Rhode Island Energy Facility Siting Board

Interstate Reliability Project
Environmental Report – Volume 1

North Smithfield and Burrillville, Rhode Island

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Glossary

AAL:	Annual Average Load.
AC:	Alternating Current – an electric current which reverses its direction of flow periodically.
ACI:	American Concrete Institute.
ACOE:	United States Army Corps of Engineers.
ACSR:	Aluminum Conductor Steel Reinforced.
ACSS:	Aluminum Conductor Steel Supported.
AIS	Air-Insulated Switchgear.
Ampere (Amp):	A unit of measure for the flow of electric current.
ANSI:	American National Standards Institute.
APL:	Annual Peak Loading.
Arrester:	Provides protection for lines, transformers and equipment from transient over-voltages due to lightning and switching surges by carrying the charge to the ground.
ASF:	Area Subject to Flooding.
ASSF:	Area Subject to Storm Flowage.
Autotransformer:	A transformer with a single winding per phase in which the lower voltage is obtained by a tap on the winding (refer to Power Transformer).
BMPs:	Best Management Practices.
BPS:	Bulk Power System.
Bundle:	Two or more wires joined together to operate as a single phase.
Bus:	An electrical conductor that serves as a common connection point for two or more electrical circuits, typically in a substation or switching station.
CAAA:	Clean Air Act Amendments.
Cable:	A fully insulated conductor usually installed underground, but in some circumstances can be installed overhead.
CCRP:	Central Connecticut Reliability Project.
CEII:	Critical Energy Infrastructure Information.
CELT Report:	ISO-NE annual regional forecast of Capacity, Energy, Loads and Transmission for New England.
Circuit:	A system of conductors (three conductors or three bundles of conductors) through which an electric current is intended to flow and which may be supported above ground by transmission structures or placed underground.
Circuit Breaker:	A switch that automatically disconnects power to a circuit in the event of a fault condition; typically located in substations or switching stations.

CLL:	Critical Load Level.
CL&P:	The Connecticut Light and Power Company, a wholly owned subsidiary of Northeast Utilities.
CO:	Carbon Monoxide.
Conductor:	A metallic wire which serves as a path for electric current to flow.
Conduit:	Pipes, usually PVC plastic, typically encased in concrete, and used to house and protect underground power cables or other subsurface utilities.
CSC:	Connecticut Siting Council.
Davit Arm Structure:	A single-shaft steel pole with an alternating arm configuration each of which supports a phase conductor.
dB:	A decibel is a logarithmic unit of measurement that expresses the magnitude of a sound.
dBA:	Decibel, on the A-weighted scale. A-weighting is used to emphasize the range of frequencies where human hearing is most sensitive.
Demand:	The total amount of electric power required at any given time by an electric supplier's customers.
DR:	Demand resource - a source of capacity whereby a customer reduces the demand for electricity e.g., by using energy-efficient equipment, shutting off equipment, or using electricity generated on site.
DG:	Distributed Generation.
Dielectric Fluid:	A fluid that insulates and cools electrical equipment and does not conduct an electric current.
Distribution Line or System:	Power lines that operate under 69 kV.
Double-Circuit:	Two circuits on one structure.
DPW:	Department of Public Works.
DSM:	Demand Side Management.
Duct Bank (or Ductline):	A group of buried conduits, usually encased in concrete, and used for installation of underground cable.
Duct:	An individual conduit used to house underground power cable (refer to "Conduit").
EFORD:	Equivalent Demand Forced Outage Rate.
EFSB:	Rhode Island Energy Facility Siting Board.
EHS:	Extra high strength.
Electric Field:	A field produced as a result of voltages applied to electrical conductors and equipment; usually measured in units of kilovolts per meter.

Electric Transmission:	Facilities (≥ 69 kV) that transmit electrical energy from generating plants to substations.
ELUR:	Environmental Land Use Restrictions.
EMF:	Electric and magnetic fields.
Fault:	A failure or interruption in an electrical circuit (a.k.a. short-circuit).
FCA:	Forward Capacity Auction.
FCM:	Forward Capacity Market.
FERC:	Federal Energy Regulatory Commission.
FEMA:	Federal Emergency Management Agency.
FHWA:	Federal Highway Administration.
FTE:	Full-time equivalent.
Gauss (G):	A unit of measure for magnetic fields; one G equals 1,000 milliGauss (mG).
Gigawatt (GW):	One gigawatt equals 1,000 megawatts.
GIS:	Gas Insulated Switchgear - this is electrical switching equipment, typically installed in a substation and insulated with SF_6 gas.
Glacial Till:	Type of surficial geologic deposit that consists of boulders, gravel, sand, silt and clay and mixed in various proportions. These deposits are predominantly nonsorted, nonstratified sediment and are deposited directly by glaciers.
Gneiss:	Light and dark, medium to coarse-grained metamorphic rock characterized by compositional banding of light and dark minerals, typically composed of quartz, feldspar and various amounts of dark minerals.
GSRP:	Greater Springfield Reliability Project.
H-frame Structure:	A wood or steel transmission line structure constructed of two upright poles with a horizontal cross-arm.
HPFF:	High Pressure Fluid Filled - a type of underground transmission cable.
HVDC:	High-Voltage Direct-Current.
Hz:	Hertz, a measure of the frequency of alternating current; expressed in units of cycles per second.
ICF:	ICF International.
IEEE:	Institute of Electrical and Electronic Engineers.
Interconnection Queue:	ISO-NE New England Generation Interconnection Queue.
ISO:	Independent System Operator.
ISO-NE:	ISO New England, Inc., the independent system operator of the New England electric transmission system.
IVM:	Integrated Vegetation Management.

kcmil:	One thousand circular mils, approximately 0.0008 square inches, a measure of conductor cross-sectional area.
kV:	Kilovolt - one kV equals 1,000 volts.
kV/ m:	Kilovolts per meter - a measurement of electric field strength.
L&RR Site:	Landfill and Resource Recovery Site. A USEPA-designated National Priorities Listing Superfund Site located on Old Oxford Road in North Smithfield, Rhode Island.
Load:	Amount of power delivered upon demand at any point or points in the electric system; load is created by the power demands of customers' equipment (residential, commercial and industrial).
LTE:	Long-Term Emergency rating.
LSZ:	Landscape Similarity Zone.
mG:	A unit of measure for magnetic fields. One milliGauss - equals 1/1000 Gauss.
MassDOT:	Massachusetts Department of Transportation.
MA EFSB:	Massachusetts Energy Facilities Siting Board.
Monopole:	A single pole supporting overhead utility wire.
MUST:	Siemens' PTI Managing and Utilizing System Transmission (computer program).
MVA:	Megavolt Ampere - measure of electrical capacity equal to the product of the line-to-line voltage, the current and the square root of 3 for three-phase systