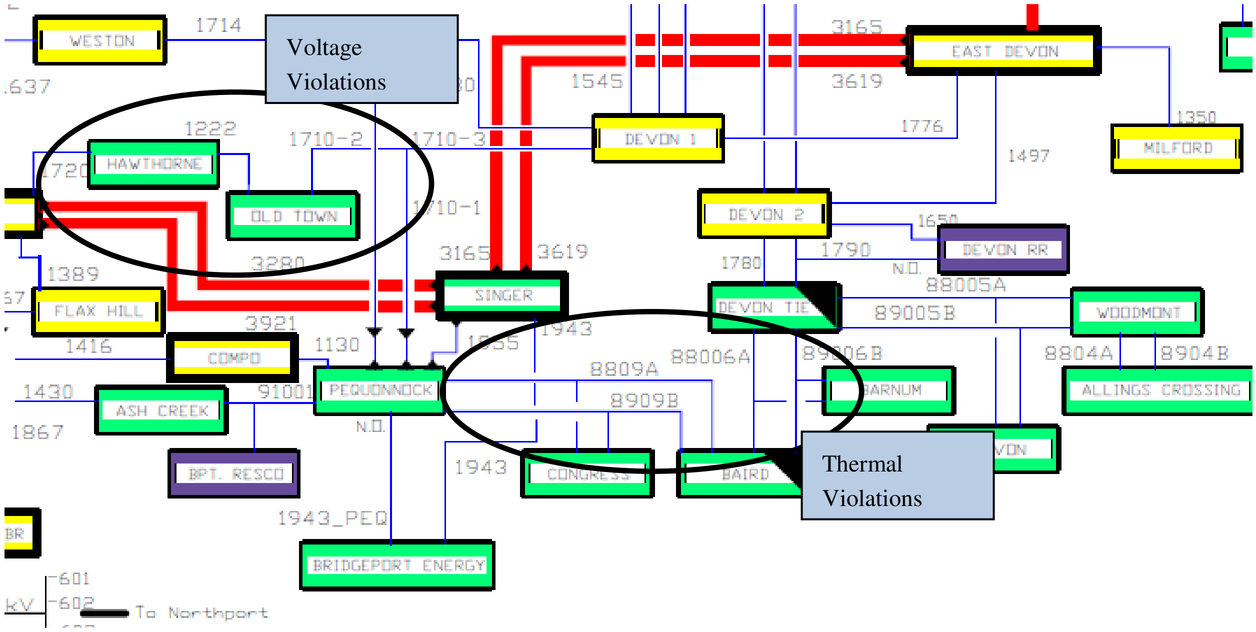

Figure 5-17: Bridgeport Thermal and Voltage Violations

5.2.3.1 Results of N-0 Testing

There were no N-0 thermal or voltage violations found in the Bridgeport subarea.

5.2.3.2 Results of N-1 Testing

N-1 testing indicated there were four LTE thermal violations in the Bridgeport subarea, as shown in Table 5-13. Two of them were also STE thermal violations.

[redacted] The increase in power flow results in thermal violations along these lines. The retirement of the Norwalk Harbor 1, 2, and 10 aggravated these thermal violations.

A diagram showing these N-1 thermal violations can be found in Section 5.2.3.3.

Table 5-13
N-1 Thermal Violations in Bridgeport

[redacted]

N-1 testing also indicated there were two PTF buses having low voltage violations in the Bridgeport subarea. [redacted] Table 5-14 summarizes the lowest voltage violations for PTF buses in this subarea. A diagram showing these N-1 voltage violations can be found in Section 5.2.2.3.

Table 5-14
N-1 PTF Low Voltage Violations in Bridgeport

[redacted]

5.2.3.3 Results of N-1-1 Testing

The results of N-1-1 testing indicated there were seven 115 kV and two 345 kV elements having thermal violations following N-1-1 contingency events in the Bridgeport subarea. [redacted] [redacted]. Table 5-15 summarizes the details of the worst case thermal violations, including the corresponding critical load levels in terms of equivalent CT loads and the year of need.

Table 5-15
N-1-1 Thermal Violations in Bridgeport

[redacted]

[redacted]

** Violation exists at Minimum Load Level

Figure 5-18 and Figure 5-19 illustrate the worst case N-1 & N-1-1 thermal violations in the Bridgeport subarea.

[redacted]

Figure 5-18: Thermal Violations in Bridgeport – East of Pequonnock

[26] [redacted] Details of the scheme can be found in Section 3.1.13.

[redacted]

Figure 5-19: Thermal Violations in Bridgeport – West of Pequonnock

Results of N-1-1 testing indicated two PTF buses having low voltage violations following N-1-1 contingency events in the Bridgeport subarea. [redacted]

Table 5-16 summarizes the details of the worst case voltage violations, including the corresponding critical load level in terms of equivalent CT load and the year of need.

Table 5-16
N-1-1 PTF Low Voltage Violations in Bridgeport

[redacted]

Figure 5-20 illustrates the worst case N-1 & N-1-1 voltage violations in the Bridgeport subarea.

[redacted]

Figure 5-20: Voltage Violations in Bridgeport

5.2.4 New Haven - Southington

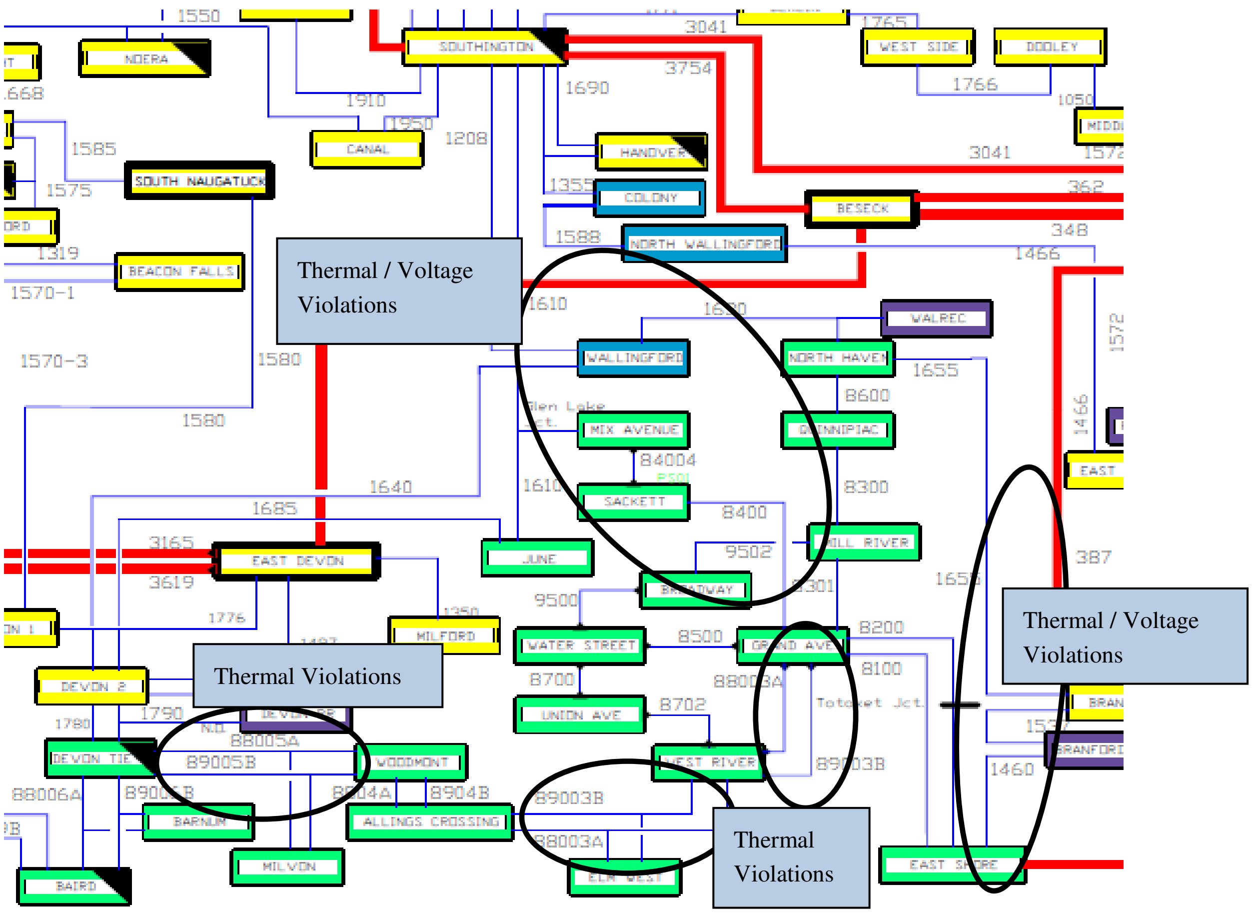

Figure 5-21: New Haven - Southington Thermal and Voltage Violations

5.2.4.1 Results of N-0 Testing

There were no N-0 thermal or voltage violations were found in the New Haven - Southington subarea.

5.2.4.2 Results of N-1 Testing

N-1 testing indicated there was one LTE thermal violation in the New Haven - Southington subarea, as shown in Table 5-17. [redacted] The DCT contingency also results in an STE thermal violation.

A diagram showing this N-1 thermal violation can be found in Section 5.2.4.3.

Table 5-17
N-1 Thermal Violations in New Haven - Southington

[redacted]

N-1 testing also indicated there was one PTF bus having a low voltage violation in the New Haven - Southington subarea. [redacted] The breaker failure contingency leaves the Branford substation being feed radially from the 1342 line (Bokum to Green Hill) resulting in low voltage. The lowest voltage violation for Branford bus is documented in Table 5-18. A diagram showing these N-1 voltage violations can be found in Section 5.2.4.3.

Table 5-18
N-1 PTF Low Voltage Violations in New Haven - Southington

[redacted]

5.2.4.3 Results of N-1-1 Testing

The results of N-1-1 testing indicate there are 14 115 kV elements having thermal violations following N-1-1 contingency events in the New Haven - Southington subarea. [redacted] The details of these thermal violations, including the corresponding critical load levels in terms of equivalent CT loads and the year of need, can be found in Table 5-19.

Table 5-19
N-1-1 Thermal Violations in New Haven - Southington

[redacted]

[redacted]

The N-1 & N-1-1 thermal violations in the New Haven - Southington subarea are illustrated in the following Figure 5-22, Figure 5-23, and Figure 5-24.

[redacted]

Figure 5-22: Thermal Violations at Railroad Corridor and Sackett in New Haven - Southington

[redacted]

Figure 5-23: Thermal Violations in New Haven – Southington West

[redacted]

Figure 5-24: Thermal Violations at East Shore in New Haven - Southington

The results of N-1-1 testing also indicate six PTF buses having low voltage violations following N-1-1 contingency events in the New Haven - Southington subarea. [redacted]

[redacted] The details of these voltage violations, including the corresponding critical load level in terms of equivalent CT load and the year of need, can be found in Table 5-20.

Table 5-20
N-1-1 PTF Low Voltage Violations in New Haven - Southington

[redacted]

The N-1 & N-1-1 voltage violations in the New Haven - Southington subarea are illustrated in the following Figure 5-20 and Figure 5-26.

[redacted]

Figure 5-25: Voltage Violations at Branford and North Haven in New Haven

[redacted]

Figure 5-26: Voltage Violations at June Street and Mix Avenue in New Haven

5.2.5 Glenbrook -Stamford

There were no N-0, N-1, and N-1-1 thermal or voltage violations in the Glenbrook –Stamford Subarea because the Glenbrook to South End 115 kV Cable (RSP ID: 1228) project was included in the SWCT needs assessment base cases as one of the SWCT advanced projects.

5.2.6 Extreme Contingency Testing Results

As a part of this Needs assessment, a number of extreme contingencies (NERC Category D contingencies) were tested. The full list of the extreme contingencies tested can be found in Section 9. According to NERC, NPCC and ISO-NE standards, the extreme contingency testing is required to understand the risks and impacts to the system following an extreme event. NERC, NPCC and ISO-NE standards do not require that corrective plans be identified for the violations following these events but rather document the results of the assessment.

Therefore, there will be no development of solutions to address violations that result from the extreme contingencies tested but the results may influence the selection of preferred solutions selected to address other violations. The results of the extreme contingency testing can be found in Appendix F: Steady State Study Results.

5.2.7 Results of Generation Re-Dispatch Analysis

Several thermal needs in the SWCT 2022 Needs Assessment were able to be eliminated through re-dispatch following the first contingency and prior to the second contingency. These include the thermal violations on the 1460 (Branford RR to East Shore), 1537 (Branford to Branford RR), and 1655 (Branford to New Haven) lines which were caused by the New Haven Harbor and New Haven Peakers generation exit issue. The needs which can be eliminated through generation re-dispatch were not reported in the body of this report.

Details of the re-dispatch analysis can be seen in Appendix G: Generation Re-dispatch Results.

5.3 Stability Performance Criteria Compliance

This section is not applicable to this study.

5.3.1 Stability Test Results Summary

Not applicable for this study.

5.4 Short Circuit Performance Criteria Compliance

5.4.1 Short Circuit Test Results Summary

The study area is known to have limited short circuit margins at multiple substations based on past studies. This is a result of heavy concentrations of fault current sources around the SWCT area, especially in the Bridgeport Area. With retirement of the Bridgeport Harbor 2 and Norwalk Harbor 1, 2, and 10, the short circuit duty levels have dropped to marginal levels for the Pequonnock circuit breakers. However, both the bus system and a number of disconnect switches at the Pequonnock 115kV Substation remain over-dutied at existing short circuit levels[27].

A summary of circuit breaker fault duty concerns appears in Table 5-21.

Table 5-21
Circuit Breaker Short Circuit Duty

Substation	Voltage	Number of Circuit Breakers		
		Over Duty (Above 100%)	High Duty (95-100%)	Marginal Duty (90-95%)
Pequonnock 8J	115 kV	--	--	17 (65kA)
East Devon 8G	115 kV	--	4 (63kA)	--
Devon Ring 2 7R	115 kV	--	--	5 (63kA)
Mill River 38M	115 kV	--	2 (50 kA)	--

Refer to Section 13 for full version(s) of short circuit study results.

[27] PAC Presentation "Pequonnock Fault Duty Mitigation Solution Study Update", dated September 20, 2012, available at https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/sep202012/pequonnock.pdf.

Section 6 Conclusions on Needs Analysis

6.1 Statement of Needs

All the criteria violations observed in the Southwest Connecticut (SWCT) area were based on steady state thermal and voltage testing. The following summarizes the needs for each subarea:

Frost Bridge – Naugatuck Valley Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the Frost Bridge – Naugatuck Valley area
- The worst-case thermal and voltage violations observed for the loss of two or three source paths serving the load pocket from Frost Bridge and Devon under various dispatches

Housatonic Valley – Plumtree – Norwalk Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the Housatonic Valley – Plumtree – Norwalk area
- [redacted]
- [redacted]

Bridgeport Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the Bridgeport area
- [redacted]
- The only voltage violations observed are for the loss of the path that connects Devon to Norwalk under various dispatches

New Haven Subarea

- Need to resolve N-1 and N-1-1 criteria violations observed in the New Haven area
- [redacted]
- [redacted]

Glenbrook-Stamford Subarea

- No thermal or voltage violations observed

Short Circuit

- High short-circuit current levels are identified as a concern in the study area, specifically with the capability of certain circuit breakers at several substations to successfully interrupt 115 kV faults.

In summary, the SWCT area fails to meet the reliability criteria standards in four geographical subareas and measures should be developed to mitigate the criteria violations.

6.2 Critical Load Levels

The critical load level for the majority of criteria violations in this study are prior to the projected 2013 summer peak with a few violations occurring in 2014-2017.

6.2.1 Frost Bridge – Naugatuck Valley Subarea

The majority of the worst-case violations in the Frost Bridge-Naugatuck Valley subarea are expected to be seen at expected summer peak load levels before 2013. The net Connecticut load at which all thermal violations will be resolved is 2,687 MW and the net Connecticut load at which all voltage violations would be resolved is 1,288 MW. The non-PTF voltage violations would only be resolved at a net Connecticut load level of 1,288 MW.

6.2.2 Housatonic Valley – Plumtree – Norwalk Subarea

The majority of the worst-case violations in the Housatonic Valley-Plumtree-Norwalk subarea are expected to be seen at expected summer peak load levels before 2013. The net Connecticut load at which all thermal violations will be resolved is 4,163 MW and the net Connecticut load at which all voltage violations would be resolved is 5,218 MW. The non-PTF voltage violations would only be resolved at a net Connecticut load level of 6,366 MW.

6.2.3 Bridgeport Subarea

The majority of the worst-case violations in the Bridgeport subarea are expected to be seen at expected summer peak load levels before 2013. The net Connecticut load at which all thermal violations will be resolved is 234 MW and the net Connecticut load at which all voltage violations would be resolved is 7093 MW. It should be noted that the voltage violations are expected to be seen at expected summer peak levels in 2014.

6.2.4 New Haven Subarea

The majority of the worst-case violations in the New Haven subarea are expected to be seen at expected summer peak load levels before 2013. The net Connecticut load minus DR at which all thermal violations will be resolved is 3,659 MW and the net Connecticut load at which all voltage violations would be resolved is 6,093 MW.

6.2.5 Glenbrook-Stamford Subarea

- No thermal or voltage violations observed

Section 7
Appendix A: Load Forecast

Table 7-1 2012 CELT Seasonal Peak Load Forecast Distributions

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2013	26470	26715	27045	27420	27840	28285	28735	29385	30135	30790
	2014	26900	27150	27485	27865	28290	28740	29200	29860	30620	31280
	2015	27410	27665	28005	28390	28825	29285	29750	30425	31185	31860
	2016	27910	28165	28515	28910	29350	29815	30295	30980	31740	32420
	2017	28325	28590	28940	29340	29790	30265	30750	31445	32210	32900
	2018	28675	28940	29295	29700	30155	30635	31125	31830	32615	33315
	2019	29025	29295	29655	30065	30525	31010	31505	32220	33010	33720
	2020	29345	29615	29980	30395	30860	31350	31855	32575	33380	34095
	2021	29670	29950	30315	30735	31205	31700	32210	32935	33755	34480
	2022	29970	30250	30625	31045	31520	32020	32535	33270	34105	34840
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)	2013/14	22025	22140	22235	22295	22445	22595	22765	22865	23080	23505
	2014/15	22205	22320	22420	22480	22630	22780	22955	23055	23255	23685
	2015/16	22385	22500	22595	22660	22810	22960	23135	23235	23440	23870
	2016/17	22540	22660	22755	22815	22970	23125	23295	23400	23620	24050
	2017/18	22680	22795	22895	22955	23110	23265	23440	23540	23780	24205
	2018/19	22800	22920	23020	23080	23235	23390	23565	23670	23920	24345
	2019/20	22915	23035	23130	23195	23350	23505	23685	23785	24045	24470
	2020/21	23030	23150	23250	23315	23470	23625	23805	23910	24160	24590
	2021/22	23145	23265	23365	23425	23585	23745	23920	24025	24280	24705
	2022/23	23255	23380	23480	23540	23700	23860	24040	24145	24395	24820
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 2022 Detailed Load Distributions by State and Company

Study Date :	06/01/2022	**Study Name :**	SWCT Needs Assessment 2022		
File Created :	2014-03-21	**CELT Forecast :**	2013	**Forecast Year :**	2022
Season :	Summer Peak	**Weather :**	90/10	**Load Distribution :**	N+10_SUM
ISO-NE CELT :	34105 MW	**% of Peak :**	100.000%	**Tx Losses :**	2.50%

State CELT L&L		2.50% Tx Losses		Non-CELT Load		Station Service		Area 104 NE Load		Area 101 Load
34105 MW	-	852.6 MW	+	364.4 MW	+	1070.9 MW	-	16.8 MW	=	34670.9 MW

1: State CELT L&L: This represents the sum of the 6 State CELT forecasts. This number can sometimes be 5-10 MW different than the ISO-NE CELT forecast number due to round-off error.
2: Non-CELT Load: This is the sum of all load modeled in the case that is not included in the CELT forecast. An example is the "behind the meter" paper mill load in Maine.
3: Station Service: This is the amount of generator station service modeled. If station service is off-line, the Area 101 report totals will be different since off-line load is not counted in totals.
4: Area 104 NE Load: This load is load modeled in northern VT that is electrically served from Hydro Quebec. To make Area Interchange load independent, this load is assigned Area 104.

Maine **State Load = 2450 MW - 2.50% Tx Losses = 2388.75 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.99%	2054.08	652.54	0.953	332.06
EM	14.01%	334.64	128.18	0.934	17.81

New Hampshire **State Load = 3150 MW - 2.50% Tx Losses = 3071.25 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	78.79%	2419.97	344.82	0.990	
UNITIL	12.14%	372.93	53.13	0.990	
GSE	9.06%	278.40	7.21	1.000	1.85

Vermont **State Load = 1220 MW - 2.50% Tx Losses = 1189.5 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	1189.43	200.23	0.986	95.79

Massachusetts **State Load = 16055 MW - 2.50% Tx Losses = 15653.625 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	28.27%	4425.14	1149.00	0.968	37.79
COMEL	11.70%	1831.00	370.89	0.980	
MA-NGRID	39.43%	6172.04	353.54	0.998	38.49
WMECO	6.33%	990.88	141.18	0.990	
MUNI:BOST-NGR	3.35%	524.72	92.52	0.985	
MUNI:BOST-NST	1.25%	195.36	29.84	0.989	
MUNI:CNEMA-NGR	2.08%	324.82	33.34	0.995	
MUNI:RI-NGR	0.88%	136.96	16.62	0.993	
MUNI:SEMA-NGR	1.85%	289.44	30.78	0.994	
MUNI:SEMA-NST	1.73%	270.82	49.99	0.983	
MUNI:WMA-NGR	0.95%	149.17	14.81	0.995	
MUNI:WMA-NU	2.19%	343.28	48.92	0.990	

Rhode Island **State Load = 2405 MW - 2.50% Tx Losses = 2344.875 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	2344.90	238.31	0.995	45.44

Connecticut **State Load = 8825 MW - 2.50% Tx Losses = 8604.375 MW**

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	76.45%	6578.11	937.35	0.990	82.50
CMEEC	4.49%	386.26	55.02	0.990	
UI	19.06%	1640.02	164.61	0.995	10.00

Table 7-3 Detailed Demand Response Distributions by Zone

ISO New England Basecase DB - Demand Resources File Report

Study Date :	06/01/2022	**Study Name :**	SWCT Needs Reassessment		
File Created :	2014-03-10	**CCP :**	2016/2017	**Load Season :**	2022 - Summer Peak
Load Distrb :	N+10_SUM	**Distrb Losses :**	5.50%	**DR Season :**	SUM

	Demand Reduction Value (DRV)	x	Load Dependent Capability Assumption (LDCA)	x	Performance Assumption (PA)	+	Distribution Losses Gross-Up	-	Area 104 DR	=	Area 101 DR
Passive :	1619.50 MW		100.00%		100.00%		89.07 MW		1.67 MW		1706.86 MW
Forecast EE :	1038.85 MW		100.00%		100.00%		57.14 MW		1.23 MW		1094.56 MW
Active :	799.89 MW		100.00%		75.00%		33.00 MW		0.41 MW		632.47 MW

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

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

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

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Load Zone - Maine	149.99	-158.28	-55.41
DR_P_NH	21	Load Zone - New Hampshire	76.80	-80.98	-11.27
DR_P_VT	22	Load Zone - Vermont	120.21	-126.80	-33.90
DR_P_NEMABOS	23	Load Zone - Northeast Massachusetts & Boston	330.81	-349.03	-75.13
DR_P_SEMA	24	Load Zone - Southeast Massachusetts	184.89	-195.05	-20.24
DR_P_WCMA	25	Load Zone - West Central Massachusetts	235.46	-248.39	-21.55
DR_P_RI	26	Load Zone - Rhode Island	136.83	-144.36	-13.93
DR_P_CT	27	Load Zone - Connecticut	384.51	-405.64	-54.53

Forecasted Energy Efficiency

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

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Load Zone - Maine	56.48	-59.55	-20.81
DR_P_NH	21	Load Zone - New Hampshire	52.78	-55.63	-7.75
DR_P_VT	22	Load Zone - Vermont	88.88	-93.82	-25.00
DR_P_NEMABOS	23	Load Zone - Northeast Massachusetts & Boston	276.34	-291.47	-62.70
DR_P_SEMA	24	Load Zone - Southeast Massachusetts	146.98	-155.05	-16.11
DR_P_WCMA	25	Load Zone - West Central Massachusetts	164.62	-173.65	-15.08
DR_P_RI	26	Load Zone - Rhode Island	113.89	-120.18	-11.59
DR_P_CT	27	Load Zone - Connecticut	138.88	-146.44	-19.64

ISO New England Basecase DB - Demand Resources File Report

Study Date : 06/01/2022 **Study Name :** SWCT Needs Reassessment

File Created : 2014-03-10 **CCP :** 2016/2017 **Load Season :** 2022 - Summer Peak

Load Distrb : N+10_SUM **Distrb Losses :** 5.50% **DR Season :** SUM

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

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

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_A_ME_BHE	30	Dispatch Zone - ME - Bangor Hydro	27.26	-21.57	-10.04
DR_A_ME_MAIN	31	Dispatch Zone - ME - Maine	143.10	-113.20	-37.50
DR_A_ME_PORT	32	Dispatch Zone - ME - Portland Maine	27.02	-21.39	-7.00
DR_A_NH_NEWH	33	Dispatch Zone - NH - New Hampshire	22.11	-17.48	-2.46
DR_A_NH_SEAC	34	Dispatch Zone - NH - Seacoast	3.92	-3.10	-0.45
DR_A_VT_NWVT	35	Dispatch Zone - VT - Northwest Vermont	25.30	-20.03	-5.64
DR_A_VT_VERM	36	Dispatch Zone - VT - Vermont	12.79	-10.14	-2.43
DR_A_MA_BOST	37	Dispatch Zone - MA - Boston	58.36	-46.12	-11.59
DR_A_MA_NSHR	38	Dispatch Zone - MA - North Shore	20.04	-15.87	-1.77
DR_A_MA_CMA	39	Dispatch Zone - MA - Central Massachusetts	37.68	-29.81	-1.55
DR_A_MA_SPFD	40	Dispatch Zone - MA - Springfield	19.20	-15.18	-2.15
DR_A_MA_WMA	41	Dispatch Zone - MA - Western Massachusetts	34.17	-27.07	-2.56
DR_A_MA_LSM	42	Dispatch Zone - MA - Lower Southeast Massachusetts	10.26	-8.14	-1.35
DR_A_MA_SEMA	43	Dispatch Zone - MA - Southeast Massachusetts	46.29	-36.65	-2.88
DR_A_RI_RHOD	44	Dispatch Zone - RI - Rhode Island	53.33	-42.18	-4.01
DR_A_CT_EAST	45	Dispatch Zone - CT - Eastern Connecticut	36.55	-28.89	-4.12
DR_A_CT_NRTH	46	Dispatch Zone - CT - Northern Connecticut	84.10	-66.52	-9.48
DR_A_CT_NRST	47	Dispatch Zone - CT - Norwalk-Stamford	34.23	-27.09	-3.66
DR_A_CT_WEST	48	Dispatch Zone - CT - Western Connecticut	104.18	-82.45	-10.74

Section 8
Appendix B: Future Projects Modeled and Case Summaries

Quick links to case summaries for each of the dispatches described in Section 3.1.10 are provided below.
[Appendix B-1: SWCT Project Summaries]

[Appendix B-2: SWCT Case Summaries]

Section 9
Appendix C: Element Out for N-1-1 Analysis

Table 9-1
Summary of N-1-1 Line Element-Out Scenarios

Line	kV	Station A	Station B	Station C	BPS Element
			Overhead Lines		
321	345	Long Mountain	Plumtree		Yes
329	345	Southington	Frost Bridge		Yes
348	345	Beseck	Haddam	Millstone	Yes
352	345	Frost Bridge	Long Mountain		Yes
362	345	Beseck	Haddam Neck		Yes
387	345	Scovill Rock	Halvarsson	East Shore	Yes
398	345	Long Mountain	Pleasant Valley, NY		Yes
3041	345	Scovill Rock	Southington		Yes
3403	345	Plumtree	Norwalk		Yes
3754	345	Beseck	Southington		Yes
3827	345	East Devon	Beseck		Yes
3533	345	Scovill Rock	Kleen		Yes
601	115	Norwalk Harbor	Northport, NY		Yes
1028 1028_LSA	115	Fitch St.	Darien		No
1130	115	Compo	Pequonnock		Yes
1146	115	South Norwalk	Sherwood		No
1163	115	Frost Bridge	Noera	Todd	Yes
1165	115	Plumtree	Triangle		Yes
1208	115	Southington	Wallingford		Yes
1222	115	Old Town	Hawthorne		No
1238	115	Frost Bridge	Carmel Hill		Yes
1241	115	Shelton	Trap Falls		No
1243 1243_LSA	115	Compo	Fitch St.		No
1261	115	Haddam	Bokum		No
1272	115	Shaws Hill	Bunker Hill		No
1305	115	Wallingford	Wallingford Energy		No
1319	115	Beacon Falls	Oxford		No
1337	115	Middle River	Triangle		No
1342	115	Bokum	Green Hill		No
1350	115	East Devon	Milford		Yes
1355	115	Southington Ring 1	Hanover	Colony	Yes

Line	kV	Station A	Station B	Station C	BPS Element
1355_LSA					
1363 **1363_LSA**	115	Plumtree	Triangle		Yes
1389	115	Norwalk	Flax Hill		Yes
1430	115	Ash Creek	Sasco Creek		No
1440	115	Glenbrook	Waterside		Yes
1445	115	Frost Bridge	Shaws Hill		Yes
1450	115	Glenbrook	South End		Yes
1460	115	Branford RR	East Shore		Yes
1470	115	Ridgefield	Peacable	Wilton	No
1497	115	East Devon	Devon Ring 2		Yes
1507	115	Wallingford	A.L.Pierce		No
1508 **1508_LSA**	115	Stepstone	Green Hill		No
1522	115	Norwalk	Glenbrook		Yes
1537	115	Branford	Branford RR		No
1545	115	Trap Falls	Devon Ring 1		Yes
1550	115	Frost Bridge	Noera	Canal	Yes
1555	115	Bulls Bridge	Rocky River		No
1560	115	Stevenson	Shelton	Ansonia	No
1565	115	Plumtree	Peaceable	Ridgefield	Yes
1570	115	Beacon Falls	Indian Well	Devon Ring 1	Yes
1575	115	Bunker Hill	Baldwin St.	Oxford	No
1578	115	Sasco Creek	Sherwood		No
1580	115	S. Naugatuck	Devon Ring 1		Yes
1585	115	South Naugatuck	Bunker Hill		No
1594	115	Indian Well	Ansonia		No
1598	115	Haddam	Bokum		Yes
1608	115	Norwalk Harbor	South Norwalk	Glenbrook	Yes
1610	115	Southington Ring 1	Mix Avenue	June	Yes
1618	115	West Brookfield	Rocky River		No
1622	115	Bates Rock	Shepaug		No
1630	115	North Haven	Walrec	Wallingford	No
1637 **1637_LSA**	115	Norwalk	Weston		Yes
1640	115	Devon Ring 2	Wallingford		Yes
1650	115	Devon Ring 2	Devon RR		Yes
1655	115	North Haven	Branford		No
1668	115	Bunker Hill	Freight		No
1682	115	Norwalk	Wilton		Yes
1685	115	Devon Ring 2	June St.		Yes
1690 **1690_LSA**	115	Southington Ring 2	Hanover		Yes

Line	kV	Station A	Station B	Station C	BPS Element
1697	115	Trumbull	Pequonnock		Yes
1710	115	Devon Ring 1	Pequonnock	Old Town	Yes
1714 **1714_LSA**	115	Trumbull	Weston		No
1720	115	Norwalk	Hawthorne		Yes
1721	115	Frost Bridge	Freight		Yes
1730	115	Devon Ring 1	Trumbull		Yes
1734	115	Norwalk	Glenbrook		Yes
1738	115	Stepstone	Branford		No
1740	115	Waterside	Cos Cob		No
1750	115	Cos Cob	Tomac	South End	No
1753	115	Glenbrook	Cedar Heights		No
1760	115	Plumtree	Newtown		Yes
1770	115	Plumtree	Stony Hill	Bates Rock	Yes
1776	115	Devon Ring 1	East Devon		Yes
1780	115	Devon Ring 2	Devon Tie		Yes
1790	115	Devon Ring 2	Devon RR	Devon Tie	Yes
1792	115	Glenbrook	Cedar Heights		No
1813	115	Carmel Hill	Rocky River		No
1843	115	Baldwin	Waterbury		No
1867	115	Norwalk Harbor	Flax Hill	Glenbrook	Yes
1876	115	Newtown	Sandy Hook	Stevenson	No
1880	115	Norwalk Harbor	Norwalk	Glenbrook	Yes
1887	115	West Brookfield	Stony Hill	Shepaug	No
1910	115	Southington Ring 2	Todd		Yes
1950	115	Southington Ring 2	Canal		Yes
1977	115	Glenbrook	South End	Darien	Yes
1990	115	Frost Bridge	Baldwin St.	Stevenson	Yes
8100	115	East Shore	Grand Avenue		Yes
8200	115	East Shore	Grand Avenue		Yes
8300	115	Grand Avenue	Quinnipiac		Yes
8301	115	Mill River	Grand Avenue		Yes
8400	115	Sackett	Grand Avenue		Yes
8600	115	North Haven	Quinnipiac		No
8804A	115	Allings Crossing	Woodmont		No
8809A	115	Pequonnock	Congress	Baird	Yes
8904B	115	Allings Crossing	Woodmont		No
8909B	115	Pequonnock	Congress	Baird	Yes
88003A-2&3	115	Allings Crossing	Elm West	West River	Yes
88003A	115	Allings Crossing	West River	Grand Avenue	Yes
88005A	115	Woodmont	Milvon	Devon Tie	Yes
88006A	115	Baird	Barnum	Devon Tie	Yes
89003B-2&3	115	Allings Crossing	Elm West	West River	Yes

Line	kV	Station A	Station B	Station C	BPS Element
89003B	115	Allings Crossing	West River	Grand Avenue	Yes
89005B	115	Woodmont	Milvon	Devon Tie	Yes
89006B	115	Baird	Barnum	Devon Tie	Yes
91001	115	Pequonnock	BPT. Resco	Ash Creek	Yes
1238&1813	115	Frost Bridge	Carmel Hill	Rocky River	Yes
1550&1950	115	Frost Bridge	Canal	Southington	Yes
1760&1876	115	Plumtree	Newtown	Stevenson	Yes
Underground Cables					
3165	345	Singer	East Devon		Yes
3280	345	Singer	Norwalk		Yes
3619	345	Singer	East Devon		Yes
3921	345	Singer	Norwalk		Yes
1151	115	Glenbrook	Southend		Yes
1270	115	Middle River	Triangle		No
1337	115	Middle River	Triangle		No
8500	115	Water Street	Grand Avenue		Yes
8700	115	Water Street	Union Avenue		No
8702	115	West River	Union Avenue		No
9500	115	Water Street	Broadway		No
9502	115	Mill River	Broadway		Yes
9550	115	Grand Avenue	Mill River		Yes
84004 **84004_LSA**	115	Sackett	Mix Avenue		No
88003A-1	115	West River	Grand Avenue		Yes
89003B-1	115	West River	Grand Avenue		Yes
High Voltage Direct Current Lines					
CSC		Halvarsson	Shoreham, NY		Yes

Table 9-2
N-1-1 Autotransformer Element-Out Scenarios

Autotransformer	Station A	Station B	BPS Element
East Devon 2X	East Devon 345 kV	East Devon 115 kV	Yes
East Shore 8X	East Shore 345 kV	East Shore 115 kV	Yes
East Shore 9X	East Shore 345 kV	East Shore 115 kV	Yes
Frost Bridge 1X	Frost Bridge 345 kV	Frost Bridge 115 kV	Yes
Norwalk 8X	Norwalk 345 kV	Norwalk 115 kV	Yes
Norwalk 9X	Norwalk 345 kV	Norwalk 115 kV	Yes
Norwalk Harbor 8X	Norwalk Harbor 138 kV	Norwalk Harbor 115 kV	Yes
Plumtree 1X	Plumtree 345 kV	Plumtree 115 kV	Yes
Plumtree 2X	Plumtree 345 kV	Plumtree 115 kV	Yes
Singer 1X	Singer 345 kV	Singer 115 kV	Yes
Singer 2X	Singer 345 kV	Singer 115 kV	Yes

Autotransformer	Station A	Station B	BPS Element
Southington 1X	Southington 345 kV	Southington 115 kV	Yes
Southington 2X	Southington 345 kV	Southington 115 kV	Yes
Southington 3X	Southington 345 kV	Southington 115 kV	Yes
Southington 4X	Southington 345 kV	Southington 115 kV	Yes

Table 9-3
Generators Element-Out Scenarios

Generator	Station
Bridgeport Energy	Pequonnock
Bridgeport Harbor 3	Pequonnock
Milford Power 2	East Devon
New Haven Harbor 1	East Shore

Table 9-4
Reactive Devices Element-Out Scenarios

Reactive Device	Station	
115 kV Capacitor	Branford	37.8 MVAR
115 kV Capacitor	Darien	37.8 MVAR
115 kV Capacitor C1	East Shore	42 MVAR
115 kV Capacitor C2	East Shore	42 MVAR
115 kV Capacitor C1	Glenbrook	50.4 MVAR
115 kV Capacitor C2	Glenbrook	50.4 MVAR
Statcom A	Glenbrook	±75 MVAR
Statcom B	Glenbrook	±75 MVAR
115 kV Capacitor C1	Frost Bridge	50.4 MVAR
115 kV Capacitor C2	Frost Bridge	50.4 MVAR
115 kV Capacitor	North Haven	42 MVAR
115 kV Capacitor	Plumtree	50.4 MVAR
115 kV Capactior C1	Rocky River	25.2 MVAR
115 kV Capacitor C1	Southington	50.4 MVAR
115 kV Capacitor C2	Southington	50.4 MVAR
115 kV Capacitor C1	Stony Hill	25.2 MVAR
115 kV Capacitor	Waterside	37.8 MVAR

Section 10
Appendix D: Contingency Listings

[Appendix D-1: SWCT 345 kV Contingency Summary.pdf]
[Appendix D-2: SWCT sub345 kV Contingency Summary.pdf]

Section 11
Appendix E: Summary of Worst-case Violations

[redacted]

[redacted]

[redacted]

Table 11-2 Detailed Summary of N-1/ N-1-1 Worst PTF Voltage Violations

[redacted]

[redacted]

[redacted]

Table 11-3 Detailed Summary of N-1/ N-1-1 Worst non-PTF Voltage Violations

Sub-area	Element	Initial Element OOS	Worst Case Contingency	Worst Case Voltage, 1 Unit OOS (per unit)	Worst Case Voltage, 2 Units OOS (per unit)	Worst Dispatch	Dispatch Scenarios	Critical Load Level CLL (MW)	Year of Need based on 2013 CELT
Frost Bridge / Naugatuck Valley	121046 BALDWIN 1575 115	--	BF_BUNK_2-68	0.755	0.751	8B	Worst seen in NE importing cases	N/A	N/A
		LN_1319	DC_1272_1721	0.228	0.227	6D	Independent of generation dispatch	1288**	prior to 2013
Frost Bridge / Naugatuck Valley	121055 BALDWIN 1990 115	LN_1760	DC_1545_1570	0.927	0.927	14D	Independent of generation dispatch	7005	prior to 2013
Frost Bridge / Naugatuck Valley	121057 WATERBURY 115	LN_1760	DC_1545_1570	0.927	0.927	8D	Independent of generation dispatch	7004	prior to 2013
Housatonic Valley / Norwalk	121163 BULLS BRIDGE 115	--	LN_1770	0.777	0.776	8B	Independent of generation dispatch	N/A	N/A
		LN_1770	BF_FRSTB_1X2	0.707	0.706	8D	Independent of generation dispatch	6366	prior to 2013
Housatonic Valley / Norwalk	121235 MIDDLE RIVER 115	TF_PLUMTR_1X	BF_PLUMT_32T	0.911	0.914	4D	Independent of generation dispatch	5343	prior to 2013
Housatonic Valley / Norwalk	121244 TRIANGLE 115	TF_PLUMTR_1X	BF_PLUMT_32T	0.913	0.917	4D	Independent of generation dispatch	5468	prior to 2013
Housatonic Valley / Norwalk	121201 SHEPAUG 69	--	LN_1770	0.733	0.732	8B	Independent of generation dispatch	N/A	N/A
		LN_1770	BF_FRSTB_1X2	0.624	0.623	8D	Independent of generation dispatch	6672	prior to 2013

** Violation exists below the Minimum Load Level

Section 12
Appendix F: Steady State Study Results (including CLL)

[Appendix F-1: Detailed N-1 Study Results.xlsx]

[Appendix F-2: Detailed N-1-1 Study Results.xlsx]

[Appendix F-3: N-1-1 Thermal CLL Results.xlsx]

[Appendix F-4: N-1-1 Voltage CLL Results.xlsx]

Section 13
Appendix G: Generation Re-dispatch Results

The following elements in Table 13-1 successfully passed the generation re-dispatch analysis and their violations were able to be resolved within 1200 MW of re-dispatch and simultaneously without causing any new thermal violations.

Table 13-1 Thermal Violation addressed by Operational Adjustments

Subarea	Element ID	LTE Rating (MVA)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Section 14
Appendix H: Short Circuit Testing Results

Appendix H-1: NU Short Circuit Study

Appendix H-2: UI Short Circuit Study

Section 15
Appendix I: Net Load in Connecticut Calculation

Table 15-1:
Calculation of Net Load in Connecticut for Year of Need Calculation

All Data below Excludes Transmission Losses[28]	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CELT Load in CT	7,776	7,878	8,010	8,136	8,234	8,312	8,395	8,463	8,541	8,604
CT Load Fed from MA	25.8	26.1	26.6	27.0	27.3	27.6	27.9	28.1	28.3	28.5
CELT Load Fed from Substations in CT	7,750	7,852	7,983	8,109	8,207	8,284	8,367	8,435	8,513	8,576
CT Passive DR and EE	414.2	421.2	410.3	413.6	433.4	459.8	485.2	508.7	531.1	551.6
CT Active DR	373.7	354.4	374.1	319.7	273.2	273.2	273.2	273.2	273.2	273.2
Available CT Active DR	280.3	265.8	280.6	239.7	204.9	204.9	204.9	204.9	204.9	204.9
Total DR	694.4	687.0	690.9	653.3	638.4	664.8	690.2	713.6	736.1	756.6
Net Load in CT	**7,055**	**7,165**	**7,292**	**7,456**	**7,568**	**7,620**	**7,677**	**7,721**	**7,777**	**7,819**

[28] Transmission losses are assumed to be 2.5% of the CELT load, which includes losses

Section 16
Appendix J: NERC Compliance Statement

This report is the first part of a two part process used by ISO-NE to assess and address compliance with NERC TPL standards. This 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 Solutions 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 Solutions Study report taken together provide the necessary evaluations and determinations required under the NERC TPL standards.

This study provides a detailed assessment of SWCT electric system performance for 2022. Section 5.1 shows that performance for NERC Category A conditions was adequate, but was inadequate for NERC Category B and NERC Category C contingencies. For the NERC Category B and C review, all contingencies were studied as described in Section 4.3.2. The results of this study show a substantial number of violations across the study area: 10 elements showing thermal violations & 19 PTF elements showing voltage violations under N-1 conditions, and 41 elements showing thermal violations & 35 PTF elements showing voltage violations under N-1-1 conditions. As shown in Section 5.2, Critical Load Levels have been identified for these thermal violations from 234 MW to 7531 MW and for the voltage violations from 1288 MW to 7343 MW in terms of equivalent Connecticut load level. As shown in Section 3.1.6, the study includes peak and minimum load testing. Shoulder load testing was unnecessary for this study area. This study uses normal operating procedures as illustrated by transfers, phase shifter settings and normal capacitor settings. Transfer levels used in this study are as described in Section 3.1.9. 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 is maintained. As described in Section 3, this study includes the effects of existing and planned Demand Response, transmission and generation facilities. The study also includes the effects of area reactive resources which were found to provide inadequate voltage support for the next five years and beyond. Planned outages are addressed through testing of numerous generator dispatches. The effects of existing and planned protection systems can be found in Section 3.1.14. 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.

EXHIBIT 2: ISO-NE, "SOUTHWEST CONNECTICUT AREA TRANSMISSION 2022 SOLUTIONS STUDY REPORT," FEBRUARY 2015, REDACTED TO SECURE CONFIDENTIAL ENERGY INFRASTRUCTURE INFORMATION (CEII))

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Southwest Connecticut Area Transmission 2022 Solutions Study Report

REDACTED-PUBLIC VERSION

February 2015

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Section 1
Executive Summary

1.1 Needs Assessment Results and Problem Statement

The objective of the Southwest Connecticut 2022 Needs Assessment[1] study was to evaluate the reliability performance and identify reliability-based transmission needs in the Southwest Connecticut (SWCT) study area, while considering the following:

- Future load growth
- Reliability over a range of generation patterns and transfer levels
- All applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Corporation (NPCC) and ISO New England transmission planning reliability standards
- Regional and local reliability issues
- Existing and planned supply and demand resources, and
- Limited short circuit margin concerns in the study area

The 2022 Needs Assessment was designed as a follow-up study to the completion of the Bethel – Norwalk and Middletown – Norwalk 345 kV projects. Those projects created a 345-kV transmission "loop" to address the reliability problems in SWCT. A large 345 kV backbone transmission project was needed to increase the import capacity of the Southwest Connecticut and Norwalk – Stamford import interfaces. During the course of that study, it was observed that several area 115 kV lines were near or above their thermal loading limit and 115 kV substations in the area had low voltage issues. It was determined at that time, the region would move forward with the 345 kV projects, and perform a follow-up Needs Assessment to identify, and a follow-up Solutions Study to correct, any local criteria violations in Southwest Connecticut. Also the scope of the study has been expanded to include many more N-1-1 scenarios in the follow-up Needs Assessment which became the largest source of criteria violations in the study area to ensure compliance with applicable standards.

The 2022 Needs Assessment used the following study assumptions:

- 2022 Summer 90/10 peak load based on the 2013 CELT report: 34,105 MW loads for New England and 8,825 MW (which represents 26% of the New England load) for the State of Connecticut
- All future transmission projects with Proposed Plan Application (PPA) approval as of the October 2012 RSP Project Listing (with the exception of the NEEWS Central Connecticut Reliability Project and most approved SWCT advanced projects as presented at the June 18, 2012 PAC meeting[2])
- All future generation projects with a Capacity Supply Obligation (CSO) as of Forward Capacity Auction #7 (FCA #7)
- All Demand Resources (DR) cleared in FCA #7. In addition, any accepted Non Price

[1] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2014/final_swct_2022_needs.pdf

[2] *SWCT Preferred Solution – New Haven and Bridgeport Areas*, (June 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/jun192012/swct_solution.pdf

Retirement (NPR) requests for DR and any DR terminations in Connecticut for FCA #8 were also taken into account
- Forecasted energy efficiency (EE) through 2022 based on the 2013 CELT forecast
- Transfer levels
    - 0 and 1200 MW import from New York
    - 0 and 100 MW export to New York on Cross Sound Cable
    - 0 MW import/export on the Norwalk/Northport Cable
- Generation dispatch scenarios included one or two relevant generation units out-of-service (OOS) combined with different New York – New England transfer stresses

Results of the N-0 testing identified there were no thermal or voltage criteria violations.

Results of the N-1 testing identified a number of thermal violations throughout the study area for certain dispatch scenarios. Some of these violations included loadings exceeding the equipment's Short Time Emergency (STE) ratings. The thermal violations in the Housatonic Valley region were aggravated by low voltage problems after a loss of source from the Plumtree substation. Results also indicated several other low voltage violations throughout the study area for certain dispatch scenarios. Results of N-1 Extreme Contingency (EC) testing did not indicate any inter-area concerns.

Results of the N-1-1 testing identified a substantial number of thermal and voltage violations in the study area, including the subareas of Frost Bridge – Naugatuck Valley, Housatonic Valley – Plumtree – Norwalk, Bridgeport, and Southington – New Haven. The announced retirement of the Bridgeport Harbor 2 and Norwalk Harbor 1, 2, & 10 units further aggravated the thermal violations in the New Haven to Bridgeport corridor. The majority of N-1-1 violations could not be addressed by operational adjustments including Special Protection Systems (SPSs) or generation re-dispatch. There were, however, seventeen thermal criteria violations in the study area that were able to be resolved by generation re-dispatch of up to 1,200 MW.

The critical load level for the majority of criteria violations in the 2022 Needs Assessment are prior to the 2013 summer peak with some violations occurring in 2014, 2015, 2016, and 2017.

Short circuit results from the Needs Assessment indicate there were no over-duty circuit breakers in the study area. A few high duty breakers (95% - 100%) with minimal remaining margin were found. In addition, several pieces of equipment at the Pequonnock 115 kV substation were found to be over-duty based on existing short circuit levels.

1.2 Recommended Solution

The Local 2 solution alternative for the Housatonic Valley and Naugatuck Valley subareas is comprised of several components as described in Table 1-1. A more detailed description of each component can be found in Section 5.3.1.

Table 1-1 Local 2 Solution Components

ID	Solution Component
1	Install a 25.2 MVAR capacitor bank at Oxford
2	Close normally open Baldwin circuit breaker
3	Reconductor 1887 line between West Brookfield and West Brookfield Junction
4	Install a circuit breaker in series with 29T at Plumtree
5	Install two 14.4 MVAR capacitor banks at West Brookfield
6	Install new 115 kV line from Plumtree to Brookfield Junction
7	Relocate the 37.8 MVAR capacitor bank at Plumtree
8	Upgrade terminal equipment at Newtown on 1876 line
9	Reduce the size of the existing capacitor bank at Rocky River to 14.4 MVAR
10	Loop 1570 line in and out of Pootatuck (formerly named Shelton)
11	Install two 25 MVAR capacitor banks at Ansonia
12	Expand Pootatuck (formerly named Shelton) into a 4-breaker ring bus and install one 30 MVAR capacitor bank
13	Loop the 115 kV 1990 line in and out of Bunker Hill
14	Replace two Freight 115 kV breakers
19	Rebuild Bunker Hill into a 9-breaker (breaker-and-a-half) substation
20	Rebuild 1682 line between Wilton and Norwalk, upgrade Wilton terminal equipment
21	Reconductor 1470-1 line between Wilton and Ridgefield Junction
22	Reconductor 1470-3 line between Peaceable and Ridgefield Junction
23	Reconductor 1575 line between Bunker Hill and Baldwin Junction
27	Relocate a 37.8 MVAR capacitor bank at Stony Hill
28	Reconfigure 1887 line into a 3-terminal line and 1770 line into 2 two terminal lines
31	Install a synchronous condenser at Stony Hill

The Alternative B solution for the Bridgeport and New Haven subareas is comprised of several components as described in Table 1-2. A more detailed description of each component can be found in Section 5.3.2.

Table 1-2 Alternative B Solution Components

ID	Solution Component
1	Baird Bus Upgrade
2	Install two 20 MVAR capacitor banks at Hawthorne
3	Upgrade Pequonnock substation equipment
4	Rebuild 8809A/8909B lines between Baird and Congress
5	Install a 345 kV circuit breaker in series with 11T at East Devon
6	Remove Sackett PAR
7	Install a series reactor and two 20 MVAR capacitor banks at Mix Avenue
8	Separate 3827/1610 double circuit tower
9	Replace two 115 kV circuit breakers at Mill River
10	Upgrade 1630 line relays at North Haven and terminal equipment at Wallingford
11	Rebuild 88005A/89005B lines between Devon Tie and Milvon
12	Rebuild 88006A/89006B lines between Housatonic River Crossing and Barnum
14	Rebuild 8806A/89006B lines and separate the DCT between Barnum and Baird

Solutions Local 2 and Alternative B were chosen as the preferred solution alternative for several reasons. Both these solutions resolved all thermal and voltage criteria violations in the 10-year planning horizon. Both solutions provided the least cost alternative to resolve those violations compared to the other alternatives as shown in Table 1-3 and Table 1-4.

Table 1-3 Global vs. Local Solution Alternative Cost Estimate Comparison

Solution Alternative	Cost Estimate +50/-25% ($M)
Global 1	261.0
Global 2	331.2
Local 1	187.4
Local 2	165.7

Table 1-4 Bridgeport and New Haven Solution Alternatives Cost Estimate Comparison

Solution Alternative	Cost Estimate +50/-25% ($M)
A	220.3
B	201.9

Table 1-5 Preferred Solution Total Cost Estimate ($M)

Local 2	Alternative B	SWCT Total
$165.7	$201.9	$367.6

Both solutions either met or exceeded the key factors when compared to other alternatives. All alternatives also show the continued need to rely on the existing New Haven Harbor SPS post second contingency to relieve thermal overloads on the Grand Avenue to West River underground cables.

1.3 NERC Compliance Statement

In accordance with NERC TPL Standards, this assessment provides:

- A written summary of plans to address the system performance issues described in the Southwest Connecticut Area Transmission 2022 Needs Assessment II, dated June 2014.
- A schedule for implementation as shown in Section 8.3, Page 711
- A discussion of expected in-service dates of facilities and associated load level when the upgrades are required as shown in Section 8.3, Page 711
- A discussion of lead times necessary to implement plans in Section 8.3, Page 711

Section 2
Needs Assessment Results Summary

2.1 Introduction

In the Southwest Connecticut (SWCT) area, reliability concerns exist that require transmission studies to identify possible improvements needed to resolve those issues and to meet established transmission reliability standards and criteria. The SWCT area, as defined in the study, extends from Southington, CT south to Long Island Sound in New Haven, CT and west to the New York state border, encompassing the population centers of New Haven, Bridgeport, Waterbury, Danbury, and Norwalk Connecticut. A Needs Assessment study for the SWCT area was conducted that included an evaluation of the reliability performance of the transmission system serving this area of New England for 2022 projected system conditions.

The 2022 Needs Assessment was designed as a follow-up study to the completion of the Bethel – Norwalk and Middletown – Norwalk 345 kV projects. Those projects created a 345 kV transmission "loop" to address the reliability problems in SWCT. A large 345 kV backbone transmission project was needed to increase the import capacity of the Southwest Connecticut and Norwalk – Stamford import interfaces. During the course of that study, it was observed that several area 115 kV lines were near or above their thermal loading limit and 115 kV substations in the area had low voltage issues. It was determined at that time, the region would move forward with the 345 kV projects, and perform a follow-up Needs Assessment to identify, and a follow-up Solutions Study to correct, any local criteria violations in Southwest Connecticut. Also the scope of the study has been expanded to include many more N-1-1 scenarios in the follow-up Needs Assessment which became the largest source of criteria violations in the study area to ensure compliance with applicable standards.

The results of the Needs Assessment were presented in a Needs Assessment report[3] "*Southwest Connecticut Area Transmission 2022 Needs Assessment II,*" dated June, 2014. This report was prepared by an ISO New England (ISO) led working group consisting of members from Northeast Utilities (NU) and The United Illuminating Company (UI).

2.2 Needs Assessment Review

The working group performed a steady-state study of the SWCT area for 2022 projected system conditions. The system was tested under N-0 (all-facilities-in), N-1 (all-facilities-in, first contingency), and N-1-1 (facility-out, first contingency) conditions for a number of possible operating scenarios. The working group also performed a short circuit study for all area substations. These studies were performed in accordance with the NERC Transmission Planning Standards[4] TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a, the Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1[5], "*Design and Operation of the Bulk Power System,*" and the ISO Planning Procedure No. 3[6] (PP-3), "*Reliability Standards for the New England Area Bulk Power Supply System.*" Section 5 of the Needs Assessment report provides detailed results for the

[3] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2014/final_swct_2022_needs.pdf

[4] http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[5] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

[6] http://www.iso-ne.com/rules_proceds/isone_plan/index.html

study.

2.2.1 Results of N-0 Testing

Results of the all facilities in-service (N-0) testing indicated no thermal or voltage violations were found in the SWCT study area.

2.2.2 Results of N-1 Testing

Results for the N-1 testing demonstrated several thermal violations within areas of the SWCT 115 kV system for certain generation dispatch scenarios. Some of these violations exceeded the equipment's summer Short Time Emergency (STE) ratings. The thermal violations in the Housatonic Valley corridor were aggravated by severe low voltages after the loss of a power source from the Plumtree substation.

Results for the N-1 testing also indicated numerous low voltage violations across the study area on the 115 kV system, under various generation dispatch scenarios.

Results for the N-1 extreme contingency (EC) testing did not demonstrate any inter-area concerns.

2.2.3 Results of N-1-1 Testing

Results for the N-1-1 testing indicated a substantial number of thermal and voltage violations across the entire study area, including the Frost Bridge – Naugatuck Valley corridor, the Housatonic Valley – Norwalk – Plumtree corridor, the Bridgeport subarea, and the Southington – New Haven subarea.

With the retirement of the Bridgeport Harbor Unit #2 and the Norwalk Harbor Station (Units 1, 2, & 10), thermal violations seen on the transmission lines along the railroad corridor from New Haven to Bridgeport were aggravated, especially under generation dispatches involving the outage of remaining Bridgeport generation.

The N-1-1 violations which could not be addressed by operational adjustments, including operation of special protection systems (SPSs) or local generation re-dispatch, were reported as needs. Analysis on these violations was then performed to determine the critical load level (CLL) and year of need.

2.2.4 Generation Re-Dispatch Analysis

Seventeen N-1-1 thermal violations seen in the Needs Assessment were able to be eliminated through re-dispatch of local generation after the first contingency and prior to the second contingency. These violations were not to be determined as criteria needs and were not addressed during the Solutions Study phase.

2.2.5 Results of Short Circuit Testing

The study area has been historically known to have limited short circuit margins at multiple substations based on past studies. Following the recent retirement announcement of local generation in the region, short circuit duty levels have dropped but remain an ongoing concern. Results of the short circuit study from this Needs Assessment determined no area circuit breakers were currently over their interrupting capability, but several breakers had limited margin.

The study also indicated a number of disconnect switches within the Pequonnock substation remained over-duty at current short circuit levels and will be addressed.

2.2.6 Needs Assessment Conclusions

The results of the Needs Assessment for the SWCT area transmission system indicated several significant thermal and voltage violations for projected 2022 system conditions.

- Both N-1 and N-1-1 thermal violations were observed in the Frost Bridge- Naugatuck Valley corridor, the Housatonic Valley-Norwalk–Plumtree corridor, the Bridgeport subarea and the New Haven-Southington subarea.
- Both N-1 and N-1-1 low voltage violations were observed in the Frost Bridge-Naugatuck Valley corridor, the Housatonic Valley-Norwalk-Plumtree corridor, the Bridgeport subarea and the New Haven-Southington subarea. Potential voltage collapse was seen in the Frost Bridge-Naugatuck Valley corridor and the Housatonic Valley-Norwalk-Plumtree corridor after N-1-1 contingency events.
- High short circuit levels remain a concern in the study area, specifically with the capability of some circuit breakers along the New Haven-Bridgeport corridor to successfully interrupt faults on the system.

In summary, the SWCT study area fails to meet the reliability standards and criteria in all subareas, with the exception of the Glenbrook Stamford subarea, and measures must be developed to mitigate the violations.

2.3 Critical Load Level – Year of Need Analysis

The critical load level for the majority of criteria violations in the study area are prior to the 2013 summer peak with a few violations occurring in 2014 through 2017. The first criteria violation appears at an equivalent load level much lower than the minimum load level seen during the course of the year. In today's system, these violations are prevented in operations by such steps as restricting transfers, running generation out-of-merit, and posturing the system for these critical contingencies.

Section 3
Solutions Study Assumptions

3.1 Analysis Description

The purpose of the study was to investigate system reinforcement options to determine feasible long-term transmission alternative plans to remedy the Southwest Connecticut study area criteria violations. The study was based on 2022 system conditions that included planned system upgrades expected to be in-service. The study analyses included a steady-state thermal and voltage study and a short circuit study. The Solutions Study was conducted in accordance with applicable NERC, NPCC and ISO standards and criteria.

At the time the Solutions Study began, base case models from the ISO Model on Demand (MOD) library were built to reflect forecasted system load from the 2012 Capacity, Energy, Loads and Transmission (CELT) report[7], and then updated based on the 2013 CELT report which was issued in May 2013. For the solution alternative development phase, the base cases included all transmission projects with Proposed Plan Application (PPA) approval as of the October 2012 Regional System Plan (RSP) Project Listing[8]. An exception was made to exclude the Central Connecticut Reliability Project (CCRP) portion of the New England East – West Solution (NEEWS), since CCRP was being re-evaluated in the Greater Hartford – Central Connecticut (GHCC) working group studies. Furthermore, specific Advanced SWCT projects that had received PPA approval but were being re-evaluated during this Solutions Study were not modeled. See Section 3.2.3 for a list of projects included in the base cases and Section 3.2.5 for a list of projects not included in the base cases. The base cases also included all generation projects in the study area with a Forward Capacity Market (FCM) Capacity Supply Obligation (CSO) as of the seventh Forward Capacity Auction (FCA #7). Demand Resources (DR) were modeled based on the active and passive DR cleared in FCA #7. In addition, any accepted Non Price Retirement (NPR) requests for in Connecticut for FCA #8 were also taken into account. See Section 3.2.6 for detailed information on DR.

The system was tested under N-0 (all-facilities-in), N-1 (all-facilities-in, first contingency), and N-1-1 (facility-out, first contingency) conditions for various operating conditions that reasonably stressed the system. The preferred solution will be tested with all currently PPA approved transmission and generation projects during the system impact study phase.

The Solutions Study analysis was run with the following applications: Siemens PTI PSS/E v32.2.1 and TARA v765e for the thermal and voltage analyses and Aspen v12.4 for the short circuit analysis.

After the preferred solutions were selected, a 2022 minimum load study was conducted to ensure no high voltage violations in the study area with both SWCT[9] and GHCC[10] preferred solutions in place.

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7 http://www.iso-ne.com/system-planning/system-plans-studies/celt

8 The October 2012 Regional System Plan (RSP) Project Listing was used and the March 2013 RSP Project Listing was considered, but no changes were made because no proposed or planned projects added in the March 2013 RSP Project Listing would significantly affect the SWCT area.

9 http://www.iso-ne.com/system-planning/key-study-areas/swct

10 http://www.iso-ne.com/system-planning/key-study-areas/greater-hartford

The assumptions for the 2022 minimum load study were documented in the following sections.

3.2 Steady State Model Assumptions

3.2.1 Study Assumptions

The regional steady-state power flow model was developed to be representative of the 10-year projection of the 90/10 summer peak system demand levels to assess reliability performance under stressed system conditions. The 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 applicable standards and criteria.

3.2.2 Source of Power Flow Models

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

3.2.3 Transmission Topology Changes

Transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff, as of the October 2012 RSP Project Listing, were included in the study base case. A comprehensive list of projects modeled in the base case can be seen in Appendix C: Upgrades Included in Base Case. A listing of the major projects relevant to the study area in southern New England is included below.

Connecticut

- NEEWS – Greater Springfield Reliability Project (RSP ID: 816, 1054, 1369-1371, 1378)
- NEEWS – Interstate Reliability Project (RSP ID: 191, 802, 810, 1085, 1090-1091, 1235)
- Advanced NEEWS Interstate Projects (RSP ID: 1235, 1245)
- Northeast Simsbury Substation 115 kV Circuit Breaker Project (RSP ID: 1230)
- Millstone 345 kV Circuit Separation & SLOD SPS System Retirement (RSP ID: 1218)
- Advanced SWCT – Line 8300 Reconfiguration (RSP ID: 1246)
- Advanced SWCT – Glenbrook to South End 115 kV Cable (RSP ID: 1228)
- Line 1990 Asset Condition Replacement Project (RSP ID: 1229)
- SWCT Minimum Load Project – Haddam Neck 150 MVAR shunt reactor (RSP ID: 1400)

Massachusetts

- NEEWS – Greater Springfield Reliability Project (RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105)
- Advanced NEEWS Interstate Projects (RSP ID: 1202, 1342)
- NEEWS – Interstate Reliability Project (RSP ID: 190, 1094, 1293)

Rhode Island

- NEEWS – Rhode Island Reliability Project (RSP ID: 795, 798-800, 1096-1097, 1099, 1106, 1109, 1331)
- NEEWS – Interstate Reliability Project (RSP ID: 794, 1233-1234, 1252, 1294-1298)

During the course of the Needs Assessment, several lines in the study area were re-rated and updated in the base case. The following lines have been updated based on the most up-to-date information:

Table 3-1 SWCT Lines with Revised Ratings

Line	kV	Stations	Norm (MVA)	LTE (MVA)	STE (MVA)
3165-UI	345	Singer – East Devon	600	1074	1085
3165-NU	345	Singer – East Devon	600	1106	1117
3403-2	345	Plumtree – Norwalk	2022	2350	3082
3403-C	345	Plumtree – Norwalk	748	869	1823
3403-D	345	Plumtree – Norwalk	748	869	1823
3619-UI	345	Singer – East Devon	600	1074	1085
3619-NU	345	Singer – East Devon	600	1106	1117
3280-NU	345	Singer – Norwalk	600	1133	1144
3921-NU	345	Singer – Norwalk	600	1133	1144
1608-1	115	Glenbrook – Ely Avenue	280	280	302
1608-2	115	Norwalk Harbor – Ely Avenue	201	263	378
1697	115	Pequonnock – Trumbull	155	209	257
1710	115	Pequonnock – Trumbull Junction	155	209	257
1880-2	115	Glenbrook – Rowayton Tap	337	436	514
1880-3	115	Norwalk – Rowayton Tap	214	251	316
8500	115	Grand Avenue – Water Street	186	242	292
8700	115	Water Street – Union Avenue	215	268	318
8702	115	Union Avenue – West River	229	279	329
9500	115	Water Street – Broadway	162	208	258
9502	115	Broadway – Mill River	148	198	248
88003A-0gpm	115	Grand Avenue – West River A	166	254	304
88003A-100gpm	115	Grand Avenue – West River A	198	263	313
89003B-0gpm	115	Grand Avenue – West River B	166	254	304
89003B-100gpm	115	Grand Avenue – West River B	198	263	313

3.2.4 Generation Assumptions (Additions & Retirements)

Generation projects with a FCM Capacity Supply Obligation as of FCA #7 were included in the study base case, except for the resources which submitted Non-Price Retirement (NPR) requests for FCA #8. A listing of significant future projects that are not currently in-service in southern New England is included below.

Connecticut

- No future projects

Massachusetts

- QP 089 – Cape Wind Turbine Generators (FCA #7)
- QP 196 – Northfield Mountain Uprates (FCA #4, 6, and 7)
- QP 387 – Combined Cycle Unit (FCA #7)

Rhode Island

- No future projects

Several resources in Connecticut have submitted NPR requests. The AES Thames unit submitted a request for FCA #7 and currently has a Qualified Capacity of 0 MW. The Bridgeport Harbor 2 unit also had a Qualified Capacity of 0 MW and did not receive a CSO for FCA #7. The unit has since followed up with a NPR request on September 20, 2013 for FCA #8 to officially retire, which was accepted.

On September 30, 2013, the Norwalk Harbor station (Units #1, 2, and 10) officially submitted a NPR request for FCA #8 and it was accepted on December 20, 2013. Since the retirement of these units had a significant impact on the SWCT study area, a re-study was triggered during the Needs Assessment and the all generation at Norwalk Harbor station along with AES Thames and Bridgeport Harbor 2 were assumed out-of-service (OOS) as a base case condition.

A summary of the NPR requests in Connecticut is provided in Table 3-2.

Table 3-2 Summary of Connecticut Non-Price Retirement Requests

Resource Name	Sum CNRC (MW)	Request Date	Approval Date
AES Thames	184.723	9/18/2012	11/19/2012
Bridgeport Harbor 2	180.000	9/20/2013	10/16/2013
John Street 1, 2, 3	6.011	9/26/2013	10/16/2013
Norwalk Harbor 1	162.000	9/30/2013	12/20/2013
Norwalk Harbor 2	168.000	9/30/2013	12/20/2013
Norwalk Harbor 10	12.300	9/30/2013	12/20/2013

All other NPR requests across New England through FCA #8 were modeled as OOS in the study base case. The proposed Ansonia unit that cleared FCA #1 has since withdrawn from the interconnection queue and withdrawn their approved PPAs. The unit was excluded from all base cases.

It should be noted that during the course of the Solutions Study, FCA #8 was completed in February 2014. The results of the auction were deemed to not have a significant impact in the current study and the cases were not re-run to reflect those changes. The differences from the auction results to what was studied are described in detail in Section 3.6.

All resources cleared in FCA #8 were modeled in the 2022 minimum load study since the study started after completion of FCA #8.

Real Time Emergency Generation (RTEG) is distributed generation which has air permit restrictions that limit their operations to ISO Operating Procedure No. 4 (OP-4), Action 6. Action 6 is an emergency action which also implements voltage reductions to five percent (5%) of normal operating voltage that require more than 10 minutes to implement. RTEG cleared in the FCM was not included in the reliability analyses because in general, long term analyses should not be performed such that the system must be in an emergency state as required for the implementation of OP-4, Action 6.

3.2.5 Explanation of Future Changes Not Included

The following projects were not modeled in the study base case due to the uncertainty concerning their final development or they will not have an impact on the Southwest Connecticut study area.

- Transmission projects that have not been fully developed and have not received PPA approval as of the October 2012 RSP Project Listing.
- Transmission projects added since the October 2012 RSP Project Listing that do not have a

significant impact on the study area. (No significant projects that would affect the study area have been approved since the October 2012 listing)

- Generation projects that do not have a CSO through FCA #7. (No significant units cleared in the February 2014 FCA #8)
- The following Southwest Connecticut PPA approved solutions alternatives based on the 2018 Needs Assessment[11]. These projects were re-evaluated during the course of this 2022 Solutions Study based on the 2022 Needs Assessment.
  - RSP 1380 – Baird to Congress 8809A-8909B 115 kV Upgrades
  - RSP 1381 – Baird 115 kV Bus Upgrade
  - RSP 1382 – Glen Lake Junction – Mix Avenue 1610-2 115 kV Line Upgrade
  - RSP 1383 – North Haven to Walrec 1630-3 115 kV Line and Relay Upgrade
  - RSP 1384 – Milvon to Devon Tie 88005A-89005B 115 kV Line Upgrade
  - RSP 1385 – Sackett 115 kV PAR Removal – Terminal Modifications
  - RSP 1386 – Mix Avenue 115 kV Capacitor Bank Additions, Series Reactor Addition and Terminal Modifications
  - RSP 1387 – Grand Avenue 115 kV Capacitor Bank Addition
  - RSP 1388 – Sackett 115 kV Capacitor Bank Addition
  - RSP 1389 – Hawthorne 115 kV Capacitor Bank Addition
- The Pequonnock Fault Duty Mitigation Solution[12] (RSP ID: 1348) since the updated short circuit studies show a reduction in fault duty at the substation due to the recent retirement of area units.
- The NEEWS – Central Connecticut Reliability Project component (RSP IDs: 576, 1114, 1372, and 1373) has PPA approval but was not included in the base case because the continuing need for the project was under re-assessment in the Greater Hartford – Central Connecticut study.

3.2.6 Forecasted Load, Demand Resources, and Energy Efficiency

A ten-year planning horizon was used for this study based on the 2012 CELT report when the solutions study began. During the course of the study, the forecasted load was updated in the base case to reflect the 2013 CELT report which was released in May 2013 but the study year remained as 2022. The forecasted 2022 summer 90/10 peak demand forecast for New England was at 34,105 MW. All system load was modeled in the base case according to the published load modeling guide[13]. The guide explains in detail the steps taken to translate the forecasted load, demand resources (DR), and energy efficiency (EE) into the power flow model. A state-by-state summary of the load forecast for the 2022 case is shown in Table 3-3.

[11] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2011/final_swct_needs_report.pdf

[12] https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/sep202012/pequonnock.pdf

[13] http://www.iso-ne.com/rules_proceds/isone_plan/othr_docs/load_modeling_guide.pdf

Table 3-3 Load Levels Studied

State	2013 CELT 2022 Summer 90/10 Load (MW)[14]
Maine[15]	2,450
New Hampshire	3,150
Vermont	1,220
Massachusetts	16,055
Rhode Island	2,405
Connecticut	8,825
New England Total	34,105

A summary by Load Zone of passive demand reduction values (DRV) cleared from FCA #7 and forecasted EE DRV from the 2013 CELT report is shown in Table 3-4.

Table 3-4 Passive DR and Forecasted EE

Load Zone	FCA #7[16] Passive DRV (MW)[17]	2013 CELT Forecasted EE DRV (MW)[18]	Total Passive DRV (MW)
Maine	150	56	206
New Hampshire	77	53	130
Vermont	120	89	209
Northeast MA & Boston	331	276	607
Southeast MA	185	147	332
West/Central MA	235	165	400
Rhode Island	137	114	251
Connecticut	385	139	523
New England Total	**1,620**	**1,039**	**2,658**

A summary by Dispatch Zone of active DRV cleared from FCA #7 is shown in Table 3-5.

[14] Includes transmission and distribution system losses

[15] The Maine total does not include paper mill load where the mills have on-site generation located behind the meter.

[16] These FCA #7 values are reduced by asset terminations and retirements that occurred prior to FCA #8.

[17] These values are cleared totals for the Capacity Commitment Period beginning June 1, 2017. DRV values are the amount of load reduced at the customer meter and do not include transmission or distribution losses.

[18] These values are forecasted additions to existing cleared capacity for the Capacity Commitment Period beginning June 1, 2022. DRV values are the amount of load reduced at the customer meter and do not include transmission or distribution losses.

Table 3-5 Active DR

Dispatch Zone	FCA #7[16] Active DRV (MW)[17]	Dispatch Zone	FCA #7[16] Active DRV (MW)[17]
Bangor Hydro	27	Springfield, MA	19
Maine	143	Western Massachusetts	34
Portland, ME	27	Lower Southeast MA	10
New Hampshire	22	Southeast Massachusetts	46
NH Seacoast	4	Rhode Island	53
Northwest Vermont	25	Eastern Connecticut	37
Vermont	13	Northern Connecticut	84
Boston, MA	58	Norwalk-Stamford, CT	34
North Shore Massachusetts	20	Western Connecticut	104
Central Massachusetts	38		
New England Total			800[19]

A detailed report of all load modeled in the study is shown in Appendix A: Load Forecast.

During the course of this study, the 2014 CELT report was issued in May 2014. The forecasted 2022 summer 90/10 peak demand forecast for New England of 33,865 MW. The state of Connecticut forecast for 2022 remained unchanged from the 2013 to 2014 forecast of 8,825 MW. The New England system had a reduction of 240 MW (0.7%) from the 2013 forecast. With an annual growth rate in New England of over 300 MW per year, this represents less than 1 year of load growth and does not defer the year of need out of the 10-year planning horizon. Therefore this change in forecast did not require a re-run of the power flow analysis.

For the 2022 minimum load study, the load distribution was modeled based on the 2014 CELT report since the study started after the release of the 2014 CELT. No demand resource or energy efficiency was explicitly modeled in the minimum load cases as it is already reflected in the studied load level.

3.2.7 Load Levels Studied

Consistent with ISO planning practices, transmission planning studies utilize the ISO 90/10 weather forecast assumptions for modeling summer peak load profiles in New England. After taking into account transmission losses, the contributions of demand resources and forecasted EE, and the addition of non-CELT and station service loads, the actual load level modeled in the base cases for the study is approximately 31,126 MW as shown in Table 3-6.

[19] New England total may differ by a few MW from sum of all individual dispatch zones due to rounding error.

Table 3-6 Actual Load Level Modeled

	Summer Peak (MW)
New England CELT Load	34,105
Transmission Losses (2.5%)	-853
Non-CELT Load (Maine)	364
Passive DR[20]	-1,710
Forecasted EE[20]	-1,097
Active DR[20] [21]	-633
Net NE Total Load	30,176
Total Station Service Load[22]	950
Actual NE Load Level Modeled (w/SS)	31,126[23]

At minimum load levels, 8,500 MW in New England, the system may experience high voltage conditions A 2022 Connecticut minimum load study was conducted with SWCT and GHCC preferred solutions in place to ensure no high voltage violations were seen with the addition of transmission upgrades.

3.2.8 Load Power Factor Assumptions

Load power factors consistent with the local transmission owner's planning practices were applied uniformly at each substation. Demand resource and energy efficiency 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 Appendix A: Load Forecast.

At minimum load levels, the Connecticut load power factor was set at 0.998 leading at the distribution bus. A list of power factors by company territory used in the 2022 minimum load study can be found in Appendix F: 2022 New England Minimum Loads.

3.2.9 Transfer Levels

In accordance with the reliability criteria of NERC, NPCC and 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: Base Case Summaries. Table 3-7 shows the external transfers modeled in the study. For N-0 and N-1 testing, the ISO no longer supports reliability needs for export to other areas (Stress A), so potential solution alternatives will not be evaluated for those transfers.

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[20] This value has been adjusted up by 5.5% to account for distribution losses.

[21] This value has been adjusted down by 25% based on performance assumptions for Active DR.

[22] This is an approximate value; because the variability of total station service load in service varies based on generation dispatch.

[23] The actual New England load levels modeled in the SWCT study are higher than the GHCC study because all of the FCA #8 Active DR NPRs were modeled in the SWCT study while the GHCC study only modeled the Active DR NPRs in Connecticut dispatch zones. The New England Active DR total is 800 MW for the SWCT study and 1,171 MW for the GHCC study.

Table 3-7 Interface Levels Tested

Interface	N-1 (Stress B)	N-1 (Stress C)	N-1-1 (Stress D)
New York to New England	0	Import 1200	0
Cross Sound Cable to NY	Export 100	Export 100	0
Norwalk-Northport Cable to NY	0	0	0
Highgate HVDC from Quebec	Import 200	Import 200	Import 200
Phase II HVDC from Quebec	Import 2000	Import 1500	Import 2000
New Brunswick to New England	Import 1000	Import 200	Import 1000

Internal transfer levels were monitored during the Solutions Study. During the Solutions Study the generation dispatches dictated the internal transfer levels.

In the 2022 Connecticut minimum load study, Cross Sound Cable to New York, Phase II HVDC from Quebec, and New Brunswick to New England transfers were all kept at zero for all three stresses.

3.2.10 Generation Dispatch Scenarios

To begin the 2022 Needs Assessment, seventeen dispatches were created, consisting of one unit and two unit OOS cases for the major units in the area. Following the retirement announcement of the Norwalk Harbor Station, only eleven dispatches were used in this evaluation (dispatch scenarios 9-13 were eliminated). Table 3-8 lists the dispatches of the major units in the study area, including four one-unit-out dispatches and seven two-units-out dispatches.

Table 3-8 Solutions Study Generation Dispatch Scenarios

Unit	1	2	3	4	5	6	7	8	14	15	16
Bridgeport Energy	OFF	ON	ON	ON	OFF	ON	OFF	ON	ON	ON	OFF
Milford Power 1	ON	ON	ON	ON	ON	OFF	ON	ON	ON	ON	ON
Milford Power 2	ON	OFF	ON	ON	OFF	OFF	ON	OFF	ON	OFF	ON
Bridgeport Harbor 3	ON	ON	OFF	ON	ON	ON	OFF	OFF	OFF	ON	ON
New Haven Harbor 1	ON	ON	ON	OFF	ON	ON	ON	ON	OFF	OFF	OFF

In this study, approximately 80% of fast-start[24] unit MWs in the state of Connecticut were assumed available and dispatched at maximum output in the base case. At locations where only a single fast-start unit exists, the unit was left off as part of the 20% of MW OOS to ensure a need was not masked by reliance on a single fast-start unit. A listing of fast-start units in the SWCT study area are listed in Table 3-9.

[24] "Fast-start" generation is defined as units with the ability to go from being off-line to their full Seasonal Claimed Capability in 10 minutes or less. These units do not need to participate in the 10-minute reserve market to be considered a fast-start unit in planning studies.

Table 3-9 SWCT Study Area Fast-Start Units

Unit	Sum QC (MW)	Status	Unit	Sum QC (MW)	Status
Bridgeport Harbor 4	18.0	OFF	**Devon 18**	49.7	OFF
Branford 10	16.2	OFF	**New Haven Harbor 2**	51.0	ON
Cos Cob 10	19.5	ON	**New Haven Harbor 3**	51.0	ON
Cos Cob 11	21.8	ON	**New Haven Harbor 4**	51.0	OFF
Cos Cob 12	18.7	ON	**Wallingford 1**	43.1	ON
Cos Cob 13	18.0	ON	**Wallingford 2**	43.6	ON
Cos Cob 14	18.0	OFF	**Wallingford 3**	43.8	ON
Devon 10	17.2	ON	**Wallingford 4**	43.5	ON
Devon 15	49.7	ON	**Wallingford 5**	43.6	OFF
Devon 16	49.7	ON	**Waterbury**	103.8	OFF
Devon 17	49.7	ON			

The performance of the hydroelectric units in the study area was examined and determined that an availability of 10% of nameplate capacity at summer peak was a reasonable assumption. This assumption was extended to most Connecticut hydro units. The exceptions to this assumption were the Rocky River and Shepaug hydro units. Historical output data has shown that Rocky River and Shepaug should be considered OOS during peak load times. Table 3-10 provides the outputs assumed for hydro units above 5 MW in Connecticut.

Table 3-10 Connecticut Hydro Unit Dispatch

Unit	Location	50° Rating (MW)	Base Case Dispatch (MW)
Bulls Bridge	Northwest	8.4	0.8
Falls Village	Northwest	9.8	1.0
Rainbow	Central	8.2	0.8
Derby Dam	Southwest	7.1	0.7
Rocky River	Southwest	29.4	OFF
Shepaug	Southwest	42.9	OFF
Stevenson	Southwest	28.9	2.9

For all other non-RTEG units in the case not specifically mentioned above in Table 3-8 through Table 3-10, they were assumed in-service for all dispatches. For all units in the base case, the most up-to-date voltage schedules obtained from ISO Operating Procedure No. 12 (OP-12) Appendix B were used in this study. A detailed listing of generation dispatches and statuses can be found in Appendix B: Base Case Summaries.

For the 2022 minimum load study, the base case dispatch reflects minimum generation dispatch in New England. One of the two Millstone units was assumed in service. In addition, Bridgeport RESCO, Dexter and South Meadow 5 and 6 were assumed in service in all cases. One of the two Bear Swamp units was on line running in the pumping mode, while all four Northfield Mountain units were out of service. Details on generation dispatches and statuses were listed in Appendix G: 2022 Minimum Load Case Summaries.

3.2.11 Reactive Resource and Dispatch Assumptions

All area shunt reactive resources were assumed available and dispatched when required. Reactive output of generating units was modeled to reflect defined limits and maximum/minimum limits were updated to OP-12 Appendix B when available. A summary of the reactive output of units and shunt devices connected to the transmission system within the study area are listed in the case summaries in Appendix B: Base Case Summaries.

All 345 kV shunt reactors in Connecticut were assumed in service in the 2022 minimum load study. The reactive output of units and shunt devices connected to the transmission system can be found in the case summaries in Appendix G: 2022 Minimum Load Case Summaries.

3.2.12 Market Solutions Consideration

In accordance with the ISO Tariff, all resources that have cleared the latest Forward Capacity Auction were assumed in the model. This includes numerous new generation and demand resources from FCA #1 through FCA #7 with the exception of the FCA #8 terminations and retirements listed in Section 3.2.4 and 3.2.6 respectively.

It should be noted that during the course of the Solutions Study, FCA #8 was completed in February 2014. The results of the auction were deemed to not have a significant impact in the current study and the cases were not re-run to reflect those changes. The differences from the auction results to what was studied are described in detail in Section 3.6.

All resources cleared in FCA #8 were modeled in the 2022 minimum load study since the study started after completion of FCA #8.

3.2.13 Demand Resource Assumptions

As stated in Section 3.2.6, Passive and Active DR cleared as of FCA #7 with the exception of FCA #8 terminations and retirements are modeled for this study. Forecasted EE for the year 2022 was modeled for this study. Passive DR and forecasted EE were assumed to perform at 100%. Active DR was assumed to perform at 75%. A summary of the assumed DR performance is shown in Table 3-11.

Table 3-11 New England Demand Resource Performance Assumptions

Load Level	Passive DR	Active DR	Forecasted EE	RTEGs
Summer 90/10 Peak	100%	75%	100%	0%

Real Time Emergency Generation (RTEG) is distributed generation which has air permit restrictions that limit their operations to ISO Operating Procedure No. 4 (OP-4), Action 6. Action 6 is an emergency action which also implements voltage reductions to five percent (5%) of normal operating voltage that require more than 10 minutes to implement. RTEG cleared in the FCM was not included in the reliability analyses because in general, long term analyses should not be performed such that the system must be in an emergency state as required for the implementation of OP-4, Action 6.

No Demand Resources were explicitly modeled in the 2022 minimum load study cases as they are already reflected in the studied load level.

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

There are five relevant Special Protection Systems (SPS) and two control schemes within the study area:

- New Haven Harbor SPS
- Bridgeport Harbor #3 SPS
- 1570 Line Section – Derby Jct to Indian Well (47P) SPS
- East Shore – Halvarsson – Scovill Rock 387 Line End Open (LEO) Scheme (SPS)
- Southington 4C Substation Auto-Throwover Scheme
- Southington 4C Autotransformer Automatic Isolation and Reclosing Scheme
- New Haven Harbor Unit 1U Torsional Stress SPS

These SPSs and schemes were modeled in the study and are described in detail below.

The New Haven Harbor SPS: (Type III SPS) This SPS reduces generation at New Haven Harbor Unit #1 in order to prevent excessive flows on the cables from Grand Avenue to West River (88003A/89003B) and the cable from Grand Avenue to Water Street (8500). This SPS uses measurements on the Grand Avenue end of these lines. These measurements are used to activate either manual or automatic reduction of generation at New Haven Harbor, or trip off the unit.

Bridgeport Harbor #3 SPS: (Type III SPS) This SPS reduces generation at the Bridgeport Harbor Unit #3 to reduce flow on circuits carrying power away from the Pequonnock (8J) substation. The specific objective of this SPS is to prevent excessive flows on the thermally limiting sections of the 1710/1697 and 8809A/8909B circuits. The thermally limiting sections of the 1710/1697 circuits are between Pequonnock and Seaview Tap and between the Congress and Baird sections of the 8809A/8909B circuits. Measurements for this SPS are taken by overcurrent relays at Pequonnock substation for the 1710/1697 circuits and at Baird substation for the 8809A/8909B circuits. These measurements are used to activate either manual or automatic reduction of generation at Bridgeport Harbor Unit #3 to reduce flows on the 1710/1697 or 8809A/8909B circuits.

1570 line section, Derby Jct to Indian Well (47P): (Type III SPS) This SPS is in place to automatically relieve an overload on the 1570 line section from Derby Junction to Indian Well (47P). The SPS monitors the 1570 line flow at Indian Well (47P), and upon sensing an overload condition a signal is sent to Ansonia (6R) by audio tone to open the 1560-6R-5. The operation of the 1560-6R-5 will redirect the flows on the transmission system and eliminate the overload on the 1570 line.

East Shore – Halvarsson – Scovill Rock 387 Line End Open (LEO) Scheme: (Type III SPS) Operation of the Scovill Rock Halvarsson – Tomson 481 line SPS transmits a signal to the Halvarsson Converter Station (14P) and will result in blocking the Cross Sound Cable HVDC facilities (0 MW and 0 MVAR) whether the flow is from Connecticut to Long Island or Long Island to Connecticut.

- [redacted]
- [redacted]

[redacted]

- The total operating time of the SPS, from sensing the line end open condition to blocking the Cross Sound Cable's converter is approximately 4.25 seconds.

Southington (4C) Substation Auto-Throwover Scheme: [redacted]

- The 4C-19T-2 115 kV ring tie breaker is operated normally open. [redacted]
- The 4C-19T-2 breaker will remain closed until opened either manually or by SCADA.

Currently, ISO operating procedures do not respect the Southington (4C) substation auto-throwover scheme. However, as part of this analysis, the performance of the system with and without the scheme in-service was evaluated.

Southington (4C) Autotransformer Automatic Isolation and Reclosing Scheme: This scheme located at the Southington (4C) substation, will upon detection of a fault within the protected zone of the basic relaying of the transformer, immediately open its associated 345 kV and 115 kV circuit breakers, isolating the faulted transformer. After this, the disconnect switches on the faulted transformer also open isolating the transformer at the disconnect switch level. This allows the 345 kV and 115 kV breakers to safely automatically reclose to restore the 345 kV and 115 kV ring bus (the transformer remains isolated via its disconnect switches). The total elapsed time for these automatic control systems to operate is roughly tens of seconds. These automatic control systems are active whenever the protection and reclosing schemes are in-service and all associated control switches are in their normal position. Currently, ISO operating procedures do not respect the Southington (4C) autotransformer automatic isolation and reclosing scheme. However, as part of this analysis the performance of the system with and without the scheme in service was evaluated.

New Haven Harbor Unit 1U Torsional Stress SPS: (Type III SPS) This SPS is activated by a torsional stress relay that monitors the sub-synchronous oscillations on the generator shaft. The primary action of this SPS will block the Cross Sound Cable HVDC facility. If oscillations persist following the primary action, a secondary action of the relay will trip the New Haven Harbor Unit 1U. This SPS is designed to protect the shaft of the New Haven Harbor Unit #1 from torsional stress by first removing the most likely cause of these oscillations and then, if the oscillations persist, tripping the unit itself.

3.2.15 Explanation of Operating Procedures and Other Modeling Assumptions

The study area transmission system is managed on a daily basis through the use of generation dispatch, HVDC schedules, and phase shifting transformers. The Halvarsson HVDC Converter station (Cross Sound Cable) is typically set to a fixed MW schedule level from New England to New York. In addition, the automatically adjusting Northport phase angle regulator (PAR) on the New York end of the Northport-Norwalk Cable (NNC) and the manually adjustable Sackett substation PAR provide further control of power flows within the study area.

These HVDC and PAR devices are set to balance power flows under normal conditions and are adjusted to mitigate power flows post-contingency, as necessary. Each controlling device is described in detail below.

Halvarsson HVDC Converter Station (Cross Sound Cable): The Cross Sound Cable (CSC) is a 330 MW, HVDC interconnection between the Shoreham station in Long Island, New York and Halvarsson station in New Haven, Connecticut. The line connecting the two converter stations, the Halvarsson Converter Station (14P) and the Tomson Converter Station (8ZN), has been designated the Halvarsson-Tomson 481 line. The Halvarsson converter station uses its reactive output capability to control the 345 kV bus on the Connecticut side to a target of 357 kV.

Sackett Phase Shifter: The existing operation of this phase shifter is in a manual mode only and is normally set in the Raise 3 Tap (-1.875°), which tends to draw power flow from Grand Avenue through this phase shifter towards Mix Avenue substation.

In recent years, this phase angle regulator (PAR) has become an increasing concern due to multiple maintenance issues. This study looked at options that would either replace or preferably eliminate this PAR based both on these maintenance concerns and thermal overloads identified in the Needs Assessment.

Northport Phase Shifter: The phase shifter is used to control the flow on Norwalk Harbor – Northport 601, 602 and 603 cables. The phase shifter is equipped for operation by automatic or supervisory control from the Long Island Power Authority (LIPA) System Operating Center and by local control from the Northport control house. Normally, the control will be automatic and the loading of Norwalk Harbor – Northport 601, 602 and 603 cables will be set to a schedule agreed to by the ISO-NE System Operator and NYISO Shift Supervisor. In an emergency, the CONVEX System Operations Supervisor may request a change in loading on this line directly to the LIPA System Operator, and then notify the ISO-NE System Operator. Similarly, the LIPA System Operator may change the loading on this line and then notify the CONVEX System Operations Supervisor. The phase shifter is normally computer controlled, and will respond to changes in flow in the following manner:

- If the actual flow exceeds the scheduled flow by greater than the dead-band entered by the LIPA System Operator (usually +/- 20 MW) and lasts at least one minute, the regulator will change at the rate of one tap a minute. If another Long Island phase shifter is also changing taps, the regulator will change at the rate of one tap every two minutes.
- The phase shifter has a total of 65 taps available through two tap changers, one on the load-side of the phase shifter and the other on the source-side of the phase shifter. The two tap changers are operated alternately and are never more than one tap apart.
- At full load and at the extreme taps, Northport can lead Norwalk Harbor by 50.3 degrees or Northport can lag Norwalk Harbor by -65.7 degrees.
- The operator can manually change taps at one tap per 30 seconds.

The change in flow per degree is in the order of 25 MW per tap. Therefore, the flow on the cable may be changed as follows:

- Automatic 25 MW per minute, and
- Manual 50 MW per minute

There is a one minute delay before the automatic operation begins.

A change of 50 MW or more on any individual LIPA tie-line will cause the Northport phase shifter to trip off "Automatic" control and will not be returned to "Automatic" control until both NYISO and ISO-NE agree to that return. The Northport phase shifter will trip off "Automatic" control for a tie-line deviation of 50 MW or greater in either direction, in to, or out of, LIPA. It will continue on "Automatic" control for any LIPA tie-line deviation of less than 50 MW. Therefore, within one minute of a change of less than 50 MW on the 601, 602 and 603 cables, the phase shifter will begin returning the 601, 602 and 603 cables flow to the scheduled flow. If returning to schedule is not desired, communication with the LIPA System Operator is required, requesting that the phase shifter be placed in "Manual" until system adjustments have been completed. If it is anticipated that such support may be required for an emergency, advance arrangements should be made with the LIPA System Operator.

3.3 Stability Modeling Assumptions

Not applicable for this study.

3.4 Short Circuit Model Assumptions

3.4.1 Study Assumptions

The short circuit study evaluated the projected 2022 available fault current levels in the study area. It also included the effects of area reliability project upgrades with PPA approval as well as selected proposed generation interconnection projects as outlined in Sections 3.4.3 and 3.4.4 of this study document.

3.4.2 Short Circuit Model

The ASPEN Circuit Breaker Rating Module software was used to calculate all circuit breaker duties. The case for the short circuit study was obtained from the 2013 short circuit base case library and all PPA approved transmission projects, as discussed in Section 3.2.3 were included in the model.

3.4.3 Contributing Generation Assumptions (Additions & Retirements)

The model included proposed generation interconnection projects that have PPA approval.

- Q384 Combined Cycle Unit (PPA Approved)

As mentioned in Section 3.2.4, several units in the study area submitted NPR requests to permanently retire. The following units were removed from the model due to those approved requests.

- AES Thames (FCA #7)
- Bridgeport Harbor Unit 2 (FCA #8)
- Norwalk Harbor Station Units 1, 2, and 10 (FCA #8)

3.4.4 Generation and Transmission System Configurations

NPCC Directory #1 and ISO PP-3 require short circuit testing to be conducted with all transmission and generation facilities in-service for all potential operating conditions.

3.4.5 Boundaries

The boundaries include testing of all 345 and 115 kV substations and breakers in the Southwest Connecticut study area.

3.4.6 Other Relevant Modeling Assumptions

Not applicable to this study.

3.5 Other System Studies

3.5.1 Sackett Phase Angle Regulator Asset Condition

The Sackett substation phase angle regulator (PAR) is a 116 kV, 125 MVA Westinghouse Type SL PAR with Type URT Load Tap Changer. The PAR was installed in 1968, with over 46 years of operational service to date. In recent years, this phase shifting transformer has become an increasing concern due to multiple maintenance issues. The Solutions Study included options to either replace or preferably eliminate this PAR based both on these maintenance concerns and thermal overloads identified in the Needs Assessment.

3.5.2 Special Protection System Screening Test

As described in Section 3.2.14, the study area has several special protection systems (SPS) and automatic control schemes. The chosen preferred solution included a screening sensitivity to determine if any of the existing SPS or control schemes could potentially be retired or would require post-project modification(s). Based on results of the screening study, further detailed evaluation(s) of each SPS and control scheme will be done in a future study.

3.5.3 Q384 Combined Cycle Assessment

ISO Queue Position #384 is a 745 MW Summer / 775 MW Winter combined cycle facility interconnecting on the NU 115 kV system between Baldwin and Oxford substations in New Haven County. The projected in-service date is June 1, 2018. The project's system impact study had been completed prior to this study and identified a criteria violation in the SWCT study area on the 1585 line between the point of interconnection and Bunker Hill substation. The project is responsible to upgrade the line section to interconnect.

Once a preferred solution had been chosen in this study, Q384 was added to the case to ensure the solution alternative did not have an adverse impact to the project and all previously identified upgrades were still applicable. The assessment concluded that the Q384 upgrades were still required and the preferred solution worked together with Q384 in-service.

3.6 Changes in Study Assumptions

During the completion of the Solutions Study, FCA #8 was completed in February 2014. The most up-to-date demand resource values from the auction did not significantly change from what was studied in this report. Therefore, no changes were made to the cases as the minor changes were not expected to alter the current results significantly. The differences between what was studied and the results of the auction are shown in Table 3-12 and Table 3-13..

Table 3-12 FCA #8 Results vs. Studied Passive DR and Forecasted EE

Load Zone	Total Studied Passive DRV (MW)	FCA #8 Passive DRV (MW)	Forecasted EE 2018-2022 (MW)	Total New Passive DRV (MW)	Difference (%)
Connecticut	523	390	112	502	– 4.2%
New England Total	2,658	1,935	837	2,772	+ 4.1%

Table 3-13 FCA #8 Results vs. Studied Active DR

Dispatch Zone	Total Studied Active DRV (MW)	FCA #8 Active DRV (MW)	Difference (%)
Eastern Connecticut	37	37	0.0%
Northern Connecticut	84	84	0.0%
Norwalk-Stamford	34	34	0.0%
Western Connecticut	104	104	0.0%
New England Total	800	812	+ 1.5%

No new generation in Connecticut cleared in FCA #8 and only 27 MW of additional generation cleared in the rest of New England. These projects were determined to not affect the results so the cases were not re-run to reflect these additional resources.

During the course of this study, the 2014 CELT report was issued in May 2014. The forecasted 2022 summer 90/10 peak demand forecast for New England was 33,865 MW. The state of Connecticut forecast remained unchanged from the 2013 to 2014 forecast of 8,825 MW for 2022. The New England system had a reduction of 240 MW (0.7%) from the 2013 forecast. The changes in the forecast were determined to not affect the results, so the cases were not re-run to reflect this change.

Since the 2022 minimum load study started at a much later date after the SWCT preferred solutions were selected, the changes in study assumptions discussed above were reflected in the minimum load cases. The 2022 minimum load distribution was modeled based on the 2014 CELT report and all resources cleared the FCA #8 were modeled in the minimum load cases.

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. Descriptions of each of the NERC, NPCC, and ISO tests that were used to assess the system performance are discussed in this section.

4.2 Performance Criteria

4.2.1 Steady State Criteria

The Solutions Study was performed in accordance with the North American Electric Reliability Corporation (NERC) Transmission Planning Standards[25] TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a, the Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1[26], "*Design and Operation of the Bulk Power System,*" and the ISO Planning Procedure No. 3[27] (PP-3), "*Reliability Standards for the New England Area Bulk Power Supply System.*" The contingency analysis steady-state voltage and thermal loading criteria, power flow solution parameters, and contingency specifications that were used are consistent with these documents. As part of the Solutions Study, the robustness of the system with respect to limited extreme contingency events was evaluated.

4.2.2 Steady State Thermal and Voltage Limits

Thermal loadings on all transmission facilities rated at 69 kV and above in the study area were monitored. The thermal violations screening criteria is defined in Table 4-1.

Table 4-1 Steady-State Thermal Criteria

System Condition	Maximum Allowable Facility Loading
All-lines-in (N-0)	Normal Rating
Post-Contingency (N-1 or N-1-1)	Long Time Emergency (LTE) Rating

Voltages were monitored at all buses greater than 69 kV in the study area. System voltages outside of limits defined in Table 4-2 were identified for all-lines-in and post-contingency after autotransformer tap changing.

[25] http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[26] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

[27] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf

Table 4-2 Steady-State Voltage Criteria

Facility Owner	Voltage Level	Bus Voltage Limits (Per-Unit)	
		Normal Conditions (Pre-Contingency)	Emergency Conditions (Post-Contingency)
Northeast Utilities	69 kV and above	0.95 to 1.05	0.95 to 1.05
United Illuminating	115 kV and above	0.95 to 1.05	0.95 to 1.05
CMEEC	69 kV and above	0.95 to 1.05	0.95 to 1.05
Millstone / Seabrook[28]	345 kV	1.00 to 1.05	1.00 to 1.05
Pilgrim[28]	345 kV	0.995 to 1.05	0.99 to 1.05
Vermont Yankee[28]	345 kV	0.985 to 1.05	0.985 to 1.05
Vermont Yankee[28]	115 kV	1.00 to 1.05	1.00 to 1.05

4.2.3 Steady State Solution Parameters

The steady-state analysis was performed with pre-contingency solution parameters that allowed for adjustment of load tap-changing transformers (LTCs), static var devices (SVDs, including automatically-switched capacitors), and phase angle regulators (PARs). These parameters are described in Table 4-3.

Table 4-3 Study Solution Parameters

Case	Area Interchange Control	Tap Adjustments	Phase Angle Regulators	SVDs & Switched Shunts
All-lines-in (N-0)	Tie Lines and Loads Enabled	Stepping	Enabled[29]	Enabled
Post-Contingency (N-1 & N-1-1)	Disabled	Stepping	Disabled[30]	Disabled

4.2.4 Stability Performance Criteria

Not applicable for this study.

4.2.5 Short Circuit Performance Criteria

This study was performed in accordance with appropriate IEEE C37 standards and specific design parameters of the circuit breakers and substation equipment. This includes specific considerations for the total-current rated and symmetrical-current rated breakers as appropriate.

The circuit breakers were evaluated for short circuit adequacy based on the following criteria:

- *Acceptable-duty*: Circuit breaker fault interrupting duty less than 90% of the available fault current. No action required.
- *Marginal-duty*: Circuit Breaker Fault Interrupting Duty greater than or equal to 90% and less than 100%. This is an acceptable operating condition; however, potential solutions should begin to be developed to address solutions that would require a significant lead time to

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

[29] PARs across New England set according to published modeling guide:
http://www.iso-ne.com/rules_proceds/isone_plan/othr_docs/system_elements_modeling_guide_rev3.pdf

[30] Results with the NNC PAR 'Disabled' are being used in this Solutions Study. This was done to match the real-time operation of the PAR described in Section 3.2.15.

complete.

- *Over-duty*: Circuit breaker fault interrupting duty greater than 100%. This is considered an unacceptable operating condition requiring a solution to be developed to eliminate the over-duty condition.

4.3 System Testing

4.3.1 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. In addition, single contingencies which may cause the loss of multiple transmission circuit facilities, such as those on a common set of tower line structures were simulated. The steady-state contingency events also included circuit breaker failures and substation bus fault conditions that could result in removing multiple transmission elements from service. A comprehensive set of contingency events, listed in Appendix D: Steady-State Contingency List, were tested to monitor thermal and voltage performance of the study area transmission network.

Additional analyses evaluated N-1-1 conditions with an initial outage of a pool transmission facility (PTF) element 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, regional reliability criteria, including ISO PP-3, allow specific manual system adjustments, such as fast-start generation re-dispatch, PAR adjustment, or HVDC adjustments prior to the next contingency event. The N-1-1 analysis also considered the operation of line switch automation for specific line out scenarios that would have an effect on the results.

A type of contingency defined in the NERC standards is loss of an element without a fault. This contingency is commonly referred to as a ‘no-fault’ contingency. This contingency type is further broken down into two types:

- Type 1: No-fault contingencies involving the opening of a terminal of a line independent of the design of the terminating facility.
- Type 2: A subset of the above contingencies that involve the opening of a single breaker without a fault.

For N-1 testing, all Type 1 no-fault contingencies were modeled. However for N-1-1 testing, only the Type 2 no-fault contingencies were modeled as the second contingency.

A listing of all contingency types that were tested is included in Table 4-4 and a listing of initial element outages for N-1-1 is included in Appendix D: Steady-State Contingency List and summarized in Table 4-5.

Table 4-4 Summary of NERC, NPCC, and/or ISO-NE Contingencies Included

Contingency Type	NERC Type	NPCC D-1 Section	ISO PP-3 Section	Tested in This Study
All Facilities In-service (N-0)	A	5.4.2.b	3.2.b	Yes
Generator (Single resource)	B1	5.4.1.a	3.1.a	Yes
Transmission Circuit	B2	5.4.1.a	3.1.a	Yes
Transformer	B3	5.4.1.a	3.1.a	Yes
Element w/o Fault	B5	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 Contingency	D	5.6	5	Yes (Limited)

Table 4-5 Summary of N-1-1 Initial Element Outages

Contingency Type	# of Elements Tested
345 kV – Overhead	12
345 kV – Underground	4
345/115 kV Autotransformers	15
115 kV – Overhead	106
115 kV – Underground	12
HVDC Lines	1
Generators	4
Reactive Devices	17
Total # of Initial Scenarios[31]	171

A total of 43 N-1-1 initial element outages were tested in the 2022 Minimum load study, along with a selective set of first contingencies. A full listing of the contingencies studied in the 2022 minimum load study can be found in Appendix H: 2022 Minimum Load Contingency List.

4.3.2 Generation Re-Dispatch Testing

As outlined in NPCC Directory 1 and ISO PP-3, allowable actions after the first contingency event and prior to the second contingency event include re-dispatch of generation (i.e. reduction in base generation and turning on quick-start generation). To simulate these actions in power flow analysis, the security constrained re-dispatch (SCRD[32]) tool in the TARA software package was used.

[31] If any modifications were made to existing facilities or new ones were created as part of solution alternative, those changes were made to the list of initial element outages tested during N-1-1 analysis.

[32] The TARA SCRD tool did not consider the economics of re-dispatch in the objective function in this study. It solely used the most effective dispatch of fast-start generation that will resolve a particular constraint on the system.

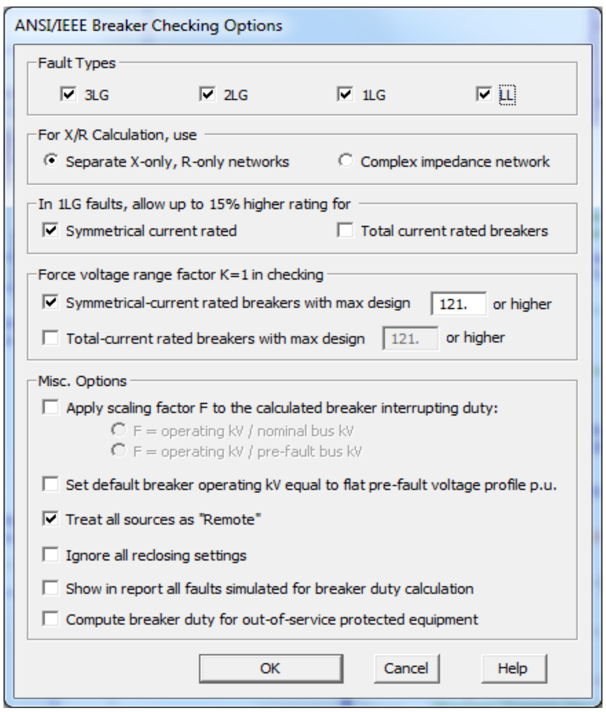
During the analysis, all available generation within the study area was allowed to be reduced or shut down (for example: New Haven Harbor Unit #1) to mitigate a thermal violation. Proxy generation, remote to the study area, was used to replace the decreased generation in the study area to simulate the re-dispatch of fast-start units within New England to maintain the system generation-load balance. A maximum limit of 1,200 MW of re-dispatch was considered acceptable. Anything higher than 1,200 MW would not be acceptable due to the amount of reserves typically available on the system.

4.3.3 Stability Contingencies/Faults Tested

Not applicable for this study.

4.3.4 Short Circuit Faults Tested

The ASPEN circuit breaker rating module software was used to calculate all circuit breaker duties in the study area. The pre-fault voltage for all buses studied was 1.04 per unit (pu). Figure 4-1 shows the ASPEN simulation options used in this study.



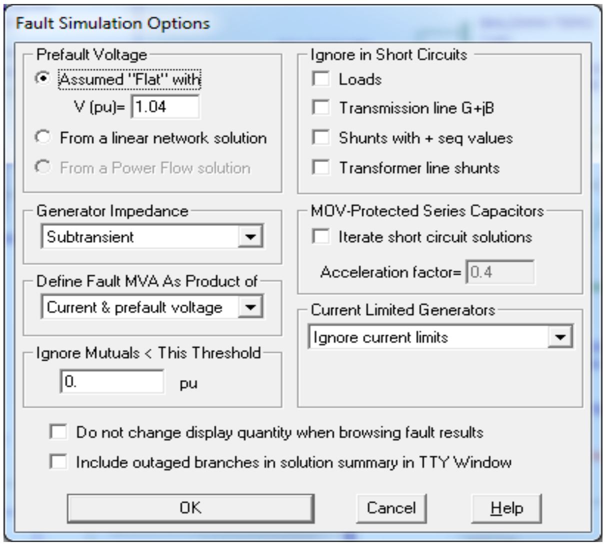


Figure 4-1 Circuit Breaker Testing Parameters

Section 5
Development of Alternative Solutions

The 2022 Needs Assessment identified numerous system weaknesses on the existing 115 kV network in Southwest Connecticut. Most involved large pockets of load being served from a few weak connections to the high voltage network. When a combination of these connections were removed during N-1-1 analysis, the remaining lines in-service were unable to handle the increased loading and resulted in thermal overloads and low voltage to potential voltage collapse in the load pocket. Other violations occurred when power was transferring to the Norwalk – Stamford load pocket through the Bridgeport and New Haven subareas after contingency events. These overloads were worsened when generation in the load pocket announced retirement, requiring the additional power to come from outside the study area.

The alternative solutions were developed to find ways to strengthen these connections to the load pockets by: adding new sources into the pocket, improving the remaining elements after N-1-1 contingency events to adequately handle the additional loading, or eliminate the contingency condition causing the violations. A description of all the alternative solutions is in Section 5.3. All of the alternative solutions were first evaluated to ensure that the solution components resolve all the identified criteria violations identified in the Needs Assessment. These evaluations are described in Section 6. The next step was to compare the alternative solution components in terms of cost, constructability, environmental concerns, and several other criteria. These comparisons are described in Section 7.

5.1 Preliminary Screen of Alternative Solutions

During the conceptual phase of the Solutions Study, several solutions were proposed to address the identified need. The addition of new 345 and 115 kV lines or new 345/115 kV autotransformers were discussed as possible solutions to serve the load pockets. At the onset it was determined that any additional 345 kV lines in the area would be far more costly than 115 kV projects and would have many challenges in the densely populated region of Southwest Connecticut. Therefore, 345 kV line alternatives were eliminated from consideration when building solution alternatives for the area.

5.2 Coordination of Alternative Solutions with Other Entities

The working group included representatives from NU, UI, and ISO. This working group helped to ensure that the study of alternatives included other planned transmission system changes outside of the Southwest Connecticut area as well as the impact that the alternative solution had on facilities outside of the study area. Coordination with other ongoing working groups in Connecticut was also done throughout the process. In particular, the Greater Hartford – Central Connecticut working group was re-evaluating the NEEWS Central Connecticut Reliability Project component as part of their Solutions Study so this study excluded that project when evaluating alternatives. The working group also coordinated efforts with the ongoing generator system impact studies in the area to ensure all proposed projects would work together and not cause each other adverse impacts.

5.3 Description of Alternative Solutions

The Southwest Connecticut study area is a large section of the transmission grid with numerous issues identified in the Needs Assessment. To study solution alternatives for the entire area at once would be logistically too complex and upon further analysis of the Needs Assessment results, the criteria violations could be grouped into common subareas within the study area to evaluate solution alternatives. Figure 5-1 shows the SWCT geographic area with subareas defined.

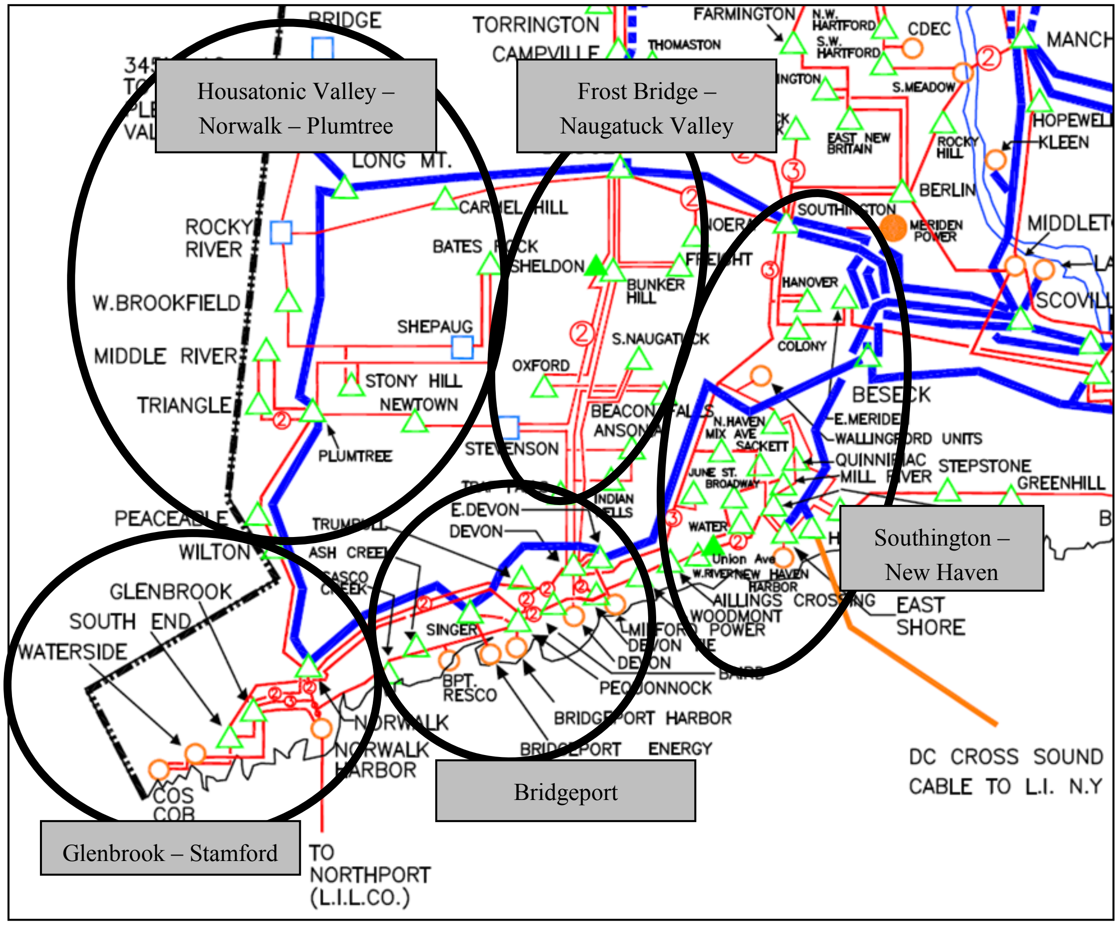


Figure 5-1 SWCT Geographic Subareas

The Glenbrook – Stamford subarea did not have any criteria violations in the 2022 Needs Assessment. This was due to the inclusion of the previously PPA approved project to add a new 115 kV underground cable from Glenbrook substation to South End substation. This project continues to solve all criteria violations in the subarea and remains the preferred solution alternative.

Early on in the Solutions Study, it was found there were possible interactions between the Housatonic Valley – Norwalk – Plumtree subarea and the Frost Bridge – Naugatuck Valley subarea. There were also interactions found between the Bridgeport subarea and the Southington – New Haven subarea. To capture these interactions, those subareas were grouped together and a complete set of solution alternatives was tested to resolve all violations in the subarea. After a preferred alternative was chosen in each group of subareas, an overall preferred solution was then tested for the entire study to ensure all violations were resolved and the combined solution did not have any adverse interactions.

5.3.1 Frost Bridge – Naugatuck Valley and Housatonic Valley-Norwalk–Plumtree

The Frost Bridge – Naugatuck Valley subarea extends from the Frost Bridge substation in Watertown, CT south to the Devon substation in Milford, CT. The subarea has a net[33] 2022 load of 652 MW and is served by three 115 kV lines from Frost Bridge, three 115 kV lines from Devon 1, two 115 kV lines from Southington, and one 115 kV line from Plumtree. The area has two small hydro generators modeled at 10% of nameplate and a single fast-start generator at Waterbury which was assumed out-of-service as part of the 20% unavailable fast-start generators in Connecticut. Figure 5-2 shows a geographic one-line of the subarea.

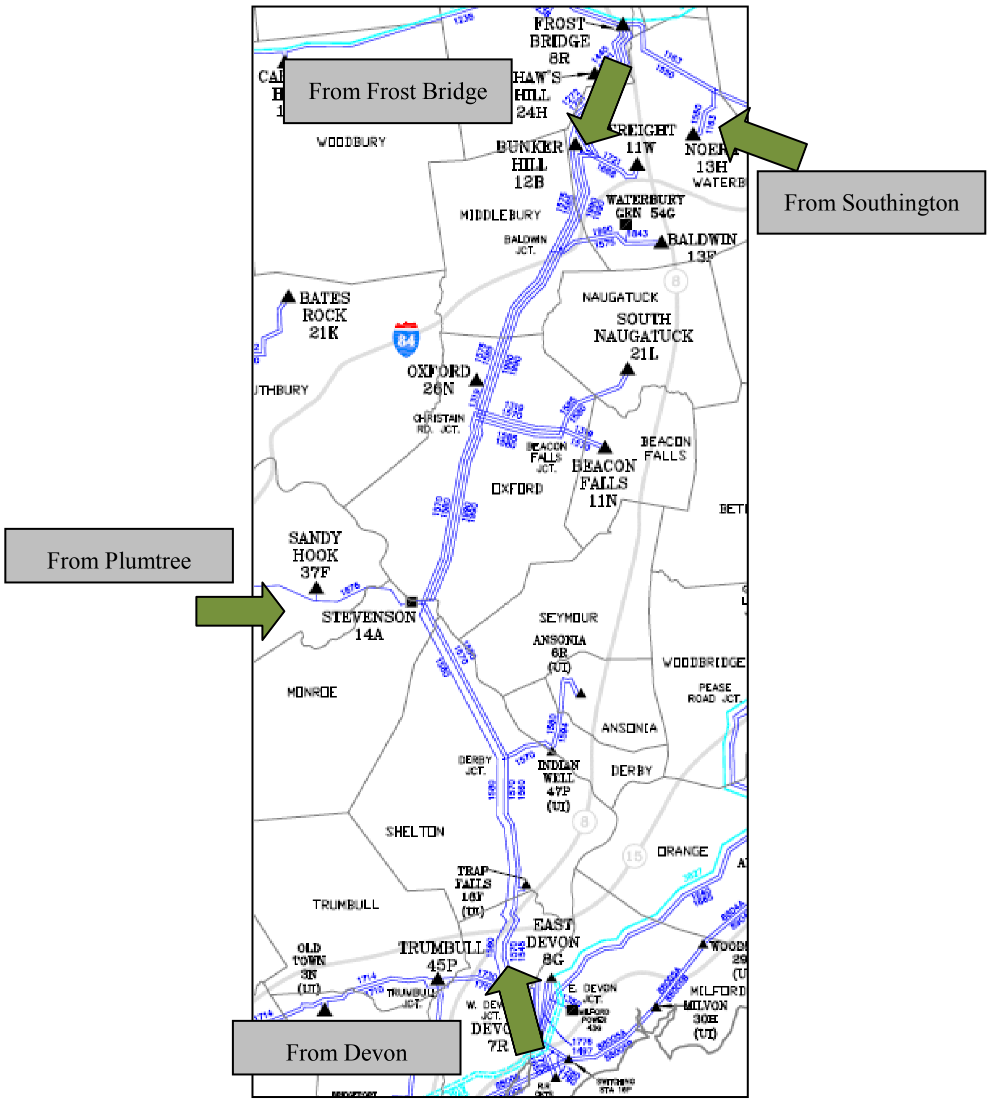


Figure 5-2 Frost Bridge – Naugatuck Valley Subarea Existing Geographic One-Line

[33] Net load is defined as the CELT load forecast minus the transmission losses minus active and passive DR and minus EE plus station service for this report. (Net Load = CELT forecast – transmission losses – Active DR – Passive DR – EE + station service load)

The Housatonic Valley – Norwalk – Plumtree subarea extends from Carmel Hill substation in Woodbury, CT west and south to the Plumtree substation in Bethel, CT south to the Norwalk substation in Norwalk, CT. The subarea has a net 2022 load of 860 MW and is served by two 345/115 kV autotransformers at Plumtree, one 115 kV line from Norwalk, one 115 kV line from Stevenson, and one 115 kV line from Frost Bridge. The area has four resources in the area, the Kimberly Clark facility at 28 MW and three hydro facilities, Rocky River, Bulls Bridge, and Shepaug. Bulls Bridge was modeled at 10% of nameplate and the other two were out-of-service as described in Section 3.2.10. Figure 5-3 shows a geographic one-line of the subarea.

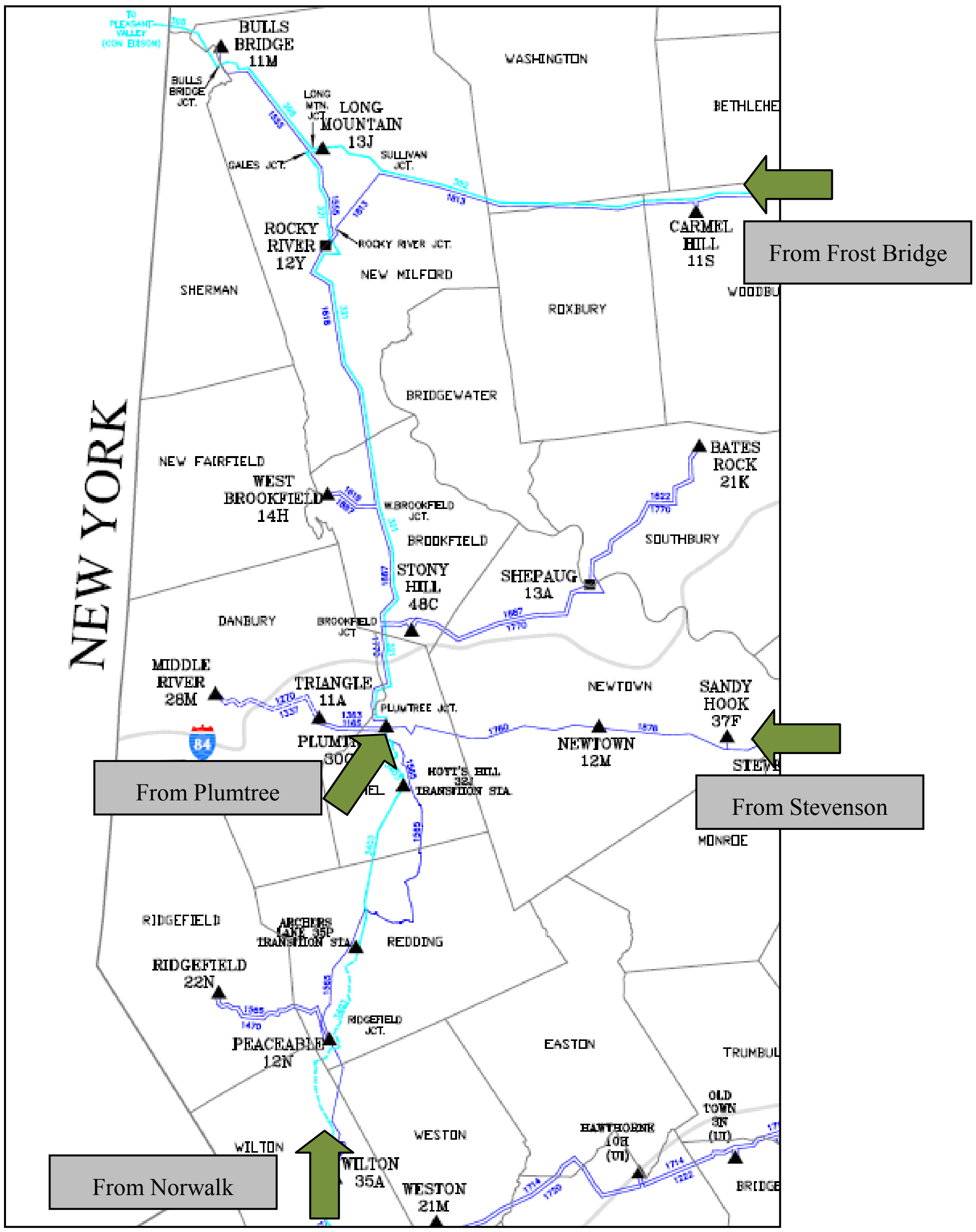


Figure 5-3 Housatonic Valley – Norwalk – Plumtree Subarea Existing Geographic One-Line

The majority of the criteria violations seen in these subareas were related to serving load within the pocket as opposed to power transferring through the subarea to serve another part of the system. Specifically, contingency pairs remove one or more transmission supplies to the load pocket and the remaining transmission connections and local generation are insufficient to serve the load. This causes severe low voltage violations and thermal overloads. Generator re-dispatching was considered as a resolution for all thermal violations and was unsuccessful in a limited number of instances. However, re-dispatching was considered ineffective since the overloads tended to be caused by serving load pockets.

Initially two local solution alternatives were developed in each subarea to solve the violations in the individual load pocket. During that analysis another alternative was proposed to build a new 115 kV line between the Bates Rock and Bunker Hill substations. This would provide an additional link to the two subareas that would be mutually beneficial. This alternative became the 'global' solution and two alternatives were created using this new line as the basis. These four solution alternatives, two local (Local 1 and Local 2) and two global (Global 1 and Global 2) were studied for the combined subareas. A listing of individual solution components that comprise the four alternatives is Table 5-1.

Table 5-1 HV & NV Global and Local Solution Components

ID	Solution Component	Global 1	Global 2	Local 1	Local 2
1	Install a 115 kV capacitor bank (25.2 MVAR) at Oxford substation on 1319 line terminal	X	X	X	X
2	Close the normally open 115 kV 2T circuit breaker at Baldwin substation	X	X	X	X
3	Reconductor the 1887 line between West Brookfield substation and West Brookfield Junction (~1.4 miles); expected summer ratings:201/260/277 MVA	X	X	X	X
4	Install a 115 kV circuit breaker (63 kA interrupting capability) in series with the existing 29T breaker at Plumtree substation	X	X	X	X
5	Install two capacitor banks (14.4 MVAR each) at West Brookfield substation on the 1618 line terminal	X	X	X	X
6	Install a new 115 kV line (~3.4 miles) from Plumtree to Brookfield Junction; expected summer ratings: 401/525/626 MVA	X	X	X	X
7	Relocate the existing 37.8 MVAR capacitor bank at Plumtree substation from 115 kV B bus to 115 kV A bus	X	X	X	X
8	Upgrade the 115 kV 1876 line terminal equipment at Newtown substation; expected new line ratings after upgrade: 293/378/432 MVA	X	X	X	X
9	Reduce the 12Y-10K (25.2 MVAR) capacitor cans at Rocky River substation to 14.4 MVAR	X	X	X	X
10	Loop the 115 kV 1570 line in and out of Pootatuck substation (formerly known as Shelton)	X	X	X	X
11	Install two 115 kV capacitor banks (25 MVAR each) at Ansonia substation, one on the 1560 line terminal and one on the 1594 line terminal	X	X	X	X
12	Expand Pootatuck substation (formerly Shelton) to 4-breaker 115 kV ring bus and install a 115 kV Capacitor bank (30 MVAR) on 1570 line terminal	X	X	X	X
13	Loop the 115 kV 1990 line in and out of Bunker Hill substation	X	X	X	X
14	Replace two Freight 115 kV 25 kA breakers with 63 kA interrupting capability	X	X	X	X

ID	Solution Component	Global 1	Global 2	Local 1	Local 2
15	Rebuild Bunker Hill substation into a 115 kV breaker-and-a-half configuration with 11 circuit breakers	X	X		
16	Install a new 115 kV line (~10.7 miles) from Bunker Hill to Bates Rock substations; expected new line ratings: 401/524/626 MVA	X	X		
17	Expand Bates Rock substation 7-breaker 115kV ring bus configuration	X	X		
18	Rebuild a portion of the 115 kV 1682 line from Wilton to Norwalk substations (~1.5 miles); expected new line ratings after upgrade: 309/435/435 MVA	X	X		
19	Rebuild Bunker Hill substation into a 115 kV breaker-and-a-half configuration with 9 circuit breakers			X	X
20	Rebuild a portion of the 115 kV 1682 line from Wilton to Norwalk substations (~1.5 miles) and upgrade Wilton substation terminal equipment; expected new line ratings after upgrade: 285/378/432 MVA			X	X
21	Reconductor the 115 kV 1470-1 line from Wilton substation to Ridgefield Junction (~5.1 miles) expected new line ratings after upgrade: 255/331/364 MVA			X	X
22	Reconductor the 115 kV 1470-3 line from Peaceable to Ridgefield Junction (~0.04 miles); expected new line ratings after upgrade: 255/331/364 MVA			X	X
23	Reconductor the 115 kV 1575 line from Bunker Hill to Baldwin Junction (~3.0 miles); expected new 556 ACSS line ratings after upgrade: 201/260/277 MVA			X	X
24	Rebuild the 115 kV 1887-2 line from Shepaug to Brookfield Junction (~7.4 miles)		X		
25	Reduce the 21K (37.8 MVAR) capacitor cans at Stony Hill substation to 25.2 MVAR	X		X	
26	Reconfigure the 115 kV 1887 line into 2 lines segments, one from Plumtree to West Brookfield to Stony Hill substations and one from Stony Hill to Shepaug substations. Reconfigure the 115 kV 1770 line into a 2 terminal line from Plumtree to Bates Rock substations.	X		X	
27	Relocate the 22K (37.8 MVAR) capacitor bank to the same side as the 10K (25.2 MVAR) capacitor bank at Stony Hill substation		X		X
28	Reconfigure the 115 kV 1887 line into a 3-terminal line from Plumtree to West Brookfield to Shepaug substations. Reconfigure the 115 kV 1770 line into 2 two terminal lines from Plumtree to Stony Hill and Stony Hill to Bates Rock substations		X		X
29	Rebuild the 115 kV 1887-2 line from Shepaug to Brookfield Junction (~0.9 miles)			X	
30	Install 2 synchronous condensers (+25/-12.5 MVAR) at Stony Hill substation			X	
31	Install 1 synchronous condenser (+25/-12.5 MVAR) at Stony Hill substation				X

X is applied to the solution component which belongs to a particular solution alternative. This note pertains to all solution alternative tables.

The following one-line diagrams show details of these solution components grouped by area substations.

The first two components are substation changes in the Frost Bridge – Naugatuck Valley subarea at the Baldwin and Oxford substations. A one-line diagram of the upgrades is shown in Figure 5-4.

ID	Solution Component	G1	G2	L1	L2
1	Install a 115 kV capacitor bank (25.2 MVAR) at Oxford substation on 1319 line terminal	X	X	X	X
2	Close the normally open 115 kV 2T circuit breaker at Baldwin substation	X	X	X	X

[redacted]

Figure 5-4 Baldwin and Oxford Substation Upgrades

The next set of solution components are in the Housatonic Valley subarea at or near the West Brookfield substation. A one-line diagram of the upgrades is shown in Figure 5-5.

ID	Solution Component	G1	G2	L1	L2
3	Reconductor the 1887 line between West Brookfield substation and West Brookfield Junction (~1.4 miles); expected summer ratings:201/260/277 MVA	X	X	X	X
5	Install two capacitor banks (14.4 MVAR each) at West Brookfield substation on the 1618 line terminal	X	X	X	X

[redacted]

Figure 5-5 West Brookfield Substation Area Upgrades

The next set of solution components involves upgrades in the Norwalk – Plumtree subarea at the Plumtree substation. A one-line diagram of the upgrades is shown in Figure 5-6.

ID	Solution Component	G1	G2	L1	L2
4	Install a 115 kV circuit breaker (63 kA interrupting capability) in series with the existing 29T breaker at Plumtree substation	X	X	X	X
6	Install a new 115 kV line (~3.4 miles) from Plumtree to Brookfield Junction; expected summer ratings: 401/525/626 MVA	X	X	X	X
7	Relocate the existing 37.8 MVAR capacitor bank at Plumtree substation from 115 kV B bus to 115 kV A bus	X	X	X	X
8	Upgrade the 115 kV 1876 line terminal equipment at Newtown substation; expected new line ratings after upgrade: 293/378/432 MVA	X	X	X	X

[redacted]

Figure 5-6 Plumtree Substation Area Upgrades

The next solution component involves an upgrade in the Housatonic Valley subarea at the Rocky River substation. A one-line diagram of the upgrade is shown in Figure 5-7.

ID	Solution Component	G1	G2	L1	L2
9	Reduce the 12Y-10K (25.2 MVAR) capacitor cans @ Rocky River substation to 14.4 MVAR	X	X	X	X

[redacted]

Figure 5-7 Rocky River Substation Upgrade

The next set of solution components involves upgrades in the Naugatuck Valley subarea at the Pootatuck (formerly known as Shelton) and Ansonia substations. A one-line diagram of the upgrades is shown in Figure 5-8.

ID	Solution Component	G1	G2	L1	L2
10	Loop the 115 kV 1570 line in and out of Pootatuck substation (formerly known as Shelton)	X	X	X	X
11	Install two 115 kV capacitor banks (25 MVAR each) at Ansonia substation, one on the 1560 line terminal and one on the 1594 line terminal	X	X	X	X
12	Expand Pootatuck substation (formerly Shelton) to 4-breaker 115 kV ring bus and install a 115 kV Capacitor bank (30 MVAR) on 1570 line terminal	X	X	X	X

[redacted]

Figure 5-8 Pootatuck and Ansonia Substation Upgrades

The next set of solution components involves connecting the Housatonic Valley and Naugatuck Valley subareas with a new 115 kV line between Bunker Hill and Bates Rock substations. This is known as the Global solution alternative. One-line diagrams of the upgrades are shown in Figure 5-9, Figure 5-10, and Figure 5-11.

ID	Solution Component	G1	G2	L1	L2
13	Loop the 115 kV 1990 line in and out of Bunker Hill substation	X	X	X	X
15	Rebuild Bunker Hill substation into a 115 kV breaker-and-a-half configuration with 11 circuit breakers	X	X		
16	Install a new 115 kV line (~10.7 miles) from Bunker Hill to Bates Rock substations; expected new line ratings: 401/524/626 MVA	X	X		
17	Expand Bates Rock substation 7-breaker 115kV ring bus configuration	X	X		
18	Rebuild a portion of the 115 kV 1682 line from Wilton to Norwalk substations (~1.5 miles); expected new line ratings after upgrade: 309/435/435 MVA	X	X		

[redacted]

Figure 5-9 Bunker Hill Substation Global Solution Alternative Upgrades

[redacted]

Bates Rock 21K

Figure 5-10 Bates Rock Substation Global Solution Alternative Upgrades

[redacted]

Figure 5-11 Wilton Substation Area Global Solution Upgrade

The next solution component involves an upgrade in the Naugatuck Valley subarea at the Freight substation. The breakers at the substation were found to be over-duty and need to be replaced. A one-line diagram of the upgrade is shown in Figure 5-12. It should be noted that the Solutions Study needed to respect the Q384 combined cycle generation interconnection project. That project, combined with the solution alternatives, causes the Freight breakers to be over-duty. If Q384 were to withdraw from the Interconnection Queue, the breakers would no longer need to be replaced.

ID	Solution Component	G1	G2	L1	L2
14	Replace two Freight 115 kV 25 kA breakers with 63 kA interrupting capability	X	X	X	X

[redacted]

Figure 5-12 Freight Substation Upgrade

The next set of solution components involves upgrades in the Housatonic Valley and Naugatuck Valley subareas independently. This is known as the Local solution alternative. One-line diagrams of the upgrades are shown in Figure 5-13 and Figure 5-14.

ID	Solution Component	G1	G2	L1	L2
13	Loop the 115 kV 1990 line in and out of Bunker Hill substation	X	X	X	X
19	Rebuild Bunker Hill substation into a 115 kV breaker-and-a-half configuration with 9 circuit breakers			X	X
20	Rebuild a portion of the 115 kV 1682 line from Wilton to Norwalk substations (~1.5 miles) and upgrade Wilton substation terminal equipment; expected new line ratings after upgrade: 285/378/432 MVA			X	X
21	Reconductor the 115 kV 1470-1 line from Wilton substation to Ridgefield Junction (~5.1 miles); expected new line ratings after upgrade: 255/331/364 MVA			X	X
22	Reconductor the 115 kV 1470-3 line from Peaceable to Ridgefield Junction (~0.04 miles); expected new line ratings after upgrade: 255/331/364 MVA			X	X
23	Reconductor the 115 kV 1575 line from Bunker Hill to Baldwin Junction (~3.0 miles); expected new 556 ACSS line ratings after upgrade: 201/260/277 MVA			X	X

[redacted]

Figure 5-13 Bunker Hill Substation Area Local Solution Upgrades

[redacted]

Figure 5-14 Peaceable and Wilton Substation Area Local Solution Upgrades

The next set of solution components involves upgrades in the Housatonic Valley subarea around the Stony Hill substation area. These upgrades are part of the Global 1 solution alternative. A one-line diagram of the upgrades is shown in Figure 5-15.

ID	Solution Component	G1	G2	L1	L2
25	Reduce the 21K (37.8 MVAR) capacitor cans @ Stony Hill substation to 25.2 MVAR	X		X	
26	Reconfigure the 115 kV 1887 line into 2 lines segments, one from Plumtree to West Brookfield to Stony Hill substations and one from Stony Hill to Shepaug substations. Reconfigure the 115 kV 1770 line into a 2 terminal line from Plumtree to Bates Rock substations.	X		X	

[redacted]

Figure 5-15 Stony Hill Area Global 1 Solution Alternative Upgrades

The next set of solution components involves upgrades in the Housatonic Valley subarea around the Stony Hill substation area. These upgrades are part of the Global 2 solution alternative. A one-line diagram of the upgrades is shown in Figure 5-16.

ID	Solution Component	G1	G2	L1	L2
24	Rebuild the 115 kV 1887-2 line from Shepaug to Brookfield Junction (~7.4 miles)		X		
27	Relocate the 22K (37.8 MVAR) capacitor bank to the same side as the 10K (25.2 MVAR) capacitor bank at Stony Hill substation		X		X
28	Reconfigure the 115 kV 1887 line into a 3-terminal line from Plumtree to West Brookfield to Shepaug substations. Reconfigure the 115 kV 1770 line into 2 two terminal lines from Plumtree to Stony Hill and Stony Hill to Bates Rock substations		X		X

[redacted]

Figure 5-16 Stony Hill Area Global 2 Solution Alternative Upgrades

The next set of solution components involves upgrades in the Housatonic Valley subarea around the Stony Hill substation area. These upgrades are part of the Local 1 solution alternative. A one-line diagram of the upgrades is shown in Figure 5-17.

ID	Solution Component	G1	G2	L1	L2
25	Reduce the 21K (37.8 MVAR) capacitor cans at Stony Hill substation to 25.2 MVAR	X		X	
26	Reconfigure the 115 kV 1887 line into 2 lines segments, one from Plumtree to West Brookfield to Stony Hill substations and one from Stony Hill to Shepaug substations. Reconfigure the 115 kV 1770 line into a 2 terminal line from Plumtree to Bates Rock substations.	X		X	
29	Rebuild the 115 kV 1887-2 line from Shepaug to Brookfield Junction (~0.9 miles)			X	
30	Install 2 synchronous condensers (+25/-12.5 MVAR) at Stony Hill substation			X	

[redacted]

Figure 5-17 Stony Hill Area Local 1 Solution Alternative Upgrades

The next set of solution components involves upgrades in the Housatonic Valley subarea around the Stony Hill substation area. These upgrades are part of the Local 2 solution alternative. A one-line diagram of the upgrades is shown in Figure 5-18.

ID	Solution Component	G1	G2	L1	L2
27	Relocate the 22K (37.8 MVAR) capacitor bank to the same side as the 10K (25.2 MVAR) capacitor bank at Stony Hill substation		X		X
28	Reconfigure the 115 kV 1887 line into a 3-terminal line from Plumtree to West Brookfield to Shepaug substations. Reconfigure the 115 kV 1770 line into 2 two terminal lines from Plumtree to Stony Hill and Stony Hill to Bates Rock substations		X		X
31	Install 1 synchronous condenser (+25/-12.5 MVAR) at Stony Hill substation				X

[redacted]

Figure 5-18 Stony Hill Area Local 2 Solution Alternative Upgrades

5.3.2 Bridgeport and Southington – New Haven

The Bridgeport subarea includes the south-central coastal region of Connecticut including the towns of Bridgeport, Fairfield, Milford, Stratford, and Trumbull, CT. The subarea has a net 2022 load of 511 MW and is served by four 115 kV lines from Norwalk, four 115 kV lines from New Haven, two 345/115 kV transformers, one at East Devon and one at Singer. The area has 1,840 MW of generation capacity at two locations, Bridgeport, CT (Bridgeport Harbor 3 & 4, Bridgeport Energy, and Bridgeport Resco) and Stratford, CT (Devon 10-18, and Milford 1 & 2). Figure 5-19 shows a geographic one-line of the subarea.

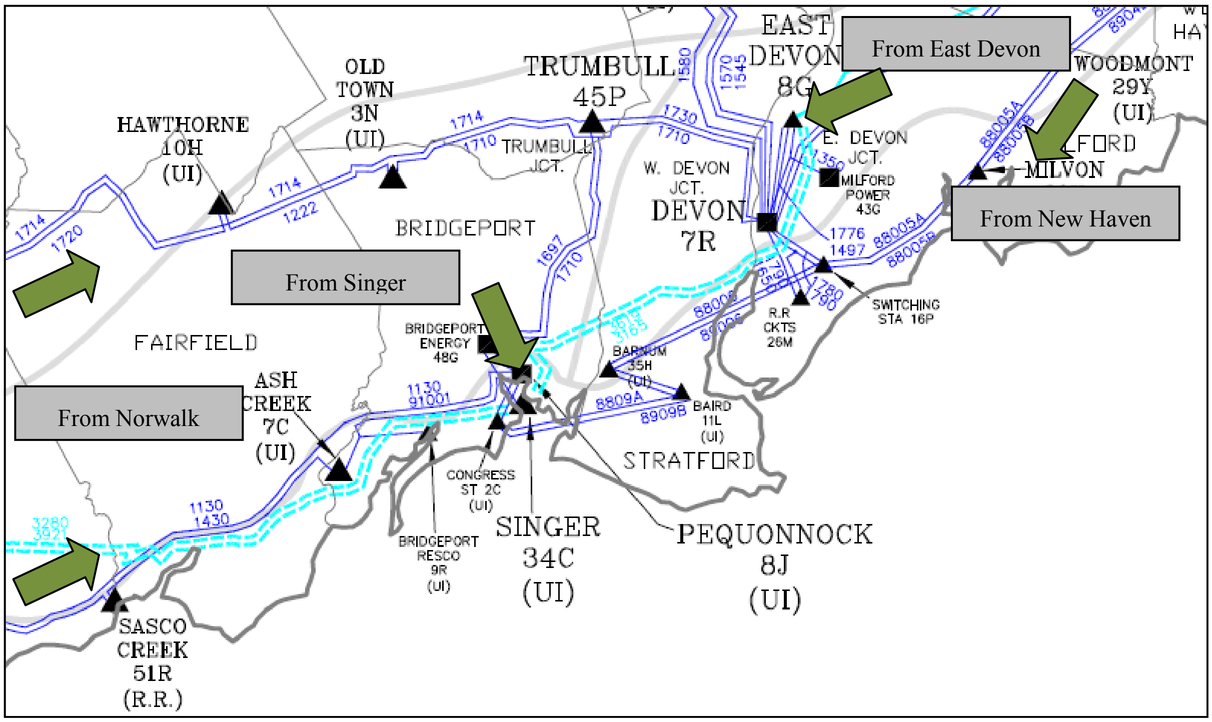


Figure 5-19 Bridgeport Subarea Existing Geographic One-Line

The New Haven subarea includes the southern region of Connecticut starting from the Southington substation in Southington, CT south to New Haven, CT and surrounding towns. The subarea has a net 2022 load of 1,044 MW and is served by four 115 kV lines from Bridgeport, two 115 kV lines from Southington, one 115 kV line from Haddam, and two 345/115 kV transformers at East Shore. The area has 949 MW of generation capacity at two main locations, New Haven, CT (New Haven Harbor 1 and New Haven Harbor Peakers 2-4) and Wallingford, CT (A.L. Pierce, Wallingford Refuse, and Wallingford 1-5). There is also a small fast-start unit located in Branford, CT. Figure 5-20 shows a geographic one-line of the subarea.

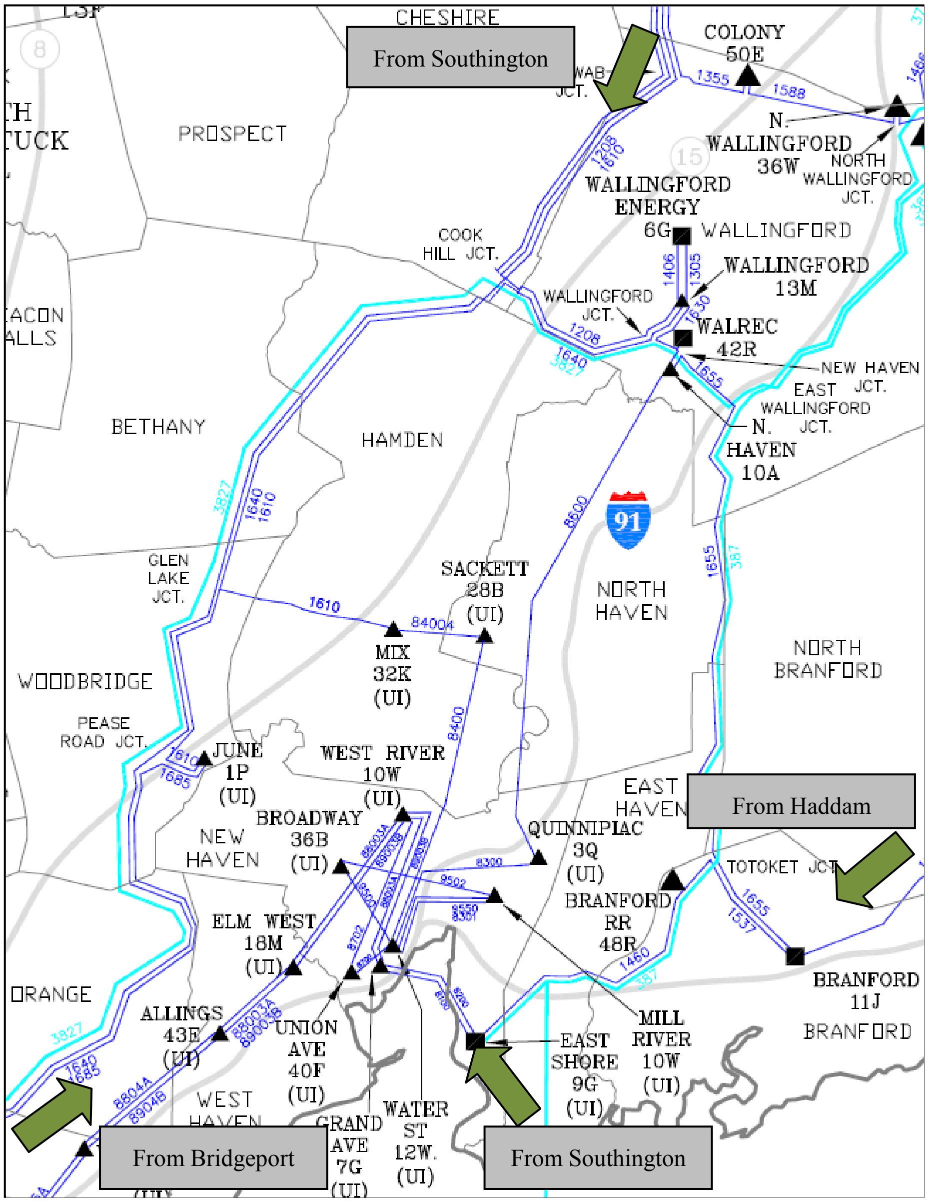


Figure 5-20 New Haven Subarea Existing Geographic One-Line

A large portion of the violations seen in these two areas comes from power transfers through the region to serve load in the Norwalk – Stamford region. These violations became more significant after the retirement of the Norwalk Harbor Station units. With local generation unavailable, N-1-1 contingencies cause numerous thermal and voltage concerns in the area specifically along the 115 kV lines along the high traffic railroad corridor that runs between Bridgeport and New Haven.

Two different solution alternatives were designed to resolve all criteria violations in the two subareas. The use of generation re-dispatch was also re-tested after some base solution upgrades were modeled to see if any remaining violations could now be mitigated that were unable to be resolved during the Needs Assessment. A listing of individual solution components that comprise the two alternatives is Table 5-2.

Table 5-2 Bridgeport and New Haven Solution Components

ID	Solution Component	Alt A	Alt B
1	Baird 115 kV bus upgrade. Expected new bus rating after upgrade to meet or exceed: 386/507/576 MVA (Proposed Line Rebuild Rating – Item 14).	X	X
2	Install two 115 kV capacitor banks (20 MVAR each) at Hawthorne substation	X	X
3	Upgrade 115 kV substation bus system and 15 disconnect switches at Pequonnock substation to 63 kA interrupting capability	X	X
4	Rebuild the 115 kV 8809A/8909B lines from Baird to Congress substations (~2.3 miles each); expected new ratings after upgrade: 340/439/490 MVA	X	X
5	Install a 345 kV circuit breaker in series with the existing 11T breaker at East Devon substation	X	X
6	Decommission and remove the 115 kV phase angle regulator (PAR) at Sackett substation	X	X
7	Install a 115 kV, 7.5 ohm series reactor on the 1610 line and install two 115 kV capacitor banks (20 MVAR each) at Mix Avenue substation	X	X
8	Separate the 345/115 kV 3827/1610 line double circuit tower (DCT) between Beseck and East Devon substations on the 3827 line and Southington substation and Glen Lake Junction on the 1610 line (~0.38 miles)	X	X
9	Replace two 115 kV circuit breakers at Mill River substation to address TRV over-duty issues	X	X
10	Upgrade the 115 kV 1630 line relay at North Haven substation and upgrade 1630 line terminal equipment at Wallingford substation; expected new ratings after upgrades: 297/382/433 MVA	X	X
11	Reconductor the 115 kV 88005A/89005B lines from Devon Tie to Milvon substation (~1.4 miles each); expected new ratings after upgrade: 340/439/490 MVA	X	X
12	Rebuild the 115 kV 88006A/89006B lines from the Housatonic River Crossing (HRX) to Barnum substation (~1.0 miles each); expected new ratings after upgrade: 386/507/576 MVA	X	X
13	Rebuild the 115 kV 1710 and 1730 lines from Devon substation to Trumbull Junction (~4.2 and ~4.3 miles respectively); expected new ratings after upgrade: 348/455/526 MVA	X	
14	Rebuild the 115 kV 88006A/89006B lines and separate the DCT from Barnum to Baird substations (~1.3 miles each); expected new ratings after upgrade: 386/507/576 MVA		X

The following one-line diagrams show details of these solution components grouped by area substations.

The first few solution components in the Bridgeport subarea are along the 115 kV railroad corridor between Congress Street substation and Devon Tie switching station. A one-line diagram of the upgrades is shown in Figure 5-21.

ID	Solution Component	A	B
1	Baird 115 kV bus upgrade; expected new bus rating after upgrade to meet or exceed: 386/507/576 MVA (Proposed Line Rebuild Rating – Item 14)	X	X
4	Rebuild the 115 kV 8809A/8909B lines from Baird to Congress substations (~2.3 miles each); expected new ratings after upgrade: 386/507/576 MVA	X	X
12	Rebuild the 115 kV 88006A/89006B lines from the Housatonic River Crossing (HRX) to Barnum substation (~1.0 miles each); expected new ratings after upgrade: 386/507/576 MVA	X	X
14	Rebuild the 115 kV 88006A/89006B lines and separate the DCT from Barnum to Baird substations (~1.3 miles each); expected new ratings after upgrade: 386/507/576 MVA		X

[redacted]

Figure 5-21 Railroad Corridor Upgrades from Congress St to Devon Tie

The next solution component involves upgrades in the Bridgeport subarea at the Hawthorne substation. A one-line diagram of the upgrade is shown in Figure 5-22.

ID	Solution Component	A	B
2	Install two 115 kV capacitor banks (20 MVAR each) at Hawthorne substation	X	X

[redacted]

Figure 5-22 Hawthorne Substation Upgrades

The next solution component involves upgrading substation equipment at the Pequonnock 115 kV substation for short circuit issues. A one-line diagram of the Pequonnock substation is in Figure 5-23.

ID	Solution Component	A	B
3	Upgrade 115 kV substation bus system and 15 disconnect switches at Pequonnock substation to 63 kA interrupting capability	X	X

[redacted]

Figure 5-23 Pequonnock Substation One-Line Diagram

The next solution component involves upgrades in the New Haven subarea at the East Devon 345 kV substation. A one-line diagram of the upgrade is shown in Figure 5-24.

ID	Solution Component	A	B
5	Install a 345 kV circuit breaker in series with the existing 11T breaker at East Devon substation	X	X

[redacted]

Figure 5-24 East Devon 345 kV Substation Upgrade

The next solution components involve upgrades in the New Haven subarea at the Mix Avenue and Sackett substations. A one-line diagram of the upgrades is shown in Figure 5-25.

ID	Solution Component	A	B
6	Decommission and remove the 115 kV phase angle regulator (PAR) at Sackett substation	X	X
7	Install a 115 kV, 7.5 ohm series reactor on the 1610 line and install two 115 kV capacitor banks (20 MVAR each) at Mix Avenue substation	X	X

[redacted]

Figure 5-25 Mix Avenue and Sackett Substation Upgrades

The next solution component involves separation of a double circuit tower in the New Haven subarea. A one-line diagram of the upgrade is shown in Figure 5-26.

ID	Solution Component	A	B
8	Separate the 345/115 kV 3827/1610 line double circuit tower (DCT) between Beseck and East Devon substations on the 3827 line and Southington substation and Glen Lake Junction on the 1610 line (~0.38 miles)	X	X

[redacted]

Figure 5-26 3827/1610 Line Double Circuit Tower Split

The next solution component involves upgrades in the New Haven subarea at the Mill River substation. A one-line diagram of the upgrades is shown in Figure 5-27.

ID	Solution Component	A	B
9	Replace two 115 kV circuit breakers at Mill River substation to address TRV over-duty issues	X	X

[redacted]

Figure 5-27 Mill River Substation Upgrades

The next solution component involves upgrades in the New Haven subarea to relays and terminal equipment on the 115 kV 1630 line between Wallingford and North Haven substations. A one-line diagram of the upgrades is shown in Figure 5-28.

ID	Solution Component	A	B
10	Upgrade the 115 kV 1630 line relay at North Haven substation and upgrade 1630 line terminal equipment at Wallingford substation; expected new ratings after upgrades: 297/382/433 MVA	X	X

[redacted]

Figure 5-28 1630 Line Terminal Equipment Upgrades

The next solution components in the Bridgeport subarea involve line upgrades between Devon Tie switching station and Milvon substation. A one-line diagram of the upgrades is shown in Figure 5-29.

ID	Solution Component	A	B
11	Reconductor the 115 kV 88005A/89005B lines from Devon Tie to Milvon substation (~1.4 miles each); expected new ratings after upgrade: 386/507/576 MVA	X	X

[redacted]

Figure 5-29 Railroad Corridor Upgrades from Devon Tie to Milvon

The final solution component involves the rebuild of two lines in the Bridgeport subarea. A one-line diagram of the upgrades is shown in Figure 5-30.

ID	Solution Component	A	B
13	Rebuild the 115 kV 1710 and 1730 lines from Devon substation to Trumbull Junction (~4.2 and ~4.3 miles respectively); expected new ratings after upgrade: 348/455/526 MVA	X	

[redacted]

Figure 5-30 1710/1730 Line Devon to Trumbull Jct Rebuild

5.3.3 Housatonic Valley Reactive Solution Testing

The Housatonic Valley subarea has demonstrated significant voltage issues up to a possible voltage collapse following certain contingency events. In addition to addressing the thermal violations in the subarea, a separate investigation was done to determine the most cost effective reactive power solution for the region. A step by step process was done to mitigate the violations in the area using the existing devices in the area to the best extent possible and adding new devices at strategic locations. Each of the four solution alternatives was tested from the current configuration to a final reactive solution to address each violation. A summary of the testing steps are shown in Table 5-3 through Table 5-6 and a detailed presentation of the investigation is given in Appendix E: Steady State Contingency and Short Circuit Results.

For each device, 'Substation C#' stands for a capacitor, 'Substation S#' stands for a synchronous condenser. For each value in the steps, the number represents the size of the device in MVAR. An 'F' following the number means the capacitor is fixed and on in the base case. An 'S' following the number means the capacitor is switched on after the first contingency and before the second. A cell shaded light red indicates a change for that device from the previous step.

Table 5-3 Local Solution #1 Housatonic Valley Reactive Solution

Device	Step 1	Step 2	Step 3	Step 4	Step 5	Step 6	Step 7
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 5-4 Local Solution #2 Housatonic Valley Reactive Solution

Device	Step 1	Step 2	Step 3	Step 4	Step 5	Step 6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 5-5 Global Solution #1 Housatonic Valley Reactive Solution

Device	Step 1	Step 2	Step 3
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 5-6 Global Solution #2 Housatonic Valley Reactive Solution

Device	Step 1	Step 2	Step 3	Step 4
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A summary of the reactive device solution for the four alternatives is shown in Table 5-7.

Table 5-7 Housatonic Valley Reactive Solution Summary

Device	LS1	LS2	GS1	GS2
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Section 6
Alternative Solution Performance Testing and Results

All results presented in this section were derived based on the criteria and assumptions identified in Section 3. Eight different combinations of solution alternatives were studied based those developed in Section 5. A summary of the eight combinations is shown in Table 6-1 and will be referred to by their 4 character ID described in the table.

Table 6-1 Solution Alternatives Combination Matrix

		Bridgeport and New Haven Alternatives	
		Alternative A	Alternative B
Housatonic and Naugatuck Valley Alternatives	Global 1	GS1A	GS1B
	Global 2	GS2A	GS2B
	Local 1	LS1A	LS1B
	Local 2	LS2A	LS2B

6.1 Steady State Performance Results

All eight combinations of solution alternatives resolved the thermal and voltage criteria violations found in the Needs Assessment. A detailed description of the results of the alternatives is described in the following sections.

6.1.1 N-0 Thermal and Voltage Performance Summary

N-0 study indicated no violations found.

6.1.2 N-1 Thermal and Voltage Performance Summary

The N-1 study found one remaining thermal violation. The remaining violation is found in Table 6-2.

Table 6-2 Local Solutions N-1 Thermal Violations Summary

[redacted]

The remaining N-1 thermal criteria violation on the 1710-1 line (Trumbull Junction to Pequonnock) can be mitigated by either switching in the series reactor at Hawthorne on the 1222 line or by activation of the Bridgeport Harbor 3 SPS.

The N-1 study found one remaining voltage violation. The remaining violation is found in Table 6-3.

Table 6-3 Local Solutions N-1 Voltage Issues Summary

[redacted]

The remaining N-1 voltage criteria violation at the Branford 115 kV station is considered an issue that is tied to the GHCC study area and will be resolved by that Solutions Study through the addition of a 37.8 MVAR capacitor bank at the Green Hill substation.

6.1.3 N-1-1 Thermal and Voltage Performance Summary

For the N-1-1 results, only the post re-dispatch results are summarized in this section. Detailed results of the lines that were re-dispatched and the amount of MW needed to resolve the pre re-dispatch overloads can be found in Appendix E: Steady State Contingency and Short Circuit Results.

The N-1-1 study found a few remaining thermal violations. The violations are found in Table 6-4.

Table 6-4 Local Solutions N-1-1 Thermal Violations Summary

[redacted]

The violations on the 88003A/89003B cables would be resolved in real-time operations by the New Haven Harbor SPS after the second contingency. This SPS will reduce the loadings on the cables below the LTE.

The N-1-1 study found a few remaining voltage violations. The violations are found in Table 6-5.

Table 6-5 Local Solutions N-1-1 Voltage Violations Summary

[redacted]

The low voltages at Branford and Branford Railroad are considered an issue in the GHCC study area and will be resolved by that Solutions Study through the addition of a 37.8 MVAR capacitor bank at the Green Hill substation.

[redacted]

[redacted]

[redacted]

6.1.4 Results of Extreme Contingency Testing

Extreme contingency testing did not show any concerns with inter-area impacts as a result of any tested contingencies.

6.2 Stability Performance Results

Not applicable for this study.

6.3 Short Circuit Performance Results

After the solution alternatives were selected, each transmission owner studied short circuit duties within their service territory. Northeast Utilities compared Housatonic and Naugatuck Valley alternatives Global 1 and 2 vs. Local 1 and 2 and United Illuminating compared Bridgeport and New Haven alternatives A and B combined with the Local 1 and 2 alternatives. Detailed study reports of the short circuit studies performed by Northeast Utilities and United Illuminating are found in Appendix E: Steady State Contingency and Short Circuit Results.

6.3.1 Short Circuit Performance Results

All four combinations of solution alternatives produced similar short circuit results and are summarized in Table 6-6.

Table 6-6 Solution Alternatives Short Circuit Study Summary

Substation	kV	Over Duty (Above 100%)	High Duty (95-100%)	Marginal Duty (90-95%)	Delta from Needs Assessment
Devon Ring 2 7R	115	--	--	7 (63 kA)	+2
East Devon 8G	115	--	6 (63 kA)	--	+2
Freight 11W	115	2 (25 kA)	--	--	+2
Middle River 28M	115	--	--	1 (25 kA)	+1
Mill River 38M	115	--	2 (50 kA)	--	+2
Pequonnock 8J	115	--	--	17 (65 kA)	--

The additional breakers found in this study compared to the Needs Assessment are due to the solution alternatives proposed in the Housatonic and Naugatuck Valley subareas, and the addition of Q384.

The Freight circuit breakers become over-duty with both the Q384 generation interconnection and then the SWCT solutions. Since Q384 has an approved PPA prior to the SWCT solutions, the SWCT solutions come after the Q384 project when evaluating short circuit duty. If Q384 withdraws, the breaker duty will fall to the Marginal Duty range of 90-95% and does not require an upgrade.

The Middle River circuit breakers only appear above 90% duty with the Global solution alternatives.

The Mill River circuit breakers are being replaced to address TRV over-duty issues even though the short circuit duty is below 100%.

It should be noted that even though the Pequonnock circuit breakers are only in the Marginal Duty (90-95%) category, it was found during the study that several switches and bus work within the substation are over-duty and need to be replaced as part of any solution alternative.

A short circuit study was conducted taking two proposed Connecticut generation interconnection projects, Q412 and Q440, into consideration. The study results revealed slightly increased short circuit levels in the study area. Specifically, there were two more, a total of nine, 115 kV circuit breakers falling into the marginal duty category at Devon Ring 2 7R for the two local solutions. There was one Broadway 115 kV circuit breaker falling into marginal duty category.

6.4 Other Assessment Performance Results

6.4.1 Special Protection System Screening Test

As described in Section 3.2.14, the study area has several special protection systems (SPS) and automatic control schemes. A screening assessment was completed on each SPS to ensure if it was still required after the preferred solution was implemented. The same base cases, generator dispatches, and system stresses were tested in the screening study as in the Solutions Study. The results of the screening test are described for each SPS in the following sections.

6.4.1.1 Ansonia Substation 1570 Line SPS

The assessment of the Ansonia Substation 1570 Line SPS is shown in Table 6-7.

Table 6-7 Ansonia Substation 1570 Line SPS Evaluation

Item	Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Based on the results of the screening study, the Ansonia Substation 1570 Line SPS is a candidate for retirement upon further analysis in a future study.

6.4.1.2 Bridgeport Harbor Unit 3 SPS

The assessment of the Bridgeport Harbor Unit 3 SPS is shown in Table 6-8 and Table 6-9.

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Table 6-8 Bridgeport Harbor Unit 3 SPS Evaluation Trigger #1

Item	Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table 6-9 Bridgeport Harbor Unit 3 SPS Evaluation Trigger #2

Item	Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Based on the results of the screening study, the Bridgeport Harbor Unit 3 SPS is a candidate for retirement upon further analysis in a future study.

6.4.1.3 Scovill Rock 22P, Halvarsson – Tomson 481 line SPS

The assessment of the Scovill Rock 22P, Halvarsson – Tomson 481 Line SPS is shown in Table 6-10.

Table 6-10 Scovill Rock 22P, Halvarsson – Tomson 481 Line SPS Evaluation

Item	Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Based on the results of the screening study, the Scovill Rock 22P, Halvarsson – Tomson 481 Line SPS is a candidate for retirement upon further analysis in a future study.

6.4.1.4 New Haven Harbor SPS

The assessment of the New Haven Harbor SPS is shown in Table 6-11 and Table 6-12.

Table 6-11 New Haven Harbor SPS Evaluation Trigger #1

Item	Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table 6-12 New Haven Harbor SPS Evaluation Trigger #2

Item	Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Based on the results of the screening study, the New Haven Harbor SPS is a candidate for modification to remove one of the existing triggers upon further analysis in a future study. The New Haven SPS is still needed post second contingency to relieve thermal overloads on the Grand Avenue to West River underground cables.

6.4.1.5 New Haven Harbor Unit 1U Torsional Stress SPS

It was determined that preferred solution does not cause a significant change to system topology that would alter the current need for the New Haven Harbor Unit 1U Torsional Stress SPS. No change will be made to the current SPS.

6.4.1.6 Southington 4C Substation Auto-Throwover Scheme

This automatic control scheme is with the Greater Hartford – Central Connecticut study area and was evaluated during the Solutions Study phase of that working group.

6.4.1.7 Southington 4C Autotransformer Automatic Isolation and Reclosing Scheme

This automatic control scheme is with the Greater Hartford – Central Connecticut study area and will be evaluated during a future study of that working group.

6.4.2 Q384 Combined Cycle Assessment

ISO Queue Position #384 is a 745 MW Summer / 775 MW Winter combined cycle facility interconnecting on the NU 115 kV system in New Haven County. The projected in-service date is June 1, 2018. The project's system impact study had been completed prior to this study and identified a criteria violation in the SWCT study area on the 1585 line between the point of interconnection (POI) and Bunker Hill substation (1585N section). The project is responsible to upgrade the line section to interconnect.

To simulate the violation found during the Q384 SIS study, a Solutions Study base case with the preferred solution was used as a start and modified to match the conditions modeled in the SIS study. [redacted] A comparison of the SIS case and the modified Solutions Study case are shown in Table 6-13.

Table 6-13 Q384 SIS vs SWCT Study Case Comparison

	Q384 SIS Case	Modified SWCT Solutions Study Case
Season	2016 Shoulder based on earlier CELT	2018 Shoulder based on 2013 CELT
Load Level	23,165 MW	23,083 MW
Losses	422 MW	405 MW
Total	23,588 MW	23,489 MW

Power flow solution parameters for the Q384 SIS study were slightly different than those used in this Solutions Study as described in Table 4-3. The analysis was run with both sets of solution parameters to ensure no issues were undiscovered based on solution parameters.

[redacted] With the preferred solution and the Q384 project modeled, the loading increased to 291 MVA. This was due to the 1990 line being looped in and out of the Bunker Hill substation as part of the preferred solution, reducing the impedance between Bunker Hill and Frost Bridge substations.

As part of the Q384 SIS the 1585N line section needed a minimum LTE rating of 281 MVA. Northeast Utilities as part of their standard conductor would install a 795 ACSS conductor to achieve that minimum. The new LTE rating of the 1585N line section with 795 ACSS conductor would be 331 MVA. This new higher rating is sufficient for both the Q384 SIS and the preferred solution. When tested with Q384 in place, no additional upgrades are required as part of the preferred solution.

6.4.3 2022 Minimum Load Analysis

There were no N-0 or N-1 high voltage violations in Connecticut in 2022 with both SWCT and GHCC preferred solutions in place. There were no N-1-1 high voltage violations when New England to New York interface was at 0 MW.

Although not a high voltage violation, the East Devon, Norwalk, and Singer 345 buses experienced N-1-1 voltage at the very high end of the acceptable range. [redacted]

In conclusion, no additional system improvement such as a shunt reactive device is required in Connecticut during minimum load conditions when tested with both SWCT and GHCC preferred solutions in place. However, close monitoring of the Connecticut voltage at minimum load is needed in the future.

Detailed 2022 minimum load voltage results can be found in Appendix I: 2022 Minimum Load Study Results.

Section 7
Comparison of Alternative Solutions

7.1 Factors Used to Compare Alternative Solutions

When the estimated cost (+50/-25% accuracy) was similar, the key factors used to compare the solution alternatives included:

- Expected ease of permitting (e.g. environmental, siting, etc.)
- Ease of constructability (during the construction phase)
- Fewer construction outages (number and length of outages)
- Better operational performance (solution alternative requires less or no re-dispatch or capacitor switching)
- Better system performance – Thermal
- Better system performance – Voltage
- Expected in-service date (ISD)

The siting issues took into consideration easements along existing rights-of-way as well as available space in existing substation. Total cost estimates were used to consider differences between all solution alternatives.

7.2 Cost Estimates for Selected Alternative Solutions

All cost estimates were developed consistent with ISO-NE cost estimation procedures as defined in Attachment D of ISO Planning Procedure No. 4.0. All cost estimates in this report were developed with +50/-25% accuracy.

For the Frost Bridge, Naugatuck Valley, Housatonic Valley, and Norwalk–Plumtree subareas, four alternatives were evaluated, Global 1 and 2, and Local 1 and 2. The cost estimates for the common components are shown in Table 7-1.

Table 7-1 Global and Local Solution Common Components Cost Estimates

ID	Solution Component	G1 ($M)	G2 ($M)	L1 ($M)	L2 ($M)
1	Install 25.2 MVAR capacitor bank at Oxford	3.4	3.4	3.4	3.4
2	Close N.O. Baldwin circuit breaker	0.9	0.9	0.9	0.9
3	Reconductor 1887 line between West Brookfield and West Brookfield Jct	2.6	2.6	2.6	2.6
4	Install circuit breaker in series with 29T at Plumtree	2.8	2.8	2.8	2.8
5	Install two 14.4 MVAR capacitor banks at West Brookfield	4.8	4.8	4.8	4.8
6	Install new 115 kV line from Plumtree to Brookfield Junction	20.5	20.5	20.5	20.5
7	Relocate capacitor bank at Plumtree	2.1	2.1	2.1	2.1
8	Upgrade terminal equipment at Newtown on 1876 line	0.1	0.1	0.1	0.1
9	Reduce size of 10K capacitor bank at Rocky River	0.3	0.3	0.3	0.3
10	Loop 1570 line in and out of Pootatuck	1.8	1.8	1.8	1.8
11	Install two 25 MVAR capacitor banks at Ansonia	9.3	9.3	9.3	9.3
12	Expand Pootatuck into 4-breaker ring bus and install one 30 MVAR cap bank	11.9	11.9	11.9	11.9
13	Loop the 115 kV 1990 line in and out of Bunker Hill	0.3	0.3	0.3	0.3
14	Replace two Freight breakers	1.1	1.1	1.1	1.1
Subtotal of Common Solution Components		**61.9**	**61.9**	**61.9**	**61.9**

The following solutions components shown in Table 7-2 were not common between solution alternatives and represent the differences between the four plans.

Table 7-2 Global and Local Solution Components Cost Estimates

ID	Solution Component	G1 ($M)	G2 ($M)	L1 ($M)	L2 ($M)
Subtotal of Common Solution Components		**61.9**	**61.9**	**61.9**	**61.9**
15	Rebuild Bunker Hill into 11-breaker substation (Breaker-and-a-half)	39.6	39.6		
16	Install new 115 kV line from Bunker Hill to Bates Rock	105.0	105.0		
17	Expand Bates Rock into 7-breaker ring bus	26.2	26.2		
18	Rebuild 1682 line between Wilton and Norwalk,	25.5	25.5		
19	Rebuild Bunker Hill into 9-breaker substation (Breaker-and-a-half)			35.5	35.5
20	Rebuild 1682 line between Wilton and Norwalk, upgrade Wilton terminal equip			27.5	27.5
21	Reconductor 1470-1 line between Wilton and Ridgefield Junction			8.6	8.6
22	Reconductor 1470-3 line between Peaceable and Ridgefield Junction			0.7	0.7
23	Reconductor 1575 line between Bunker Hill and Baldwin Junction			5.4	5.4
24	Rebuild 1887-2 line between Shepaug and Brookfield Junction		69.1		
25	Reduce size of 21K capacitor bank at Stony Hill	0.3		0.3	
26	Reconfigure 1887 into 2 lines, and 1770 line into a 2 terminal line	2.5		2.5	
27	Relocate capacitor bank at Stony Hill		2.8		2.8
28	Reconfigure 1887 line into a 3-terminal line and 1770 line into 2-two terminal lines		1.1		1.1
29	Rebuild 1887-2 line between Shepaug and Brookfield Junction			9.5	
30	Install 2 synchronous condensers at Stony Hill			35.5	
31	Install 1 synchronous condenser at Stony Hill				22.2
Solution Alternative Totals		**261.0**	**331.2**	**187.4**	**165.7**

The next set of cost estimates shown in Table 7-3 were for the two solution alternatives in the Bridgeport and New Haven – Southington subareas.

Table 7-3 Bridgeport and New Haven Solution Components Cost Estimates

ID	Solution Component	A ($M)	B ($M)
1	Baird Bus Upgrade	8.9	8.9
2	Install two capacitor banks at Hawthorne	8.9	8.9
3	Upgrade Pequonnock substation equipment	6.0	6.0
4	Rebuild 8809A/8909B lines between Baird and Congress	56.3	56.3
5	Install a circuit breaker in series with 11T at East Devon	2.5	2.5
6	Remove Sackett PAR	1.0	1.0
7	Install series reactor and two capacitor banks at Mix Avenue	16.9	16.9
8	Separate 3827/1610 double circuit tower	2.0	2.0
9	Replace two circuit breakers at Mill River	2.3	2.3
10	Upgrade 1630 line relays at North Haven and terminal equipment at Wallingford	0.4	0.4
11	Rebuild 88005A/89005B lines between Devon Tie and Milvon	37.5	37.5
12	Rebuild 88006A/89006B lines between Housatonic River Crossing and Barnum	24.3	24.3
13	Rebuild 1710 and 1730 lines between Devon and Trumbull Junction	53.3	
14	Rebuild 8806A/89006B lines and separate the DCT between Barnum and Baird		34.9
Subtotal of Common Solution Components		**220.3**	**201.9**

7.3 Comparison of Alternative Solutions

As shown in Table 7-4, when comparing the costs of the solution alternatives for the Housatonic Valley and Naugatuck Valley subareas, it becomes clear the global solution alternatives are far more expensive.

Table 7-4 Global vs. Local Solution Alternative Cost Estimate Comparison

Solution Alternative	Cost Estimate +50/-25% ($M)
Global 1	261.0
Global 2	331.2
Local 1	187.4
Local 2	165.7

The local solution alternatives are 28% to 50% less expensive than the global alternatives. This is largely due to the new 115 kV line construction between Bunker Hill and Bates Rock substations. Based on the higher cost and the increased difficulty in building a new 10 mile line on new right of way, the global solution alternatives were discarded in the remainder of alternative comparisons.

When evaluating between the remaining local alternatives, they contain several common components. To differentiate between the two, only the projects that are not common in each alternative will be evaluated against the remaining key factors. Both alternatives are expected to have minimal permitting risks since they stay within existing right of way. Both alternatives are constructible and are not expected to have complex or lengthy outages during construction. Both alternatives are expected to be completely in-service by 2017.

As shown in Table 7-5, the Bridgeport and New Haven solution alternatives have similar costs with alternative B coming in 9% less than alternative A.

Table 7-5 Bridgeport and New Haven Solution Alternatives Cost Estimate Comparison

Solution Alternative	Cost Estimate +50/-25% ($M)
A	220.3
B	201.9

When evaluating between the two alternatives, they contain several common components. To differentiate between the two, only the projects that are not common in each alternative will be evaluated against the remaining key factors. Both alternatives are expected to be constructible. Alternative A is expected to have some risks in both permitting and duration of outages during construction. Both alternatives are expected to be completely in-service by 2017.

7.4 Comparison Matrix of Alternative Solutions

The primary factor in selecting the preferred solution was cost. Other factors included permitting, constructability, operational performance, and expected in-service date. Table 7-6 shows a comparison matrix of the two remaining local solutions for the Housatonic Valley and Naugatuck Valley subareas.

Table 7-6 Comparison Matrix of Housatonic/Naugatuck Alternative Solutions

Key Factors	L1	L2
Expected ease of permitting (e.g. environmental, siting, etc.)	✓	✓
Ease of constructability (during the construction phase)	✓	✓
Fewer construction outages (number and length of outages)	✓	✓
Better operational performance (solution alternative requires less or no re-dispatch or capacitor switching)	✓	✓
Better system performance – Thermal	✓	✓
Better system performance – Voltage	✓	✓
Expected in-service date (ISD)	2017	2017
Estimated cost for the non-common solution components in $M (+50/-25% accuracy)	47.8 ✘	26.1 ✓

✘ - Is applied to the Alternative which does not achieve the objective as well as the other Alternative

✓ - Is applied to the Alternative which better achieves the objective

Table 7-7 shows a comparison matrix of the two remaining local solutions for the Bridgeport and New Haven subareas.

Table 7-7 Comparison Matrix of Bridgeport/New Haven Alternative Solutions

Key Factors	A	B
Expected ease of permitting (e.g. environmental, siting, etc.)	✘	✓
Ease of constructability (during the construction phase)	✘	✘
Fewer construction outages (number and length of outages)	✘	✓
Better operational performance (solution alternative requires less or no re-dispatch or capacitor switching)	✓	✓
Better system performance – Thermal	✓	✓
Better system performance – Voltage	✓	✓
Expected in-service date (ISD)	2017	2017
Estimated cost for the non-common solution components in $M (+50/-25% accuracy)	53.3 ✘	34.9 ✓

✘ - Is applied to the Alternative which does not achieve the objective as well as the other Alternative

✓ - Is applied to the Alternative which better achieves the objective

7.5 Recommended Solution Alternative

Based on the estimated cost, system performance and other key factors used to compare the solution alternatives, the Local 2 alternative is the preferred solution for the Housatonic Valley and Naugatuck Valley subareas and alternative B is the preferred solution for the Bridgeport and New Haven subareas.

Solutions Local 2 and Alternative B were chosen as the preferred solution alternative for several reasons. Both these solutions resolved all thermal and voltage criteria violations in the 10-year planning horizon. Both solutions provided the least cost alternative to resolve those violations compared to the other alternatives as shown in Table 7-4 and Table 7-5.

Table 7-8 Preferred Solution Total Cost Estimate ($M)

Local 2	Alternative B	SWCT Total
$165.7	$201.9	$367.6

Both solutions either met or exceeded the key factors when compared to other alternatives. All alternatives also show the need to rely on the existing New Haven Harbor SPS post second contingency to relieve thermal overloads on the Grand Avenue to West River underground cables.

Section 8
Conclusion

Comparison of solutions alternatives was based on the estimated cost, system performance and other key factors like ease of permitting, constructability and expandability. The preferred solution to resolve the criteria violations found in the 10-year planning horizon is the Local 2 solution in the Housatonic Valley and Naugatuck Valley subareas combined with Alternative B in the Bridgeport and New Haven subareas.

8.1 Recommended Solution Description

The Local 2 solution alternative for the Housatonic Valley and Naugatuck Valley subareas is comprised of several components as described in Table 8-1. A more detailed description of each component can be found in Section 5.3.1.

Table 8-1 Local 2 Solution Components

ID	Solution Component
1	Install 25.2 MVAR capacitor bank at Oxford
2	Close N.O. Baldwin circuit breaker
3	Reconductor 1887 line between West Brookfield and West Brookfield Junction
4	Install a circuit breaker in series with 29T at Plumtree
5	Install two 14.4 MVAR capacitor banks at West Brookfield
6	Install new 115 kV line from Plumtree to Brookfield Junction
7	Relocate 37.8 MVAR capacitor bank at Plumtree
8	Upgrade terminal equipment at Newtown on 1876 line
9	Reduce size of 10K capacitor bank at Rocky River
10	Loop 1570 line in and out of Pootatuck
11	Install two 25 MVAR capacitor banks at Ansonia
12	Expand Pootatuck into 4-breaker ring bus and install one 30 MVAR capacitor bank
13	Loop the 115 kV 1990 line in and out of Bunker Hill
14	Replace two Freight 115 kV breakers
19	Rebuild Bunker Hill into 9-breaker (breaker-and-a-half) substation
20	Rebuild 1682 line between Wilton and Norwalk, upgrade Wilton terminal equip
21	Reconductor 1470-1 line between Wilton and Ridgefield Junction
22	Reconductor 1470-3 line between Peaceable and Ridgefield Junction
23	Reconductor 1575 line between Bunker Hill and Baldwin Junction
27	Relocate a 37.8 MVAR capacitor bank at Stony Hill
28	Reconfigure 1887 line into a 3-terminal line and 1770 line into 2 two terminal lines
31	Install a synchronous condenser at Stony Hill

The Alternative B solution for the Bridgeport and New Haven subareas is comprised of several components as described in Table 8-2. A more detailed description of each component can be found in Section 5.3.2.

Table 8-2 Alternative B Solution Components

ID	Solution Component
1	Baird Bus Upgrade
2	Install two 20 MVAR capacitor banks at Hawthorne
3	Upgrade Pequonnock substation equipment
4	Rebuild 8809A/8909B lines between Baird and Congress
5	Install a 345 kV circuit breaker in series with 11T at East Devon
6	Remove Sackett PAR
7	Install a series reactor and two 20 MVAR capacitor banks at Mix Avenue
8	Separate 3827/1610 double circuit tower
9	Replace two 115 kV circuit breakers at Mill River
10	Upgrade 1630 line relays at North Haven and terminal equipment at Wallingford
11	Rebuild 88005A/89005B lines between Devon Tie and Milvon
12	Rebuild 88006A/89006B lines between Housatonic River Crossing and Barnum
14	Rebuild 8806A/89006B lines and separate the DCT between Barnum and Baird

Solutions Local 2 and Alternative B were chosen as the preferred solution alternative. Total cost estimate of the preferred solution is $367.6M.

8.2 Solution Component Year of Need

The Needs Assessment states the majority of violations occur in today's system or earlier. Currently operations postures the system by generation re-dispatch and other system adjustments to prevent violations. The projected in-service date of all solution components is by the end of 2017.

8.3 Schedule for Implementation, Lead Times and Documentation of Continuing Need

In accordance with NERC TPL Standards, the assessment provided:

- A written summary of plans to address the system performance issues described in the Needs Assessment Study, "*Southwest Connecticut Area Transmission 2022 Needs Assessment II,*" dated June, 2014[34]),
- A schedule for implementation as described below,
- A discussion of expected in-service dates of facilities and associated load level when the upgrades are required as described below, and
- A discussion of lead times necessary to implement plans describe below.

The preferred solution Local 2 and Alternative B resolve all thermal and voltage criteria violations within the 10-year planning horizon as identified in the Needs Assessment report. The planned completion date of the preferred solution as described in Section 8.1 above is 2017. With this schedule the preferred solution will be in-service after potential violations could occur. Currently System Operations postures the system by generation re-dispatch and other system adjustments to prevent these violations. The longest lead time item required to complete the project is the

[34] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2014/final_swct_2022_needs.pdf

synchronous condenser at Stony Hill substation with a projected lead time of 18 months. This study has reviewed the continuing need and has identified a recommended solution.

Section 9
Appendix A: Load Forecast

Table 9-1
CELT 2013 Seasonal Peak Load Forecast

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2013	26470	26715	27045	27420	27840	28285	28735	29385	30135	30790
	2014	26900	27150	27485	27865	28290	28740	29200	29860	30620	31280
	2015	27410	27665	28005	28390	28825	29285	29750	30425	31185	31860
	2016	27910	28165	28515	28910	29350	29815	30295	30980	31740	32420
	2017	28325	28590	28940	29340	29790	30265	30750	31445	32210	32900
	2018	28675	28940	29295	29700	30155	30635	31125	31830	32615	33315
	2019	29025	29295	29655	30065	30525	31010	31505	32220	33010	33720
	2020	29345	29615	29980	30395	30860	31350	31855	32575	33380	34095
	2021	29670	29950	30315	30735	31205	31700	32210	32935	33755	34480
	2022	29970	30250	30625	31045	31520	32020	32535	33270	34105	34840
	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)	2013/14	22025	22140	22235	22295	22445	22595	22765	22865	23080	23505
	2014/15	22205	22320	22420	22480	22630	22780	22955	23055	23255	23685
	2015/16	22385	22500	22595	22660	22810	22960	23135	23235	23440	23870
	2016/17	22540	22660	22755	22815	22970	23125	23295	23400	23620	24050
	2017/18	22680	22795	22895	22955	23110	23265	23440	23540	23780	24205
	2018/19	22800	22920	23020	23080	23235	23390	23565	23670	23920	24345
	2019/20	22915	23035	23130	23195	23350	23505	23685	23785	24045	24470
	2020/21	23030	23150	23250	23315	23470	23625	23805	23910	24160	24590
	2021/22	23145	23265	23365	23425	23585	23745	23920	24025	24280	24705
	2022/23	23255	23380	23480	23540	23700	23860	24040	24145	24395	24820
	Dry-Bulb Temperature (3)	**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

FOOTNOTES:

(1) WTHI - a three-day weighted temperature-humidity index for eight New England weather stations. It is the weather variable used in producing the summer peak load forecast. For more information on the weather variables see http://www.iso-ne.com/trans/celt/fsct_detail/.

(2) Dry-bulb temperature (in degrees Fahrenheit) shown in the summer season is for informational purposes only.

(3) Dry-bulb temperature (in degrees Fahrenheit) shown in the winter season is a weighted value from eight New England weather stations.

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

File Created :	2014-03-21	**CELT Forecast :**	2013	**Forecast Year :**	2022
Season :	Summer Peak	**Weather :**	90/10	**Load Distribution :**	N+10_SUM
ISO-NE CELT :	34105 MW	**% of Peak :**	100.000%	**Tx Losses :**	2.50%

State CELT L&L	-	2.50% Tx Losses	+	Non-CELT Load	+	Station Service	-	Area 104 NE Load	=	Area 101 Load
34105 MW	-	852.6 MW	+	364.4 MW	+	1070.9 MW	-	16.8 MW	=	34670.9 MW

1: State CELT L&L: This represents the sum of the 6 State CELT forecasts. This number can sometimes be 5-10 MW different than the ISO-NE CELT forecast number due to round-off error.
2: Non-CELT Load: This is the sum of all load modeled in the case that is not included in the CELT forecast. An example is the "behind the meter" paper mill load in Maine.
3: Station Service: This is the amount of generator station service modeled. If station service is off-line, the Area 101 report totals will be different since off-line load is not counted in totals.
4: Area 104 NE Load: This load is load modeled in northern VT that is electrically served from Hydro Quebec. To make Area Interchange load independent, this load is assigned Area 104.

Maine State Load = 2450 MW - 2.50% Tx Losses = 2388.75 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.99%	2054.08	652.54	0.953	332.06
EM	14.01%	334.64	128.18	0.934	17.81

New Hampshire State Load = 3150 MW - 2.50% Tx Losses = 3071.25 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	78.79%	2419.97	344.82	0.990	
UNITIL	12.14%	372.93	53.13	0.990	
GSE	9.06%	278.40	7.21	1.000	1.85

Vermont State Load = 1220 MW - 2.50% Tx Losses = 1189.5 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	1189.43	200.23	0.986	95.79

Massachusetts State Load = 16055 MW - 2.50% Tx Losses = 15653.625 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	28.27%	4425.14	1149.00	0.968	37.79
COMEL	11.70%	1831.00	370.89	0.980	
MA-NGRID	39.43%	6172.04	353.54	0.998	38.49
WMECO	6.33%	990.88	141.18	0.990	
MUNI:BOST-NGR	3.35%	524.72	92.52	0.985	
MUNI:BOST-NST	1.25%	195.36	29.84	0.989	
MUNI:CNEMA-NGR	2.08%	324.82	33.34	0.995	
MUNI:RI-NGR	0.88%	136.96	16.62	0.993	
MUNI:SEMA-NGR	1.85%	289.44	30.78	0.994	
MUNI:SEMA-NST	1.73%	270.82	49.99	0.983	
MUNI:WMA-NGR	0.95%	149.17	14.81	0.995	
MUNI:WMA-NU	2.19%	343.28	48.92	0.990	

Rhode Island State Load = 2405 MW - 2.50% Tx Losses = 2344.875 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	2344.90	238.31	0.995	45.44

Connecticut State Load = 8825 MW - 2.50% Tx Losses = 8604.375 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	76.45%	6578.11	937.35	0.990	82.50
CMEEC	4.49%	386.26	55.02	0.990	
UI	19.06%	1640.02	164.61	0.995	10.00

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Table 9-3 Detailed Demand Response Distributions by Zone

Study Date :	06/01/2022	**Study Name :**	SWCT Solutions Study - Base		
File Created :	2013-10-16	**CCP :**	2016/2017	**Load Season :**	2022 - Summer Peak
Load Distrb :	N+10_SUM	**Distrb Losses :**	5.50%	**DR Season :**	SUM

	Demand Reduction Value (DRV)	x	Load Dependent Capability Assumption (LDCA)	x	Performance Assumption (PA)	+	Distribution Losses Gross-Up	-	Area 104 DR	=	Area 101 DR
Passive :	1619.50 MW		100.00%		100.00%		89.07 MW		1.67 MW		1706.86 MW
Forecast EE :	1038.85 MW		100.00%		100.00%		57.14 MW		1.23 MW		1094.56 MW
Active :	799.89 MW		100.00%		75.00%		33.00 MW		0.41 MW		632.47 MW

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

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

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

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Load Zone - Maine	149.99	-158.28	-55.41
DR_P_NH	21	Load Zone - New Hampshire	76.80	-80.98	-11.27
DR_P_VT	22	Load Zone - Vermont	120.21	-126.80	-33.90
DR_P_NEMABOS	23	Load Zone - Northeast Massachusetts & Boston	330.81	-349.03	-75.13
DR_P_SEMA	24	Load Zone - Southeast Massachusetts	184.89	-195.05	-20.24
DR_P_WCMA	25	Load Zone - West Central Massachusetts	235.46	-248.39	-21.55
DR_P_RI	26	Load Zone - Rhode Island	136.83	-144.36	-13.93
DR_P_CT	27	Load Zone - Connecticut	384.51	-405.64	-54.53

Forecasted Energy Efficiency

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

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_P_ME	20	Load Zone - Maine	56.48	-59.55	-20.81
DR_P_NH	21	Load Zone - New Hampshire	52.78	-55.63	-7.75
DR_P_VT	22	Load Zone - Vermont	88.88	-93.82	-25.00
DR_P_NEMABOS	23	Load Zone - Northeast Massachusetts & Boston	276.34	-291.47	-62.70
DR_P_SEMA	24	Load Zone - Southeast Massachusetts	146.98	-155.05	-16.11
DR_P_WCMA	25	Load Zone - West Central Massachusetts	164.62	-173.65	-15.08
DR_P_RI	26	Load Zone - Rhode Island	113.89	-120.18	-11.59
DR_P_CT	27	Load Zone - Connecticut	138.88	-146.44	-19.64

Study Date :	06/01/2022	**Study Name :**	SWCT Solutions Study - Base		
File Created :	2013-10-16	**CCP :**	2016/2017	**Load Season :**	2022 - Summer Peak
Load Distrb :	N+10_SUM	**Distrb Losses :**	5.50%	**DR Season :**	SUM

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

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

Zone	ID	Description	DRV (MW)	Total P (MW)	Total Q (MVAR)
DR_A_ME_BHE	30	Dispatch Zone - ME - Bangor Hydro	27.26	-21.57	-10.04
DR_A_ME_MAIN	31	Dispatch Zone - ME - Maine	143.10	-113.20	-37.50
DR_A_ME_PORT	32	Dispatch Zone - ME - Portland Maine	27.02	-21.39	-7.00
DR_A_NH_NEWH	33	Dispatch Zone - NH - New Hampshire	22.11	-17.48	-2.46
DR_A_NH_SEAC	34	Dispatch Zone - NH - Seacoast	3.92	-3.10	-0.45
DR_A_VT_NWVT	35	Dispatch Zone - VT - Northwest Vermont	25.30	-20.03	-5.64
DR_A_VT_VERM	36	Dispatch Zone - VT - Vermont	12.79	-10.14	-2.43
DR_A_MA_BOST	37	Dispatch Zone - MA - Boston	58.36	-46.12	-11.59
DR_A_MA_NSHR	38	Dispatch Zone - MA - North Shore	20.04	-15.87	-1.77
DR_A_MA_CMA	39	Dispatch Zone - MA - Central Massachusetts	37.68	-29.81	-1.55
DR_A_MA_SPFD	40	Dispatch Zone - MA - Springfield	19.20	-15.18	-2.15
DR_A_MA_WMA	41	Dispatch Zone - MA - Western Massachusetts	34.17	-27.07	-2.56
DR_A_MA_LSM	42	Dispatch Zone - MA - Lower Southeast Massachusetts	10.26	-8.14	-1.35
DR_A_MA_SEMA	43	Dispatch Zone - MA - Southeast Massachusetts	46.29	-36.65	-2.88
DR_A_RI_RHOD	44	Dispatch Zone - RI - Rhode Island	53.33	-42.18	-4.01
DR_A_CT_EAST	45	Dispatch Zone - CT - Eastern Connecticut	36.55	-28.89	-4.12
DR_A_CT_NRTH	46	Dispatch Zone - CT - Northern Connecticut	84.10	-66.52	-9.48
DR_A_CT_NRST	47	Dispatch Zone - CT - Norwalk-Stamford	34.23	-27.09	-3.66
DR_A_CT_WEST	48	Dispatch Zone - CT - Western Connecticut	104.18	-82.45	-10.74

Section 10
Appendix B: Base Case Summaries

Appendix B1 - Case Summaries_LS1A.pdf
Appendix B2 - Case Summaries_LS1B.pdf
Appendix B3 - Case Summaries_LS2A.pdf
Appendix B4 - Case Summaries_LS2B.pdf
Appendix B5 - Case Summaries_GS1A.pdf
Appendix B6 - Case Summaries_GS1B.pdf
Appendix B7 - Case Summaries_GS2A.pdf
Appendix B8 - Case Summaries_GS2B.pdf

Section 11
Appendix C: Upgrades Included in Base Case

[Appendix C- Upgrades Included in Base Case.pdf]

Section 12
Appendix D: Steady-State Contingency List

Appendix D1 - SWCT Solutions_345kV 2022 Contingency Summary Rpt.pdf
Appendix D2 - SWCT Solutions_sub345kV 2022 Contingency Summary Rpt.pdf

Section 13
Appendix E: Steady State Contingency and Short Circuit Results

Appendix E1 - NU-SWCT_Solutions_Short_Circuit_Study_11-17-14.pdf
Appendix E2 - UI-SWCT_Soluitons_Short_Circuit_ report_12-02-2014.pdf
Appendix E3 - Housatonic Valley Voltage Solutions

Section 14
Appendix F: 2022 New England Minimum Loads

Table 14-1 2022 New England Minimum Loads by State and Company

File Created :	2014-09-04	CELT Forecast :	2014	Forecast Year :	2022
Season :	Min Load	Weather :	50/50	Load Distribution :	N+10_SLL
ISO-NE CELT :	8500 MW	% of Peak :	27.144%	Tx Losses :	2.50%

State CELT L&L	-	2.50% Tx Losses	+	Non-CELT Load	+	Station Service	-	Area 104 NE Load	=	Area 101 Load
8500 MW		212.5 MW		364.4 MW		968.9 MW		4.8 MW		9616.0 MW

1: State CELT L&L: This represents the sum of the 6 State CELT forecasts. This number can sometimes be 5-10 MW different than the ISO-NE CELT forecast number due to round-off error.
2: Non-CELT Load: This is the sum of all load modeled in the case that is not included in the CELT forecast. An example is the "behind the meter" paper mill load in Maine.
3: Station Service: This is the amount of generator station service modeled. If station service is off-line, the Area 101 report totals will be different since off-line load is not counted in totals.
4: Area 104 NE Load: This load is load modeled in northern VT that is electrically served from Hydro Quebec. To make Area Interchange load independent, this load is assigned Area 104.

Maine State Load = 2295 MW * 27.14% - 2.50% Losses = 607.38 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CMP	85.99%	522.29	140.61	0.966	332.06
EM	14.01%	85.10	9.67	0.994	12.02

New Hampshire State Load = 2900 MW * 27.14% - 2.50% Losses = 767.50 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
PSNH	78.79%	604.76	-38.33	-0.998	
UNITIL	12.14%	93.20	-5.91	-0.998	
GSE	9.06%	69.57	-3.32	-0.999	1.85

Vermont State Load = 1180 MW * 27.14% - 2.50% Losses = 312.29 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
VELCO	100.00%	312.27	-4.67	-1.000	88.74

Massachusetts State Load = 14705 MW * 27.14% - 2.50% Losses = 3891.74 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
BECO	28.27%	1100.16	-57.59	-0.999	37.79
COMEL	11.70%	455.21	-28.85	-0.998	
MA-NGRID	39.43%	1534.45	-86.43	-0.998	38.49
WMECO	6.33%	246.35	-15.61	-0.998	
MUNI:BOST-NGR	3.35%	130.41	-8.29	-0.998	
MUNI:BOST-NST	1.25%	48.57	-3.08	-0.998	
MUNI:CNEMA-NGR	2.08%	80.74	-5.12	-0.998	
MUNI:RI-NGR	0.88%	34.04	-2.15	-0.998	
MUNI:SEMA-NGR	1.85%	71.98	-4.55	-0.998	
MUNI:SEMA-NST	1.73%	67.31	-4.27	-0.998	
MUNI:WMA-NGR	0.95%	37.09	-2.33	-0.998	
MUNI:WMA-NU	2.19%	85.35	-5.41	-0.998	

Rhode Island State Load = 2130 MW * 27.14% - 2.50% Losses = 563.71 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
RI-NGRID	100.00%	563.69	2.69	1.000	45.44

Connecticut State Load = 8105 MW * 27.14% - 2.50% Losses = 2145.02 MW

Company	State Share	Total P (MW)	Total Q (MVAR)	Overall PF	Non-Scaling (MW)
CLP	76.45%	1639.92	-97.99	-0.998	63.30
CMEEC	4.49%	96.29	-6.08	-0.998	
UI	19.06%	408.82	-26.28	-0.998	10.00

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Section 15
Appendix G: 2022 Minimum Load Case Summaries

[Appendix G - 2022 Minimum Load Case Summaries.pdf]

Section 16
Appendix H: 2022 Minimum Load Contingency List

Appendix H - 2022 Minimum Load Contingency List.xlsx

Section 17
Appendix I: 2022 Minimum Load Study Results

Table 17-1 2022 Minimum Load N-1-1 Voltage Results

Most Severe N-1-1 Voltage Violations				
[redacted]	[redacted]		[redacted]	
	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]			
[redacted]	[redacted]	[redacted]		
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EXHIBIT 3: ISO-NE “TRANSMISSION PLANNING TECHNICAL GUIDE,” MARCH 2, 2016)

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Transmission Planning Technical Guide

System Planning
March 2, 2016

Contents

Section 1
Introduction

This guide describes the current standards, criteria and assumptions used in various transmission planning studies in New England.

Section 1 of this guide describes its purpose and the source of the standards, criteria and assumptions used in transmission planning studies. Section 2 describes the various types of transmission planning studies that use these standards, criteria and assumptions. Sections 3 and 4 discuss thermal and voltage ratings used in planning studies.

The remaining sections each describe the different assumptions that are utilized in transmission planning studies and the basis for these assumptions. The assumptions are presented in an order that is useful to a planner performing a transmission planning study.

Sections 5, 6 and 7 discuss modeling load in different types of transmission planning studies. Section 8 discusses the topology, transmission system and generators, used in different types of transmission planning studies. Sections 9-11 describe assumptions associated with generators. Section 12 discusses contingencies and Section 13 discusses interface stresses.

Sections 14-20 discuss modeling of specific types of equipment. The remaining sections describe specific parts of planning studies.

Capitalized terms in this guide are defined in Section I of the Tariff or in Section 2 or Appendix A of this guide.

The provisions in this document are intended to be consistent with ISO New England's Tariff. If, however, the provisions in this planning document conflict with the Tariff in any way, the Tariff takes precedence as the ISO is bound to operate in accordance with the ISO New England Tariff.

1.1 Purpose

The purpose of this guide is to clearly articulate the current assumptions used in planning studies of the transmission system consisting of New England Pool Transmission Facilities ("PTF"). Pursuant to Attachment K, ISO New England ("the ISO" or "ISO-NE") is responsible for the planning of the PTF portion of New England's transmission system. Pool Transmission Facilities are the transmission facilities owned by Participating Transmission Owners ("PTOs"), over which the ISO exercises Operating Authority in accordance with the terms set forth in the Transmission Operating Agreement, rated at 69 kV and above, except for lines and associated facilities that contribute little or no parallel capability to the PTF. The scope of PTF facilities is defined in Section II.49 of the ISO New England Open Access Transmission Tariff ("OATT" or "Tariff").

The PTO's are responsible for planning of the Non-PTF and coordinating such planning efforts with the ISO. The planning assumptions in this guide apply to the non-PTF transmission system when studying upgrades to the non-PTF transmission system which will result in new or modified PTF transmission facilities. The PTO's establish the planning assumptions for planning of the Non-PTF which does not impact the PTF. Section 6 of Attachment K to the OATT describes the responsibilities for planning the PTF and non-PTF transmission systems.

The planning assumptions in this guide also apply to studies of the impacts of system changes on the PTF transmission system, the Highgate Transmission System, Other Transmission Facilities, and Merchant Transmission Facilities. This includes studies of the impacts of Elective Transmission Upgrades and generator interconnections, regardless of the point of interconnection.

1.2 Reliability Standards

ISO New England establishes reliability standards for the six-state New England region on the basis of authority granted to the ISO by the Federal Energy Regulatory Commission. Because New England is part of a much larger power system, the region also is subject to reliability standards established for the northeast and the entire United States by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

The standards, criteria and assumptions used in planning studies are guided by a series of reliability standards and criteria:

- North American Electric Reliability Corporation ("NERC") Reliability Standards for Transmission Planning ("TPLs") which apply to North America. These standards can be found on the NERC website at http://www.nerc.com/page.php?cid=2|20.

- Northeast Power Coordinating Council ("NPCC") Design and Operation of the Bulk Power Systems (Directory #1) and NPCC Classification of Bulk Power System Elements (Document A-10) which describe criteria applicable to Ontario, Quebec, Canadian Maritimes, New York and New England. These criteria can be found at the NPCC website at: https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

- ISO New England Planning and Operating Procedures which apply to the New England transmission system except for the northern section of Maine that is not directly interconnected to the rest of the United States but is interconnected to New Brunswick. These standards can be found at the ISO-NE website at http://www.iso-ne.com/rules_proceds/index.html.

NERC, NPCC and ISO-NE describe the purpose of their reliability standards and criteria as:

- NERC describes the intent of Transmission Planning Standards, its TPLs, as providing for system simulations and associated assessments that are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and that continue to be modified or upgraded as necessary to meet present and future system needs.

- NPCC describes the intent of its criteria as providing a "design-based approach" to ensure the Bulk Power System is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design contingencies.

- ISO-NE, in its Planning Procedure No. 3 ("PP-3"), describes that the purpose of the New England Reliability Standards is to assure the reliability and efficiency of the New England bulk power supply system through coordination of system planning, design and operation.

The ISO-NE planning standards and criteria, which are explained in this guide, are based on the NERC, NPCC and ISO-NE specific standards and criteria, and are set out for application in the region in ISO-NE Planning and Operation procedures. As the NERC registered Planning Authority, ISO-NE has the responsibility to establish procedures and assumptions that satisfy the intent of the NERC and NPCC standards.

Section 2
Types of Transmission Planning Studies

There are a number of different types of planning studies conducted in New England which assess or reflect the capability of the transmission system, including Market Efficiency upgrade studies, operational studies and reliability studies. The focus of this guide is on reliability studies.

The major types of studies addressed in this guide are:

- Proposed Plan Application ("PPA") Study - study done to determine if any addition or change to the system has a significant adverse effect on stability, reliability or operating characteristics of the PTF or Non-PTF transmission system.(See Section I.3.9 of the OATT). Note that this does not need to be an independent study but can be submission or supplementation of another study such as a System Impact Study or Transmission Solutions Study as long as appropriate system conditions were included in that study.

- System Impact ("SIS") Study - study done to determine the system upgrades required to interconnect a new or modified generating facility (See Schedule 22 of the OATT, Section 7 and Schedule 23 of the OATT, Section 3.4), to determine the system upgrades required to interconnect an Elective Transmission Upgrade (See Schedule 25 of the OATT, Section 7), or to determine the system upgrades required to provide transmission service pursuant to the OATT. A Feasibility Study is often the first step in the interconnection study process and may be done as part of the System Impact Study or separately.

- Transmission Needs Assessment - study done to assess the adequacy of the PTF system (See OATT Section II, Attachment K, Section 4)

- Transmission Solutions Study - study done to develop regulated solutions to issues identified in a Transmission Needs Assessment of the PTF system (See OATT Section II, Attachment K, Section 4.2 (b))

- NPCC Area Transmission Review - study to assess Bulk Power System reliability (See NPCC Directory #1, Appendix B)

- Bulk Power System ("BPS") Testing - study done to determine if Elements should be classified as part of the Bulk Power System (See NPCC Document A-10, Classification of Bulk Power System Elements)

- Transfer Limit Study - study done to determine the range of megawatts ("MW") that can be transferred across an interface under a variety of system conditions

- Interregional Study - study involving two or more adjacent regions, for example New York and New England

- Overlapping Impact Study - optional study that an Interconnection Customer may select as part of its interconnection studies. This study provides information on the potential upgrades required for the generation project to qualify as a capacity resource in the Forward Capacity Market. (See Schedule 22 of the OATT, Section 6.2 or 7.3 and Schedule 25 of the OATT, Section 6.2 or 7.3)

- FCM New Resource Qualification Network Capacity Interconnection Standard Analyses - study of the transmission system done to determine a list of potential Element or interface loading problems caused by a resource seeking to obtain a new or increased capacity supply obligation. This study is done if a System Impact Study for a generator interconnection is not complete. (See Planning Procedure 10, section 5.6)

- FCM New Resource Qualification Overlapping Impact Analyses - study of the transmission system done to determine the deliverability of a resource seeking to obtain a new or increased capacity supply obligation. (See Planning Procedure 10, section 5.8)

- FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals - study of the transmission system done to determine the reliability impact of a resource seeking to obtain a new or increased capacity supply obligation. (See Planning Procedure 10, sections 7and 8)

- FCM Delist/Non-Price Retirement Analyses - study of the transmission system done to determine the reliability impacts of delists and retirements. (See Planning Procedure 10, section 7)

- Transmission Security Analyses - deterministic study done to determine the capacity requirements of import constrained load zones. (See Planning Procedure 10, section 6)

- Non-Commercial Capacity Deferral Notifications - study done to determine the reliability impacts of non-commercial capacity deferral notifications. (See Planning Procedure 10, section 11)

Section 3
Transmission Element Ratings

Planning utilizes the following thermal capacity ratings for transmission facilities, as described in ISO-NE Operating Procedure No. 16 Transmission System Data - Appendix A - Explanation of Terms and Instructions for Data Preparation of NX-9A (OP-16A):

- Normal
  Normal is a continuous 24-hour rating

- Long Time Emergency (“LTE”)
  LTE is a 12-hour rating in Summer and a 4-hour rating in Winter

- Short Time Emergency (“STE”)
  STE is a 15-minute rating

Summer equipment ratings (April 1 through October 31) and Winter equipment ratings (November 1 through March 31) are applied as defined in ISO-NE Operating Procedure 16. The twelve-hour and four-hour durations are based on the load shape for Summer and Winter peak load days.

The transmission Element ratings used in planning studies are described in ISO New England Planning Procedure 5-3 and in ISO New England Planning Procedure 7: Procedures for Determining and Implementing Transmission Facility Ratings in New England. In general, Element loadings up to normal ratings are acceptable for "All lines in" conditions. Element loadings up to LTE ratings are acceptable for up to the durations described above. Element loadings up to the STE ratings may be used following a contingency for up to fifteen minutes. STE ratings may only be used in limited situations such as in export areas where the Element loading can be reduced below the LTE ratings within fifteen minutes by operator or automatic corrective action.

There is also a Drastic Action Limit that is only used as a last resort during actual system operations where preplanned immediate post-contingency actions can reduce loadings below LTE within five minutes. Drastic Action Limits are <u>not</u> used in testing the system adequacy in planning studies or for planning the transmission system.

Element ratings are calculated per ISO New England Planning Procedure 7, and are submitted to ISO New England per ISO New England Operating Procedure 16: Transmission System Data.

Section 4
Voltage Criteria

4.1 Overview

The voltage standards used for transmission planning have been established to satisfy three constraints: maintaining voltages on the distribution system and experienced by the ultimate customer within required limits, maintaining the voltages experienced by transmission equipment and equipment connected to the transmission system within that equipment's rating, and avoiding voltage collapse. Generally the maximum voltages are limited by equipment and the minimum voltages are limited by customer requirements and voltage collapse. Note: This Transmission Planning Technical Guide does not address voltage flicker or harmonics.

The voltage standards prior to equipment operation apply to voltages at a location that last for seconds or minutes, such as voltages that occur prior to transformer load tap changer ("LTC") operation or capacitor switching. The voltage standards prior to equipment operation do not apply to transient voltage excursions such as switching surges, or voltage excursions during a fault or during disconnection of faulted equipment.

The voltage standards apply to PTF facilities operated at a nominal voltage of 69 kV or above.

4.2 Pre-Contingency Voltages

The voltages at all PTF buses must be in the range of 0.95-1.05 per unit with all lines in service.

There are two exceptions to this standard. The first is voltage limits at nuclear units, which are described in Section 4.9. The second exception is that higher voltages are permitted at buses where the Transmission Owner has determined that all equipment at those buses is rated to operate at the higher voltage. Often the limiting equipment under steady-state high voltage conditions is a circuit breaker. IEEE standard C37.06 lists the maximum voltage for 345 kV circuit breakers as 362 kV, the maximum voltage for 230 kV circuit breakers as 245 kV, the maximum voltage for 138 kV circuit breakers as145 kV, the maximum voltage for 115 kV circuit breakers as 123 kV and the maximum voltage for 69 kV circuit breakers as 72.5 kV. Older 115 kV circuit breakers may have a different maximum voltage.

For testing N-1 contingencies, shunt VAR devices are modeled in or out of service pre-contingency, to prepare for high or low voltage caused by the contingency, as long as the pre-contingency voltage standard is satisfied. For testing of an N-1-1 contingency, shunt VAR devices are switched between the first and second contingencies to prepare for the second contingency as long as the post contingency voltage standard is satisfied following the first contingency and prior to the second contingency.

4.3 Post-Contingency Low Voltages Prior to Equipment Operation

The lowest post-contingency voltages at all PTF buses must be equal to or higher than 0.90 per unit prior to the automatic or manual switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors. Dynamic devices such as generator voltage regulators, STATCOMs, SVCs, DVARs, and HVDC equipment are assumed to have operated properly to provide voltage support when calculating these voltages.

Also capacitor banks that switch automatically with no intentional time delay (switching time is the time for the sensing relay and the control scheme to operate, usually a few cycles up to a second) may be assumed to have operated when calculating these voltages.

No contingency defined in Section 12.4 or 12.5 is allowed to cause a voltage collapse.

4.4 Post-Contingency Low Voltages After Equipment Operation

The lowest voltages at all PTF buses must be equal to or higher than 0.95 per unit after the switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors.

There are two exceptions to this standard. The first is voltage limits at nuclear units. The other exception is that voltages as low as 0.90 per unit are allowed at a limited number of PTF buses where the associated lower voltage system has been designed to accept these lower voltages and where the change in voltage pre-contingency to post-contingency is not greater than 0.1 per unit. The planner should consult with the Transmission Owner and ISO-NE to determine if the second exception applies to any buses in the study area.

4.5 Post-Contingency High Voltages Prior to Equipment Operation

The standard for high voltages prior to corrective action is under development.

4.6 Post-Contingency High Voltages After Equipment Operation

The highest voltages at all PTF buses must be equal to or lower than 1.05 per unit.

The only exception is that higher voltages are permitted where the Transmission Owner has determined that all equipment at those buses is rated to operate at the higher voltage. The planner should consult with the Transmission Owner and ISO-NE to determine if the exception applies to any buses in the study area.

4.7 Voltage Limits for Line End Open Contingencies

There is no minimum voltage limit for the open end of a line if there is no load connected to the line section with the open end. If there is load connected the above standards for post-contingency low voltage apply.

The maximum voltage limit for the open end of a line is under development.

4.8 Transient Voltage Response

NERC is has revised its transmission planning procedures to establish the requirement for transient voltage response criteria. This section will address those criteria once the new requirement becomes effective.

4.9 Voltage Limits at Buses Associated with Nuclear Units

The minimum voltage limits at the following buses serving nuclear units, both for pre-contingency and for post-contingency after the switching of capacitors and operation of transformer load tap changers, are listed below. These limits apply whether or not the generation is dispatched in the study.

Table 4-1
Nuclear Unit Minimum Voltages

Critical Bus	Minimum Bus Voltage
Millstone 345 kV bus	345 kV
Pilgrim 345 kV bus	343.5 kV
Seabrook 345 kV bus	345 kV
Vermont Yankee 115 kV bus	112 kV[1]

[1] Due to the retirement of Vermont Yankee, the unique minimum voltage limit at Vermont Yankee 345 kV will be eliminated. The unique voltage limit at Vermont Yankee 115 kV will temporarily be 112 kV and will be eliminated within about three years dependent on NRC approval.

The minimum voltage requirements at buses serving nuclear units are provided in accordance with NERC Standard NUC-001 and documented in the appendices to Master Local Control Center Procedure MLCC 1.

Section 5
Assumptions Concerning Load

Load data is included in the power flow cases provided by ISO-NE. The following describes the make-up of the load data in those cases. Appendix J provides additional detail on how the load data is developed for power flow cases.

ISO New England's Planning Procedure 5-3: Guidelines for Conducting and Evaluating Proposed Plan Application Analyses states:

- Disturbances are typically studied at peak load levels in steady-state analysis since peak load levels usually promote more pronounced thermal and voltage responses within the New England Control Area than at other load levels. However, other load levels may be of interest in a particular analysis and, as appropriate, additional studies are conducted.

The following load levels are used in planning studies:

- Peak Load
- Intermediate Load
- Light Load
- Minimum Load

The Report of Capacity, Energy, Loads, and Transmission ("CELT") is the primary source of assumptions for use in electric planning and reliability studies for the ISO New England Reliability Coordinator area. The CELT includes generators at their net output and customers with behind the meter generation at their net load or generation. In many planning studies, this generation is modeled at its gross output. When this is done, it is necessary to add generating station service loads and certain manufacturing loads, predominately mill load in Maine, to the CELT load forecast. These loads add approximately 1,464 MW of load that is not included in the CELT load forecast. About 1,100 MW of this is station service load and 364 MW is associated with the manufacturing loads. The amount of station service represented will be dependent on the generation that is in service. Station service should be turned off if the generation it is associated with is out of service, with the exception of station service to nuclear plants. Also specific large new loads, such as data centers and large green house facilities, are not generally included in the CELT load forecast, and may be included in the study depending on the degree of certainty that the large new load will come to fruition.

When assessing peak load conditions, 100% of the projected 90/10 Summer peak load for the New England Control Area is used. The New England system experiences its peak load in the Summer. The 90/10 Peak Load represents a load level that has a 10% probability of being exceeded due to variations in weather. Summer peak load values are generally obtained from the CELT report. This forecast includes losses of about 8% of the total load, 2.5% for transmission and large transformer losses and 5.5% for distribution losses. Thus the amount of customer load served is typically slightly less than the forecast. The peak load level is adjusted for modeling of Demand Resources as discussed in Section 11.8. The target load level for Peak Load is achieved by requesting a case with the 90/10 CELT forecast year and the study year being evaluated.

The Intermediate Load, Light Load and Minimum Load levels were derived from actual measured load, which is total generation plus net flows on external tie lines. These load levels include transmission losses and manufacturing loads. The loads in the base cases provided by ISO-NE are adjusted to account for these factors. Since actual measured load includes the impacts of distributed resources and distributed generation, no adjustments to ISO-NE bases cases are needed to address these impacts. The

Intermediate Load, Light Load and Minimum Load will be reviewed periodically and may be adjusted in the future based on actual load levels.

The Intermediate Load level, also called the shoulder load level, represents both loads in off peak hours during the Summer and loads during peak hours in the Spring and Fall. The Intermediate Load level was developed by reviewing actual system loads for the three years (2011-2013) and approximating a value system loads were at or below 90% of the time (7884 hours.) The load level analysis used 500 MW increments and the current value was rounded down to account for the anticipated impact of continuing energy efficiency programs. The target load level of 18,000 MW for Intermediate Load is adjusted to 17,636 MW to properly account for the manufacturing loads.

The Light Load level was developed by reviewing actual system loads for the last ten years and approximating a value system loads were at or below for 2000 hours. The load level analysis used 500 MW increments and the current value was rounded down to account for the anticipated impact of continuing energy efficiency programs. The target load level of 12,500 MW for Light Load is adjusted to 12,136 MW to properly account for the manufacturing loads.

In a similar fashion, the Minimum Load level was developed by reviewing actual minimum system loads, excluding data associated with significant outages such as after a hurricane. The original intent was to base the load level used on 500 MW increments and the value was rounded down to account for the anticipated impact of continuing energy efficiency programs. The original intent was to model 8,500 MW as the total of CELT load plus manufacturing loads. However, the concept was never clearly documented and most studies have been based on a CELT load of 8,500 MW plus the additional 364 MW of manufacturing load. This has been reviewed and is acceptable and therefore will be carried forward until such time that historic data shows that this value needs revision

Steady-state testing is done at Summer load levels because equipment ratings are lower in the Summer and loads are generally higher. Stability testing is always done at the Light Load level to simulate stressed conditions due to lower inertia resulting from fewer generators being dispatched and reduced damping resulting from reduced load. Except where experience has shown it is not necessary, stability testing is also done at peak loads to bound potential operating conditions and test for low voltages. Testing at the Minimum Load level is done to test for potential high voltages when line reactive losses may be low and fewer generators are dispatched resulting in lower availability of reactive resources.

The following table lists the load levels generally used in different planning studies:

Table 5-1
Load Levels Tested in Planning Studies

Study	Peak Load	Intermediate Load	Light Load	Minimum Load
System Impact Study (Steady State)	Yes	Yes	(6)	(1)
System Impact Study (Stability)	Yes	No	Yes	No
PPA Study of Transmission (Steady State)	Yes	(2)	No	(1)
PPA Study of Transmission (Stability)	Yes	No	Yes	No
Transmission Needs Assessment (Steady State)	Yes	(2)	No	Yes
Transmission Needs Assessment (Stability)	Yes	No	Yes	No
Transmission Solutions Study (Steady State)	Yes	(2)	No	Yes
Transmission Solutions Study (Stability)	Yes	No	Yes	No
NPCC Area Review Analyses (Steady State)	Yes	No	No	No
NPCC Area Review Analyses (Stability)	Yes	No	Yes	No

Study	Peak Load	Intermediate Load	Light Load	Minimum Load
BPS Testing (Steady State)	Yes	No	No	No
BPS Testing (Stability)	Yes	No	Yes	No
Transfer Limit Studies (Steady State)	Yes	(3)	No	No
Transfer Limit Studies (Stability)	Yes	No	Yes	No
Interregional Studies	Yes	No	No	No
FCM New Resource Qualification Overlapping Impact Analyses (4)	Yes	No	No	No
FCM New Resource Qualification NCIS Analyses (4)	Yes	No	No	No
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals (4) (5)	Yes	No	No	No
FCM Delist/Non-Price Retirement Analyses (4)	Yes	No	No	No
Transmission Security Analyses (4)	Yes	No	No	No
Non-Commercial Capacity Deferral Notifications (4)	Yes	No	No	No

(1) Testing at a Minimum Load level is done for projects that add a significant amount of charging current to the system, or where there is significant generation or other facilities such as conventional HVDC that do not provide voltage regulation.
(2) It may be appropriate to explicitly analyze intermediate load levels to assess the consequences of generator and transmission maintenance.
(3) Critical outages and limiting facilities may sometimes change at load levels other than peak, thereby occasionally requiring transfer limit analysis at intermediate loads.
(4) These studies are described in ISO New England Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market.
(5) Sensitivity analyses at load levels lower than peak are considered when such lower load levels might result in high voltage conditions, system instability or other unreliable conditions per ISO New England Planning Procedure No. 10.
(6) Testing at Light Load is done when generation may be limited due to Light Load export limits.

Section 6
Load Power Factor Assumptions

The power factor of the load is important in planning studies because it impacts the current flow in each transmission Element. For example, a 100 MW load causes about 500 amps to flow in a 115 kV line if it is at unity power factor and about 560 amps to flow if it is at 0.90 power factor. The larger current flow resulting from a lower power factor causes increased real power and reactive power losses and causes poorer transmission voltages. This may result in the need for replacing transmission Elements to increase their ratings, in the need for additional shunt devices such as capacitors or reactors to control voltages, or in a decrease in the ability to transfer power from one area to another.

Each transmission owner in New England uses a process that is specific and appropriate to their particular service area to determine the load power factor to be assumed for loads in its service territory. The following summarizes the methods used by transmission owners within the New England area to set the load power factor values to be used in modeling their systems at the 90/10 Peak Load:

Table 6-1
Power Factor Assumptions

Company	Base Modeling Assumption
Emera Maine (formerly BHE)	Uses Historical Power Factor (PF) values
CMP	Historical metered PF values (Long term studies use 0.955 lagging)
Municipal Utilities	Uses Historical PF values
National Grid	1.00 PF at Distribution Bus
Eversource(Boston) (Formerly NSTAR North)	Individual Station 3 Year Average PF at Distribution Bus
Eversource (Cape Cod) (Formerly NSTAR South)	0.985 lagging PF at Distribution Bus
Eversource (CT,NH,WMA) (Formerly NU)	0.990 lagging PF at Distribution Bus
UI	0.995 lagging PF at Distribution Bus
VELCO	Historical PF at Distribution Bus provided by Distribution Companies

The above power factor assumptions are also used in Intermediate Load and Light Load cases. The power factor at the Minimum Load level is set at 0.998 leading at the distribution bus for all scaling load in New England with the exception of:

1. Boston downtown load fed by Eversource that is set to a power factor of 0.978 lagging at the distribution bus
2. Boston suburban load fed by Eversource this is set to unity power factor at the distribution bus

The non-scaling load includes mill loads in Maine, MBTA loads in Boston, railroad loads in Connecticut and other similar loads.

ISO-NE Operating Procedure 17, Load Power Factor Correction, discusses load power factor and describes the annual survey done to measure compliance with acceptable load power factors.

Section 7
Load Models

7.1 Load Model for Steady-State Analysis

In steady-state studies, loads are modeled as constant MVA loads, comprised of active ("real") P and reactive ("imaginary") Q loads. They are modeled by the Transmission Owners based on historical and projected data at individual buses, modeling equivalent loads that represent line or transformer flows. These loads may be modeled at distribution, sub-transmission, or transmission voltages.

7.2 Load Model for Stability Analysis

Loads (including generator station service) are assumed to be uniformly modeled as constant impedances throughout New England and New York. The constant impedances are calculated using the P and Q values of the load. This representation is based on extensive simulation testing using various load models to derive the appropriate model from an angular stability point of view, as described in the 1981 NEPOOL report, "Effect of Various Load Models on System Transient Response."

For under frequency load shedding analysis, other load models are sometimes used, such as either a polynomial combination of constant impedance, constant current and constant load; or a complex load model, including modeling of motors. The alternate modeling is based on the end use composition of the load.

Voltage stability analysis is sometimes done using a complex load model, including modeling of motors.

Section 8
Base Case Topology

8.1 Summary of Base Case Topology

Base case topology refers to how system Elements are represented and linked together for the year(s) to be studied. System Elements modeled in base cases include, but are not limited to transmission lines, transformers, other series and shunt Elements in New England, generators on the New England transmission system, generators on the New England distribution system, merchant transmission facilities in New England, and similar topology for adjacent systems.

There are a number of Tariff and practical considerations that determine the topology used for various types of planning studies. For example, Needs Assessments and Solutions Studies need to include the facilities that have a commitment to be available (e.g. an obligation in the Forward Capacity Market, a reliability upgrade with an approved PPA or a merchant facility with an approved PPA and an associated binding contract) and need to exclude projects that are not committed to be available. For System Impact Studies for generation the studies need to include all active generators in the FERC section of the ISO-NE queue that have earlier (higher) queue positions. The starting point for the development of a base case is ISO-NE's Model on Demand database which includes a model of the external system from the Multi-regional Modeling Working Group ("MMWG"). This Model on Demand data base is used to create ISO-NE's portion of the MMWG base case. However, the Model on Demand data base is updated periodically to include updated ratings, updated impedances and newly approved projects. The following table summarizes the topology used in planning studies:

Table 8-1
Base Case Topology

Study	Transmission in New England	Generation in New England (7,8)	Merchant Facilities	Transmission outside New England	Generation outside New England
PPA Study of transmission project (Steady State and Stability)	In-Service, Under Construction, and Planned (1)	In-Service, Under Construction or has an approved PPA (1)	In-Service, Under Construction or has an approved PPA	Models from recent Multiregional Modeling Working Group ("MMWG") base case	Models from recent MMWG base case
System Impact Study (Steady State and Stability)	In-Service, Under Construction, and Planned (1)	In-Service, Under Construction, or has an approved PPA or is included in FERC section of the ISO-NE queue (1)	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
Transmission Needs Assessment (Steady State)	In-Service, Under Construction, Planned, and Proposed (6)	Has a capacity supply obligation or a binding contract (4)	In-Service, Under Construction, or has an approved PPA; and delivers an import with a capacity supply obligation or a binding contract (4); and has a certain ISD	Models from recent MMWG base case	Models from recent MMWG base case

Study	Transmission in New England	Generation in New England (7,8)	Merchant Facilities	Transmission outside New England	Generation outside New England
Transmission Solutions Study (Steady State and Stability)	In-Service, Under Construction, Planned, and Proposed (6)	Has a capacity supply obligation or a binding contract (4)	In-Service, Under Construction, or has an approved PPA: and delivers an import with a capacity supply obligation or a binding contract (4); and has a certain ISD	Models from recent MMWG base case	Models from recent MMWG base case
Area Review Analyses (Steady State and Stability)	In-Service, Under Construction, and Planned	In-Service, Under Construction, or has an approved PPA	In-Service, Under Construction, or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
BPS Testing Analyses (Steady State and Stability)	In-Service, Under Construction, and Planned	In-Service, Under Construction, or has an approved PPA	In-Service, Under Construction, or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
Transfer Limit Studies (Steady State and Stability)	In-Service, Under Construction, and Planned	In-Service, Under Construction or has an approved PPA	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
Interregional Studies	In-Service, Under Construction, and Planned (2)	In-Service, Under Construction or has an approved PPA	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
FCM New Resource Qualification Overlapping Impact Analyses (3) (4)	In-Service, or Under Construction, Planned, or Proposed with an In Service Date (ISD) certified by the Transmission Owner ("TO")	Existing resources and resources that have a capacity supply obligation	In-Service, Under Construction , Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas
FCM New Resource Qualification Network Resource Interconnection Standard Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the TO	Existing resources and resources that have a capacity supply obligation	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas

Study	Transmission in New England	Generation in New England (7,8)	Merchant Facilities	Transmission outside New England	Generation outside New England
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the TO	Existing resources and resources that have a capacity supply obligation	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas
FCM Delist/Non-Price Retirement Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the TO	Existing resources and resources that have a capacity supply obligation	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas
Transmission Security Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the TO	Existing resources and resources that have a capacity supply obligation	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	N/A	N/A
Non-Commercial Capacity Deferral Notifications (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the TO	Existing resources and resources that have a capacity supply obligation	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas

(1) Projects with a nearly completed PPA Study and that have an impact on this study are also considered in the base case. This includes transmission projects and generation interconnections to the PTF or non-PTF transmission system. Also generators without capacity supply obligations in the Forward Capacity Market are included in PPA Studies.
(2) Some interregional studies may include facilities that do not have approved Proposed Plan Applications.
(3) Base Cases for preliminary, non-binding overlapping impact analysis done as part of a generation Feasibility Study or generation System Impact Study are developed with input from the Interconnection Customer.
(4) Section 4.2 of Attachment K describes that resources that are bound by a state-sponsored RFP or financially binding contract are represented in base cases.
(5) These studies are described in ISO New England Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market.
(6) Sensitivity analysis may also be done to confirm the Proposed Projects in the Study Area continue to be needed.

(7) Generators that have submitted a Non-Price Retirement Request are considered to be retired in the year associated with their Non-Price Retirement Request and in subsequent years.
(8) In Transmission Needs Assessments and Transmission Solutions Studies, additional generators are often considered unavailable. Generators that have a rejected Permanent De-list bid are considered unavailable (See Attachment K 4.1.c). Also, generators that have delisted in the two most recent FCM auctions are considered unavailable. In addition, the ISO may consider generators unavailable because of circumstances such as denial of license extensions or being physically unable to operate.

8.2 Modeling Existing and Proposed Generation

Generating facilities 5 MW and greater are listed in the CELT report and are explicitly modeled in planning study base cases. The current exception to this is generators 5 MW and greater that are "behind the meter" and do not individually participate in the ISO New England energy market. Some of these generators are netted to load. However, as these generators could have an impact on system performance, future efforts will be made to model these resources in greater detail. The ISO is collecting load flow, stability and short circuit models for generators 5 MW and greater that are new or being modified. Additional models such as PSCAD models are collected as necessary. For example a PSCAD model is often required for solar and wind generation connecting to the transmission system.

Generators less than 5 MW are modeled explicitly, either as individual units or as the equivalent of multiple units, or are netted to load. Generators connected to the distribution system are generally modeled at a low voltage bus connected to the transmission system through a load serving transformer.

8.3 Base Cases for PPA Studies and System Impact Studies

Similar topology is used in base cases for PPA Studies for transmission projects and System Impact Studies. Both types of studies include projects in the Planned status in their base cases. However, projects with a nearly completed PPA Study and that have an impact on a study area are also considered in the base case.

Section 2.3 of Schedule 22 of the OATT states that base cases for generation interconnection Feasibility and System Impact Studies shall include all generation projects and transmission projects, including merchant transmission projects that are proposed for the New England Transmission System for which a transmission expansion plan has been submitted and approved by the ISO. This provision has been interpreted that a project is approved when it is approved under Section I.3.9 of the Tariff.

Sections 6.2 and 7.3 of Schedule 22 of the OATT further state that on the date the Interconnection Study is commenced, the base cases for generation interconnection studies shall also include generators that have a pending earlier-queued Interconnection Request to interconnect to the New England Transmission System or are directly interconnected to the New England Transmission System.

8.4 Coordinating Ongoing Studies

At any point in time there are numerous active studies of the New England transmission system. The New England planning process requires study teams to communicate with other study teams to ascertain if the different teams have identified issues which may be addressed, in whole or in part, by a common solution, or if changes to the transmission system are being proposed that might impact their study. It is appropriate for a Needs Assessment, a Solutions Study or a Generator Interconnection Study to consider relevant projects that have nearly completed their PPA analyses. For example, a study of New Hampshire might consider a 345 kV line from New Hampshire to Boston that is a preferred solution in a Solutions Study of the Boston area, or, when issues in both areas are considered, may suggest a benefit of modifying a solution that has already progressed to the Proposed or the Planned stage.

8.5 Base Case Sensitivities

Often in transmission planning studies, there is uncertainty surrounding the inclusion of a resource, a transmission facility, or a large new load in the base case for a study. These uncertainties are handled by doing sensitivity analysis to determine the impact the inclusion or exclusion of a particular resource, transmission project or load has on the study results. Sensitivity studies are done to determine the impact of changes that are somewhat likely to occur within the planning horizon and may influence the magnitude of the need or the choice of the solution. Typically, stakeholder input is solicited at PAC meetings in determining the manner in which sensitivity results are factored into studies. Examples are resources that may be retired or added, and transmission projects that may be added, modified, or delayed. Sensitivity analysis usually analyzes a limited number of conditions for a limited number of contingencies.

8.6 Modeling Projects with Different In-Service Dates

In some situations it is necessary to do a study where the year of study is earlier than the in service dates of all the projects that need to be considered in the base case. In such situations it is necessary to also include a year of study that is after the in-service-dates of all relevant projects.

As an example, consider two generation projects in the ISO's queue. The first project has queue position 1000 and a Commercial Operation Date of 2018. The second project has queue position 1001 and a Commercial Operation Date of 2015. Sections 6.2 and 7.3 of Schedule 22 of the OATT require that the study of the project with queue position 1001 to include the project with queue position 1000. To accomplish this, the study of the project with queue position 1001would be done with 2015 base case without the project with queue position 1000 and also with a 2018 base case that includes the project with queue position 1000 and any transmission upgrades associated with queue position 1000.

Section 9
Generator Ratings

9.1 Overview of Generator Real Power Ratings

Within New England, a number of different real power (MW) ratings for generators connected to the grid are published. Examples of the different generator ratings are summarized in the table below. The detailed definitions of these ratings are included in Appendix A. CNRC and NRC values for New England generators are published each year in the CELT (Capacity, Energy, Loads, & Transmission) Report.[1] QC values are calculated based on recent demonstrated capability for each generator. The Capacity Supply Obligation value and QC values are published for each Forward Capacity Auction in the informational results filings to FERC.[2]

Table 9-1
Generator Real Power Ratings

Capacity Network Resource Capability ("CNRC") – Summer- (maximum output at or above 90 degrees Fahrenheit)	CNRC Summer is the maximum amount of capacity that a generator has interconnection rights to provide in Summer. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 90 degrees Fahrenheit
Capacity Network Resource Capability ("CNRC") - Winter (maximum output at or above 20 degrees Fahrenheit)	CNRC Winter is the maximum amount of capacity that a generator has interconnection rights to provide in Winter. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 20 degrees Fahrenheit
Capacity Supply Obligation ("CSO")	A requirement of a resource to supply capacity. This requirement can vary over time based on the resource's participation in the Forward Capacity Market.
Network Resource Capability ("NRC") -Summer (maximum output at or above 50 degrees Fahrenheit)	NRC Summer is the maximum amount of electrical output that a generator has interconnection rights to provide in Summer. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 50 degrees Fahrenheit
Network Resource Capability ("NRC") –Winter (maximum output at or above 0 degrees Fahrenheit)	NRC Winter is the maximum amount of electrical output that a generator has interconnection rights to provide in Winter. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 0 degrees Fahrenheit
Qualified Capacity ("QC")	QC is the amount of capacity a resource may provide in the Summer or Winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes

In New England planning studies, except for the FCM studies, generators connected to the transmission system are generally modeled as a generator with its gross output, its station service load and its generator step-up transformer ("GSU"). In FCM studies, except for Network Capacity Interconnection Standard studies, generation is generally modeled net of station service load at the low voltage side of the

[1] http://www.iso-ne.com/trans/celt/index.html

[2] http://www.iso-ne.com/regulatory/ferc/filings/index.html

GSU and station service load is set to zero. This is done because the CSO, QC and CNRC values are net values. One exception is made in FCM-related studies for nuclear resources, where the generator is modeled at its gross output, in order to capture the need to maintain supply to the generator's station service load if the generator is out of service. Another exception is generating facilities composed of multiple smaller generators such as wind farms, solar and small hydro units. These facilities are often modeled as a single equivalent generator on the low voltage side of the transformer that interconnects the facility with the transmission system.

The ratings and impedances for an existing GSU are documented on the NX-9 form for that transformer. The existing generator's station service load is documented on the NX-12 form for that generator. Similar data is available from the Interconnection Requests for proposed generators. The generator's gross output is calculated by adding its appropriate net output to its station service load associated with that net output. GSU losses are generally ignored in calculating the gross output of a generator. This data is used by the ISO-NE to help create the base cases for planning studies.

In New England planning studies, generators connected to the distribution system are generally modeled as connected to a low voltage bus that is connected to a transformer that steps up to transmission voltage or netted to distribution load. Multiple generators connected to the same low voltage bus may be modeled individually or as an equivalent generator.

9.2 Generator Ratings in Steady-State Needs Assessments, Solutions Studies, and NPCC Area Review Analyses

The Summer Qualified Capacity value is used to represent a machine's maximum real power output (MW) for all load levels studied except for Light Load (when applicable) and Minimum Load Studies. QC is used in these studies because QC represents the recently demonstrated capability of the generation. The QC value is the maximum Capacity Supply Obligation that a resource may obtain in the Forward Capacity Market. Any requested reduction in obligation from a resource's QC is subject to a reliability review and may be rejected for reliability reasons. The Capacity Network Resource Capability acts as an approved interconnection capability cap within the Forward Capacity Market that limits how much a resource could increase its QC without an Interconnection Request. In other words, QC cannot exceed CNRC. Because QC corresponds to the recently demonstrated capability, as opposed to CNRC which is the upper limit of the capacity capability of a resource, using QC instead of CNRC does not overstate the amount of capacity that could potentially be obligated to provide capacity to the system.

For reliability analysis conducted at Light Load and Minimum Load Levels, the generator's Summer NRC value (maximum MW output at or above 50 degrees) is used. Some generators have higher individual resource capabilities at 50 degree ratings compared with 90 degrees. Therefore, using 50 degree ratings allows a smaller number of resources to be online to serve load. The fewer the number of resources online, the less overall reactive capability on the system to mitigate high voltage concerns. This value is also consistent with the expected ratings of machines at the temperatures that are typically experienced during lighter load periods in the Summer rating period.

9.3 Generator Ratings in PPA Studies and System Impact Studies

The generator's Summer NRC value is used to represent a machine's maximum real power output (MW) for all load levels. For generator System Impact Studies, using this value ensures that studies match up with the level of service being provided. Studying Elective Transmission Upgrades and transmission projects with machines at these ratings also ensures equal treatment when trying to determine the adverse impact to the system due to a project.

9.4 Generator Ratings in Stability Studies

The generator's Winter NRC value is used to represent a machine's maximum real power output (MW) for all load levels in all stability studies. Using the Winter NRC values ensures that stressed dispatches (in terms of limited inertia on the system and internal generator rotor angles) are studied and addressed, therefore ensuring reliable operation of the system in real-time. This operability is required because real-time power system analysis is unable to identify stability concerns or determine stability limits that may exist on the system. These limits are determined in offline operational studies performed in a manner that ensures that they are applicable over a wide range of system conditions, including various ambient temperatures and load levels.

9.5 Generator Ratings in Forward Capacity Market Studies

The generator's Summer CNRC value is used to represent a machine's maximum real power output (MW) for FCM New Resource Qualification Overlapping Impact Analyses. This output represents the level of interconnection service that a generator has obtained for providing capacity.

The generator's Summer NRC value is used to represent a machine's maximum real power output (MW) for FCM New Resource Qualification NCIS Analyses. This output represents the level of interconnection service that a generator has obtained for providing energy.

The generator's Summer QC value is used to represent a machine's maximum real power output (MW) for FCM Delist/Non-Price Retirement Analyses and Transmission Security Analyses. This output represents the expected output of a generator during Summer peak periods.

The lower of a generator's Summer QC value or Summer Capacity Supply Obligation is used to represent a machine's maximum real power output (MW) for FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals. This output represents the expected capacity capability of a generator during Summer peak periods.

9.6 Generator Reactive Ratings

This section is under development.

Section 10
Generators Out of Service in Base Case

In Transmission Needs Assessments and Transmission Solutions Studies, generally two generation resources are considered out of service in the study area. These resources can be individual generators or interdependent generating facilities such as combined-cycle units (see section 11.9). The most impactful generators, those whose outage creates the greatest stress on the portion of transmission system under study, are considered out of service. Identifying the most impactful generators may in itself require some analysis. Additional generators could be considered to be out of service if the area under study has a large population of generators or if examining Intermediate, Light or Minimum Load maintenance conditions. Often multiple base cases are required to assess the impact of different combinations of generators being out of service. In general, having several generators out in a base case addresses issues such as the following:

- Higher generator forced outage rates than other transmission system Elements
- Higher generator outages and limitations during stressed operating conditions such as a heat wave or a cold snap
- Past experience with simultaneous unplanned outages of multiple generators
- High cost of Reliability Must Run Generation
- Generator maintenance requirements
- Unanticipated generator retirements
- Fuel shortages

In some of the other transmission planning studies listed in Section 2, the most impactful single generators are considered out of service in the base cases and other generators may be turned off in order to create system stresses. For example, in FCM overlapping impact studies, the system is stressed by assuming that the most impactful helper is out of service. The most impactful helper is the generator that, when placed in service at its full output, will result in the most significant reduction in the flow on the limiting element.

Section 11
Determination of Generation Dispatch in Base Case

11.1 Overview

Different types of studies are conducted to achieve different transmission planning objectives. Therefore, it is necessary to consider the different range of anticipated generator capabilities which are appropriate to the objectives of study and the specific conditions which are being examined.

11.2 Treatment of Different Types of Generation

The following table lists the maximum generation levels generally used in different planning studies. Generators, when dispatched, are usually dispatched up to their maximum output in a study.

Table 11-1
Generator Maximum Power Output in Planning Studies

Study	Conventional Generation	Fast Start Generation	Hydro (1) Generation	Wind Generation	Solar Generation (3)
System Impact Study (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
System Impact (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
PPA Study of Transmission (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
PPA Study of Transmission (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
Transmission Needs Assessment (Steady State)	Summer QC	Summer QC	Historical Level	5% of nameplate for on-shore wind (2)	Summer QC
Transmission Solutions Study (Steady State)	Summer QC	Summer QC	Historical Level	5% of nameplate for on-shore wind (2)	Summer QC
Transmission Solutions Study (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
Area Review Analyses (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
Area Review Analyses (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
BPS Testing Analyses (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
BPS Testing Analyses(Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
Transfer Limit Studies (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
Transfer Limit Studies (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC

(1) Table lists treatment on conventional hydro. The treatment of pumped storage hydro is described in Section 11.5.
(2) 20% of the nameplate for off-shore wind.
(3) Table lists treatment of solar generation 5 MW or greater that is in the ISO system model. See Section 11.7 for a complete description of treatment of solar generation.

Study	Conventional Generation	Fast Start Generation	Hydro (1) Generation	Wind Generation	Solar Generation (3)
Interregional Studies	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
FCM New Resource Qualification Overlapping Impact Analysis	Summer CNRC	Summer CNRC	Summer CNRC	Summer CNRC	Summer CNRC
FCM New Resource Qualification Network Capacity Interconnection Standard Analyses	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
FCM Delist/Non-Price Retirement Analyses	Summer QC	Summer QC	Summer QC	Summer QC	Summer QC
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO
Transmission Security Analyses	Summer QC	Summer QC	Summer QC	Summer QC	Summer QC
Non-Commercial Capacity Deferral Notifications	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO

(1) Table lists treatment on conventional hydro. The treatment of pumped storage hydro is described in Section 11.5.
(2) 20% of the nameplate for off-shore wind.
(3) Table lists treatment of solar generation 5 MW or greater that is in the ISO system model. See Section 11.7 for a complete description of treatment of solar generation.

11.3 Treatment of Wind Generation

Studies of wind generation in New England reveal that the output of on-shore (land-based) wind generation can be very low during Summer peak load hours.[3] In general, when it is needed to support area transmission requirements, on-shore wind generation is modeled at 5% of nameplate and off-shore wind is modeled at 20% of nameplate for Needs Assessment and Solutions Studies. If a wind farm's Qualified Capacity is lower than the above value, the Qualified Capacity will be used in Needs Assessments and Solutions Studies.

The above percentages are estimates of the level of wind generation output that can be counted on during Summer peak for reliability analysis. To ensure that the interconnection rights of wind resources are preserved, wind generation is modeled at its NRC value in PPA studies.

11.4 Treatment of Conventional Hydro Generation

There are two classifications of conventional hydro, those hydro facilities that have no control over water flow, for example no capability to store water, and those hydro facilities that can control water flow, for example those facilities with a reservoir or river bed that can store water. For the purpose of planning studies, hydro facilities listed as "hydro (weekly cycle)" or "hydro (daily cycle-pondage)" in the CELT report are considered to be able to control water flow. Hydro facilities listed as "hydro (daily cycle-run of river)" in the CELT report, are assumed to have no ability to control water flow and are classified as intermittent resources. Hydro facilities that can control water flow are classified as non- intermittent

[3] This was discussed at the Planning Advisory Committee meetings on September 21, 2011 and October 22, 2014.

resources. For both classifications the output of the hydro generation is set at its historic capability that can be relied on for reliability purposes or at 10% of nameplate, which is an estimate of that historic capability, in the base cases for Needs Assessments and Solutions Studies. Post contingency, conventional hydro that has the capability to control water flow and has sufficient water storage capability is dispatched up to 100% of its nameplate to relieve criteria violations in Needs and Solutions Analysis. Hydro facilities that have no control over water flow or limited water storage capability are dispatched at the same output pre and post contingency.

11.5 Treatment of Pumped Storage Hydro

There are three pumped storage-hydro plants connected to the New England Transmission System: Northfield Mountain and J. Cockwell (also known as Bear Swamp) in Massachusetts and Rocky River in Connecticut. Records indicate that these facilities historically have had limited stored energy during prolonged heat waves because limited time and resources are available to allow these units to refill their reservoirs during off-peak periods. Additionally J. Cockwell and Northfield are often used to provide reserve capacity. Based on this, the following generation levels are generally used in Needs Assessments and Solutions Studies.

Table 11-2
Pumped Storage Hydro Generation Levels

Generating Facility	MW Output
J. Cockwell	50% of Summer QC
Northfield Mountain	50% of Summer QC
Rocky River	Treated as conventional hydro with ponding capability

In Needs Assessments and Solutions Studies addressing the area that includes a pumped storage-hydro facility, the pumped storage-hydro facility in that area may also be dispatched at their maximum and/or minimum values to ensure that they can be utilized to serve load when they are available since they are often utilized in operations to provide reserve. In PPA studies, pumped storage-hydro plants are dispatched at their full output when necessary to show that their ability to supply load is maintained.

11.6 Treatment of Fast Start Generation

Fast start units are generally used as reserve for generation that has tripped off line, for peak load conditions, and to mitigate overloads or unacceptable voltage following a contingency, N-1 or N-1-1. Based on operating experience and analysis, 80% of fast start units in the study area are assumed to be available. However, it is not appropriate to rely on any one specific fast start unit as the solution to an overload.

For the purpose of transmission planning studies, fast start units are those combustion turbines or diesel generators that can go from being off line to their full Seasonal Claimed Capability in 10 minutes. A list of fast start units has been developed by reviewing market information such as notification times, start times and ramp rates. The list is included as Appendix B in the guide. The capacity included in the list is from Forward Capacity Auction 8. The capacity of any generator may have changed and needs to be confirmed. The unit does not need to participate in the 10-minute reserve market to be considered a fast start unit in planning studies.

For the steady-state portion of Transmission Needs Assessments and Solutions Studies at peak load, the fast start units can be turned on in the base cases. When using this approach, criteria violations that can be mitigated by turning off fast start generation can be disregarded.

For Transmission Needs Assessments and Solutions Studies at Intermediate or Light load level, fast start units are turned off in the base cases and turned on to mitigate post-contingency criteria violations.

One exception to the above is that fast start generation in Vermont is not dispatched in the base case in Needs Assessments and Solutions Studies due to their past poor performance, but they are may be turned on between the first and second contingency.

11.7 Treatment of Solar Generation

Solar generation will be represented in the power flow base cases that are provided by ISO-NE. ISO-NE includes a solar PV forecast in its annual CELT Report. This forecast includes the solar PV that has been installed as of the prior year as well as provides a forecast by state of the total PV (by AC Nameplate) that is expected to be in-service by the end of each forecast year for the next 10 years. As an example the 2015 PV forecast provides the PV that is in-service as of the end of 2014 as well as provides an annual forecast for the PV that will be in-service for end of 2015, end of 2016 and so on until the end of 2024.

The solar PV forecast is a part of the CELT Report and can be found at:

http://www.iso-ne.com/system-planning/system-plans-studies/celt

As a part of the 2015 PV forecast the data on solar PV was divided into the following four mutually exclusive groups:

1. PV as a capacity resource in the Forward Capacity Market (FCM)
   - Qualified for the FCM
   - Have capacity supply obligations
   - Size and location identified and visible to the ISO
   - May be supply or demand side resources
2. Non-FCM Settlement only Resources (SOR) and Generators (per OP-14)
   - ISO collects energy output
   - Participate only in the energy market
3. Behind-the-Meter (BTM) PV Embedded in Load (BTMEL)
   - Reduces system load
   - ISO has an incomplete set of information on generator characteristics
   - ISO does not collect energy meter data, but can estimate it using other available data
   - The portion of BTM that is captured in the historical load forecast and can be estimated via reconstitution of hourly historical BTM PV production
4. Behind-the-Meter (BTM) PV Not Embedded in Load (BTMNEL)
   - Reduces system load
   - ISO has an incomplete set of information on generator characteristics
   - ISO does not collect energy meter data, but can estimate it using other available data
   - The portion of BTM that is not captured in the historical load forecast (i.e., not embedded)

Of the four groups, the Behind-the-Meter PV Embedded in Load is already embedded in the CELT forecast and hence will not be modeled explicitly in any studies. The remaining three groups need to be considered when accounting for solar PV in studies.

For long-term transmission planning studies including Generator interconnection studies, the solar PV will be modeled in the base cases to account for all three groups that are not already included as part of the load forecast:

- PV as a capacity resource in FCM
- Settlement only Resources and Generators
- Behind-the-Meter PV Not Embedded in Load (BTMNEL)

The solar PV forecast only forecasts the PV values on a state-wide basis. However, within a state the PV does not grow uniformly, with some areas in the state having larger amounts of PV. To account for this locational variation of PV, the locational data of existing PV that is in-service as of the end of 2014 was utilized to obtain the percentage of PV that is in each dispatch zone. New England is divided into 19 dispatch zones and the percentage of PV in each dispatch zone as a percentage of total PV in the state is available. This percentage is assumed to stay constant for future years to allocate future PV to the dispatch zones. The percentage of existing solar in each dispatch zone as of the end of each year that is used as a part of the Solar PV forecast is based on Distribution Owner interconnection data and the materials are located at:

http://www.iso-ne.com/system-planning/system-forecasting/distributed-generation-forecast

As an example if the SEMA dispatch zone accounts for 20% of existing PV in Massachusetts, it will be assumed that 20% of any growth in PV as a part of the PV forecast will be in SEMA.

Once we have the solar PV data by dispatch zone the PV within the dispatch zone falls into three categories:

- Category 1 : Units greater than 5MW:
  - Location data available
  - Will be modeled as an individual generators
- Category 2 : Units greater than 1 MW and less than 5 MW
  - Location data available through the PPA notifications
  - Needs to be modeled as injections at specific locations – Negative loads similar to DR
- Category 3: Units below 1 MW
  - No location data available
  - Needs to be modeled by spreading the MWs across the dispatch zone – Negative loads similar to DR and spread across the load zone/dispatch zone like DR is spread

For PV in categories 2 and 3 the PV will be modeled as negative loads at the buses.

Load Levels at which PV will be modeled

For shoulder, light and minimum load levels the ISO uses fixed load levels for studies based on historic data, which already includes the impacts of PV. Hence, no PV in Category 2 or 3 will be explicitly modeled in shoulder, light and minimum load cases. The Winter peak conditions are expected after sunset and hence no solar PV in Category 2 or 3 will be modeled for Winter peak cases. The only case where PV under category 2 and 3 will be explicitly modeled is for Summer peak load conditions.

PV under category 1 will be modeled in all the cases. The specific output of the unit will vary dependent on the study.

Further, since the PV data is available only as end of year installed AC nameplate, long term planning studies will use the forecast for the end of the year prior to that being evaluated. As an example for a study in the year 2018, all the PV as of end of 2017 will be modeled.

Adjustment for Losses

For PV in categories 2 and 3 an adjustment to the AC nameplate PV will need to be made to account for avoided losses on the distribution system. Currently, the ISO assumption for distribution losses as a percentage of load is 5.5%. Hence the negative loads will be the AC nameplate load at the bus + 5.5% avoided distribution losses.

Modeling Solar Generation in Transmission Planning

Based on a review of historic PV outputs ISO Transmission Planning has determined a 26% availability factor to be appropriate for transmission planning studies. The 26% level represents the output of solar generation during the peak load period between 4 p.m. and 6 p.m. in the Summer. This is the time period when solar output begins to go down due the angle of the sun and when loads are still at or near the peak level.

The PV in categories 2 and 3 will be assumed to be at 26% output for Needs Assessments and Solutions Studies. For transmission PPA studies and generation system impact studies, the PV in Category 2 and 3 may be assumed to be up to 100% available.

For Needs and Solutions studies the Category 1 PV will be modeled at 26% of their nameplate rating (50 degree rating) for peak load studies. For all other load levels the Category 1 PV generators will be modeled based on the study specific requirements. For transmission PPA studies and generation system impact studies, the Category 1 PV will be treated consistent with the treatment of conventional generators.

Modeling Solar Generation in FCM Studies (including the Transmission Security Analyses and Non-Commercial Capacity Deferral Notifications)

PV that has qualified in FCM will be treated consistent with the treatment of other intermittent generators that have qualified in FCM. Non-FCM PV that is participating in the ISO-NE energy market will not be included in FCM studies because they have no obligation to generate. Behind-the-Meter (BTM) PV Not Embedded in Load (BTMNEL) will be modeled at a level based on the estimated median of its net output during Intermittent Reliability Hours.

Forecasting Solar PV beyond the Solar PV forecast

Occasionally, transmission planning studies have to look beyond the 10 year PV forecast horizon. For these cases the growth of PV forecast from year 9 to year 10 will be used to obtain the year 11 PV forecast. This process will be repeated to obtain year 12 PV forecast from year 11 PV forecast and year 10 PV forecast and so on.

Solar Impacts on Power Factor

Solar generation will be represented in peak power flow cases such that it does not affect the net power factor of the load. It is assumed that distribution companies will adjust their power factor correction programs to account for solar generation. At peak load levels, solar generation generally should reduce distribution VAR losses, therefore modeling solar power such that it does not impact net load power factor should be a slightly conservative approach. If no load is present at the bus then a unity power factor will be assumed.

11.8 Treatment of Demand Resources

Through the Forward Capacity Market, Demand Resources ("DR") can be procured to provide capacity and have future commitments similar to that of a generator. There are currently two categories of DR in the FCM: Passive Demand Resources ("Passive DR") and Active Demand Resources ("Active DR"). Passive DR consists of two types of Resources: On-Peak and Seasonal Peak. Active DR reduces load based on ISO-NE instructions under real-time system conditions. Active DR consists of Real-Time Demand Response resources ("RTDR") and Real-Time Emergency Generation resources ("RTEG"). After June 2017, RTDR will be replaced with Demand Response Capacity Resources ("DRCR"). In addition to the demand resources mentioned above that are procured through the FCM, the ISO forecasts Energy Efficiency as a part of the annual CELT forecast. This Energy Efficiency is a form of passive DR but is treated separately as it is forecasted beyond the FCM horizon. This DR is included for studies that analyze time periods beyond the FCM horizon.

The modeling of Demand Resources in planning studies varies with the type of study and the load level being studied. Demand Resources and their modeling are described fully in Appendix C, "Guidelines for Treatment of Demand Resources in System Planning Analyses".

Demand Resources will not be modeled explicitly in the fixed load level cases representing shoulder, light and minimum loads, because the impact of Demand Resources was included in the actual measured load used to establish the fixed load levels (see Section 5, "Assumptions Concerning Load").

11.9 Treatment of Combined Cycle Generation

For the purposes of modeling generating units in a base case and in generator contingencies, all generators of a combined cycle unit are considered to be in-service at the same time or out-of-service together. The basis for this assumption is that many of the combustion and steam generators that make up combined cycle units cannot operate independently because they share a common shaft, they have air permit or cooling restrictions, or they do not have a separate source of steam. Other combined cycle units share a GSU or other interconnection facilities such that a fault on those facilities causes the outage of the entire facility. ISO New England's operating history with combined cycle units has shown that even for units that claim to be able to operate in modes where one portion of the facility is out of service, they rarely operate in this partial mode.

11.10 Generator Dispatch in Stability Studies

At both Peak and Light load levels, generators are modeled at highest gross (maximum) MW output at 0^0 F or higher. Generators are generally dispatched either "full-on" at maximum capability, or "full-off." If transmission transfers need to be adjusted, then the following is done:

- First, generators are re-dispatched by simulating them "full on" or "off"
- Second, adjust generators, if necessary, least critical to study results to obtain desired transfers ("off" or as close to "full on" as possible).

This is done to obtain generators' maximum stressed internal angles in order to establish a stability limit under worst-case conditions. Generator reactive dispatch must also be considered for generators being evaluated for stability performance. Pre-fault reactive output is based on the Light Load voltage schedule in Operating Procedure OP-12.

Section 12
Contingencies

12.1 Basis for Contingencies Used in Planning Studies

The contingencies that are tested in planning studies of the New England transmission system are defined in NERC, NPCC and ISO New England reliability standards and criteria. These standards and criteria form deterministic planning criteria. The application of this deterministic criteria results in a transmission system that is robust enough to operate reliably for the myriad of operating conditions that occur on the transmission system.

These standards and criteria identify certain contingencies that must be tested and the power flow in each Element in the system must remain under the Element's emergency limits following any specified contingency. In most of New England, the Long Time Emergency Rating is used as the emergency thermal limit. The Short Time Emergency Rating may be used as the emergency thermal limit when an area is exporting if generation can be dispatched lower to mitigate overloads. The Short Time Emergency Rating may be used as the emergency thermal limit in areas where phase-shifting transformers can be used to mitigate overloads. Voltage limits are discussed earlier in this guide.

Contingencies used for the design of the transmission system can be classified as:

- N-1, those Normal Contingencies("NCs") with a single initiating cause (a N-1 contingency may disconnect one or more transmission Elements)
- N-1-1, those NCs with two separate initiating causes and where timely system adjustments are permitted between initiating causes
- Extreme contingencies

Planning criteria allow certain adjustments to the transmission system between the two initiating causes resulting in N-1-1 contingencies as described in Section 12.5.

Steady-state analysis focuses on the conditions that exist following the contingencies. Stability analysis focuses on the conditions during and shortly after the contingency, but before a new steady-state condition has been reached.

12.2 Contingencies in Steady-State Analysis

NERC and/or NPCC require that the New England Bulk Power System shall maintain equipment loadings and voltages within normal limits for pre-disturbance conditions and within applicable emergency limits for the system conditions following the contingencies described in Sections 12.4 and 12.5.

12.3 Contingencies in Stability Analysis

NERC and NPCC require that the New England Bulk Power System shall remain stable and damped and the Nuclear Plant Interface Coordinating Standard (NUC-001-2 approved August 5, 2009) shall be met. This requirement must be met during and following the most severe of the contingencies stated below "With Due Regard to Reclosing", and before making any manual system adjustments. For each of the contingencies below that involves a fault, system stability and damping shall be maintained when the simulation is based on fault clearing initiated by the "system A" Protection Group, and also shall be maintained when the simulation is based on fault clearing initiated by the "system B" Protection Group where such protection group is required or where there would otherwise be a significant adverse impact outside the local area.

New England's planning criteria defines a unit as maintaining stability when it meets the damping criteria in Appendix C of ISO-NE Planning Procedure No. 3 (also included as Appendix D to this guide). New England also uses the voltage sag guideline, which is included as Appendix E to this guide, to determine if it may be necessary to mitigate voltage sags.

Consistent with Operating Procedure OP-19, New England's planning procedures require generator unit stability for all Normal Design Contingencies as defined in Planning Procedure PP-3. This criterion applies when the fastest protection scheme is unavailable at any BPS substation involved in the fault clearing. This criterion applies if the fastest protection scheme is available at any non-BPS substation involved in the fault clearing. If the fastest protection scheme is unavailable at a non-BPS substation, unit instability is permitted as long as the net source loss resulting from the Normal Design Contingency is not more than 1,200 MW, and the net source loss is confined to the local area (i.e. no generator instability or system separation can occur outside the local area).

The 1,200 MW limit derives from the NPCC Directory 1 criteria which require that a Normal Design Contingency have no significant adverse impact outside the local area. The maximum loss of source for a Normal Design Contingency has been jointly agreed upon by NYISO (formerly NYPP), ISO-NE (formerly NEPEX) and PJM to be between 1,200 MW and 2,200 MW depending on system conditions within NYISO and PJM. This practice is observed pursuant to a joint, FERC-approved protocol, which is Attachment G to the ISO-NE Tariff. The low limit of 1,200 MW has historically been used for Design Contingencies in New England.

Table 12-1
Protection Modeling in Stability Studies

Station Type	Fastest Protection System Modeling for Normal Design Contingencies	
	Fastest Protection System In-Service	Fastest Protection System Out-of-Service
BPS	Not Tested	Tested
Non-BPS	Tested	Not Tested

12.4 N-1 Contingencies

NERC and/or NPCC require that the following N-1 contingencies be tested:

a. A permanent three-phase fault with Normal Fault Clearing on any:
   - Generator
   - Transmission circuit
   - Transformer
   - Bus section
   - Series or shunt compensating device

b. Simultaneous permanent phase-to-ground faults on:
   - Different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower, with Normal Fault Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition and other similar situations can be excluded from ISO-NE testing on the basis of acceptable risk, provided that the ISO approves the request for an exclusion. For exclusions of more than five towers, the ISO and the NPCC Reliability Coordinating Committee need to specifically approve each request for exclusion.
   - Any two circuits on a multiple circuit tower

c. A permanent phase-to-ground fault, with Delayed Fault Clearing, on any:
   - Transmission circuit
   - Transformer
   - Bus section

   This Delayed Fault Clearing could be due to malfunction of any of the following:
   - Circuit breaker
   - Relay system
   - Signal channel

d. Loss of any Element without a fault (See Section 12.7)

e. A permanent phase-to-ground fault in a circuit breaker, with Normal Fault Clearing. (Normal Fault Clearing time for this condition may not be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

g. The failure of any Special Protection System which is not functionally redundant to operate properly when required following the contingencies listed in "a" through "f" above.

h. The failure of a circuit breaker to operate when initiated by an SPS following: loss of any Element without a fault: or a permanent phase to ground with Normal Clearing, on any transmission circuit, transformer or bus section.

12.5 N-1-1 Contingencies

NERC and/or NPCC require that the N-1-1 contingencies be tested. These are events that have two initiating events that occur close together in time. The list of first initiating events tested must include events from all of the following possible categories of events:

a. Loss of a generator

b. Loss of a series or shunt compensating device

c. Loss of one pole of a direct current bipolar facility

d. Loss of a transmission circuit

e. Loss of a transformer

Following the first initiating event, generation and power flows are adjusted in preparation for the next initiating event using units capable of ten-minute reserve, generator runback, generator tripping, phase angle regulators and high-voltage direct-current controls, transformer load tap changers, and switching series and shunt capacitors and reactors. Generator adjustments must not exceed 1,200 MW. The second events tested must include all of the contingencies in Section 12.4.

12.6 Extreme Contingencies

Consistent with NERC and NPCC requirements, New England tests extreme contingencies. This assessment recognizes that the New England transmission system can be subjected to events that exceed in severity the contingencies listed in Section 12.4 and 12.5. Planning studies are conducted to determine the effect of the following extreme contingencies on New England bulk power supply system performance as a measure of system strength. Plans or operating procedures are developed, where appropriate, to reduce the probability of occurrence of such contingencies, or to mitigate the consequences that are indicated as a result of the simulation of such contingencies.

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a:
   - Generating station
   - Switching station
   - DC terminal
   - Substation (either all circuits at a single voltage level, or all circuits at any voltage level)

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any:
   - Generator
   - Transmission circuit
   - Transformer or bus section

   with Delayed Fault Clearing and with due regard to reclosing

   This Delayed Fault Clearing could be due to malfunction of:
   - Circuit breaker
   - Relay system
   - Signal channel

e. The sudden dropping of a large load or major load center

f. The effect of severe power swings arising from disturbances outside of New England

g. Failure of a Special Protection System to operate when required following the normal contingencies listed in "a" through "f"

h. The operation or partial operation of a Special Protection System for an event or condition for which it was not intended to operate

i. Common mode failure of the fuel delivery system that would result in the sudden loss of multiple plants (i.e., gas pipeline contingencies, including both gas transmission lines and gas mains)

The following responses are considered unacceptable responses to an extreme contingency involving a three phase fault with Delayed Clearing and should be mitigated:

- Transiently unstable response resulting in wide spread system collapse

- Transiently stable response with undamped or sustained power system oscillations

- A net loss of source within New England in excess of 2,200 MW resulting from any combination of the loss of synchronism of one or more generating units, generation rejection initiated by a Special Protection System, tripping of the New Brunswick-New England tie, or any other system separation. The loss of source is net of any load that is interrupted as a result of the contingency.

The following response can be considered acceptable to an extreme contingency involving a three phase fault with Delayed Clearing:

- A net loss of source above 1,400 MW and up to 2,200 MW, resulting from any combination of the loss of synchronism of one or more generating units, generation rejection initiated by a Special Protection System, or any other defined system separation, if supported by studies, on the basis of acceptable likelihood of occurrence, limited exposure to the pre-contingent operating conditions required to create the scenario, or efforts to minimize the likelihood of occurrence or to mitigate against the consequence of the contingency. The loss of source is net of any load that is interrupted as a result of the contingency. The 1,400 MW and 2,200 MW levels are documented in a NEPOOL Stability Task Force presentation to the NEPOOL Reliability Committee on September 9, 2000. This presentation is included as Appendix F to this guide.

12.7 Line Open Testing

The requirement to evaluate a no-fault contingency (sometimes thought of as the opening of one terminal of a line) as a contingency event in transmission studies is described below. Additional detail is provided in the white paper that is included as Attachment H to this guide.

The following is a summary of the line open testing requirements:

1. NERC BES facilities:
    a. Single contingency testing (N-1) - Evaluate the opening of the terminal of a line, independent of the design of the termination facilities.

    b. First or Second contingency in N-1-1 testing – Not required

2. NPCC BPS and New England PTF facilities:
    a. Single contingency testing (N-1) – Evaluate the opening of a single circuit breaker.

    b. Second contingency in N-1-1 testing – Evaluate the opening of a single circuit breaker as the second contingency, not as the first contingency in the pair

When evaluating the no-fault contingencies pursuant to implementation of NERC, NPCC, and ISO New England criteria, the following will be used to establish the acceptability of post-contingency results and potential corrective actions:

1. If voltage is within acceptance criteria and power flows are within the applicable emergency rating, operator action can be assumed as a mitigating measure.

2. If voltage is outside of acceptance criteria or power flows are above the applicable emergency rating, operator action cannot be assumed as a mitigating measure. Mitigating measures may include, but are not limited to, transfer trip schemes detecting an open circuit breaker(s) or open disconnect switch(es), or, special protection systems ("SPS") designed to trigger for specific system conditions that include the no fault opening of a transmission line.

Special consideration must be given to the design and operation of the system when evaluating this no fault contingency. Control schemes, transfer trip schemes and Special protection Systems may not operate for a line end open condition if their triggers are not satisfied, or may operate inappropriately if their triggers are satisfied but only one terminal of a line is open.

Generally, in New England, opening one end of a two terminal line is not a concern. However, in instances of long lines, high voltages may be a concern due to the charging associated with an unloaded line.

Section 13
Interfaces/Transfer Levels To Be Modeled

13.1 Overview

Reliability studies begin with development of system models which must include definition of the initial or base conditions that are assumed to exist in the study area over the study horizon. These assumed initial conditions must be based on requirements as described within the applicable reliability standards and criteria as well as supplemental information that describe system operating conditions likely to exist.

It is important to note that study assumptions used for interface transfer level analysis must always be coordinated with generator outage assumptions. Specifically, unit unavailability is only relevant to generation inside the boundaries of a specific local study area. On the other hand, interface transfer levels are adjusted to target levels by only varying generation resources outside the boundaries of the local study area. This approach ensures interface transfer levels are tested at appropriate levels while maintaining a disciplined approach to unit unavailability consideration.

13.2 Methodology to Determine Transfer Limits

In response to NERC standard FAC-013-2, the ISO documented the methodology used to determine transfer limits. This document has been updated to reference this Guide and is included as Appendix I.

13.3 Modeling Assumptions – System Conditions

NPCC's Regional Reliability Reference Directory #1 requires in Section 5.1.1 - Design Criteria, that planning entities include modeling of conditions that "stress" the system when conducting reliability assessments:

> "Design studies shall assume power flow conditions utilizing transfers, load and generation conditions that stress the system. Transfer capability studies shall be based on the load and generation conditions expected to exist for the period under study. All reclosing facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative."

ISO-NE's Planning Procedure PP 3, " Reliability Standards for the New England Area Bulk Power Supply System" also states in Section 3 - Area Transmission Requirements, that studies be conducted assuming conditions that "reasonably stress" the system:

> "With due allowance for generator maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load, and resource conditions that reasonably stress the system. Transfers of power to and from another Area, as well as within New England, shall be considered in the design of inter-Area and intra-Area transmission facilities."

In each case, an assumption that considers stressed system conditions with respect to transfer levels must be included in reliability studies. ISO-NE has the primary responsibility for interpreting these general descriptions.

Additionally, these requirements are confirmed by ISO-NE's PP5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analysis," which sets forth the testing parameters for the required PPA approval under Section I.3.9 of ISO-NE's Tariff. PP5-3 requires that "intra-area transfers will be simulated at or near their established limits (in the direction to produce 'worst cases' results)." Given the reliability standard obligations as well as the requirements for the PPA approval of any transmission upgrade, reasonably stressed transfer conditions that simulate interfaces at or near their defined limits are used in determining the transmission system needs.

13.4 Stressed Transfer Level Assumptions

The system is designed to preserve existing range of transfer capabilities. This is a requirement defined in ISO-NE Planning Procedure PP 5-3, the Reliability Standards for the New England Area Bulk Power Supply System and is a fundamental objective of the minimum interconnection standard. In order to meet this requirement, interfaces that may affect the area under study are modeled with transfer levels that cover the full range of existing capabilities. The review of interface stresses includes an evaluation of each interface internal to New England as well as interfaces between New England and adjacent control areas to determine the set of interfaces that may have a significant impact on the results of studies for the study area. Interfaces that are not directly connected to a study area but may have a significant effect on the study area interface are considered "coincident interfaces". The procedures for selecting transfer levels for study area interfaces and coincident interfaces are provided below.

There may be a need to increase transfer capabilities as generation patterns shift across the system. General system trends in the direction of flow and magnitude may change dramatically over time. Some examples of conditions in which transfer capabilities requirements have changed include:

- The Connecticut area used to export across the Connecticut interface to eastern New England over many hours, but significant load growth and the outage of the nuclear units changed this to an import
- Whether the New Brunswick control area is an exporter to New England or an importer from New England can vary and depends on many factors including the availability of generation in New Brunswick.
- There has been an increase of "in-merit" natural gas generation being sited adjacent to existing gas pipelines in southern New England.
- Studies associated with the New England East West Solution have in the past been focused on the need to move power from across New England from east to west. The most recent update of these studies now shows the need to move power from west to east, even prior to consideration of the retirement of Salem Harbor station in 2014.

13.5 Transfer Level Modeling Procedures

Interfaces associated with a study area must be considered individually as well as in combination with each other when more than one interface is involved. Transfer levels for defined interfaces are tested based on the defined capability for the specific system conditions and system configurations to be studied.
Transfer levels are also adjusted as appropriate for the load levels that are to be studied. Transfer level testing may require thermal, voltage and/or stability testing to confirm no adverse impact on transfer limits.

Interface transfer levels are tested up to their capability in order to sustain the economic efficiency of the electric system and reliable operation and transmission service obligations of the New England transmission system.

The following procedure is used when conducting system reliability assessments:

For the steady-state studies, the relevant interface transfer levels need to be determined up front for each dispatch in Needs Assessment studies. Solutions Study transfer levels are tested with the same transfer levels as tested in any associated Needs Assessment study as well as additional variations in transfer levels as determined to be appropriate to demonstrate that solution alternatives have not adversely affected any existing interface transfer capabilities.

In the past, Needs Assessments supported by ISO New England included base case conditions that simulated local generation outages simultaneously with power exports from New England to other Areas, such as New York. Simulation results that failed to meet system performance criteria (typically steady state thermal and voltage) would identify base case and contingency related system needs to be addressed.

In November, 2013, the ISO revised its practice with respect to Needs Assessments and Solutions Studies. Needs Assessments (steady state and dynamics) no longer model power exports to other Areas (New York, New Brunswick, and Quebec) in the base case conditions and N-1 contingency analysis when evaluating transmission system needs. As a result, reliability based needs and their related backstop transmission solutions will not be identified and developed to support power exports out of New England. The only exception to this policy change would be long term power exports realized through the Forward Capacity Market, such as certain power exports across the Cross Sound Cable, which will be modeled with 100 MW from New England to Long Island due to the Administrative Export De-list bid associated with Bear Swamp.

However, testing required by NPCC Document A-10, Classification of Bulk Power System elements, as part of a Needs Assessment must consider the full range of potential operating conditions and therefore will continue to consider conditions where New England is exporting to other Areas.

Even with this decision by the ISO, planned system changes still need to respect Section I.3.9 of the Tariff, generally referred to as the PPA process. As part of the I.3.9 evaluation, the applicant must demonstrate that any proposed system changes do not have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner. In carrying out these responsibilities, testing must demonstrate that the project has not reduced transfer capability from pre-project levels.

Transfer level modeling when conducting a Needs Assessment are based on the dispatch conditions within the study area such that the transfer level = local load – local generation. The local area generation dispatch assumptions are consistent with stressed system modeling unit availability assumptions and provide the basis for the transfer level expected to exist for the area under study.

Transfer level modeling for Solutions Studies, in addition to modeling conditions as studied in any associated Needs Assessments, also includes modeling of system conditions that evaluate the ability to dispatch units with a capacity supply obligation within an area under heavy load conditions. ISO-NE may also determine that additional transfer level variations need to be tested in order to demonstrate that there is no adverse impact to existing interface transfer capabilities associated with any proposed solution alternatives.

Transfer level modeling for those cases in which more than one coincident interface (i.e. surrounding interfaces rather than an interface internal to the study area) can impact a study area is based on a set of transfer level combinations that includes the maximum and minimum values for each interface. This includes situations where the interface limits are not independent and for which simultaneous limits have been identified. For example, study of the Greater Boston area would consider the Boston Import interface as internal to the study and the North-South, SEMA/RI and East-West as coincident interfaces. Modeling of the Boston interface would be based on the procedures as described above. Modeling of the North-South, SEMA/RI and East-West interfaces would include those levels as shown in the table below.

Testing of coincident interfaces includes interface transfers modeled at high as well as low transfer levels. High transfer levels are modeled as close as possible to the defined maximum for an interface and low values are modeled as close as possible to the defined minimum for an interface. For example, if three interfaces can all affect a study area there will be eight variations in interface levels such that all combinations are tested:

Table 13-1
Example of Modeling Interface Flows in Planning Studies

Interface 1	Interface 2	Interface 3
High	High	High
High	High	Low
High	Low	High
High	Low	Low
Low	Low	High
Low	High	Low
Low	High	High
Low	Low	Low

If specific transfer level combinations cannot be achieved due to load and/or dispatch constraints an explanation of the conditions that prevented testing of the combination is provided.

Section 14
Modeling Phase Angle Regulators

The modeling of each Phase Shifting Transformers (Phase Angle Regulators) is described in ISO New England's ***Reference Document for Base Modeling of Transmission System Elements in New England.*** This document is located in the ISO New England Planning Procedures subdirectory of the Rules & Procedures directory, on the ISO New England web site and is included as Appendix G to this guide. Modeling of phase shifting transformers in power flow studies is also addressed in Section 26.

Phase Shifting Transformers are used by system operators in the following locations within New England to control active (real) power flows on the transmission system within operating limits.

- The Saco Valley / Y138 Phase Shifter is located along the New Hampshire – Maine border, and is used to control 115 kV tie flow along the Y138 line into central New Hampshire
- The Sandbar Phase Shifter is located along the Vermont – New York border, and is used to control power flow into the northwest Vermont load pocket from northeast New York
- The Blissville Phase Shifter is located along the Vermont – New York border, and is mainly used to prevent overloads on the New York side
- The Granite Phase Shifters are located in Vermont and are mainly used to control flow on the 230 kV line between New Hampshire and Vermont
- The three Waltham Phase Shifters and the two Baker Street Phase Shifters are located in the Boston, Massachusetts area. They are adjusted manually to regulate the amount of flow into and through Boston. One of the Waltham Phase Shifters will be removed as part of the Greater Boston project.
- The Sackett Phase Shifter is located in southwest Connecticut and will be replaced by a series reactor at Mix Avenue in late 2017. It is run in manual mode only and is normally set in the Raise 3 Tap Position (1,875^{o}) which tends to draw power from Grand Avenue towards Mix Avenue Substation.
- The Northport/Norwalk Harbor Cable (NNC) Phase Shifter, located at LILCO's Northport station (controlled by Long Island Power Authority) is used to control the power flow on the Norwalk Harbor – Northport 601, 602, and 603 submarine cables

Section 15
Modeling Load Tap Changers

Many transformers connected to the New England Transmission system have the capability of automatic load tap changing. This allows the transformer to automatically adjust the turns' ratio of its windings to control the voltage on the regulated side of the transformer. In transmission planning studies, load tap changers are allowed to operate when determining the voltages and flows after a contingency.

Modeling the operation of load tap changers on transformers that connect load to the transmission system generally produces conservative results because raising the voltage on the distribution system will reduce the voltage on the transmission system. Operation of load taps changers on autotransformers raises the voltage on the lower voltage transmission system (typically 115 kV) and reduces the voltage on the higher voltage transmission system (typically 230 kV or 345 kV).

In areas of the transmission system where there are known voltage concerns that occur prior to load tap changer operation, it is necessary to do sensitivity testing to determine if voltage criteria violations occur prior to load tap changer operation. This is further discussed in the voltage criteria section. Modeling of transformer load tap changers in load flow studies is also addressed in Section 26.

Section 16
Modeling Switchable Shunt Devices

In transmission planning studies, switchable shunt devices are allowed to operate when determining the voltages and flows after a contingency.

In areas of the transmission system where there are known high or low voltage concerns that occur prior to operation of switchable shunt devices, it is necessary to do testing to determine if voltage criteria violations occur prior to operation of switchable shunt devices. This is further discussed in the voltage criteria section 4.

Modeling of switchable shunt devices in load flow studies is also addressed in Section 26.

Section 17
Modeling Series Reactors

There are 17 series reactors on the New England transmission system. Some of these are permanently in service to limit short circuit duty, others may be switched to control flows on specific transmission Elements. The following table lists these devices and briefly describes their purpose and operation in planning studies.

Table 17-1
Modeling Series Reactors in Planning Studies

Device	Ohms	State	Normal Operation	Purpose
Breckwood series reactor in 1322 line	5.55 ohms	MA	Out of Service (Shorted)	Inserted to limit short circuit duty at Breckwood when 1T circuit breaker is closed
Cadwell Series Reactor in 1556 line	3.97 ohms	MA	In Service	Limits short circuit duty at 115 kV East Springfield substation, not to be switched in planning studies
Cadwell Series Reactor in 1645 line	3.97 ohms	MA	In Service	Limits short circuit duty at 115 kV East Springfield substation, not to be switched in planning studies
East Devon series reactor in 1497 line	1.32 ohms	CT	In Service	Limits short circuit duty on 115 kV system, not to be switched in planning studies
East Devon series reactor in 1776 line	1.32 ohms	CT	In Service	Limits fault duty on 115 kV systems, not to be switched in planning studies
Greggs series reactor in F162 line	10 ohms	NH	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Hawthorne series reactor in 1222 line	5 ohms	CT	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Mix Avenue series reactor in 1610	7.5 ohms	CT	In Service	Will be installed in late 2017 to control flows on the 115 kV system and will normally be operated in service
North Bloomfield series reactor in 1784 line	2.65 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
North Cambridge series reactor in 329-530 line	2.75 ohms	MA	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
North Cambridge series reactor in 329-531 line	2.75 ohms	MA	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
Norwalk series reactor in 1637 line	5 ohms	CT	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Potter series reactor in115-10-16 line	3 ohms	MA	In Service	Limit flows on 115 kV cables, not to be switched in planning studies
Sandbar Overload Mitigation Series reactor in PV-20 line	30 ohms	VT	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Southington series reactor in 1910 line(Existing)	3.97 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southington series reactor in 1910 line (ISD 12/2018 – replaces the existing reactor)	6.61 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southington series reactor in 1950 line (Existing)	3.97 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads

Device	Ohms	State	Normal Operation	Purpose
Southington series reactor in 1950 line(ISD 12/2018 – replaces the existing reactor)	6.61 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Woburn series reactor in 211-514 line	2.75 ohms	MA	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
Southwest Hartford series reactor in 1346 line (ISD 12/2018)	2.65 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southwest Hartford series reactor in 1704 line (ISD 12/2018)	3.97 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads

Section 18
Modeling High Voltage Direct Current Lines

There are three existing high voltage direct current facilities on the New England Transmission System, Highgate, Hydro Quebec Phase 2 and the Cross Sound Cable. There are no future high voltage direct current facilities with an approved PPA. The following tables list the flows on these facilities generally used in the base cases for different planning studies. Table 18-1 addresses existing facilities and table 18-2 is a placeholder for future facilities that have obtained an approved PPA.

Table 18-1
Modeling Existing DC Lines in Planning Studies

Study[1]	Highgate	Phase 2	Cross Sound Cable
PPA Study (I.3.9) of transmission project (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
System Impact Study (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
Transmission Needs Assessment (Steady State)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
Transmission Solutions Study (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
Area Review Analyses (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
BPS Testing Analyses (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
Transfer Limit Studies (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
Interregional Studies	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
FCM New Resource Qualification Overlapping Impact Analyses	0 to 225 towards Vermont at border	0 to 1400 MW towards New England	0 MW
FCM New Resource Qualification NCIS Analyses	0 to 225 towards Vermont at border	0 MW towards New England	0 MW
FCM Delist/Non-price Retirement Analyses	0 to qualified existing imports	0 to qualified existing imports	Qualified Administrative export to 0 MW
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	0 to cleared imports	0 to cleared imports	Cleared Administrative export to 0 MW
Transmission Security Analyses	Qualified existing imports	Qualified existing imports	0 MW
Non-Commercial Capacity Deferral Notifications	0 to cleared imports	0 to cleared imports	Cleared Administrative export to 0 MW

[1] Imports on these facilities are considered Resources as discussed in Planning Procedure PP5-6.

Table 18-2
Modeling Future DC Lines in Planning Studies

Study[1]	Future DC Line
PPA Study (I.3.9) of transmission project (Steady State and Stability)	To Be Determined
System Impact Study (Steady State and Stability)	To Be Determined
Transmission Needs Assessment (Steady State)	To Be Determined
Transmission Solutions Study (Steady State and Stability)	To Be Determined
Area Review Analyses (Steady State and Stability)	To Be Determined
BPS Testing Analyses (Steady State and Stability)	To Be Determined
Transfer Limit Studies (Steady State and Stability)	To Be Determined
Interregional Studies	To Be Determined
FCM New Resource Qualification Overlapping Impact Analyses	To Be Determined
FCM New Resource Qualification NCIS Analyses	To Be Determined
FCM Delist/ Non-price Retirement Analyses	To Be Determined
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	To Be Determined
Transmission Security Analyses	To Be Determined
Non-Commercial Capacity Deferral Notifications	To Be Determined

[1] Imports on these facilities are considered Resources as discussed in Planning Procedure PP5-6.

Modeling of high voltage direct current lines in load flow studies is also addressed in Section 26.

Section 19
Modeling Dynamic Reactive Devices

This section is under development.

Section 20
Special Protection Systems (Remedial Action Schemes)

Special Protection Systems ("SPSs") may be employed in the design of the interconnected power system subject to the guidelines in the ISO New England Planning Procedure 5-6 "Special Protection Systems Application Guidelines." All SPSs proposed for use on the New England system must be reviewed by the Reliability Committee and NPCC and approved by the ISO. Some SPSs may also require approval by NPCC. The requirements for the design of SPSs are defined in the NPCC Directory #4 "Bulk Power System Protection Criteria" and the NPCC Directory #7 "Special Protection Systems".

The owner of the SPS must provide sufficient documentation and modeling information such that the SPS can be modeled by the ISO, and other planning entities, in steady-state and stability analyses. The studies that support the SPS must examine, among other things:

- System impact should the SPS fail to operate when needed
- System impact when the SPS acts when not needed
- Will the SPS function properly and acceptably during facility out conditions

Once an SPS is approved, its operation should be considered in all transmission planning studies.

Section 21
Load Interruption Guidelines

This section is under development.

Guidelines, which describe the amount of load that may be interrupted and the circumstances where load may be interrupted, were presented to the Reliability Committee ("RC") on November 17, 2010. At the request of stakeholders, ISO-NE retransmitted this material to the RC on November 17, 2011 for comment and to the Planning Advisory Committee on November 21, 2011. ISO-NE has received comments on the guideline and is reviewing those comments.

Section 22
Short Circuit Studies

This section is under development.

NPCC requires that the transmission system be designed such that equipment capabilities are adequate for fault levels with all transmission and generating facilities in service. In New England, the base case for short circuit studies include transmission projects that are In-Service, Under Construction, and Planned and generators that are In-Service, Under Construction, are included in FERC section of the ISO-NE queue at the time the study begins, or have an approved Proposed Plan Applications. Projects with a nearly completed PPA Study and that have an impact on this study are also considered in the base case.

The voltage values that are used in short circuit studies are:

EM (formerly BHE)-1.05 per unit
CMP -1.05 per unit
NGRID - 1.03 per unit
Eversource (Boston, Cape Cod) -1.03 per unit
Eversource (CT, W.MA, NH) -1.04 per unit
UI - 1.04 per unit
Vermont- 1.05 per unit

Section 23
Critical Load Level Analysis

The Critical Load Level is the lowest load level at which the criteria violation occurs. One technique used to estimate Critical Load Level ("CLL") for overloads is linear extrapolation. Other methods are also acceptable.

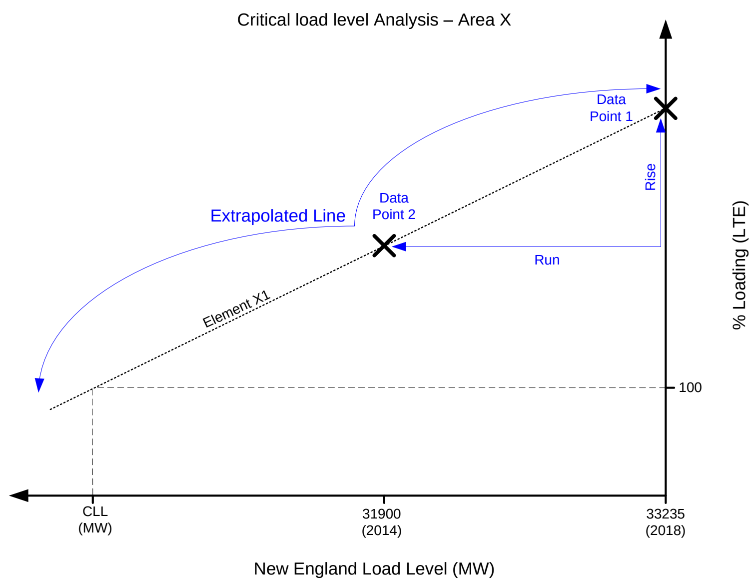
The linear extrapolation method is an approximation and provides a reasonable estimate with a minimum of additional analyses. The method requires that level of the loading on a transmission Element be determined at two load levels for the contingency or contingencies that have the largest impact on that transmission Element. This is done for each transmission Element that is overloaded. The load level in each base case is plotted on the x axis of a graph and percentage of the overload is plotted on y-axis. A straight line is drawn to connect these two points. The critical load level is the load level (x axis value) associated with 100 percent on the y axis.

An example of the use of linear extrapolation from a study of southwest Connecticut follows:

The initial base case was a 2018 base case. A second base case was developed by adjusting loads in the first case to 2014 year load levels taking into account the following:

- Loads plus losses in ISO-NE adjusted to 2009 CELT year 2014 levels (31,900 MW)
- Generation outside of CT was used to adjust to the new 2014 load levels
- Connecticut loads scaled according to 2009 RSP to 2014 levels (8,455 MW)
- Loads adjusted to account for FCA 3 cleared DR

No transmission topology changes were made to the adjusted 2014 cases. The highest overload per Element was identified in 2018 and the same Element's loading was obtained from the 2014 case results. This was done for the same single contingency (N-1) or line-out plus contingency pair (N-1-1) for every case. That is, both N-1 and N-1-1 analysis were performed in order to obtain two data points (2018 and 2014). Using the two data points available, linear extrapolation was used to form a line loading equation (slope = rise / run, y = mx + b, etc.) for each monitored Element which can then provide the loading of a particular line for different New England load levels. As an example, below shows the extrapolated line for Element X1 in Area X for a thermal violation.



Section 24
Bulk Power System Testing

This section is under development.

Section 25
Treatment on Non-Transmission Alternatives

This section is under development.

Section 26
Power Flow Study Solution Settings

26.1 Area Interchange

Enabling area interchange models the normal operation of the power system in that it adjusts generation to maintain inter-area transfers at a pre-determined level. Each area defined in the power system model has one of its generators designated as the area-slack bus. Area interchange is implemented by setting an overall interchange with all neighboring areas and the power flow program adjusts the output of the area-slack machines to match that set point. The area-slack bus for the New England Area is generally Canal 2. For studies of the area near Canal 2, a remote generator such as Seabrook in New Hampshire or Yarmouth 4 in Maine (also referred to as Wyman 4) is typically chosen as the area-slack bus.

Annually the Multiregional Modeling Working Group ("MMWG") establishes the area interchange assumptions for different seasons, load levels, and years. These assumptions are included in base cases provided by the ISO. Requesting base cases from the ISO, which represent the scenarios that will be studied, ensures that area interchanges external to New England are appropriate.

In establishing a base case (N-0 or N-1) for a particular study, the planner selects the appropriate interchanges between New England and other areas. This should be done with area interchange enabled for tie lines and loads. This ensures that area interchanges external to New England are correct and that loads shared between New England and Quebec are accounted for properly. The planner should re-dispatch generation in New England to obtain the desired interchanges with areas external to New England. The area-slack bus will adjust its output for the change in losses resulting from this re-dispatch. The planner should verify that the generation at the area-slack bus is within the operating limits of that generator.

For contingency analysis, area interchange is generally disabled. This causes the system swing bus output in the power flow model to increase for any generation lost due to a contingency. Following a loss of generation, each generator in the Eastern Interconnection increases its output in proportion to its inertia. About 95% of the total inertia for the eastern interconnection is to the west of New England. The system swing bus in the New England base cases is Browns Ferry in TVA. Using the system swing bus to adjust for any lost generation appropriately approximates post-contingency conditions on the power system prior to system-wide governors reacting to the disturbance and readjusting output.

26.2 Phase-Angle Regulators

The modeling of each Phase Shifting Transformers (Phase Angle Regular) is described in ISO New England's ***Reference Document for Base Modeling of Transmission System Elements in New England.*** This document is located in the ISO New England Planning Procedures subdirectory of the Rules & Procedures directory, on the ISO New England web site and is included as Appendix G to this guide.

26.3 Transformer Load Tap Changers

Transformer load tap changers ("LTC's") can exist on autotransformers, load serving transformers and transformers associated with generation (e.g. transformers associated with wind parks). LTC's allow the ratio of the transformer to be adjusted while the transformer is carrying load so that voltage on low voltage side of the transformer can be maintained at a pre-determined level.

An LTC adjusts voltage in small steps at a rate of about 3-10 seconds per step. A typical LTC may be able to adjust its ratio by plus or minus ten percent may have sixteen 5/8% steps. Also the action of an LTC is delayed to prevent operations during temporary voltage excursions. For example, a 345 kV autotransformer might delay initiating tap changing by thirty seconds. A load-serving transformer, which is connected to the 115 kV system near the autotransformer, might delay changing its tap by forty-five seconds to coordinate with the autotransformer. The total time for an LTC to adjust voltage can be several minutes. For example, a LTC, which has thirty-two 5/8% steps, requires five seconds per step and has a thirty second initial delay, would require seventy seconds to adjust its ratio by five percent.

To model the actual operations of the system, LTC operation is typically enabled in the power system model to allow the LTC's to adjust after contingencies for Steady State analysis. This generally represents the most severe condition because contingencies typically result in lower voltages and operation of LTC's to maintain distribution voltages result in higher current flow and lower voltages on the transmission system. Similarly operation of LTC's on autotransformers typically results in lower voltage on the high voltage side of the autotransformer.

In some portions of the transmission system, the voltage immediately following a contingency may be problematic because voltage collapse may occur. When instantaneous voltage is a concern, sensitivity analysis should be done with LTC's locked (not permitted to adjust) in the power flow model due to the amount of time required for the taps to move.

26.4 Shunt Reactive Devices

This section is under development by the ISO/TO study coordination group and will be sent out at a later date.

26.5 Series Reactive Devices

Section 17 of this guide describes the series reactive devices in the New England transmission system. The following table lists those series reactive devices that can be switched to resolve criteria violations. Those devices that are out-of service in the base case can be switched into service. Those devices that are in-service in the base case can be switched out of service. The switching can be done post contingency if flows do not exceed STE ratings. When post contingency flows exceed STE ratings, switching must be done pre-contingency and analysis must be done to ensure that the switching does not create other problems.

Table 26-1
Modeling Series Reactors in Planning Studies

Device	Base Case	Adjustments
Greggs series reactor in F162 line	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate criteria violations
Hawthorne series reactor in 1222 line	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate criteria violations
Mix Avenue series reactor in 1610	In Service	Controls flows on the 115 kV system, can be bypassed to mitigate criteria violations
North Bloomfield series reactor in 1784 line	In Service	Controls flows on the 115 kV system, can be bypassed to mitigate criteria violations
Norwalk series reactor in 1637 line	In Service	Controls flows on the 115 kV system, can be bypassed to mitigate criteria violations
Sandbar Overload Mitigation Series reactor in PV-20 line	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate criteria violations. This reactor is controlled by a Special Protection System
Southington series reactor in 1910 line (existing or new)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations
Southington series reactor in 1950 line (existing or new)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations
Southwest Hartford series reactor in 1346 line (ISD 12/2018)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations
Southwest Hartford series reactor in 1704 line (ISD 12/2018)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations

26.6 High Voltage Direct Current Lines

The flows in higher voltage direct current lines are not automatically adjusted after a contingency except where an adjustment is triggered by a Special Protection System.

Appendix A – Definitions

50/50 PEAK LOAD
A peak load with a 50% chance of being exceeded because of weather conditions, expected to occur in New England at a temperature of 90.4°F.

90/10 PEAK LOAD
A peak load with a 10% chance of being exceeded because of weather conditions, expected to occur in New England at a temperature of 94.2°F.

ADVERSE IMPACT
See Significant Adverse Impact

APPLICABLE EMERGENCY LIMIT

- These Emergency limits depend on the duration of the occurrence, and are subject to New England standards.
- Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.
- The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system stability performance, meet the Nuclear Plant Interface Requirements and should not adversely affect the operation of the New England Bulk Power Supply System.
- The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities.

AREA
An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system.

AREA TRANSMISSION REVIEW (see NPCC Directory #1, Appendix B)
A study to assess bulk power system reliability

BULK ELECTRIC POWER SYSTEM (as defined in the NERC Glossary of Terms Used in Reliability Standards)
As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

BULK POWER SUPPLY SYSTEM
The New England interconnected bulk power supply system is comprised of generation and transmission facilities on which faults or disturbances can have a significant effect outside of the local area.

BULK POWER SYSTEM TESTING (see NPCC Document A-10, Classification of Bulk Power System Elements)
A study done to determine if Elements are classified as part of the Bulk Power System

BULK POWER SYSTEM (as defined in NPCC Glossary of Terms Used in Directories)
The interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have significant adverse impact outside the local area

CAPACITY SUPPLY OBLIGATION (as defined in Section I of the Tariff)
This is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

CONTINGENCY (as defined in NPCC Document A-7)
An event, usually involving the loss of one or more Elements, which affects the power system at least momentarily

CAPACITY NETWORK RESOURCE CAPABILITY (as defined in Schedule 22 of the OATT)
Capacity Network Resource Capability ("CNR Capability") is defined in Schedule 22 of the Tariff and means (i) in the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, the highest MW amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, or (ii) in the case of a Generating Facility that meets the criteria under Section 5.2.3 of this LGIP, the total MW amount determined pursuant to the hierarchy established in Section 5.2.3. The CNR Capability shall not exceed the maximum net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 F. degrees for Summer and at or above 20 degrees F. for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F. for Summer and at or above 20 degrees F. for Winter. The CNR Capability of a generating facility can be found in the Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) which is produces annually by ISO New England.

DELAYED FAULT CLEARING (as defined in NPCC Document A-7)
Fault clearing consistent with correct operation of a breaker failure protection group and its associated breakers, or of a backup protection group with an intentional time delay.

ELEMENT (as defined in NPCC Document A-7)
Any electric device with terminals which may be connected to other electric devices, usually limited to a generator, transformer, circuit, circuit breaker, or bus section.

FCM STUDY FOR ANNUAL RECONFIGURATION AUCTIONS AND ANNUAL BILATERALS
The FCM study as part of the annual reconfiguration auction or annual evaluation of Capacity Supply Obligations as described in Sections 13.4 and 13.5 of Market Rule 1.

FCM DELIST/NON-PRICE RETIREMENT ANALYSES
The FCM Delist/Non-Price Retirement Analyses is the analysis of de-list bids, demand bids and non-price retirement requests as described in Section 7.0 of Planning Procedure PP-10.

FCM NEW RESOURCE QUALIFICATION OVERLAPPING IMPACT ANALYSES
The FCM New Resource Qualification Overlapping Analyses is the analysis of overlapping interconnection impacts as described in Section 5.7 of Planning Procedure PP-10. This study is similar in

scope as the thermal analyses performed in a System Impact Study associated with a generator interconnection request.

FCM NEW RESOURCE QUALIFICATION NCIS ANALYSES

The FCM New Resource Qualification NCIS Analyses is the initial interconnection analysis under the Network Capability Interconnection Standard as described in Section 5.6 of Planning Procedure PP-10. This study is similar in scope as the thermal analyses performed in a System Impact Study associated with a generator interconnection request.

NORMAL FAULT CLEARING (as defined in NPCC Document A-7)

Fault clearing consistent with correct operation of the protection system and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system

NR CAPABILITY

Network Resource Capability ("NR Capability") is defined in Schedule 22 of the Tariff and means the maximum gross and net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 50 degrees Fahrenheit for Summer and at or above 0 degrees Fahrenheit for Winter. Where the Generating Facility includes multiple energy production devices, the NR Capability shall be the aggregate maximum gross and net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 50 degrees Fahrenheit for Summer and at or above 0 degrees Fahrenheit for Winter. The NR Capability shall be equal to or greater than the CNR Capability. The NR Capability of a generating facility can be found in the Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) which is produces annually by ISO New England.

NUCLEAR PLANT INTERFACE REQUIREMENTS (as defined in the NERC Glossary of Terms Used in Reliability Standards)

The requirements based on Nuclear Plant Licensing Requirements (NPLRs) and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

NUCLEAR PLANT LICENSING REQUIREMENTS (NPLRs) (as defined in the NERC Glossary of Terms Used in Reliability Standards)

Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for:

1. Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and
2. Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

PLANNED (as defined in Attachment K of Section II of the ISO-NE Tariff)

A transmission upgrade the ISO has approved under Section I.3.9 of the tariff. (Both a Needs Assessment and a Solutions Study have been completed for planned projects.)

PROPOSED (as defined in Attachment K of Section II of the ISO-NE Tariff)

A regulated transmission solution that (1) has been proposed in response to a specific identified needs in a needs assessment or the RSP and (2) has been evaluated or further defined and developed in a Solutions Study, as specified in the OATT, Attachment K, Section 4.2(b) but has not received ISO-NE approval under Section I.3.9 of the tariff. The regulated transmission solution must include analysis sufficient to support a determination by the ISO, as communicated to the PAC, that it would likely meet the identified need included in the needs assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

PROTECTION GROUP (as defined in NPCC Document A-7)
A fully integrated assembly of protective relays and associated equipment that is designed to perform the specified protective functions for a power system Element, independent of other groups.

Notes:
1. Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.
2. Pilot protection is considered to be one protection group.

PROTECTION SYSTEM (as defined in NPCC Document A-7)
Element Basis: One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system Element to provide the complete protection of that Element.

Terminal Basis: One or more protection groups, as above, installed at one terminal of a power system Element, typically a transmission line.

QUALIFIED CAPACITY (as defined in Section I of the ISO-NE Tariff)
Qualified Capacity is the amount of capacity a resource may provide in the Summer or Winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

RESOURCE (as defined in Section I of the ISO-NE Tariff)
Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction.

SIGNIFICANT ADVERSE IMPACT (Based on Section I.3.9 of the Tariff and Planning Procedure 5-3)
A change to the transmission system that increases the flow in an Element by at least two percent of the Element's rating and that causes that flow to exceed that Element's appropriate thermal rating by more than two percent. The appropriate thermal rating is the normal rating with all lines in service and the long time emergency or short time emergency rating after a contingency (See Section 3).

A change to the transmission system that causes at least a one percent change in a voltage and causes a voltage level that is higher or lower than the appropriate rating by more than one percent (See Section 4).

A change to the transmission system that causes at least a one percent change in the short circuit current experienced by an Element and that causes a short circuit stress that is higher than an Element's interrupting or withstand capability. (See Section 22)

With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

A fault or a disturbance that cause:

- any loss of synchronism or tripping of a generator

- unacceptable system dynamic response as described in Planning Procedure PP-3

- unacceptable equipment tripping: tripping of an un-faulted bulk power system element (element that has already been classified as bulk power system) under planned system configuration due to operation of a protection system in response to a stable power swing or operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required

SPECIAL PROTECTION SYSTEM (SPS) (as defined in NPCC Document A-7)
A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted Elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic under frequency load shedding, as defined in NPCC Emergency Operation Criteria A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

STEADY STATE (as defined in ANSI/IEEE Standard 100)
The state in which some specified characteristic of a condition such as value, rate, periodicity, or amplitude exhibits only negligible change over an arbitrary long period of time (In this guide, the term steady state refers to sixty hertz currents and voltages after current and voltages deviations caused by abnormal conditions such as faults, load rejections and the like are dissipated)

SUMMER (as defined in ISO-NE OP-16 Appendix A)
The Summer period is April 1 to October 31.

TEN-MINUTE RESERVE (as defined in NPCC Document A-7)
The sum of synchronized and non-synchronized reserve that is fully available in ten minutes.

VOLTAGE COLLAPSE
The situation which results in a progressive decrease in voltage to unacceptable low levels, levels at which power transfers become infeasible. Voltage collapse usually leads to a black-out.

WINTER (as defined in ISO-NE OP-16 Appendix A)
The Winter period is November 1 to March 31.

WITH DUE REGARD TO RECLOSING (as defined in NPCC Document A-7)
This phrase means that before any manual system adjustments, recognition will be given to the type of reclosing (i.e., manual or automatic) and the kind of protection.

Appendix B – Fast Start Units

The list of fast start units referenced in Section 11.6 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_b_reference_document.pdf

Appendix C – Guidelines for Treatment of Demand Resources in System Planning Analysis

This document referenced in Section 11.8 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_c_guidelines_for_treatment_of_demand_resources_in_system_planning_analysis.pdf

Appendix D – Dynamic Stability Simulation Damping Criteria

The damping criteria referenced in Section 12.3 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_d_damping_criteria.pdf

Appendix E – Dynamic Stability Simulation Voltage Sag Criteria

This document referenced in Section 12.3 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_e_voltage_sag_guideline.pdf

Appendix F – Stability Task Force Presentation to Reliability Committee - September 9, 2000

This document referenced in Section 12.6 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_f_stabiliy_task_force_presentation.pdf

Appendix G – Reference Document for Base Modeling of Transmission System Elements in New England

This document, referenced in Sections 14 and 26.2, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_g_reference_document.pdf

Appendix H – Position Paper on the Simulation of No-Fault Contingencies

This document, referenced in Section 12.7, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/2016/03/technical_guide_appendix_h_2016_03_02.pdf

Appendix I – Methodology Document for the Assessment of Transfer Capability

This document, referenced in Section 13.2, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/2016/01/technical_guide_appendix_i_2016_01_14.pdf

Appendix J – Load Modeling Guide for ISO New England Network Model

This document, referenced in Section 5, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/2016/01/technical_guide_appendix_j_2016_01_14.pdf

EXHIBIT 4: LONDON ECONOMICS "ANALYSIS OF THE FEASIBILITY AND PRACTICALITY OF NON-TRANSMISSION ALTERNATIVES (NTAS)," MARCH 2015

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ANALYSIS OF THE FEASIBILITY AND PRACTICALITY OF NON-TRANSMISSION ALTERNATIVES ("NTAS")

March 11th, 2016

prepared for Eversource Energy

by

LONDON ECONOMICS

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Synopsis

Eversource Energy ("Eversource") retained London Economics International LLC ("LEI") to provide independent expert analysis on the feasibility and practicality of relying on non-transmission alternatives ("NTAs") in lieu of a transmission project proposed to fix reliability violations in the Southwest Connecticut electrical area ("SWCT"), more specifically the Housatonic Valley/Norwalk/Plumtree subarea ("HVNP"). This report is intended to be filed with Eversource's application for the transmission solution for this subarea before the Connecticut Siting Council ("CSC").

As part of the siting application to CSC, Eversource's planning staff studied the preferred transmission solution proposed for HVNP. As part of this study, the planning staff examined supply-side resources and demand-side resources that could address the same reliability concerns (i.e., thermal overloads and low voltage violations) which the proposed HVNP transmission solution was designed to solve. The results of the analyses prepared by Eversource's planning staff indicate that demand-side resources alone could not properly address thermal overloads and voltage violations observed in the HVNP subarea, and as such could not be a viable alternative to the HVNP proposed transmission solution. Supply-side resources, however, could potentially qualify as technically feasible alternatives to the HVNP proposed solution. Eversource identified the quantity and locations of supply-side NTAs that would alleviate both thermal system overloads and voltage violations in the HVNP subarea. LEI relied upon the quantities and locations of NTAs specified in Eversource's studies. Specifically, the planning staff determined that a total of 247 MW of energy injection over four locations (50 MW at Stony Hill substation, 47 MW at West Brookfield substation, 50 MW at Triangle substation and 100 MW at Peaceable substation) is required to alleviate reliability needs in the HVNP subarea in lieu of transmission upgrades. LEI then examined the technical feasibility of various NTA technologies for fulfilling these energy injection amounts, and selected hypothetical technically feasible NTA technologies based on the location, costs and other practical factors of consideration. LEI defined "technically feasible" technologies as technologies that could hypothetically be implemented based on planning criteria and technology-specific operating profiles. A technically feasible NTA technology therefore meets the reliability issues being addressed by the proposed transmission components.

LEI considered two cases in its analysis: i) an NTA solution solely based on supply-side resources ("Supply Case") and ii) an NTA solution combining both demand and supply-side resources ("Combination Case"). In both the Supply Case and Combination Case, LEI identified supply-side resources including slow discharge batteries, peaker aeroderivative[1] and fuel cells as technically feasible NTA technologies at the designated four locations. The assessment of technical feasibility included the ability to provide reactive power instantaneously. In the Combination Case, energy efficiency resources (limited to location-specific demand and assumed peak load reduction capability) were incorporated into the NTA solution, and as such would cover a portion of the energy injection requirement, while a supply-side resource would address the remainder of the energy requirement, as well as provide reactive power. Gas-fired generation plant would be the primary supply-side technology for providing reactive power; however, in order to be able to provide it instantaneously, such a generator would need to be constantly running, which would be uneconomic for many of the technically feasible generation technologies. Therefore, in both the Supply Case and the Combination

[1] Aeroderivative gas turbines (derivative from aircraft engines) are compact, light-weight designs suited for power generation. These turbines are known for their high efficiency and fast-start capabilities.

Case, we assumed that all the considered technologies (including engine-based technologies such as gas-fired generation) will need to be accompanied by a synchronous condenser to address the instantaneous nature of the reactive power requirement. Although we explored the technical feasibility of solar photovoltaic ("PV") as NTA at the considered locations, such technology was excluded from the analysis at this stage due to cost, the volume of nameplate capacity needed, and the associated land requirements.

Next, LEI assessed whether the technically feasible NTAs could be cost-effective or practical. LEI employed industry-standard levelized costing principles to select the least cost NTA for each location from the group of technically feasible NTA technologies. Since no merchant sponsor (private investor) has proposed to build such NTAs to date within the construct of the ISO-NE's capacity and energy markets, LEI assumed that these NTAs would be built only if their net costs were imposed on electric ratepayers using a cost-of-service tariff model. LEI estimated the net direct cost to Connecticut ratepayers by reference to the levelized annual gross costs of the least cost NTA technology less any market-related revenues that the NTA technology may receive from ISO-NE energy and capacity markets, or income from other sources (i.e., RECs or other subsidies). The total net direct cost to ratepayers was estimated to range from $53 million a year (for the Supply Case) to $82 million a year (Combination Case) based on a selection of the least cost technically feasible NTA solution for HVNP under various scenarios. For example, the least cost NTA solution under the Supply Case requires developing 291 MW of gas-fired peaking capacity (using aeroderivative technology) across four locations (and each of the peaking facility would feature a synchronous condenser for voltage regulation). The least cost NTA solution under the Combination Case requires developing 255 MW of gas-fired peaking capacity (using aeroderivative technology with synchronous condensers) across four locations, as well as 31 MW of incremental energy efficiency ("EE") resources. The Supply Case, at $53 million per year, is less costly than the Combination Case because it does not include energy efficiency resources, which are more expensive on levelized cost basis than gas-fired peaking generation. In summary, the least cost hypothetical NTA Solution, at $53 million, would be 25 times greater than the $2.1 million per year estimated by Eversource as the Connecticut taxpayer's allocated share of the annual revenue requirement associated with the HVNP transmission solution.

In addition to the cost prohibitive nature of an NTA solution, a host of factors – including land availability, enabling infrastructure, and technology durability – will affect the practicality of implementing the NTA solution. For example, gas-fired peaking units were determined as the resources associated with the least cost NTA solution in the HVNP subarea. Although Stony Hill substation is located close to a gas pipeline, the West Brookfield, Triangle, and Peaceable substations are about 1.3 miles, 1.5 miles and 8.2 miles away from the nearest gas pipeline respectively. Therefore, a new gas lateral would need to be constructed at these locations should the selected NTA be gas-fired generators, which would further increase the cost for Connecticut end-users. There are also questions related to siting, permitting, and the development process in general, as no private developer to date has shown interest in bringing to market a project that would fit the technological requirements and geographical requirements of a technically feasible NTA solution.

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Acronyms

AC	Alternating Current
ACP	Alternative Compliance Payment
CCGT	Combined Cycle Gas Turbine
CLL	Critical Load Level
CSC	Connecticut Siting Council
DALRP	Day Ahead Load Response Program
DG	Distributed Generation
DR	Demand Response
EPRI	Electric Power Research Institute
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FO&M	Fixed Operating & Maintenance
HVDC	High Voltage Direct Current
HVNP	Housatonic Valley
ISO	Independent System Operator
ISO-NE	Independent System Operator- New England
kW	Kilowatt
LCOE	Levelized Cost of Entry
LEI	London Economics International
MRA	market resource alternative
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NTA	Non-Transmission Alternative
O&M	Operating & Maintenance
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
REC	Renewable Energy Credit
RTDR	Real-Time Active DR
RTEG	Real-Time Emergency Generation
RTO	Regional Transmission Organization
VOLL	Value of Lost Load
VOM	Variable Operating and Maintenance

1 Executive Summary

Over the course of 2013 and 2014, the reliability aspects of the bulk power system in the SWCT area were studied by the Independent System Operator of New England ("ISO-NE"). This study, referred to as the *Southwest Connecticut Area Transmission 2022 – Needs Assessment Report* ("SWCT Needs Assessment") was issued in June 2014. SWCT Needs Assessment analyzed a geographic area inside the Southwest Connecticut Import Interface. This area borders the New England to New York Interface along the Connecticut state border. For purposes of its analysis, ISO-NE analyzed five subareas within the SWCT area, namely the Frost Bridge – Naugatuck Valley area, Housatonic Valley / Norwalk – Plumtree area (HVNP), Bridgeport area, New Haven – Southington area, and Glenbrook – Stamford area. The principal component of the HVNP is a 3.4 mile 115-kV line from Plumtree to Brookfield Junction within an existing right of way corridor. The full scope of the project is summarized in the table below, extracted from the Southwest Connecticut Siting Plan.

Figure 1. HVNP solution components

ID	Solution Component
1	Install a new 115-kV line with ACSS conductor from Plumtree to Brookfield Junction within existing right-of-way (~3.4 miles)
2	Reconductor the 1887 Line (~1.4 miles)
3	Reconfigure into a three terminal line (Plumtree - W. Brookfield - Shepaug) (~0.93 miles)
4	Reconfigure the 1770 line into two, two terminal lines between Plumtree - Stony Hill and Stony Hill - Bates Rock.
5	The substation fence will be expanded.
6	Relocate the Stony Hill 22K 115-kV capacitor bank (37.8 Mvar) to the same side as the 10K (25.2 Mvar) 115-kV capacitor bank at Stony Hill
7	Relocate the existing Plumtree 115-kV capacitor bank (37.8 Mvar) from the 115 kV "B" bus to 115-kV "A" bus at Plumtree Substation
8	Install two 14.4 MVAR capacitor banks at West Brookfield Substation on the 1618 line terminal
9	Reduce the Rocky River 115-kV capacitor bank capability from 25.2 Mvar to 14.4 Mvar
10	Rebuild a portion of 1682 line between Wilton and Norwalk Substations and upgrade the Wilton Substation terminal equipment
11	Reconductor the 1470-1 line From Wilton Substation to Ridgefield Junction
12	Reconductor the 1470-3 line From Peaceable Substation to Ridgefield Junction
13	Plumtree Substation Install a 115-kV circuit breaker (63 kA interrupting capability) in series with the existing 29T breaker.
14	Newtown Substation Upgrade 1876 line terminal equipment

LEI was engaged by Eversource to analyze the potential for technically feasible, cost-effective and practical NTAs to replace the HVNP transmission solution. LEI described in detail the methodology and approach used to conduct its analysis in sections 4 and 5.

A Non-Transmission Alternative is a solution (or group of solutions) to an identified electric system need that does not involve the construction of traditional transmission infrastructure. NTA technologies may include supply-side resources (e.g. conventional generation, distributed generation or advanced generation technologies such as energy storage technologies), demand-side resources (e.g. demand response or energy efficiency), or a combination of both.

How to choose between a transmission solution and an NTA?

In theory, if an NTA can satisfactorily meet the technical requirements of the system that are driving the need for the transmission solution, it can then delay the timing of needed transmission investment under current practices. Consumers would pay for the transmission solution unless a private investor steps in. Consumers may also need to pay for the costs of deploying the NTA. Therefore, it is important to compare the costs of the transmission solution against the NTA. However, it is also important to recognize that NTAs and transmission may also have different characteristics that affect other aspects of electricity service. Even if an NTA has a lower cost and can fulfill the technical requirements of the system (e.g., the reliability need), there may also be other services and benefits that transmission can provide versus an NTA. An NTA should only be pursued if it can fulfill all the same technical requirements and generate benefits at comparable or lower costs than those associated with transmission projects.

LEI was asked to determine whether there are technically feasible NTA technologies that could be more cost-effective than the HVNP transmission solution in addressing reliability concerns in the HVNP subarea.

Eversource's planning staff analyzed the relevant parts of the transmission system to determine the amount of resources required at the point(s) of injection to eliminate all thermal and voltage violations in the portion of the transmission system between Plumtree and Frost Bridge Substations. The assumptions underpinning Eversource's analysis are based on the Needs Assessment study (June 2014). Four injection locations were identified for implementing an NTA solution: 50 MW injection at Stony Hill 115 kV substation, 47 MW injection at West Brookfield 115 kV substation, 50 MW at Triangle 115 kV substation, and 100 MW at peaceable 115 kV substation. In addition to the active power requirements (in Megawatt or MW), these locations also require reactive power regulation of up to 16 MVar (Stony Hill and Triangle substations), 15 MVar (West Brookfield substation), and 33 Mvar (Peaceable substation). Eversource's planning staff indicated that demand resources alone would not properly address thermal overload and voltage violations at the relevant injection locations. Reliability concerns could, however, be technically addressed by either a combination of demand–side and supply-side resources or by just supply-side resources.

LEI evaluated technically feasible NTA resources at the four identified locations with the goal of fulfilling the megawatt and voltage requirements, as determined by Eversource's planning staff. In its analysis, LEI considered two cases: i) an NTA solution solely based on supply-side resources (Supply Case); and ii) an NTA solution combining both demand and supply-side resources (Combination Case). The Supply Case analysis started with identifying a list of technically feasible NTA technologies that possess the operating characteristics required to meet the criteria of the NTA injections (in terms of size, location, and operating profile) at the four locations. LEI recognized that a technically feasible

NTA solution for the HVNP subarea would need to provide both active power (i.e., energy) and reactive power (i.e., voltage support) given the requirements laid out by Eversource's planners. Therefore, for supply-side technologies that are unable to generate reactive power continuously, LEI added a synchronous condenser unit into the NTA solution.[2] Once the technically feasible NTA technologies were identified, LEI then compared the costs of implementing each of the prospective technologies, in order to select the least cost option. The least cost NTA solution under the Supply Case requires developing 291 MW of gas-fired peaking capacity (using aeroderivative technology with synchronous condensers) across four locations, for a net direct cost of $53 million a year to Connecticut ratepayers.

The Combination Case approach followed a similar logic, except that energy efficiency resources were assumed to be part of the technically feasible solution in acknowledgement of the state of Connecticut's commitment to energy conservation measures. Specifically, LEI assumed that potential energy efficiency resources available at the injection locations would reduce the relevant megawatt requirements while supply-side resources would cover the remainder of the energy requirements as well as the entirety of the voltage requirements (since energy efficiency resources do not have such capability). The least cost NTA solution under the Combination Case requires developing 255 MW of gas-fired peaking capacity (using aeroderivative technology with synchronous condensers) across four locations, as well as 31 MW of incremental (e.g., new) energy efficiency resources (also distributed across four locations). The net direct cost to Connecticut ratepayers for this NTA solution amounts to $82 million a year.

As previously discussed, the results of LEI's analyses suggest that the least cost NTA solution would include 291 MW of aeroderivative peaker technology (under the Supply Case), for a net direct cost to Connecticut ratepayers of $53 million a year. This is significantly higher than the Connecticut ratepayers' share of HVNP transmission solution (estimated at $2.1 million a year). The implementation of this NTA solution would face its own respective siting, permitting challenges. Some of these challenges suggest that it may be more difficult to implement this NTA solution as compared to the transmission solution.

1.1 Background on LEI

LEI is a global economic and financial consultancy specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI benefits from a balance of private sector and government clients, which enables the firm to effectively advise both regarding the impact of regulatory initiatives on private investment, as well as regulatory responses to activities undertaken by individual firms. LEI has extensive experience working with both renewable and conventional generation technologies, as well as transmission infrastructure in the New England region, and specifically in Connecticut. LEI has extensive experience undertaking economic cost-benefit analysis, market price forecasting and asset valuation as well as presenting expert witness testimony in front of various regulators in North America, including the Connecticut Siting Council, Public Utilities

[2] A synchronous condenser is a motor-based hardware component that can generate or absorb reactive power as required, without producing active power.

Regulatory Authority ("PURA"), and the Connecticut Department of Public Utility Control ("DPUC"), a predecessor entity to PURA. A detailed description of LEI's experience is presented in Appendix A.

1.2 What NTA technologies were considered?

The analysis presented in this report was designed around a mix of supply-side and demand-side technologies initially identified by both LEI and the Eversource:

1. conventional fossil fuel fired generation (natural gas-fired peaking and combined cycle technologies);
2. large scale renewable generation (solar, and fuel cells);
3. distributed generation (solar);
4. active demand response (such as real-time demand response and real-time emergency generation);
5. passive demand response (such as energy efficiency programs); and
6. energy storage technologies (such as utility-scale battery technology and flywheels).

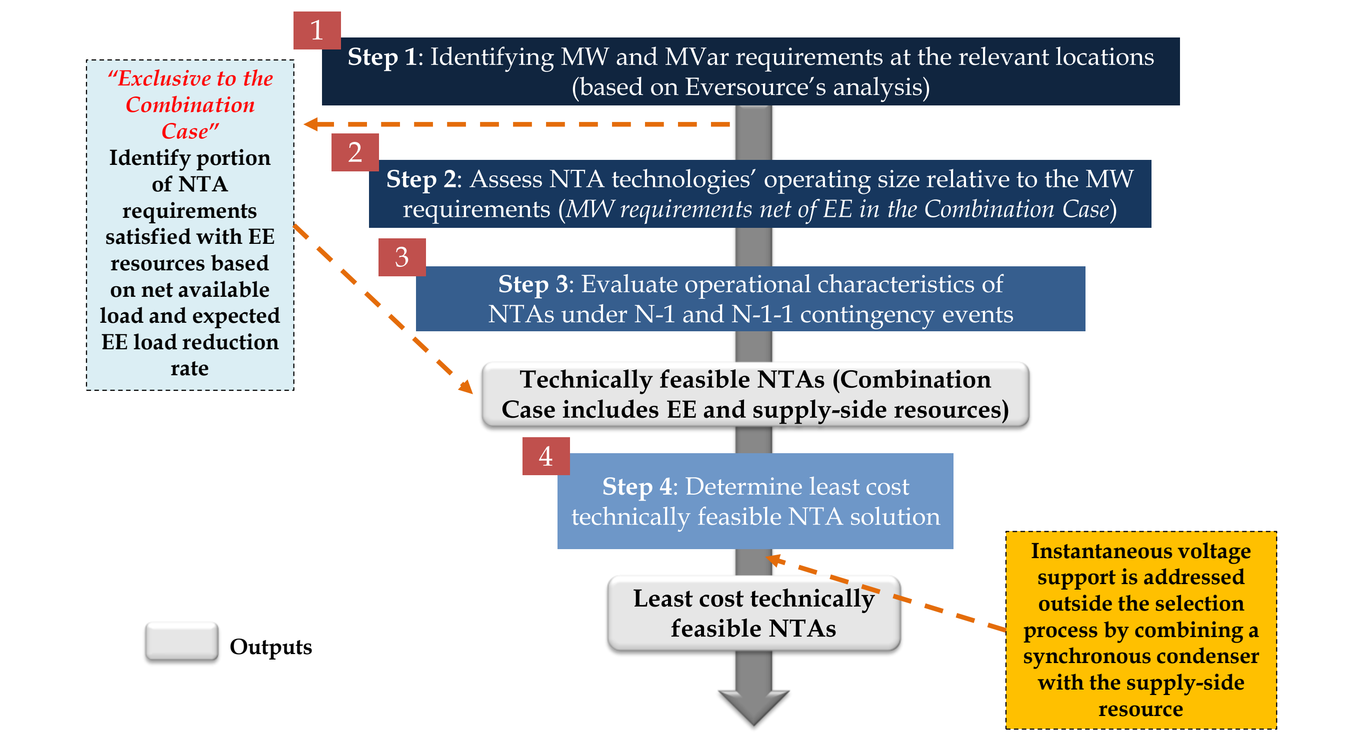
In undertaking the technology identification and cost analysis, LEI relied primarily on real world operating experience with such technologies in New England, as well as research documents and market information made publicly available by ISO-NE and the State of Connecticut related to technologies' operational data and statistics. Understanding of local market conditions was enhanced by Eversource's proprietary information, such as load levels at the considered injection locations, and public filings, such as Eversource's 2016-2018 Electric and Natural Gas Load Management Plan.[3] Where necessary, information from actual operational experience was supplemented by LEI with engineering–related data and generic technology information, including data on capital and operating costs, as well as operating parameters. Such generic information was collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers, and engineering procurement companies that work with such technologies. A detailed bibliography list is provided in Appendix D.

1.3 Overview of methodological approach

In order to identify technically feasible NTA technologies that can cost-effectively satisfy the reliability issues being addressed by the HVNP transmission solution, a four-step methodology was designed and implemented on two different cases (the Supply and Combination Cases), and two scenarios, as further discussed in Section 1.5. These steps are shown in Figure 2 below and are detailed in Section 4 of this report.

[3] 2016-2018 Electric and Natural Gas Load Management Plan, Connecticut DEEP, October 1, 2015.

Figure 2. Illustration of the Methodological Approach



LEI undertook a technology mapping process in order to identify and associate a technically feasible NTA technology with the hypothetical NTA requirements for the designated location and injection amount. In the instance of the HVNP subarea, the injection amount was represented in active power terms (i.e., capability to produce energy, measured in MW), and the capacity to support system voltage or reactive power (measured in MVar). LEI used decision tree techniques to sequentially filter and narrow down the available list of technologies according to the technical requirements at each location.

While LEI recognizes that there may be multiple NTA technologies that are feasible with each injection location/amount, the purpose of this analysis is to identify technically feasible NTA technologies that possess the operating characteristics required to meet the criteria of the hypothetical NTA injections (either in terms of size, location, or operating profile). The details of LEI's methodology are presented in Section 4.3 of this report.

The next step in LEI's analysis employs a levelized cost methodology in order to evaluate the direct costs to ratepayers of implementing NTA technologies. The direct costs were calculated by aggregating the total cost of implementing least cost technically feasible NTA technologies by location. LEI first assessed the costs of technically feasible NTA solutions by evaluating the total costs of investment and operations (based on gross Levelized Cost of Entry ("LCOE") per kW year). Then, LEI considered the net costs of investment and operations that ratepayers would bear after accounting for possible market revenues to the selected NTA technologies. LEI conducted a scenario analysis around the net direct costs to account for the uncertainty associated with market revenues attributable to the operation of the NTA technologies. Section 1.5 provides a detailed description of the scenario analysis.

1.4 Key Findings on technically feasible NTA technologies

Under the Supply Case and the Combination Case, peaker aeroderivative, slow discharge batteries and fuel cell units are the most suitable supply-side NTA technologies at the identified injection locations due to the size of the requirement (ranging between 50 MW and 100 MW). However, these units are not sufficient to meet all the reliability needs of HVNP: synchronous condensers need to be included in order to provide instantaneous voltage regulation at all times.

In both the Supply and the Combination Cases, peaker aeroderivative units and slow discharge batteries are technically feasible NTA technology at all the locations. Fuel cells technologies however, were only technically feasible at West Brookfield, Stony Hill, and Triangle substations, primarily due to the relative small size of the requirement (~50 MW). Peaker aeroderivative units are by design technically capable of generating reactive power for voltage regulation; however the technical requirements at the four locations under consideration specify that the reactive power must be provided instantaneously after a contingency event occurs. In other words, a peaking unit complying with this requirement would need to be running at all times similar to a baseload generation technology. There is no economic rationale for a peaking plant to generate energy at all times (except under emergency situations, if committed by ISO-NE). Consequently, to solve the instantaneous nature of the voltage issue, external voltage regulating equipment, such as a synchronous condenser, is included in the NTA solution.[4] Fuel cells are a scalable baseload technology, able to generate power continuously pending fuel availability. However, in order to comply with the voltage requirements at the relevant locations, fuel cell units would also need to be coupled with additional voltage control equipment, such as a synchronous condenser. The same observation goes for slow discharge batteries.

In the Combination Case, LEI assumed that a portion of the NTA requirement will be filled out by demand-side resources (limited by net load availability and assumed load reduction rate), while supply-side resources will be used to address the residual NTA requirement. In other words, the technically feasible technologies identified through LEI's Combination Case consist of incremental EE and a supply-side resource. To be consistent with assumptions made in Eversource's study of the preferred transmission solution, LEI assumed that any incremental energy efficiency program (above and beyond existing and planned programs[5]) would be able to reduce peak load by no more than 15% at the four locations.[6] Technically feasible supply-side resources under the Combination Case are similar to the technologies identified under the Supply Case.

In Figure 3, we present the NTA requirements at the four locations, and summarize all the possible NTA technologies based on size and operational criteria.

[4] An alternative to the synchronous condenser is a capacitor bank which is usually more expensive.

[5] EE resources above and beyond resources cleared in FCA#7, as well as EE resources forecast for the years corresponding to ISO-NE's FCA#8.

[6] The 15% assumption is discussed in detail in Section 3.2 of the report.

Figure 3. Range of feasible NTA technologies for location in the HVNP subarea

Technically feasible technologies	EE	Peaker aeroderivative	Slow discharge battery	Fuel Cell	Requirements (N-1 and N-1-1)	
Supply Case	(MW)	(MW)	(MW)	(MW)	(MW)	(MVar)*
Stony Hill	N/A	59	800	53	50	16
West Brookfield	N/A	55	752	49	47	15
Triangle	N/A	59	800	53	50	16
Peaceable	N/A	118	1,600	N/A	100	33
Combination Case	(MW)	(MW)	(MW)	(MW)	(MW)	(MVar)*
Stony Hill	8	49	575	38	50	16
West Brookfield	7	47	556	37	47	15
Triangle	10	48	546	36	50	16
Peaceable	5	111	1,457	N/A	100	33

Notes:

**All supply-side technologies would need additional equipment to address the instantaneous reactive power needs (MVar at the four locations).*

All capacity numbers are nameplate ratings, adjusted for performance factors of each technology. The large size of the slow discharge battery is due to the number of units needed to provide energy injection over a continuous 12 hour span.

Peaker aeroderivative units, slow discharge batteries, and fuel cells (in combination with incremental energy efficiency under the Combination Case) could potentially meet the NTA requirements (assuming remediation of voltage issues with synchronous condensers). The final selection among these NTA technologies was made on the basis of each technology's net levelized costs and the associated nameplate capacity (MWs) required in order to achieve the required level of power capability for the duration of N-1 and N-1-1 contingency events.

The NTA requirements, as determined by the Eversource planners' analyses, are presented under N-1 and N-1-1 contingency events in Figure 3 above. Based on standard planning protocols as provided for in ISO-NE procedures, N-1 and N-1-1 contingency events are defined as follows:

- In the context of Eversource's planning practices, an N-1 contingency event refers to a situation when a single element of the generation or transmission system fails, and a technically feasible NTA technology must be able to provide energy within fifteen minutes and continue to operate until the failed element is repaired or as long as deemed necessary by the ISO-NE.
- An N-1-1 contingency event refers to a situation when an additional single element of transmission or generation system fails, and a technically feasible NTA technology must be able to provide energy within thirty minutes and continue to operate until the failed elements are repaired or as long as deemed necessary by the ISO-NE. Typically, ISO-NE can resolve contingency events within a 12 to 24 hour cycle, and LEI has conservatively assumed a 12 hour duration[7] to resolve the contingency in its analysis.

[7] The basis of a 12-hour load period comes from the expected length of time of high load on a summer day. This corresponds to the length of time for which a long-term emergency ("LTE") rating can be applied and is based on the same reasoning.

As a first step in its analyses, LEI strived to understand when the occurrence of contingency events could potentially cause a reliability issue (and create reliability needs). Such understanding was needed to do a preliminary screening of technologies based on their operational capability during the day (and night). For instance, if reliability needs only occur at nighttime, solar based technologies would only be considered in tandem with a battery storage unit.

LEI ran an analysis comparing ISO-NE's forecasted hourly load for the year 2022 to the critical load limit ("CLL") estimated in the SWCT Needs Assessment. According to the ISO-NE, the CLL is defined as the load level at which a contingency would result in a reliability concern (a "violation"), and therefore a system upgrade is needed.[8] In the SWCT Needs Assessment, ISO-NE performed a CLL study and determined the level of load for the entire Connecticut area, at which the overloads and thermal violations would result in reliability concerns within the HVNP subarea. The Needs Assessment concluded that the net Connecticut load at which all thermal violations would be resolved is 4,163 MW ("Thermal CLL"), whereas the net Connecticut load at which all voltage violations would be resolved is 5,218 MW ("Voltage CLL"). LEI compared both CLL numbers to hourly load forecasts in Connecticut zone in 2022.[9] This comparison yielded an understanding that load in Connecticut is expected to reach and exceed the two CLL numbers (Voltage and Thermal CLL) during various periods of the day (and night) in all seasons.

We define "technically feasible" technologies as technologies that could hypothetically be implemented based on planning criteria and technology- specific operating profiles. A technically feasible NTA technology therefore meets the reliability issues being addressed by the proposed transmission components. Given the hypothetical NTA requirements, some technologies are not technically feasible, mainly due to their operational characteristics. For example, fast discharge energy storage resources (such as flywheels) are not technically feasible on a standalone basis because they cannot inject power continuously for 12 hours as required by an N-1-1 contingency event.

Other small scale NTA technologies, such as solar DG, cannot effectively meet the technical requirements of the contingencies and the sizing required of hypothetical NTA requirements in the HVNP subarea. In addition, solar DG resources have an operating profile that does not provide for the sustained performance required under N-1-1 contingencies. Even if solar DG were to be paired with energy storage technologies (such as batteries) to overcome the intermittency and sustainability of operations (for example, lack of energy production during nighttime periods), a single solar DG unit would not provide a technically feasible NTA technology because of the very small amount of energy generated by a typical 5 MW[10] solar DG unit. Therefore, ***multiple*** solar DG units would be required. As such, LEI's examination of utility-scale solar PV installations is a sufficient proxy for solar technology in general.

[8] Section 5.5: Information on Critical Load Level. Regional System Plan 2013. Available at: http://iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docx.

[9] Source: ISO-NE 2015 CELT.

[10] According to the ISO New England Transmission, Markets And Services Tariff, General Terms and Conditions Section I.2.2, solar distributed generation are limited in size at 5 MW.

Finally, it bears noting that Real-Time Active DR ("RTDR"), which is typically associated with industrial or large commercial customer sites (such as manufacturing facilities or processing factories), was not directly taken into consideration in the NTA technology identification analysis, although LEI still estimated the hypothetical levelized gross costs of such a NTA technology. There is a lack of publicly available information on RTDR's operational mode (such parameters will vary with equipment type and size), timing and duration of operation, as well as response/performance rates and opportunity costs, which prevented its inclusion in LEI's technically feasible pool of NTA technologies. Furthermore, under ISO-NE's rules, RTDR and real-time emergency generation ("RTEG") are not typically operable at any given time of the day, which would be a stumbling block to their ability to remedy all N-1-1 contingency events (which can occur at any time of day).[11]

Technically, peaker frame units could also operate in the size range of between 20 and 250 MW, but these units do not qualify as a technically feasible NTA technology within the HVNP subarea, due to technical and market economics-related reasons. Under N-1 contingency events, a technically feasible NTA technology would need to be able to inject power within 15 minutes.[12] In order for peaker frame units to fulfill these timing requirements, and given the source of fuel (i.e., pipeline gas) and nominations required for such fuel, such units would need to be effectively committed to run day-ahead in order to be capable of operating in real-time, because of the advance notice required for fuel supply and the speed of ramping. Although the ISO-NE has the authority to commit resources "out-of-merit" on a day-ahead basis, bringing a gas-fired frame peaker online and having it running essentially "out-of-merit" in order to be prepared for contingencies may be expensive and potentially distortive to market price signals. The ISO-NE may have more economic resources available for such purposes, such as other types of peakers (including dual fuel aeroderivative units and jet engines), if and when such a contingency occurs. Due to these operational and market economics-related considerations, LEI did not qualify peaker frame units as technically feasible NTA technology for the HVNP subarea.

1.5 Key Findings from cost analysis

LEI employed industry-standard levelized costing principles to the identified pool of technically feasible NTA technologies in order to estimate the total cost of implementing the least cost NTA technologies. For each selected technology, LEI estimated a gross LCOE which represents a resource's all-in-costs, annualized and levelized over its life cycle. The gross LCOE is reported in annual, per kilowatt terms ($/kW-year) and embodies all investment and operating costs, including capital costs (equity and debt), fixed operating and maintenance ("FOM") costs, fuel costs (where relevant), and variable operating and maintenance ("VOM") costs. For the potential NTA technologies that require additional equipment to generate sufficient levels of reactive power, the gross LCOE also includes the

[11] "ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." *ISO-NE, November 7, 2014* http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

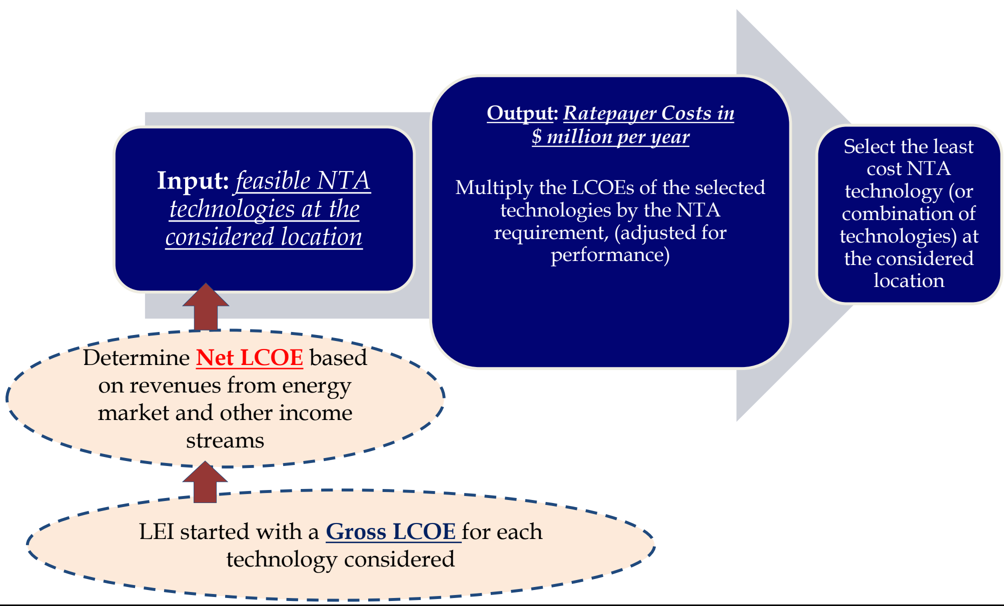
[12] Eversource plans its transmission system to the Long Term Emergency ("LTE") rating which means that if there is a thermal overload that exceeds the LTE rating, Eversource will have 15 minutes to get the flow below the LTE rating. When the planning is done looking at Short Term Emergency ("STE"), the required response time is 5 minutes.

levelized cost of a synchronous condenser. We relied on Eversource's procurement experience to derive our capital cost assumptions for synchronous condenser units.[13]

The net LCOE for each NTA technology is derived by deducting a bundle of potential revenues from gross LCOE and income streams associated with each NTA technology. The net LCOE is used to reflect the fact that the total direct cost to ratepayers of implementing an NTA could be reduced through revenues earned by the resource from other sources, such as wholesale energy and capacity markets, ancillary services, or other income streams.[14]

At the four HVNP injection locations, LEI calculated the total costs for the identified technically feasible NTA technologies based on the combination of their respective gross LCOE (or net LCOE) and total capacity needs (at the injection location), with adjustment for operating factors.[15] LEI selected the least costly NTA technology (or combination of energy efficiency and supply-side resources under the Combination Case) by comparing the resulting costs for all technically feasible NTA technologies (presented in Figure 3) at an injection location. The least cost solution is then used to derive the overall direct cost for Connecticut's ratepayers in dollar million terms per year.

Figure 4. Methodology for estimating net direct costs of technically feasible NTA technologies ($/kW-year)



[13] The capital cost of a 25 Mvar synchronous condenser unit was estimated at $22 million. It was levelized in the cost analysis over a 25 year period at 8%.

[14] These revenues were estimated notionally based on current market intelligence and are discussed further in Section 5.1.2.

[15] Operating factors include capacity factor, availability factor (which is defined as 1-forced outage rate), and ramping rates, which describe how "fast" a power plant can increase or decrease output - it is usually defined in MW per minute.

Under the baseline gross LCOE, gross cost for ratepayers is estimated to range between $104 million and $164 million a year across the Supply Case and the Combination Case. When adding a +/- 20% sensitivity, the resulting gross cost falls within a range of $83 million to $197 million per year between the two cases. LEI recognizes that total costs of NTA technologies can be defrayed by revenues from ISO-NE wholesale markets as well as other sources (such as the sale of RECs). In order to capture an accurate estimate of net direct cost to Connecticut ratepayers from technically feasible NTA solutions, LEI deducted these revenues from the gross costs (to derive net LCOE). Nonetheless, there is a significant amount of uncertainty regarding the magnitude and sustainability of these revenue offsets. To account for this uncertainty, LEI conducted a scenario analysis on the net LCOEs.

LEI considered the uncertainty of all new generating resources such as Combined Cycle Gas Turbines ("CCGTs") or peakers clearing forward capacity auctions ("FCAs"). Some of the uncertainty is based upon the fact that the auctions for the next three years have already been completed; there are also some interrogations on the needs of such new resources in future FCAs, in which case new resources – as represented by these NTA technologies – may not be able to get capacity revenues for some time. Securing these resources in a timely fashion in order to meet the reliability requirements of the HVNP subarea will need to be done outside the Forward Capacity Market ("FCM") timetable, given that new capacity has already been procured for the 2018-2019 delivery period in the Forward Capacity Auction #9 ("FCA#9"). In addition, the preliminary results of ISO-NE's latest Forward Capacity Auction (FCA #10) released on February 10, 2016, further confirm that private investors are not interested or otherwise planning to build new generation in this area of Connecticut. Therefore, an NTA solution will necessitate an out-of market solicitation, exposing Connecticut ratepayers to greater cost. LEI calculated the net direct costs to Connecticut ratepayers under two scenarios: (i) feasible resources would not be able to clear all FCAs but would receive capacity payments over half[16] of the years of their life span; and (ii) feasible resources do not clear any FCA and consequently do not earn any capacity revenues over their life span to defray the investment and operating costs. Figure 5 provides a summary of the two scenarios.

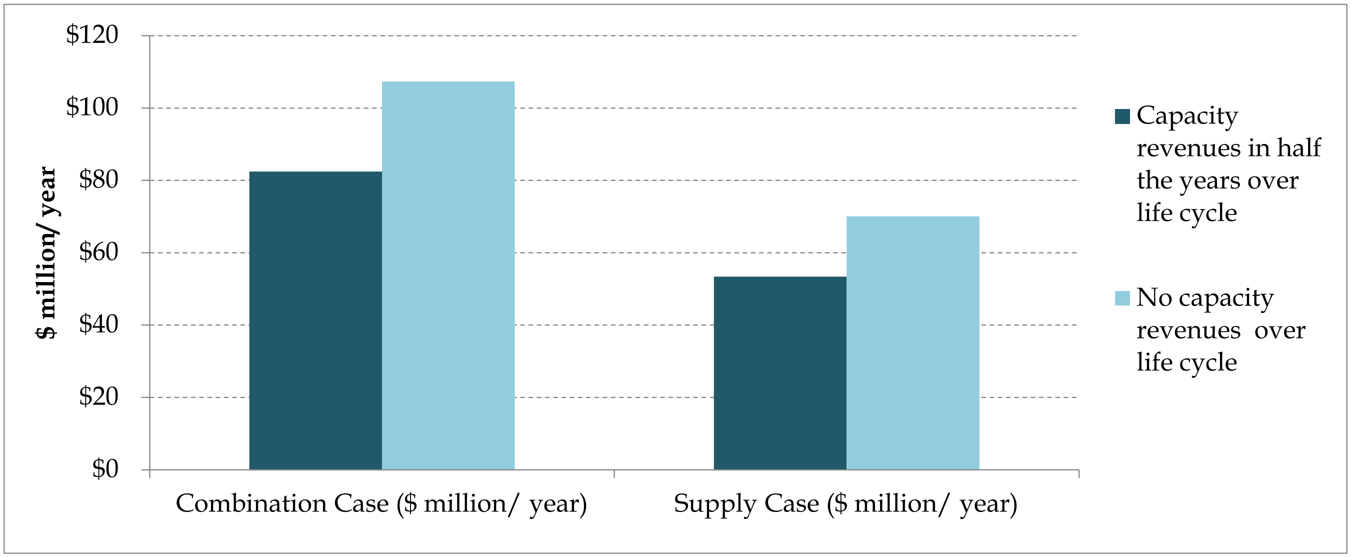
Figure 5. Summary of LEI's scenarios

Scenario	Methodology	Key assumptions for net LCOE
Scenario 1 (Capacity revenues in half the years over life cycle)	Net LCOE used to select the least cost technologies	We assumed that new resources such as CCGT and peakers would receive capacity payments over half the years of their life cycle
Scenario 2 (No capacity revenues in years over life cycle)	Net LCOE used to select the least cost technologies	We assumed that none of the new resources would receive capacity payments over their respective life cycle

16 There is also uncertainty in the future price of capacity, which we indirectly reflect with this 50% variable in the capacity revenue formula.

The total net direct cost (gross costs net of revenues offsets) for ratepayers was determined to range between $53 million and $107 million a year across the two scenarios and the two cases, as shown in Figure 6 below.[17] The lowest annual net direct costs estimated for Connecticut ratepayers ($53 million per year under Supply Case - Scenario 1) is several times higher than the share of the estimated annual revenue requirement for the HVNP transmission solution that would be borne by Connecticut ratepayers ($2.1 million a year).

Figure 6. Estimated net direct costs of NTA solution for the HVNP subarea per annum based on varying assumptions regarding offsetting revenues and subsidies



	Scenario 1	Scenario 2	HVNP
Scenarios	Capacity revenues in half the years over life cycle	No capacity revenues over life cycle	Cost of the transmission solution shouldered by end-users
Combination Case ($ million/ year)	$82.4	$107.3	$2.1
Supply Case ($ million/ year)	$53.4	$70.0	

Connecticut ratepayers are expected to shoulder 26% of the HVNP transmission solution annual revenue requirements based on current load projections published by ISO-NE and current rules with respect to transmission cost allocation. The total estimated revenue requirement is $8.2 million for the HVNP transmission solution. Therefore, Connecticut ratepayers would be responsible for $2.1 million a year. However, based on current transmission cost allocation policies, it is probably that 100% of the NTA technologies costs will be borne by Connecticut end-users.

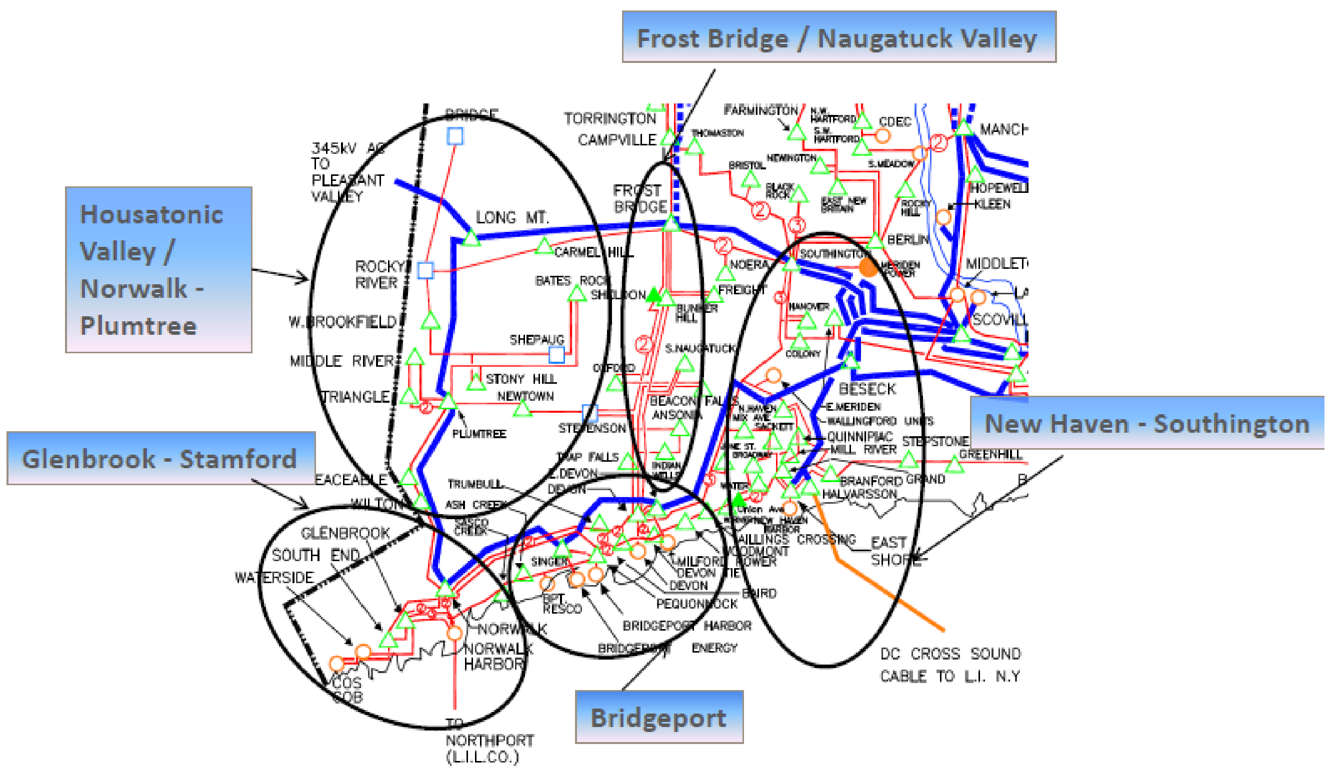
[17] Net LCOEs were derived from mid-range gross LCOE values.

2 Background on the Transmission Project solution

2.1 ISO-NE's Review of Southwest Connecticut Transmission Needs

Over the course of years 2013 and 2014, the reliability aspects of the bulk power system in the SWCT area were studied by ISO-NE. This study, referred to as the *Southwest Connecticut Area Transmission 2022 – Needs Assessment Report* ("SWCT Needs Assessment") was issued in June 2014. The SWCT Needs Assessment analyzed a geographic area inside the Southwest Connecticut Import Interface. The SWCT area also borders the New York Control Area. For purposes of its analysis, ISO-NE analyzed five subareas within SWCT, namely the Frost Bridge – Naugatuck Valley subarea, Housatonic Valley / Norwalk Plumtree subarea, Bridgeport subarea, New Haven – Southington subarea, and Glenbrook – Stamford subarea, shown in Figure 7.

Figure 7. Map of the SWCT's five subareas



Source: Southwest Connecticut 2022 Preferred Solutions Selection, Planning Advisory Committee, July 15, 2014

2.2 The transmission solution for the HVNP subarea

The principal component of Eversource's transmission solution in the HVNP subarea is a 3.4 mile 115-kV line from Plumtree to Brookfield Junction within an existing right of way corridor, combined with multiple upgrades and equipment additions - as summarized in the table below.

Figure 8. HVNP solution components

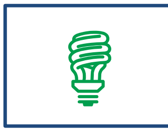
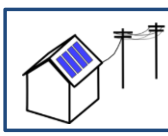
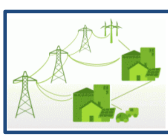
ID	Solution Component
1	Install a new 115-kV line with ACSS conductor from Plumtree to Brookfield Junction within existing right-of-way (~3.4 miles)
2	Reconductor the 1887 Line (~1.4 miles)
3	Reconfigure into a three terminal line (Plumtree - W. Brookfield - Shepaug) (~0.93 miles)
4	Reconfigure the 1770 line into two, two terminal lines between Plumtree - Stony Hill and Stony Hill - Bates Rock.
5	The substation fence will be expanded.
6	Relocate the Stony Hill 22K 115-kV capacitor bank (37.8 Mvar) to the same side as the 10K (25.2 Mvar) 115-kV capacitor bank at Stony Hill
7	Relocate the existing Plumtree 115-kV capacitor bank (37.8 Mvar) from the 115 kV "B" bus to 115-kV "A" bus at Plumtree Substation
8	Install two 14.4 MVAR capacitor banks at West Brookfield Substation on the 1618 line terminal
9	Reduce the Rocky River 115-kV capacitor bank capability from 25.2 Mvar to 14.4 Mvar
10	Rebuild a portion of 1682 line between Wilton and Norwalk Substations and upgrade the Wilton Substation terminal equipment
11	Reconductor the 1470-1 line From Wilton Substation to Ridgefield Junction
12	Reconductor the 1470-3 line From Peaceable Substation to Ridgefield Junction
13	Plumtree Substation Install a 115-kV circuit breaker (63 kA interrupting capability) in series with the existing 29T breaker.
14	Newtown Substation Upgrade 1876 line terminal equipment

3 What is an NTA?

An NTA is a solution (or a group of solutions) to an identified electric system need that does not involve the construction of traditional transmission infrastructure. NTAs may include supply-side resources (e.g. conventional generation, distributed generation, and advanced generation-like technologies such as batteries and storage), demand-side resources (e.g. demand response and energy efficiency), or a combination of the two. More recently, the term "NTAs" has been expanded to include smart grid distribution technologies.

Discussions of NTAs occurring in wholesale power markets and at state regulatory bodies generally focus on six categories of NTA technologies as described further in Figure 9 below: energy efficiency; demand response; utility-scale generation; distributed generation; energy storage; and smart grid technology.

Figure 9. NTA Technology Categories

	**Energy Efficiency**	improvements that result in the ability to use less energy to provide end-use customers with the same (or a better) level of service in an economically efficient way
	**Demand Response**	changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments
	**Utility-scale Generation**	relatively large generators that connect to the grid at the transmission (high voltage) level
	**Distributed Generation**	small generation systems located at a customer site
	**Energy Storage**	technologies that allow electricity generated at one time to be used at another time
	**Smart Grid**	technologies that enable a more efficient use of the electric power grid through computer-based remote control and automation

Note: LEI was not asked to consider SmartGrid as a technology category in this analysis because it is relatively untested and there is limited data available to model it as an NTA technology with confidence.

Consistent with the general categories of NTA technologies and adjusted for what is reasonable in New England (and specifically in Connecticut), the analysis presented in this report was designed around a list of six types of NTA technologies as follows:

1. conventional fossil fuel fired generation (natural gas-fired peaking and combined cycle technologies);
2. large scale renewable generation (solar and fuel cells);
3. distributed generation (solar);
4. active demand response (such as real-time demand response and real-time emergency generation)[18];
5. passive demand response (such as energy efficiency programs); and
6. energy storage technologies (such as utility-scale battery technology and flywheels).

The six types of NTA technologies listed above include both supply-side and demand-side resources. Supply-side technologies include conventional fossil fuel-fired generation, large-scale renewable generation, distributed generation, and energy storage technologies. Supply-side technologies can also include applications with energy storage technologies. Demand-side technologies include various forms of demand response.

Each of these NTA technologies has inherent operating characteristics that may determine their applicability as a technically feasible NTA technology vis-à-vis the reliability-driven requirements for a solution. When evaluating the practical feasibility of NTA technologies (ability for the NTA technologies-based solution to be implemented in real life) versus a transmission solution, the analysis must be done in a way that would make NTAs and transmission comparable in terms of both technical characteristics (reliability) and economic attributes (costs and benefits), as we discuss further below.

3.1 Evaluation of an NTA

As part of its ongoing work with the energy industry, LEI has proposed a set of tools and analytical techniques to allow for a comprehensive evaluation of NTAs and transmission solutions.[19] Although the specific steps and analytical tools can differ, subject to the specific context of a given investment need and system operator's planning process, there are a number of guiding principles that must be considered.

First and foremost, a rigorous analysis needs to ensure that NTAs meet the technical needs underpinning the transmission solution (i.e. NTA must be technically equivalent to the transmission solution – no partial solution). Furthermore, a rigorous analysis should acknowledge that NTA technologies and transmission will provide different services and therefore could generate different levels of benefits for consumers. Finally, LEI recommends that a comparative analysis is conducted within the discipline of cost-benefit framework, where benefits and costs are considered as comprehensively as possible. Economic cost-benefit analysis should consider the dynamic evolution of

[18] Active DR was not considered in the analysis due to the lack of publicly available information on these resources' operational mode, timing and duration of operation, as well as response/performance rates and opportunity costs for resources' owners.

[19] *Market Resource Alternatives – an examination of new technologies in the Electric Transmission Planning Progress*, WIRES Group, September 2014.

the system, rational market response to NTAs and/or transmission, and consideration of the operational uncertainties of each over time.[20]

LEI has applied these principles in this NTA analysis. The study begins with the preferred solution study performed by Eversource planning staff, where the reliability requirements for the HVNP subarea were determined in the form of location-specific NTA requirements for four locations – Stony Hill, West Brookfield, Triangle, and Peaceable. LEI then assigned technologies to the specified NTA requirements using a logical decision tree analysis process to sequentially filter and narrow down the available list of technologies that meet the technical needs underpinning the solutions. Next, LEI employed a levelized cost methodology in order to evaluate the direct costs per annum to ratepayers of implementing NTA technologies. LEI's cost analysis was designed to be as comprehensive as possible and consider the market revenues that NTA technologies may earn from various sources. For each NTA technology, LEI developed an all-in cost (gross LCOE) inclusive of development and operation costs (capital cost, fixed and variable operating and maintenance cost, and fuel cost) and costs associated with additional equipment for reactive power, wherever required by specific candidate NTA technology. The net LCOE values were then derived by adjusting gross LCOE values by potential revenues from other sources, tailored to each NTA technology.

3.2 Prospective NTA technologies

LEI reviewed thirteen prospective NTA technologies based on their ability to operate in the HVNP subarea. The considered technologies have unique operating characteristics which are compared against NTA injection requirements to determine their feasibility. Figure 10 lists the technologies under consideration for technically feasible NTAs. Figure 10 also outlines typical capacity ranges, operating profiles and performance rates associated with these technologies, which are detailed in Appendix B. In addition to stand-alone NTAs, the analysis also includes various practical combinations such as solar PV with storage, which are also included in the Figure 10.

In undertaking the technology identification and cost analysis, and for developing the technical assumptions in Figure 10, LEI relied primarily on real world operating experience with such technologies in New England, as well as research documents and market information made publicly available by ISO-NE, and the state of Connecticut related to technologies' operational data and statistics. The understanding of local market conditions was facilitated through Eversource's proprietary market information;[21] and, where necessary, technologies' operational data was supplemented with engineering–related data and generic information on technologies, including generic information on levelized costs. Such generic information was collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers, and engineering procurement companies that work with such technologies. A detailed bibliography list is provided in Appendix D.

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[20] A comprehensive benefit analysis was outside the scope of work in this engagement, given that the levelized cost analysis demonstrated such a wide disparity between the costs (and associated practical challenges) related to implementing NTAs versus the costs linked to the development of the proposed transmission project.

[21] This includes costing information on synchronous condenser, as well as available load and associated end-users breakdown by category at the injection locations.

Figure 10. Descriptive summary of NTA technologies

Numbers	NTA Resource	Installed Capacity range	Operations profile	Performance Rate	Duration (Hr.)
1	**Combined Cycle Gas Turbine (CCGT)**	200 to 700 MW range in CT	Baseload	95% availability factor	24
2	**Peaker Aeroderivative Unit**	1 to 125 MW range	Peaking load	85% availability factor	24
3	**Peaker Frame Unit**	20 to 250 MW range	Peaking load	83% availability factor	24
4	**Dual-fuel Jet Engine**	<1 to 50 MW	Peaking load	85% availability factor	24
5	**Solar Utility Scale (with storage)**	5 to 250 MW	Potential baseload depending on storage capacity	15% efficiency ratio	24
6	**Solar Utility Scale**	5 to 250 MW	Daytime peaking load during sunny days	15% efficiency ratio	12
7	**Solar DG (with storage)**	<1 to 5 MW	Potential peaking load depending on storage	15% efficiency ratio	12
8	**Solar DG**	<1 to 5 MW	Daytime peaking load during sunny days	15% efficiency ratio	8
9	**Fast Discharge Battery**	<1 to 10 MW	Can provide instantaneous power for short periods	Variable, depending on efficiency, charging time and storage capacity	2
10	**Slow Discharge Battery**	10 to 20 MW	Can provide steady supply of power for short periods	Variable, depending on efficiency, charging time and storage capacity	12
11	**Active DR - Emergency Generation**	Variable (based on type of equipment and load)	Peaking load	Assume 25% of peak load becomes available to respond	24
12	**Passive DR (Energy Efficiency)**	Variable (based on type of equipment and load)	Intermittent	Assume 25% of peak load becomes available to respond	24
13	**Fuel Cells**	2.8 MW to 63 MW	Baseload	95% availability factor	24

Note 1: Wind was not considered as a technically feasible NTA due to the lack of potential for sizeable wind capacity development in the Connecticut.

Note 2: Installed capacity range for utility scale fast and slow discharge batteries depends on the number of individual batteries connected together at a given site. The range indicated in the figure above is indicative, and LEI used variable sizes depending on requirements in order to ascertain the technical feasibility of using batteries as NTA technologies.

Note 3: Performance rates for CCGTs, Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines calculated based on the ISO New England EFORd Class Averages, sourced from: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf

Note 4: Active DR emergency profile is sourced from ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." ISO-NE, November 7, 2014 http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

Note 5: Size of fuel cells based on DFC3000 units from FuelCell Energy. The maximum size was based on the anticipated 63 MW fuel cells plant to be built in Connecticut (the largest yet in the world). Fuel Cells technology is baseload and can run 24/7 pending fuel availability. Given the limited information on availability factor, we assumed the same availability factor as a CCGT.

More details on the methodology and sources are provided in Appendix B.

In analyzing the potential for new energy efficiency as a technically feasible NTA technology, LEI assumed that at most 15% of the net peak load could hypothetically be reduced using new energy efficiency measures. It is worth noting that this level of peak reduction through passive energy efficiency resources would be unprecedented in Connecticut and the wider New England region, according to Eversource's experience with such programs. Achieving demand reduction will – and, indeed, already has -- become increasingly challenging and costly. In addition, successful geo-targeting energy efficiency to small geographic areas can be challenging as it relies upon customers mix and willingness to participate in programs. For example, Eversource's Marshfield Distribution Relief Pilot (a targeted attempt to reduce 2 MW of demand on key circuits/substations through a combination of energy efficiency, direct load control, and solar PV installation) resulted in actual kW reductions of approximately 715 kW – less than 3% of peak day afternoon loads of 25,000 – 30,000 kW on the affected lines. Energy efficiency contributed only 320 kW to this achieved load reduction.

Operations profiles for each NTA technology are used to determine when a given technology can operate during a 24 hour period. N-1-1 contingency events require that a technically feasible NTA technology can operate for 12 hours. For each NTA technology listed in the figure above, its operations profile determines if it can meet the requirements posed by the contingency events. For example, while a peaker frame unit can operate for 24 hours, it may not be operating during off-peak night-time hours, which prevents it from a technically feasible NTA technology.

It bears noting that RTDR, which is typically associated with industrial or large commercial customer sites (such as manufacturing facilities or processing factories), was not directly taken into consideration in the analysis, although it could theoretically be considered as a potential NTA technology. There is limited publicly available information on RTDR's operational mode. Operation characteristics would vary from one resource to the other due to a host of parameters including equipment type, timing and duration of operation, response/performance rates and opportunity costs, which does not allow us to model these technologies with confidence. In addition, the load in these injection locations is mainly residential.[22] Furthermore, under ISO-NE's rules, RTDR and RTEG are not typically operable at any given time of the day, which would be a material shortcoming to their technical feasibility under N-1-1 contingency events, given what we know about the CLL relative to forecast hourly demand.[23] For reference purposes, LEI nevertheless estimated gross and net LCOE figures associated with both RTDR and RTEG in Appendix C.

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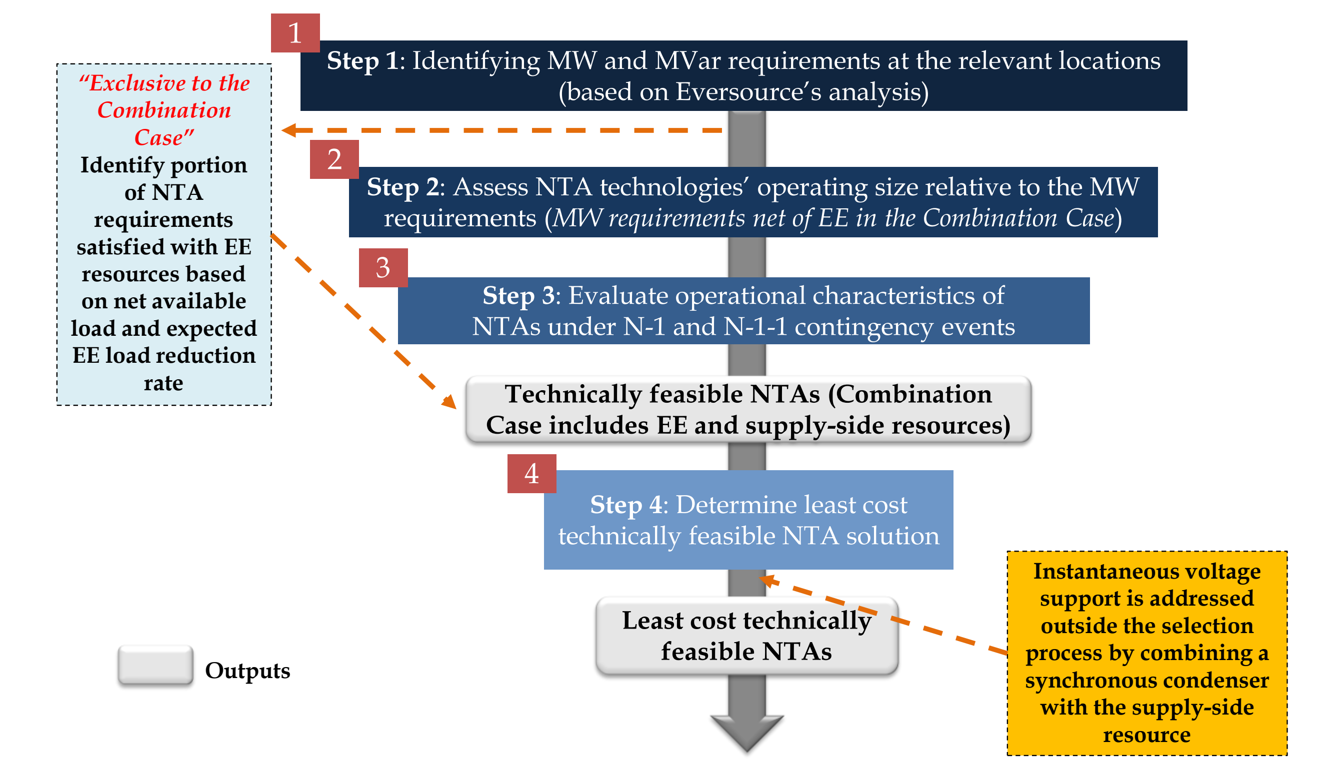
[22] Based on information received form Eversource.

[23] "ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." *ISO-NE, November 7, 2014* <http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf>.

4 Overview of Methodological Approach

In order to identify technically feasible NTA technologies that can satisfy the reliability issues being addressed by the HVNP transmission solution, a four-phase methodology was designed as illustrated in Figure 11 below.

Figure 11. Illustration of Methodological Approach



The overarching objective of LEI's methodology from Step 1 through Step 3 is to: i) identify the portion of NTA requirements that could be covered by energy efficiency programs at a given location (under the Combination Case); and ii) determine both volume (MW) and type of supply-side NTA technologies required to address the capacity and voltage needs at the injection point (under both Supply and Combination Cases). The methodology uses decision tree analytics to sequentially filter and narrow down the available list of technologies according to the technical requirements at each location. In summary, the three steps for selecting a technically-feasible NTA technology are as follows:

- Step 1: determine capability (in MW and MVar terms) at the four designated locations to solve active power and reactive power reliability issues (this step was performed by Eversource planners);

- Step 2: use the technical requirements for MW injection to screen prospective technologies based on their relative size. For example, a small CCGT technology of 200 MW would still be too large to be considered for addressing in a cost effective fashion a 50 MW injection requirement.

- *Step 2 - under the Combination Case*, determine the portion of MW requirements covered by EE programs based on local load available and assumed load reduction rate. The technical requirements of MW injection net of the EE resources would be used as the basis to filter supply-side resources expected to cover the remaining reliability needs; and

- Step 3: refine the selection of the NTA technologies successfully screened in Step 2, based on the conformity of their technical parameters to the contingency event requirements.

While LEI recognizes that there may be multiple NTA technologies (or combination of NTA technologies) that are technically feasible at a substation, the purpose of this analysis was not to list out all possible combinations but rather to identify all possible technically feasible NTA technologies that could, individually or coupled with energy efficiency, meet the criteria of the hypothetical NTA injections (either in terms of size, location, or operating profile).

In the last step (Step 4), the levelized cost methodology evaluates the direct cost of implementing the combination of technically feasible NTA technologies for Connecticut ratepayers. Since no merchant sponsor is proposing to build an NTA, we assume that it would be built only if its costs were borne by electric ratepayers. The direct cost to Connecticut customers is calculated by aggregating net direct costs to consumers associated with constructing and operating the least cost technically feasible NTA technologies (including the installation of additional equipment for reactive power, when relevant) identified for the four locations in the HVNP subarea. Those direct costs are then compared to the costs of building and servicing the components of the HVNP transmission solution. We assumed, pursuant to the current ISO-NE tariffs, that the full cost of the NTA technologies would be passed through to Connecticut ratepayers. On the other hand, for the proposed transmission solution, the costs of the transmission solution will be rolled into regional network service and recovered through the Pooled Transmission Facilities rates. Therefore, Connecticut ratepayers would only pay a share of those costs based on current ISO-NE rules for transmission cost allocation (i.e., 26% of the total costs to construct and operate, based on current load projections).

4.1 Determination of hypothetical NTA solutions

Subsequent to the process for the needs assessment for the SWCT area and identification of preferred transmission solutions, Eversource's planning staff conducted a study that identified the smallest aggregate quantity of injections (as measured in MW terms) in the HVNP subarea that would alleviate the thermal overloads and voltage violations. The assumptions underpinning the NTA studies are based on the Needs Assessment study (June 2014). Four injection locations were identified for NTA solution:

1. Stony Hill 115 kV substation (50 MW and 16 MVar of capacity and voltage requirements respectively),
2. West Brookfield 115 kV substation (47 MW and 15 Mvar of capacity and voltage requirements respectively),
3. Triangle 115 kV substation (50 MW and 16 MVar of capacity and voltage requirements respectively), and

4. Peaceable 115 kV (100 MW and 33 MVar of capacity and voltage requirements respectively). Figure 12 summarizes the assumptions relied upon for the initial Needs Assessment and therefore for the NTA studies.

Figure 12. Summary of modeling assumptions used in the NTA studies

Items	Description	Sources
Horizon	10 years (2013-2022) with a focus on the year 2022	SWCT Area Transmission 2022 Needs Assessment
Power Flow Study	ISO-NE's model on demand system to reflect system conditions in 2022	
Topology	All relevant transmission projects with Proposed Plan Application (PPA) approval have been included in the study base case except for the Central Connecticut Reliability Project (CCRP), which is under re-assessment in the Greater Hartford Central Connecticut (GHCC) study, and previously PPA approved SWCT project which were presented at the June 18, 2012 PAC meeting, since they are being re-evaluated in this assessment.	
Supply	All generation project with a Capacity Supply Obligation as of Forward Capacity Auction 7 (FCA #7) were included in the study base case. The base case does not include Bridgeport Haarbor 2 and Norwalk Harbor.	
Load	The summer peak 90/10 load level forecast is 34,105 MW for all of New England and 8,825 MW (which represents 26%) of the New England load for the state of Connecticut	
Energy Efficiency (Passive and active demand response)	Demand resources (passive and active) were modeled based on the Demand Resource (DR) cleared in FCA #7. In addition, any accepted NPR requests for DR and any DR terminations in Connecticut for FCA #8 were also taken into account.	

4.2 Methodology for identifying technically feasible NTA technologies

As summarized in the previous section, LEI used a four-step methodology for selecting the least cost technically feasible NTA technologies at the four locations in HVNP.

A technically feasible NTA technology is defined as one that can independently fulfill all the requirements at the specific location. In other words, if at a location, two different technologies are required to work together (e.g. solar PV during the day and a CCGT at night) to meet the requirements, then neither of these technologies is determined to be technically feasible for this location on their own.[24] In the Combination Case however, as previously discussed, we allowed the combination of EE and supply-side resources by design.

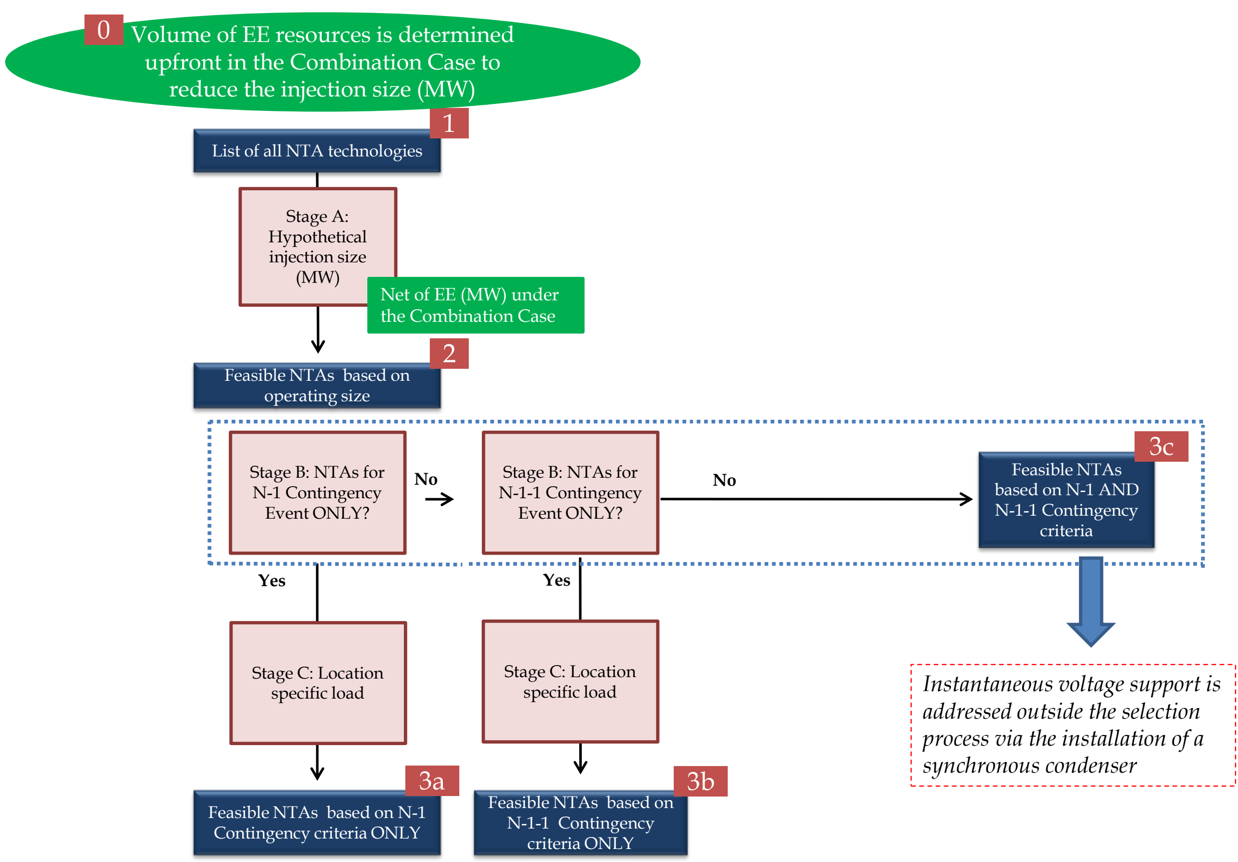
Given that a location can have multiple NTA technologies that could each independently meet the NTA requirement, as previously discussed, the final selection from among the technically feasible NTA technologies is based on their levelized costs (multiplied by the NTA requirement), as discussed further in Section 5.1 below.

[24] The exception to this philosophy relates to solar PV technologies and energy storage. We do combine these two separate NTA technologies in order to form a third unique technology; energy storage enables the solar PV unit to qualify as a technically feasible NTA technology (if some of the production from day-time hours is stored so that it can be injected into the grid at night).

When we use the term "technically feasible," we are reflecting on a specific technology's ability to meet requirements set out by system planning criteria, and therefore in the case of this analysis; "feasibility" is not to be interpreted in the more connotative sense of the word (and the technologies may still be deemed to be impractical or commercially infeasible, as discussed in Section 5 of this report). System planning criteria refers to requirements such as the maximum allowable time for an NTA technology to respond to N-1 and N-1-1 contingency events (response time) and the minimum duration of time for which an NTA technology must remain operational after being called into service. In contrast, physical considerations, which are not a part of this methodology, refer to the amount of land required for a given NTA technology to be located at a substation and the time required for siting and construction, as well as the anticipated market need for the NTA technology in the future. These physical constraints and commercial development considerations are presented in Section 5.2. The cost implications of technically feasible NTA technologies are also discussed in detail in Section 5.1.

Figure 13 depicts the decision process in a flow chart, followed to arrive at a selection of technically feasible technologies that clears both the size and the operational criteria commanded by N-1 and N-1-1 contingency events. The decision process is another interpretation of Steps 1 through 3 of Figure 11.

Figure 13. Methodology for identifying technically feasible NTA technologies



Note: Circled in dotted line is the process followed for selecting technically feasible NTA technologies based on operating size, operational characteristics and N-1 and N-1-1 contingency criteria.

Stage A: Size

In both Supply and Combination Cases, the first step focuses on the size of injection required by location or node. Upon reviewing commercial information provided by manufacturers (such as General Electric ("GE"), Siemens, Wärtsilä and FuelCell Energy) on technologies, and comparing the typical size of the prospective resources in operation in Connecticut against the size of injection requirements at each location, it is possible to eliminate NTA technologies that are not suitable to the size of the injection. The maximum and minimum sizes considered for each NTA technology are summarized in Figure 10.

Under the Combination Case, this stage of the methodology evaluates the potential for implementing incremental EE measures based on the net load (MW demand) at each injection location. We assumed that energy efficiency programs will be part of any NTA solution deemed feasible to address reliability requirements. The underlying assumption is that the level of peak reduction achieved through passive energy efficiency resources would not exceed 15% at the relevant location, consequently lowering the associated NTA requirements. As previously discussed, it is worth noting that achieving incremental peak load reductions from energy efficiency of 15% above levels achieved through state-mandated programs would be unprecedented, as such a target reduction goes well beyond Eversource's geo-targeting experiences to date. The selection of NTA technologies in Stage A of the Combintion Case is based on the injection requirements net of the EE resources (MW).

Stage B: Operational

We then moved to consider the operating characteristics of the list of technically feasible NTA technologies from Stage A, relative to the requirements of the NTA injection amounts. These operating characteristics refer to N-1 and N-1-1 contingency events. LEI understands that as part of the NTA studies, Eversource modeled both N-1 and N-1-1 contingency events.

N-1 and N-1-1 contingency events have associated operational considerations that must be met by a technology in order to be considered a technically feasible NTA technology. To be consistent with Eversource's study, LEI's selection process was designed to determine NTA technologies addressing both N-1 and N-1-1 requirements – as highlighted in dotted line on Figure 13. An N-1 contingency event refers to a situation when a single element of the generation or transmission system fails. An N-1-1 contingency event refers to a situation where an additional single element of the generation or transmission system fails within 30 minutes of the N-1 contingency event. The required response time of a resource under N-1-1 contingency event is 30 minutes, which is less stringent than the mandatory 15 minutes response time under N-1 contingency event.[25] As such, a resource satisfying N-1 operational requirements would automatically satisfy N-1-1 requirements all being equal. In other words, a qualified NTA technology under our analysis must be able to provide energy within 15 minutes (at a minimum) and must continue to do so until the elements are repaired or as long as deemed necessary by the ISO-NE (typically, ISO-NE can resolve contingency events within a 12 to 24 hour cycle; LEI has assumed a 12 hour duration to resolve N-1 and N-1-1 contingency events).

[25] Based on Eversource's planning practices.

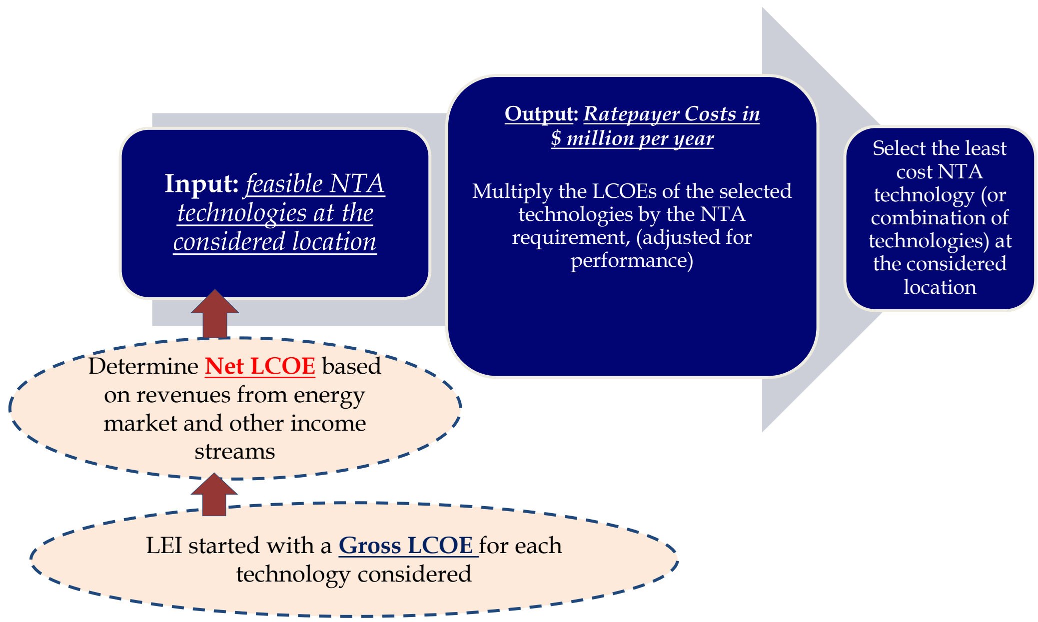
In addition to these stages for identifying technologies that can provide the required power injection required at each substation, LEI also analyzed reactive power requirements at the four locations. LEI understands that engine-based technologies such as peaker aeroderivative units and CCGTs can, by design, satisfy reactive power requirements (depending on how it is scheduled). However as discussed in Section 1, since it is not economic for a peaking unit to be running at all times in order to be capable of injecting reactive power at any given time, peaking units will also need an external voltage control equipment to address the instantaneous nature of the voltage requirement. Technologies, such as batteries and fuel cells, while generating the needed quantity of active power, might not come standard with the technical capability of generating reactive power on their own. These technologies would also need external voltage regulator equipment (such as capacitor bank or synchronous condenser) to provide reactive power. LEI's selection process did not eliminate any technology that requires additional equipment for reactive power. Instead, the cost of additional equipment is included in the cost analysis stage of LEI's methodology.

The sample of NTA technologies resulting from LEI's selection process were then used as direct inputs into the cost analysis.

4.3 Methodology for estimating cost of technically feasible NTA technologies

LEI applied industry-standard levelized costing principles to the identified pool of technically feasible NTA technologies from Stage 3C (Figure 13) above in order to estimate the total cost of implementing the least cost technically feasible NTA technologies. For each selected technology, LEI estimated a gross LCOE, which represents a resource' all-in-costs, levelized over its life cycle. The gross LCOE is a per kilowatt per year figure ($/kW-year) that embodies all costs including capital costs, going-forward FOM costs, as well as fuel and VOM costs. The gross LCOE also included the cost of additional equipment required for generating reactive power for technologies that need this retrofit. The gross LCOE represents a long term timeframe that is consistent with the requirements identified at Stony Hill, West Brookfield, Triangle and Peaceable substations. As a next step, LEI derived Net LCOE for each technology by deducting from gross LCOE a bundle of potential revenue streams associated with each NTA technology. The analysis then consisted of multiplying, at the considered injection point, the net LCOEs of all feasible technologies by the NTA capacity requirements (adjusted for performance and availability). The least cost technically feasible NTA solution for the four injection locations were selected by comparing the products of net LCOEs and NTA capacity requirements for all feasible technologies. Finally, we aggregated the total costs associated with the identified least cost technically feasible NTA technologies at the four injection locations in order to determine net direct cost for the Connecticut ratepayers. Figure 14 provides an illustration of this methodology.

Figure 14. Methodology for estimating net direct costs of technically feasible NTA technologies ($/kW-year)



Gross and Net LCOE are expressed in dollars per kW-year unless otherwise specified.

4.3.1 Determining gross LCOE for technically feasible NTA technologies

Gross LCOE represents the total fixed cost of NTA technologies levelized over the lifetime of the relevant technologies. As discussed previously, gross LCOE includes capital costs, fuel costs, as well as both FOM and VOM. Gross LCOE is denominated in $/kW per year and then multiplied by the installed capacity of the technically feasible NTA technologies to derive an annual gross cost. Figure 15 provides a summary of calculated gross LCOE for all technologies deemed technically feasible. For cost information, LEI relied primarily on data made publicly available by ISO-NE and the state of Connecticut. We then cross-compared and supplemented this data with information collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers and engineering procurement companies that work with such technologies, as well as actual operating data from similar installations across New England.

Appendix C provides a detailed description of assumptions and sources used for determining the ranges of gross LCOEs. LEI defined a +/- 20% range of gross LCOE to take into consideration the uncertainty associated with cost assumptions. In fact, in real life, development and operation costs of facilities can vary significantly and deviate from a generic assumption due to a variety of reasons including plant location, financing structure and market conditions, technology types, labor cost, environmental cost, site preparation, fuel supply, etc. The cost range was suggested in an attempt to crystallize this uncertainty. The +/-20% cost range was used to measure the impact of this uncertainty on the net direct costs of technically feasible NTA solutions.

Figure 15. Summary of Gross LCOE per year for each technology

Feasible Technologies (all numbers in $/kW - year unless specified otherwise)	Gross LCOE ($/kW-y)	Range ($/kW-Y) -/+20%	
Peaker Aeroderivative**	$ 323	$ 259	$ 388
Slow Discharge Batteries*	$ 181	$ 145	$ 218
Passive DR (Energy Efficiency)	$ 2,867	$ 2,294	$ 3,440
Fuel Cells*	$ 734	$ 587	$ 881

Note: Figure 25 in Appendix C summarizes the capital costs assumed for each of the prospective NTA technologies

* In the context of our analysis, these technologies would require additional equipment to generate reactive power. Although it is not built in the technology cost ($/kw-year), the levelized cost of a synchronous condenser will be added to the total cost of developing the relevant technology ($million). LEI assumed that a synchronous condenser will be the additional equipment of choice because other alternatives such as a capacitor bank are more expensive.

** Although the peaker aeroderivative unit is capable of generating reactive power and thus does not need additional equipment, LEI had to assume the presence of additional equipment since the reactive power is required instantaneously, which a stand-alone peaker aeroderivative unit cannot accomplish.

Sources: ISO-NE (ISO New England Inc. and New England Power Pool, Docket No. ER14) 000, Demand Curve Changes, Paril 2014), National Renewable Energy Laboratory ("NREL"), Pacific Northwest National Laboratory ("PNNL"), International Energy Agency, Electric Power Research Institute ("EPRI"), Department of Energy, FuelCell Energy and LEI

4.3.2 Determining Net LCOE for technically feasible NTA technologies

The total gross cost of NTA technologies can be defrayed by market revenues and other sources of income received by these resources when they begin operations, which in turn would reduce the cost of the NTA to ratepayers. Therefore, we deduct these revenues from the gross LCOEs, so as to isolate the net direct costs to ratepayers for a technically feasible NTA solution. In this respect, LEI adjusted the gross LCOE analysis by incorporating a number of potential market revenue streams associated with each feasible technology. The resulting calculation is the net LCOE which is relied upon to evaluate net direct cost of implementing technically feasible NTA technologies for ratepayers. The revenue streams considered in this analysis include revenues from the energy and capacity markets, Local Forward Reserve Market ("LFRM") and Regulation Market revenues, income associated with avoided retail rate costs (for solar DG and energy efficiency resources), as well as Renewable Energy Credits. However, we did not integrate in the analysis any additional charges (such as Net Commitment Period Compensation ("NCPC")) associated with operating the technologies out of merit.[26] Figure 16 depicts the revenue streams considered and provides a summary of calculated Net LCOE by feasible technology. Appendix C summarizes the sources relied upon to estimate the revenue offsets.

[26] NCPC is the additional compensation received by a resource that is committed for reliability purposes but not dispatched above its economic minimum output level.

Figure 16. Components of the net LCOE calculations for each technically feasible NTA technology ($/kW-year)

	Aeroderivative peaker	Slow discharge batteries	Passive DR (EE)	Fuel Cell
Gross LCOE	323	181	2,867	734
Energy*	118	0	0	434
FCM	57	0	0	0
LFRM	0	13	0	0
Regulation	0	33	0	0
Avoided retailed cost	0	0	0	0
RECs (SRECs)	0	0	0	0
Net LCOE	148	136	2,867	301
Overnight capital cost ($/kW-year)	1,486	1,330	N/A	7,475
Synchronous condenser ($million-year)	2	2	N/A	2

Notes: This table illustrates net LCOEs for a scenario assuming half of FCM payments are received by the resources. Rows in white represent revenue offsets, while the bottom blue row contains the net LCOE results from the realization of all of these revenue offsets.

Based on Eversource's inputs, LEI estimated the capital cost of a standard 25 MVar synchronous condenser at $2.1 million year ($22 million lump sum). This capital cost is levelized at 8% over a 25 year time-frame to reflect the useful economic life of the equipment.

FCM price based on FCA#9 results ($9.55/kW-month) (before adjustment for derating factor and scenario)
**Energy revenues inclusive of VOM and fuel cost recovery*
LFRM ($/MW-month) for summer 2014: $9,500; LFRM ($/MW-month) for winter (2014/2015): $5,781
Annual average regulation price (without performance payment in 2014):$18/MWh
Avoided retail cost: (based on average residential retail rate in September 2015) $19.2/MWh
Charging costs for battery have not been taken into account

Sources: ISO-NE, NREL, PNNL, IEA, EPRI, EIA, DOE and LEI

5 Analysis and results

Of the total thirteen NTA technologies under consideration, three technologies qualify as technically feasible for the HVNP subarea. At the four locations, technically feasible NTA technologies include: (i) peaker aeroderivative unit, (ii) slow discharge battery and, (iii) fuel cells.[27] Under the Combination Case, a portion of the requirements can be fulfilled by EE. We assumed that no more than 31 MW of load reduction via EE should be assumed at the four locations given the modeled 15% threshold of demand reduction. Fast discharge batteries, solar PV (DG and utility scale) without storage, and peaker frame units are among the technologies that never qualify as technically feasible NTA technologies owing to their various technical characteristics (i.e., limitations on performance duration, and/or time of performance).

The injection amounts associated with these technologies need to be converted into an installed capacity figure using the performance rates of each individual technology (e.g., availability factor and ramping rates for thermal technologies, conversion efficiency for solar units and batteries). In this analysis, we considered technologies' ramp start, which corresponds to the incremental percentage of full capacity released by a resource per minute from cold start to 100% full capacity. An aeroderivative peaking unit for instance would have a 50%/minute ramp rate.[28] Based on these criteria, a requirement of 1 MW may actually lead to installed capacity exceeding 1 MW.

The cost analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and estimated required nameplate capacity. Under the baseline gross LCOE, gross costs for a technically feasible NTA to the HVNP transmission solution are estimated to range from $104 to $164 million a year between the Supply Case and the Combination Case. When adding a +/- 20% sensitivity on gross LCOEs, the resulting gross costs range from $83 million to $197 million a year.

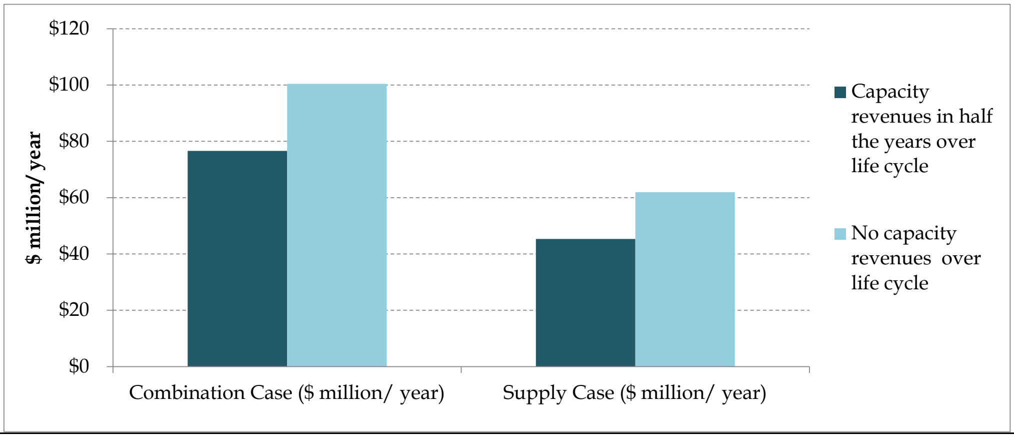
LEI recognizes that total costs of NTA technologies can be defrayed by revenues from markets as well as other sources. Therefore, in estimating the cost of a feasible NTA solution that would be payable by Connecticut ratepayers, LEI elected to deduct expected notional market revenues from the gross costs in order to derive a net LCOE. The net LCOE multiplied by the required nameplate capacity[29] for the technically feasible NTA technologies completes the process of estimating the net direct cost to ratepayers.

[27] As previously discussed Fuel Cells did not qualify at the Peaceable substation.

[28] Assuming an LMS100 turbine from General Electric as documented in PGE 2013 IRP, *Black Veatch* - Appendix G Cost and performance data for power generation technologies.

[29] The estimated capacity estimated for each technology could technically be higher had we followed ISO-NE's transmission planning guidelines and considered additional capacity to account for the potential failure of some of the units composing the potential NTA solution.

Figure 17. Illustration of net direct cost per case



The primary uncertainty in estimating the net LCOE is the revenue forecast for each technology. Projected revenue offsets were estimated using existing market information and general market expectations for the future.[30] For example, for capacity revenue, LEI assumed an average price over time consistent with FCA#9. Energy market revenues were forecast based on information relied upon by ISO-NE to establish net CONE for various technologies, and other rules within the FCM. In summary, the net direct cost was estimated to range between $53 million and $107 million per year across the two scenarios and the two cases. The two scenarios vary according to the level of capacity revenues attributable to NTA resources during the technologies' lifecycle. The scenario that produces the lowest net direct cost to ratepayers is Scenario 1 under the Supply Case, where the technically feasible NTA technologies are assumed to receive capacity payments over half the years of their lifecycle. Under this scenario, the net direct cost to ratepayers is estimated at $53 million a year, which is significantly more than the portion of the annual revenue requirements of the HVNP transmission solution supported by Connecticut ratepayers (approximately $2.1 million). In addition, it is important to keep in mind that 100% of the NTA technologies' costs would be shouldered by Connecticut ratepayers whereas only 26% of the projected annual revenue requirement (26% of $8.2 million a year) for the transmission solution is expected to be borne by Connecticut end-users.[31]

5.1 Cost estimates

The goal of the cost analysis is to evaluate the net direct cost of implementing NTA technologies for Connecticut ratepayers as opposed to building the components of the HVNP transmission solution. The analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and nameplate capacity, followed by a net LCOE analysis which leads to an estimate of the net direct costs to ratepayers.

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[30] A detailed modeling analysis would be required to further refine these revenue estimates and factor in the resources' year on year impacts on market conditions and how that, in turn, affects market prices; such an analysis is beyond the scope of this report.

[31] Revenue requirements associated with the proposed transmission solution were provided by Eversource.

5.1.1 Gross cost estimates for ratepayers

Under the baseline gross LCOE, gross cost for ratepayers is estimated at $164 million a year under the Combination Case at the four locations in the HVNP subarea. This gross cost reflects 31 MW of EE (8 MW at Stony Hill, 7 MW at West Brookfield, 10 MW at Triangle, and 5 MW at Peaceable), along with 255 MW of peaker aeroderivative unit (49 MW at Stony Hill, 47 MW at West Brookfield, 48 MW at Triangle, and 111 MW at Peaceable). When adding a +/- 20% sensitivity, the resulting gross direct cost falls within a range of $131 million to $197 million a year. The cost analysis was done for all identified technically feasible NTA technologies based on the combination of their respective gross LCOE and total nameplate capacity requirements - adjusted for operating factors.[32] Under the Supply Case, the gross cost for ratepayers was estimated to range between $83 and $125 million a year for a total installed capacity of 291 aeroderivative peaking units across the four locations. The process of selecting the least cost technically feasible NTA solution is shown in Figure 18. For illustration purposes, we demonstrated the selection process at the Stony Hill substation under the Combination Case.

Figure 18. Illustration of least cost technically feasible technologies selection (Combination Case)

1 Illustration at the Stony Hill substation (N-1)

Active power requirement (MW)	Reactive power requirement (MVar)
50 MW	16.4 MVar

Active power requirement adjusted for assumed EE availability (MW)

8 MW of EE

Active power requirement (MW)	Reactive power requirement (MVar)
42 MW	16.4 MVar

2 Technically feasible technologies at the given location

	Net LCOE ($/kW-y) Scenario 1	Corresponding nameplate capacity required (MW)
Peaker aeroderivative	$148	49
Slow discharge battery	$138	665
Fuel cell	$330	44
EE	$1,630	8

3 Total cost per feasible technology ($million/year)

	Total Cost	Synchronous condenser cost
Fuel cell	$15.5	$2.2
Slow discharge battery	$82.2	$2.2
Peaker aeroderivative	$7.3	$2.2
EE	$13.7	

4 Peaker aeroderivative technology in combination with EE make up the least cost NTA solution at Stony Hill substation

It is worth noting that the successful commercial development of 255 MW or 291 MW of gas-fired generation across the four locations under the Combination Case and the Supply Case respectively

[32] Operating factors include capacity factor, availability factor and ramping rates.

would be challenging for a host of physical constraints such as land and fuel supply availability, and other factors, as discussed in Section 5.2. Therefore, the gross LCOE analysis of technically-feasible NTA technologies is not a comprehensive cost analysis for the specific locations and is not sufficient to determine whether a NTA solution is cost effective and practical.

5.1.2 Net direct cost estimates of NTA solutions for ratepayers

As discussed in Section 4.3.1, the major revenue offsets for NTA technologies include energy and capacity revenues. However, capacity revenues are not certain for these NTAs. First of all, the capacity auction occurs three years in advance and new resources must apply to qualify a year in advance. Therefore, an NTA that is aiming to go into service in 2016 would not be able to secure capacity revenues until May 2021 at the earliest (assuming it has not yet applied in the Show of Interest window for the next FCA for the 2019-2020 deliverability period). In fact, if there is surplus capacity supply, a new resource may not clear, even if it qualified to participate in the capacity auction. Based on LEI's analysis of market developments and ISO-NE's load projections for the future, there may not be "room" in the near term future auctions for additional resources to clear. Therefore, NTA resources brought to market in order to serve as part of an NTA solution for the HVNP sub-area would likely not get revenues from capacity sales for some time, and especially in the initial operating years.[33] In fact, in the (FCA#9), there was enough capacity to meet the system-wide Installed Capacity Requirement ("ICR"). Going forward, we do not see an immediate need for new capacity resources as future capacity needs are expected to be met by other resources, including energy efficiency and other announced resources. As such, there will be little "room" in the capacity market for significant new gas-fired peaking unit, unless existing resources decide to exit the market (i.e., delist and retire). Moreover, for a new generating resource to be accepted and qualified to participate in the FCM, it would not be able to use out-of-market funding (by customers) to gain a competitive advantage on other capacity suppliers. ISO-NE requires that all new resources offer into the FCA consistently with their fundamental costs of investment. Based on ISO-NE's published offer review trigger price ("ORTP") data available at the time LEI performed its analysis, the minimum acceptable offer price for a generic gas-fired CCGT is $9.1/kW-month and minimum acceptable offer price for a generic gas-fired peaker is $13.8/kW-month.[34] Therefore, if the capacity price is lower than this minimum offer price, neither the new CCGT nor the new peaker would be able to compete with existing generation and therefore would not clear the FCA.

In addition, there is uncertainty regarding future capacity prices. Although the most recent FCA (FCA#10) cleared at a lower price than the prior FCA ($7.03 kW-month versus $9.55 kW-month), over time we expect that the ISO-NE capacity market will be balanced, and capacity clearing prices in the FCA will trend to the net CONE. However, there may be years where prices are significantly below that price level. In addition, if all the resources in an NTA solution were to clear the FCA, that would reduce the clearing price in the FCA (and the capacity revenue offsets in the net LCOE), which would

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[33] None of the technically feasible NTA technologies are currently being considered by investors for development at either of the two substations under consideration in the HVNP subarea. Should gas-fired generation be built and interconnected with the two substations, it would likely require out-of-market compensation, especially given the timetables of the Forward Capacity Market vis-à-vis the timing of the required solution.

[34] Parameters for the Tenth Forward Capacity Auction (FCA #10), Capacity Commitment Period 2019-2020. www.iso-ne.com/static-assets/documents/2015/05/parameters_for_the_tenth_forward_capacity_auction.pdf.

then raise the net direct costs of the NTA solution to ratepayers. In light of these capacity market timings and pricing uncertainties, LEI calculated the net direct costs to ratepayers under two scenarios: (i) technically feasible resources would be able to clear FCAs for half the years % of their life span (or alternatively, one can view this scenario as one where capacity prices are depressed below net CONE levels); and (ii) technically feasible resources do not clear any FCA and consequently do not earn any capacity revenues throughout their life-cycle, to defray NTA direct costs to Connecticut ratepayers. Figure 19 summarizes the two scenarios considered by LEI.

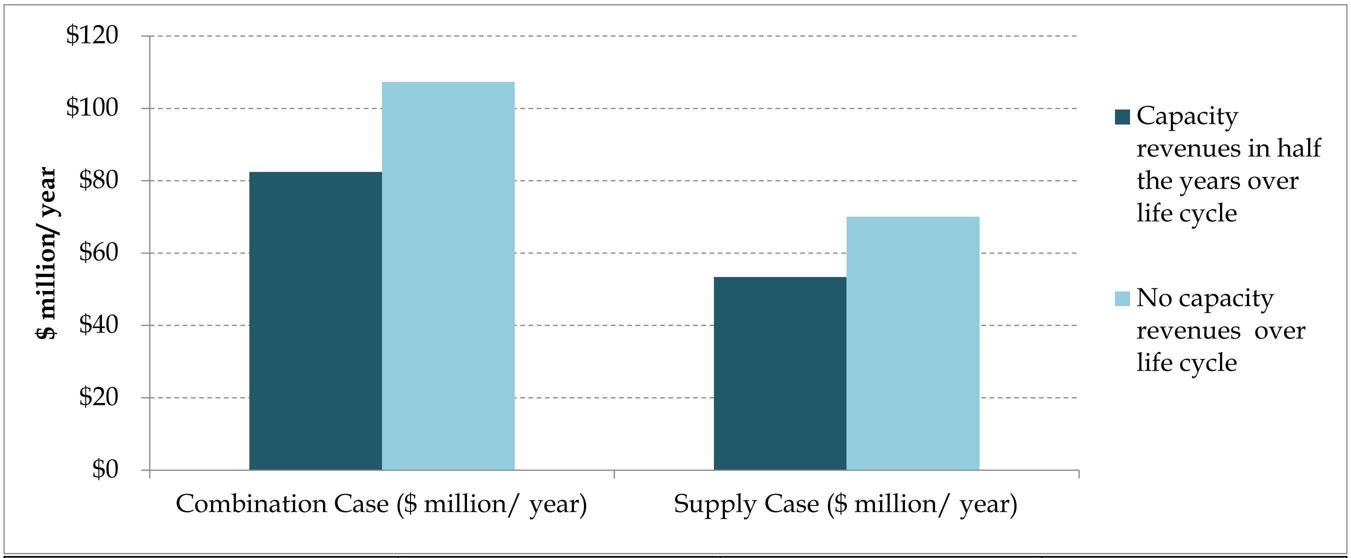
The total net direct cost[35] (gross costs net of revenues offsets) of an NTA solution for the HVNP subarea payable by Connecticut ratepayers was determined to range between $53 million and $107 million a year across the two cases and the two scenarios. The lowest net direct costs ($53 million per year) to ratepayers materialize under Scenario 1 of the Supply Case, where we assume some capacity revenues over the lifetime of the NTA solution (which entails gas-fired peaking capacity using aeroderivative technology).

Figure 19. Summary of LEI's scenarios

Scenario	Methodology	Key assumptions for net LCOE
Scenario 1 (Capacity revenues in half the years over life cycle)	Net LCOE used to select the least cost technologies	We assumed that new resources such as CCGT and peakers would receive capacity payments over half the years of their life cycle
Scenario 2 (No capacity revenues in years over life cycle)	Net LCOE used to select the least cost technologies	We assumed that none of the new resources would receive capacity payments over their respective life cycle

[35] Net LCOEs were derived from mid-range gross LCOE values.

Figure 20. Estimated net direct costs of NTA solution for the HVNP subarea per annum based on varying assumptions regarding offsetting revenues and subsidies



	Scenario 1	Scenario 2	HVNP
Scenarios	Capacity revenues in half the years over life cycle	No capacity revenues over life cycle	Cost of the transmission solution shouldered by end-users
Combination Case ($ million/ year)	$82.4	$107.3	$2.1
Supply Case ($ million/ year)	$53.4	$70.0	

5.2 Qualitative discussion of the practical feasibility of NTA solution in the HVNP subarea

There are several factors associated with each NTA technology that will have further bearing on its practical feasibility at the required interconnection point or node. The scope of this analysis does not presume to identify and evaluate all criteria for successful development of technically feasible, least cost NTA technologies at the four locations within the HVNP subarea. However, we have considered general development requirements associated with each NTA technology and a macro-level assessment of the practical feasibility of the necessary NTAs.

A community's enthusiasm towards a project is usually a key determinant in a project's success. Some of the community's major concerns relate to the project's impact on the environment (emission of pollutants), and the impact on life quality (potential for noise disturbance or irreversible changes in the landscape). Moreover, the costs associated with developing accompanying infrastructure are prone to increase the financial burden for the community. All of these concerns can weigh on a project's permitting process, as well as eventual completion. Some of the important practical considerations for all the technologies reviewed (including those not considered technically feasible) are summarized in Figure 21 below. The discussion of these considerations in the following paragraph is, however, focused on the technically feasible NTA technologies identified in LEI's analysis.

Figure 21. Qualitative review of NTA technologies

NTA Resource	Land requirement	Enabling infrastructure	Pollution
Combined Cycle Gas Turbine (CCGT)	Sizeable footprint	Gas lateral/pipeline; access to water; interconnection costs	Noise; air emissions
Peaker Aeroderivative Unit	Small footprint	Gas lateral/pipeline; interconnection costs	Noise; air emissions
Peaker Frame Unit	Sizeable footprint	Gas lateral/pipeline; interconnection costs	Noise; air emissions
Dual-fuel Jet Engine	Small footprint	Gas lateral/pipeline; on-site fuel storage	Noise; air emissions
Solar Utility Scale (with storage)	Sizeable footprint	Interconnection costs	N/A
Solar DG (with storage)	Sizeable footprint	Interconnection costs	N/A
Slow Discharge Battery	Small footprint	Interconnection costs	N/A
Active DR - Emergency Generation	Small footprint	N/A	Noise; air emissions
Passive DR (Energy Efficiency)	N/A	N/A	N/A
Fuel Cells	Small footprint	Gas lateral/pipeline; interconnection costs	N/A

Market limitations

No gas-fired peaking unit is currently operating or has been proposed in the ISO-NE's interconnection queue[36] for development at West Brookfield, Stony Hill, Triangle, and Peaceable substations. ISO-NE's load growth projections coupled with LEI's analysis of market developments suggest there is not likely to be sufficient "room" in the capacity market or a market need for additional gas-fired generation in the next few upcoming capacity markets auctions. Therefore, securing these resources without sustained capacity revenues might require out-of market funding, exposing Connecticut ratepayers to greater cost.

End-use customers mix

We conservatively assumed a load reduction rate of 15% for new (incremental) EE programs that could be a demand-side NTA solution. These new EE programs would be above and beyond existing and planned programs (as of ISO-NE's load forecast for 2022) which was relied upon by the Eversource planners. This load reduction rate depends a great deal on the participation and mix of customer types in the specific location being targeted. A zone dominated by large commercial and industrial facilities is likely to feature the best load reduction rates; whereas zones dominated by residential customers could achieve load reduction rates as low as 1% to 2%, in which case, demand-side resources would not be an

[36] Accessed as of November 19, 2015.

effective NTA. The load at the studied locations is dominated by residential customers (according to Eversource, about 50% of the load is residential).

Land requirements

The development of many supply-side NTA technologies is contingent upon the availability of buildable space (measured in acres) at or near the proposed hypothetical injection point in order to be a practically feasible solution. The least cost, technically feasible NTA technologies for the HVNP subarea entails the commercialization of several aeroderivative peaker units at the four locations, totaling 291 MW of capacity. Building this amount of capacity would require permitting the usage of about 7.3 acres[37] in largely a residential area.

Enabling infrastructure

In addition to land, some NTA technologies need other enabling infrastructure to be practically feasible at a given hypothetical injection point. There needs to be sufficient transmission infrastructure to interconnect a generation unit and provide for the delivery of the energy into the bulk power system.[38] In addition, gas-fired resources (including fuel cell facilities) will require access to fuel supply through pipeline infrastructure. Some peaking units can be co-located alongside existing generation facilities (if there are sufficient land resources for zoning and permitting) or on-site of retired generation or other former "brownfield" facilities, which could reduce the costs of installation. Although Stony Hill substation is situated next to a major gas pipeline,[39] it is not the case for the rest of the locations. West Brookfield substation, Triangle substation, and Peaceable substations are located at 1.3 miles, 1.5 miles, and 8.2 miles away respectively from the closest natural gas pipeline.[40] Figure 22 shows the geographical location of the four locations in relation to the interstate natural gas pipelines that supply within the state of Connecticut.

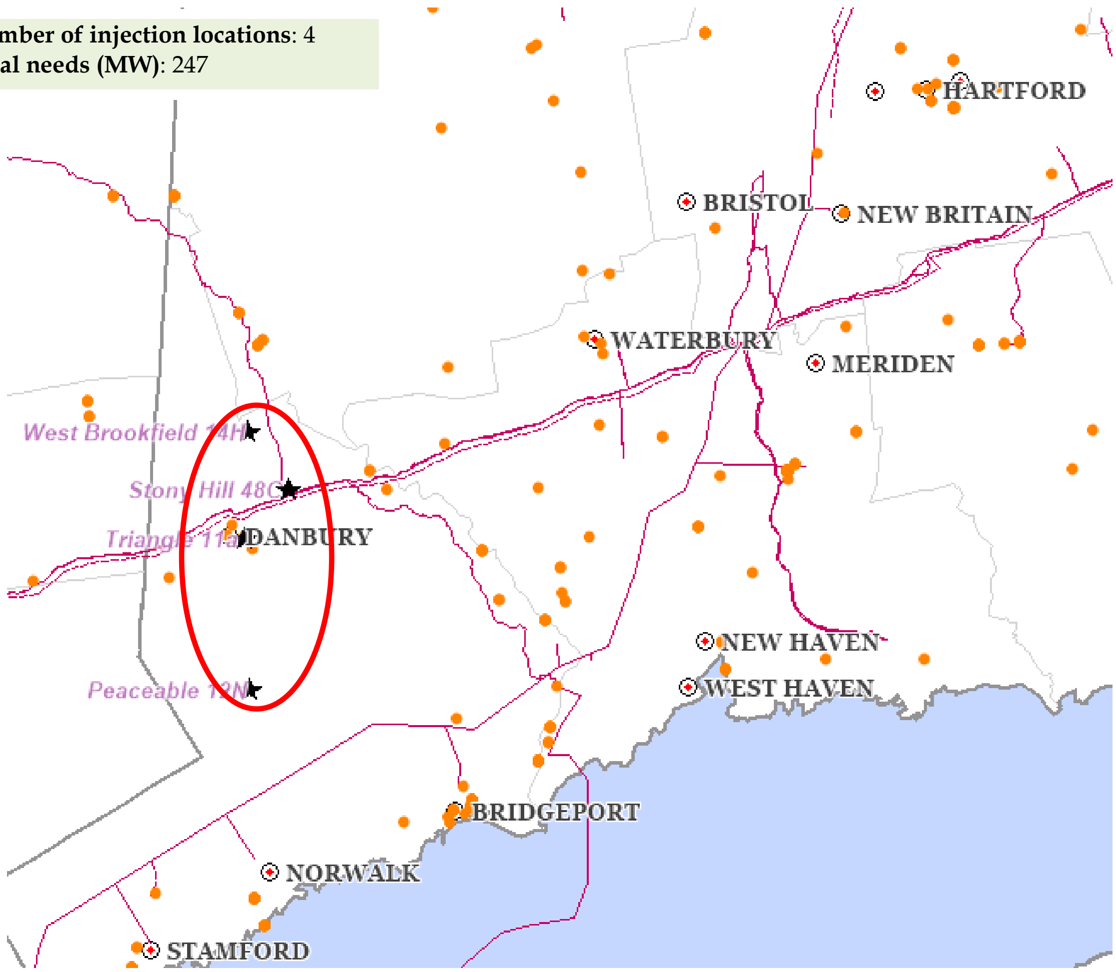
[37] Assuming 1 acre per 10 MW – (source: PGE 2013 IRP, Black Veatch - Appendix G Cost and performance data for power generation technologies).

[38] No interconnection study was performed to determine whether there may be transmission upgrade costs associated with interconnection and/or deliverability.

[39] Iroquois gas transmission system.

[40] West Brookfield substation is also located 1.3 miles away from the Iroquois Gas Transmission pipeline; Triangle substation is also located 1.5 miles away from the Algonquin Gas Transmission pipeline; Peaceable substation is located 8.2 miles away from the Tennessee Gas pipeline.

Figure 22. NTA requirements at the four injection locations



The closest (large) cities are demarcated with red dots; orange dots represent existing generation assets; injection locations are labeled with a blue marker; and gas pipelines are represented by pink lines.

As such, any gas-fired facility at this location will require building additional gas pipelines (laterals) to secure access to gas supply. Based on preliminary estimates using distance-based metrics and typical costs per mile, this would result in more than $31.9 million[41] in additional up-front capital costs that was not considered in LEI's net LCOE analysis for the least cost, technically feasible NTA solution involving gas-fired peaker technologies.

[41] We assumed a $2.9 million per mile pipeline cost based on the average of $/mile of natural gas lateral projects (without any consideration for line capacity) built in New England over the past years (Source: EIA, natural gas pipelines projects via SNL Finance).

6 Conclusion

The least cost alternative to the HVNP transmission solution, determined under the Supply Case (Scenario 1), required a total of 291 MW of additional new peaker aeroderivative capacity (with synchronous condensers). The Combination Case suggesting an NTA solution combining EE resources and supply-side NTA technologies was not the least cost alternative.

Many NTA technologies are simply not technically feasible from a planning perspective. Certain NTA technologies, such as solar DG, do not possess the operating characteristics required to meet the reliability needs under N-1 and N-1-1 contingencies and therefore could not provide the same reliable service as the preferred HVNP transmission solution. Other technologies, like utility scale solar (with battery storage), could not be developed in these particular geographical areas in sufficient quantities (due to land requirement and associated cost) to meet the NTA requirement amount.

Although there are technically feasible NTA technologies that could meet the reliability needs in the HVNP subarea at the specific nodes identified by Eversource's planning staff, these NTA technologies are estimated to be more costly than the preferred transmission solution. In fact, the least cost technically feasible NTA solution was estimated to cost Connecticut ratepayers significantly more than the portion of the annual cost of the transmission solution payable by Connecticut end-use customers. Furthermore, there are a host of practical impediments to developing and bringing to fruition an NTA solution. Such practical hurdles include the siting challenges related to land availability (and permitting), as well as the build-out of the requisite fuel supply infrastructure (as well as negotiating fuel supply contracts). There are also questions related to the development process itself, as no private developer to date has shown interest in bringing to market an NTA that would fit the technological requirements and geographical requirements of the necessary NTA solution.

7 Appendix A: LEI's Qualifications

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation, transmission and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulating markets worldwide.

LEI's areas of expertise straddle both the deregulated/market environments (including for example, price forecasting and asset valuation; wholesale power market analysis; market design (ISO market rules); and competitive procurement) and application of regulatory economics (such as regulated tariff design; cost of service ratemaking and performance based ratemaking; productivity analysis; policy design for incentivizing renewable energy and new technologies; and transmission and distribution network analysis). Provided below is a sample of previous LEI work showcasing its considerable experience, notably in the analysis of transmission projects and Non-Transmission Alternatives.

<u>Sample of projects relating to Non-transmission alternatives, cost-benefit analysis of transmission projects</u>

Non-transmission Alternatives analysis for the Greater Boston area: LEI was engaged by National Grid and Eversource Energy ("the Utilities") to determine the economic viability of non-transmission alternatives ("NTAs") to replace a combination of three transmission solutions designed to address reliability and performance issues in the Greater Boston area starting in 2018. More specifically, LEI's scope of work consisted of determining the least cost combination of technologies that could be integrated to the New England transmission system and provide the same reliability benefits as the proposed transmission lines. A combination of supply-side and demand-side resources were considered for the study, this included: distributed solar PV, utility-scale solar PV, energy efficiency and active demand response, conventional generation (gas CCGT and peakers), as well as energy storage devices. LEI started the analysis by screening prospective NTA technologies based on their technical characteristics, their relevance in the New England market and their technical applicability with regards to the operational criteria required by the grid to address contingency events (i.e volume of available capacity/energy, time of response, duration of response, flexibility etc…). Next, LEI conducted a comparative cost analysis to estimate the levelized cost per kW-month over the economic life of each of the technologies. Through his selection process, we retained technically feasible NTAs that are materially less expensive than other comparable options at the same locations (substations). Finally the most probable combinations of NTA technologies identified in the selection process were further evaluated based on their probability of materialization taking into account a spectrum of criteria including physical constraints such as land availability, siting issue, financing hurdle, etc.

White paper on Non-transmission Alternatives ("NTAs"): London Economics International LLC ("LEI") was engaged by WIRES to prepare a White Paper on Market Resource Alternatives ("MRAs") which provides external parties with a clear understanding of MRAs and a concise description of how

MRAs can work effectively alongside transmission investment in US power markets to support market development, reliability, and cost-effective supply. The structure of the White Paper specifically has the goal of "education" in mind. It started with the definition of MRAs, and then LEI presented case studies and lessons learned from several regional markets. The White Paper also recommended a conceptual analytical framework for proper and effective consideration of MRAs in transmission planning processes.

Cost-benefit analysis of a proposed transmission line: For a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible.

CHPE application for siting - Julia Frayer led LEI's team regarding the detailed cost-benefit analysis and macroeconomic impact analysis in support of the Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Department of Public Service ("DPS"). LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between Transmission Developers, Inc. ("TDI") and a number of New York agencies. Julia acted as independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. Julia's testimony was used in the DPS proceeding in the summer of 2012.

Lake Erie HVDC transmission project – cost /benefit analysis: LEI was hired by a private developer to assess the economics of the proposed Lake Erie HVDC transmission project and determining the additional revenue streams or value adders of the Lake Erie HVDC transmission project ("LEP") from the perspective of third-party shippers. The LEP is a 100-km long 1,000 MW bi-directional HVDC transmission line that will connect the Ontario energy market with the PJM market. LEI prepared a comprehensive report that includes a review of the Ontario and PJM markets, a 20-year (2017 to 2036) market outlook and prices for electricity, capacity and renewable energy credits in Ontario and the relevant zone/s in PJM; the total gross arbitrage value for the energy congestion rents, the capacity revenue potentials for PJM, and the renewable energy credits revenue potential in PJM.

Forecast the impact of a 1,000 MW DC transmission line on New England market prices: LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices. The project proposes to build a 1,000 MW DC-based transmission line that between Quebec and Vermont and import energy into Vermont. LEI modeled the long-term price forecast for Vermont and the rest of ISO-NE over the 2019-2028 period, and examined the price differentials. Two cases were modeled: a Base Case (without the HVDC project), and the Project Case (with the HVDC project). Analysis was done under the assumption that the transmission capacity on the project will accommodate low-cost hydro imports from Quebec. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to Vermont and other New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

Assess the potential economic benefits of a New England transmission project: LEI was commissioned by Northeast Utilities to determine the potential economic benefits of the proposed NEEWS transmission project. Using detailed hourly simulation modeling of future power market conditions, LEI studied the potential market implications of NEEWS for ten years from a notional expected date of commercial operation of 2014. LEI reached the following conclusions: New England ratepayers could expect cumulative energy cost savings attributable to NEEWS over ten years under normal operating conditions; NEEWS would create regional energy market impacts; each phase of NEEWS would create energy market benefits over the ten-year modeling horizon; NEEWS would reduce LFRM costs each year; NEEWS would provide an insurance hedge against stressed system events; and NEEWS would offer market access to renewable resources in Northern New England/Canada.

Forecast the impact of a proposed transmission interconnection on Maine customers: LEI was engaged by a US power utility to perform a 15-year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.

Analysis of congestion rents and forecasted impact on energy and capacity prices due to a proposed transmission line: In connection with a proposed transmission line from Hydro Quebec to New York City, LEI Managing Director Julia Frayer led a team that forecasted 10-year energy and capacity prices of the New York market using POOLMod. The team also conducted analysis on congestion rents to support the client's negotiation with potential shippers. In support of the client's filing at the NYPSC, the LEI team conducted analyses on generation and production cost savings, emission reductions and sensitivities.

MA Energy Facilities Siting Board ("EFSB"): in response to NU retaining LEI, New England wholesale electricity markets were simulated in order to determine whether the Greater Springfield Reliability Project ("GSRP") would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, a distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results introduced as testimony to the EFSB, which is scheduled to be presented in October. (2009) **[MA EFSB, EFSB 08-2/DPU 08-105/DPU 08-106].**

Assess the economic value of a proposed transmission project: LEI was hired by a transmission developer to conduct an independent rigorous modeling exercise to determine the potential revenues for the proposed transmission project wheeling power from western MISO to East MISO (and eventually PJM). LEI evaluated both the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM. LEI's modeling exercise entailed evaluating intrinsic revenues (originating from power markets), extrinsic revenue (originating from price volatility), along with the green value of the Project (originating from the purchase of low cost renewable energy). LEI's overall analysis was comprehensive and included a series of sensitivity scenarios testing key value drivers.

Sample of projects in Connecticut

Connecticut

Connecticut Siting Council ("CSC") – NU/GSRP: LEI simulated the New England wholesale electricity markets in order to compare the economic benefits between Greater Springfield Reliability Project ("GSRP") and responses to the Connecticut Energy Advisory Boards' ("CEAB") RFP for a non-transmission alternative ("NTA") to GSRP. The NTA consisted of modeling a new CCGT plant to be placed in Southwestern Connecticut. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. In effect these 30 different simulations added further robustness to our results because it captured the flexibility of the New England energy market under several different normal operating conditions. Furthermore the simulations created a distribution of results which was used to calculate confidence intervals and hypothesis tests, hence further increasing the robustness of our findings. The study results were used to produce written testimony to the CSC, oral testimony was provided in late August and early September 2009. (2008-2009) **[CSC, Docket 370].**

NU-NSTAR merger: in support of a client's opposition of a proposed NU-NSTAR merger, LEI analyzed the potential competitive market effects on a vertical scale and considered the extent of buyer market power for the purchase of standard service (full requirements) products. The testimony was submitted to the Public Utility Regulatory Authority (PURA). In a later submission, LEI also analyzed the settlements reached or proposed in a number of recent utility mergers. (2012) **[PURA Docket No. 12-01-07].**

Impact analysis of transmission project: LEI advised a major transmission company on financial implications of proposed new 400kV transmission line to New York City and Connecticut. LEI analyzed the impact of new transmission, assuming it delivered 100% carbon-free energy, on electricity prices and emissions levels in New York and New England.

2006 "All Source" RFP: LEI served as the economic advisor to the Connecticut Department of Public Utility Control (DPUC), helping them design and implement an "all source" RFP for new capacity in the state in order to mitigate the exposure to ratepayers from Federally Mandated Congestion Costs. As economic advisor and RFP Coordinator, LEI was responsible for managing all aspects of the RFP, including design of innovative financial contracts for capacity, administration of RFP process, and evaluation of bids submitted by project sponsors, and recommendation to the DPUC for selection of winning projects. The selection of projects is based on a proprietary set of models that LEI staff designed to estimate the cost-benefit to ratepayers from long term contracts with new capacity, based on reduction in wholesale market costs across three different ISO New England power markets. LEI also submitted significant written testimony during the 18 months of this engagement, and LEI staff also testified orally on numerous occasions. (2006-2007) **[DPUC, Docket No. 05-07-14PH02; FERC, ER03-563-000**].

DPUC auction oversight: the DPUC retained the services of LEI to assist it in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and in September 2005 to monitor the November 2005 auction for services in 2006. LEI 's mandate included providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. LEI filed affidavits after the completion of each auction process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders. (2004 and 2005) **[DPUC, Docket No. 03-07-18PH02].**

Sample of projects in New England

Projection of retail rates for commercial customers in New England: LEI performed a market study reviewing historical electric rates (and projecting forward electric rates) for large commercial customers in the New England market. The electric rates analysis was composed of a number of components, such as the commodity costs of electricity, compliance costs for certain state programs (like RPS), delivery charge for delivering electricity, and ancillary services and administrative supply charges. LEI created projections for each of these components and considered state retail sales requirements for renewables and other factors.

New England energy price outlook and economic impacts: LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed transmission project on New England market prices. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI took into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

Review of NESCOE study: LEI conducted a comprehensive review of the NESCOE Gas Electric Phase Three study in order to ensure that the appropriate economic models and techniques were being used to accurately model the hydro and gas solutions. LEI also aided the client in identifying any assumptions and modeling approaches which may be suboptimal, and communicated how these issues can be addressed and improved in future studies.

Maine

Advisory to Maine Public Utilities Commission on RPS: LEI presented a written report on the state of renewable portfolio standard (RPS) requirements in Maine and regionally across New England. LEI also testified at the Maine legislature. The report was commissioned by the Maine Public Utility Commission to fulfill a statutory requirement to provide research on the issue of RPS and its impact on generators and consumers.

Advisory to Maine Public Utilities Commission on transmission cost allocation: LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report will provide a 'strawman' recommendation for an effective cost allocation methodology. (2010) **[Docket No. RM10-23-000].**

Advisory to the Maine Public Utilities Commission on RFP: LEI assisted the Commission on the RFP related to the procurement of electricity in response to statutory mandates and state policy preferences. LEI provided economic analyses of bid proposals by estimating the benefits and costs to the ratepayers, and is currently supporting Commission staff in negotiations with short-listed bidders. (2009).

Development of an Electric Resource Adequacy Plan in Maine: in Docket No. 2008-104, LEI assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts. LEI submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market, an examination of historical price trends, and review of the investment needs assessments prepared by the utilities and ISO-NE, as well as relevant sub-regional planning studies. (2008) **[Maine PUC, Docket No. 2008-104].**

Maine renewable portfolio requirement: LEI was engaged by the Maine Public Utilities Commission to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by a legislative Act. This analysis supported a Commission study and report to the Legislature. Julia led the team in preparation of the report, which was submitted to the Commission and later testified at the state legislature on the key findings of that report.

New Hampshire

Testimony describing wholesale market dynamics and benefits of Northern Pass in averting supply risks associated with generation "at risk" for retirement: On behalf of Public Service of New Hampshire, LEI testified in front of the new Hampshire Senate Committee on issue of eminent domain generally and more specifically, on the power market context and near term outlook for the New England power market and reasons for the development of a new proposed transmission project known as Northern Pass.

Vermont

Testimony on proposed merger between Central Vermont Public Service and Green Mountain Power: for a small independent power producer, LEI prepared a testimony on the potential harms of the proposed merger to the client and proposed certain conditions for the Vermont Public Service Board to consider. (2012) **[PSB Docket No. 7770].**

ISO-NE tariff design: LEI submitted testimony on behalf of ISO New England to the FERC to help defend ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, and then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, and frequent interaction with stakeholders. (2000) **[ER01-316-000].**

Commercial litigation in New England

PPA contract dispute: LEI provided expert witness service for a private equity investor in matter related to a contractual dispute regarding a long term power purchase agreement between a municipal utility located in New England and a landfill gas generator. LEI analyzed the key contractual terms of the PPA and providing an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. LEI will also be providing an independent estimate of potential contractual damages. (2010-2011) **[Commonwealth of Massachusetts Superior Court Department, Civil Action No. PLCV2006-00651-B].**

Updated market power analysis: prepared for a US utility's triennial review of market-based rate authorizations for certain subsidiaries in the northeast region. LEI analyzed the company's market power in PJM and ISO-NE. (2010) **[ER98-4159, et al.].**

Section 203 and 205 analysis in support of NRG's acquisition of certain Dynegy assets in CAISO and ISO-NE: LEI was engaged to provide testimony in support of a proposed acquisition. LEI performed a Delivered Price Test (DPT) for CAISO and ISO-NE energy markets as well as a standalone Herfindahl-Hirschman Index (HHI) analysis for the capacity markets. In addition, LEI discussed the impact of the acquisition of the ancillary services markets. (2010) **[EC10-88-000]**

Confidential FERC investigation in 2009-2010 of market manipulation in New England: Julia and her team assisted the client with certain matters pertaining FERC investigation. Specifically, the scope of this retention included economic and market analysis in support of a market participant in ISO New England's day ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.

8 Appendix B: Technical and operational characteristics of various NTA technologies

Operating size and capacity factor

Each injection point has a specified amount of MW requirement that must be met by an eligible NTA. Each NTA under consideration has been selected based on whether previous examples of its successful operations have been documented in Connecticut. In addition, the minimum and maximum operating size for the short-listed NTAs were determined by evaluating typical operating size of similar technologies in New England, Connecticut and where available in the SWCT subarea. Furthermore, each NTA has a representative capacity factor which is based on actual data relevant to installations of that technology in Connecticut. Together these parameters help determine if a particular NTA can meet the injection requirements at a specific injection point.

NTA Performance Parameters

Response time is an important criterion to determine eligible technologies under N-1-1 contingency events. Under an N-1-1 contingency event, eligible NTAs must be able to inject power in less than 30 minutes. In addition to response time and ramp rate, the duration for which a given NTA can inject power after it has been called into service during a contingency event is also a vital criterion. Based on its understanding of ISO-NE rules,[42] LEI's model uses a conservative estimate of 12 hours (the standard duration of high load in the summer season) as the minimum duration for which an NTA must remain online for N-1-1 contingency event in order to qualify as a technically feasible NTA.

Specific values for each of these criteria defined above are summarized in Figure 23. The second column indicates the typical minimum and maximum MW size for each NTA, while the third column defines the operations profile of the NTA, finally, the last column, duration, refers to the length of time these NTAs can produce power without interruption. For fossil fuel powered NTAs, the underlying assumption is that the availability of fuel is not a constraint. For NTAs with storage technologies such as solar PV, we assume that the storage capacity is long enough to support the NTA for during nighttime hours.

[42] Subsection III of Part III – Procedure of ISO New England Operating Procedure No. 8 Operating Reserve and Regulation. May 2, 2014. Available at http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

Figure 23. Technical characteristics of NTA technologies

Numbers	NTA Resource	Installed Capacity range	Operations profile	Performance Rate	Duration (Hr.)
1	**Combined Cycle Gas Turbine (CCGT)**	200 to 700 MW range in CT	Baseload	95% availability factor	24
2	**Peaker Aeroderivative Unit**	1 to 125 MW range	Peaking load	85% availability factor	24
3	**Peaker Frame Unit**	20 to 250 MW range	Peaking load	83% availability factor	24
4	**Dual-fuel Jet Engine**	<1 to 50 MW	Peaking load	85% availability factor	24
5	**Solar Utility Scale (with storage)**	5 to 250 MW	Potential baseload depending on storage capacity	15% efficiency ratio	24
6	**Solar Utility Scale**	5 to 250 MW	Daytime peaking load during sunny days	15% efficiency ratio	12
7	**Solar DG (with storage)**	<1 to 5 MW	Potential peaking load depending on storage	15% efficiency ratio	12
8	**Solar DG**	<1 to 5 MW	Daytime peaking load during sunny days	15% efficiency ratio	8
9	**Fast Discharge Battery**	<1 to 10 MW	Can provide instantaneous power for short periods	Variable, depending on efficiency, charging time and storage capacity	2
10	**Slow Discharge Battery**	10 to 20 MW	Can provide steady supply of power for short periods	Variable, depending on efficiency, charging time and storage capacity	12
11	**Active DR - Emergency Generation**	Variable (based on type of equipment and load)	Peaking load	Assume 25% of peak load becomes available to respond	24
12	**Passive DR (Energy Efficiency)**	Variable (based on type of equipment and load)	Intermittent	Assume 25% of peak load becomes available to respond	24
13	**Fuel Cells**	2.8 MW to 63 MW	Baseload	95% availability factor	24

Note 1: Wind was not considered as a technically feasible NTA due to the lack of potential for sizeable wind capacity development in the Connecticut.

Note 2: Installed capacity range for utility scale fast and slow discharge batteries depends on the number of individual batteries connected together at a given site. The range indicated in the figure above is indicative, and LEI used variable sizes depending on requirements in order to ascertain the technical feasibility of using batteries as NTA technologies.

Note 3: Performance rates for CCGTs, Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines calculated based on the ISO New England EFORd Class Averages, sourced from: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf

Note 4: Active DR emergency profile is sourced from ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." ISO-NE, November 7, 2014 http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

Note 5: Size of fuel cells based on DFC3000 units from FuelCell Energy. The maximum size was based on the anticipated 63 MW fuel cells plant to be built in Connecticut (the largest yet in the world). Fuel Cells technology is baseload and can run 24/7 pending fuel availability. Given the limited information on availability factor, we assumed the same availability factor as a CCGT.

Figure 24. Technology parameter determination assumptions

	Parameter	Methodology	Source
CCGT	**Minimum/Maximum Size**	Based on typical observed installed capacities, capped at the maximum value of CCGT unit in Connecticut	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE (based on new construction over the past 20 years)
	Ramp Rate	CCGTs are assumed already committed	Not applicable
	Performance Rate	CCGTs are assumed to have 95% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	CCGTs are not energy limited resources	Not applicable
Peaker Frame Unit	**Minimum/Maximum Size**	Based on typical observed installed capacities	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance Rate	Peaker Aeroderivative units are assumed to have 85% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Frame units are not energy limited resources	Not applicable
Peaker Aeroderivative Unit	**Minimum/Maximum Size**	Based on typical observed installed capacities, with the assumption that several units can be installed together (capped at the value for which a peaker aeroderivative unit becomes a feasible technology	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE (based on new construction over the past 20 years)
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance Rate	Peaker Frame units are assumed to have 83% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Aeroderivative units are not energy limited resources	Not applicable
Dual-Fuel Jet Engines	**Minimum/Maximum Size**	Based on typical observed installed capacities	Review of information provided by manufacturers (Wärtsilä) and actual data of operation in ISO-NE
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational

	Parameter	Methodology	Source
			data in ISO-NE
	Performance factor	Dual fuel jet engines are assumed to have 85% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Jet Engines are not energy limited resources	Not applicable
Solar Utility-Scale	**Minimum/Maximum Size**	Based on typical observed installed capacities and ISO's definition	Review of utilities' new installations in CT and external sources such as "Utility-Scale Concentrating Solar Power and Photovoltaic Projects: A Technology and Market Overview." (National Renewable Energy Laboratory)
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in CT	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Connecticut
	Duration	Limited to daytime	Not applicable
Solar Utility-Scale with storage	**Minimum/Maximum Size**	Based on typical observed installed capacities and ISO's definition	Similar assumptions as for "utility scale solar"
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in CT	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Connecticut
	Duration	Storage capacity assumed sufficient to deliver energy equivalent to solar capacity factor at night [needed for a minimum of 12 hours to last through a contingency]	Not applicable
Solar DG	**Minimum/Maximum Size**	Based on typical observed installed capacities and ISO's definition	Connecticut and external sources such as "Utility-Scale Concentrating Solar Power and Photovoltaic Projects: A Technology and Market Overview." National Renewable Energy Laboratory. April 2012. http://www.nrel.gov/docs/fy12osti/51137.pdf
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in New England	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Connecticut
	Duration	Limited to daytime	Not applicable

	Parameter	Methodology	Source
Fast-Discharge Batteries	Minimum/Maximum Size	Based on typical observed installed capacities, with the assumption that batteries can be installed in banks (capped in the model to total installed capacity in the US in 2015)	Review of information provided by manufacturers (Flywheel (Beacon Power, NaS Batteries (NJK)) & Energy Storage Association
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Based on typical charging-discharging cycle efficiency	Review of information provided by manufacturers, and Electric Power Research Institute
	Duration	Typical value for available technologies	Review of information provided by manufacturers , and Electric Power Research Institute ("EPRI"),
Slow-Discharge Batteries	Minimum/Maximum Size	Based on typical observed installed capacities, with the assumption that batteries can be installed in banks (capped in the model to total installed capacity in the US in 2015)	Review of information provided by manufacturers (Flywheel (Beacon Power, sodium sulfur (NaS) Batteries (NJK)) & Energy Storage Association
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Based on typical charging-discharging cycle efficiency	Review of information provided by manufacturers, and Electric Power Research Institute
	Duration	Typical value for available technologies	Electric Power Research Institute ("EPRI")
Fuel Cells	Minimum/Maximum Size	Based on DFC3000 unit size	FuelCell Energy (manufacturer)
	Ramp Rate	(baseload/running at all time)	Not applicable
	Performance factor	Assumed same as CCGT 95%	Not applicable
	Duration	Available at all times pending fuel availability	FuelCell Energy and EIA

9 Appendix C: Derivation of cost estimates for various NTA technologies

In this appendix we disclose gross and Net LCOE of all considered technologies (feasible and infeasible) and provide detailed information on all sources used. A summary of the sources utilized is documented in the following Figures.

Figure 25. Gross and net LCOE per technology ($/kW-year)

	CCGT	Frame Peaker	Aeroderivative peaker	Dual Fuel Jet engine	Slow discharge batteries	Fast response energy storage	Utility-scale solar (with storage)	Solar DG (with storage	Passive DR (EE)	Fuel Cell
Gross LCOE	398	231	323	363	181	154	416	523	2,867	734
Energy*	283	130	118	120	0	0	66	0	0	434
FCM	57	57	57	57	0	0	20	0	75	0
LFRM	0	0	0	0	13	0	0	0	0	0
Regulation	0	0	0	0	33	33	0	0	0	0
Avoided retailed cost	0	0	0	0	0	0	0	22	1,163	0
Net LCOE	57	44	148	185	136	121	8	180	1,630	301
Overnight capital cost ($/kW-year)	1,146	783	1,486	1,486	1,330	1,277	3,697	5,830	N/A	7,475

**** Includes fuel and variable operating and maintenance costs***

Sources: Summarized in Figure 26 below.

Figure 26. Assumptions and sources on gross LCOE

Technologies	Methodology	Sources
Peaker (aeroderivative and frame units) and CCGT technologies	Gross LCOE based on ISO-NE's estimates adjusted for O&M and fuel cost. Gross LCOE for CCGT was adjusted to reflect smaller than standard size of the required plant. The generic CCGT considered by ISO-NE it is analysis has a size ranging between 500 and 700 MW. CCGT qualified as smaller than usual will likely be more expensive due to the lack of scale. This is reflected by a 12% increase in gross LCOE based on the overnight cost difference between 400 MW and a 600 MW power plant	ISO New England's demand curve assumptions for the Forward Capacity Auction # 9 EIA http://www.iso-ne.com/regulatory/ferc/filings/2014/apr/er14-1639-000_demand_curve_c
Energy storage (slow discharge and fast operating response)	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs such as overnight capital cost and VOM and FOM were sourced from NREL and PNNL. Results were then cross-checked against industry's estimates (IEA)	National Assessment of Energy Storage for Grid Balancing and Arbitrage", Pacific Northwest National Laboratory http://energyenvironment.pnnl.gov/pdf/National_Assessment_Storage_PHASE_II_vol_2_ International Energy Agency http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapEnergystorage.pdf and LEI
Utility -scale solar	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to such as overnight capital costs and O&M sourced from NREL, EIA and DOE. Results were then cross-checked against industry's estimates.	National Renewable Energy Laboratory ("NREL") http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html Sun Shot Initiative (US Department of Energy), SEIA - http://www.seia.org/research-resources/solar-market-insight-report-2014-q1; and LEI
Solar DG	Gross LCOE was estimated through LEI's proprietary LCOE model and industry's estimates -(from NREL and DOE)	NREL (PV system pricing trends, 2014 - http://www.nrel.gov/docs/fy14osti/62558.pdf and LEI
Dual fuel jet engine	Key inputs to LEI's proprietary LCOE model such as overnight capital costs and O&M sourced from NYISO's estimates (technologies reviewed to established cost of new entry) sand Wärtsilä	Wärtsilä, NYISO Demand curves filing http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-22/2013%20NYISO%20Demand%20Curve%20Recommendation_draft_8-18-13.pdf
Passive DR (EE)	Eversource's internal projection of costs associated with energy savings (Electric and Natural Gas Conservation and Load Management plan 2016-2018, publicly filed on October 1st, 2015)	Eversource
Active DR (RTEG and RTDR)	Key inputs to LEI's proprietary LCOE model such as overnight capital costs and O&M sourced from EPRI (RTEG); Cost estimates for RTDR determined based on VOLL for a 12 hour requirement (N-1 and N-1-1 criteria)	EPRI- http://www.publicpower.org/files/deed/finalreportcostsofutilitydistributedgenerators.pdf LEI and ISO-NE http://www.iso-ne.com/markets-operations/system-forecast-status/current-system-status/op4-archiv
Fuel Cell	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to LEI's proprietary LCOE model such as overnight capital costs and O&M sourced from FuelCell Energy (DFC3000 technology) as well as fixed costs of existing units such as astlake Mobile Fuel Cell System, Bloom Energy Fuel Cell Project, or CSU – East Bay Fuel Cell	FuelCell Energy http://www.fuelcellenergy.com/assets/PID000218_FCE_BFCP_Open-House-Spotlight_r2_HIRES.pdf

For market revenue information, we relied primarily on documents and market information made publicly available by ISO-NE and as relevant for the state of Connecticut. For technical and cost information, sources relied upon include mainly independent engineering reports and market research performed by US government sponsored laboratories and research institutes as well as US Government agencies and manufacturing companies when relevant.

Figure 27. Assumptions and sources of revenue streams

Technologies	Methodology	Source
Energy	Determined average annual revenue on the energy markets for a generic technology based on LEI's outlook of market prices	Based on LEI's ISO-NE wholesale price forecasts
FCM	Revenues calculated based on FCA#9 results	Based on FCA#9 - http://www.iso-ne.com/markets-operations/markets/forward-capacity-market
LFRM	Revenues calculated using most recent clearing price (winter and summer) adjusted for participation time	Based on 2014 summer and 2014/2015 winter results (net of capacity payments) http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf
Regulation	Revenue calculated based on regulation price adjusted for estimated market share	Based on 2014 clearing prices (ISO NE) (Commercially available database)
Avoided retailed cost	Avoided cost calculated based on average annual retail costs (based on September 2015 average) and EE programs' target customers (documented in Electric and Natural Gas Conservation and Load Management plan 2016-2018, publicly filed on October 1st, 2015)	EIA's statistics on CT's retail costs ; http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a

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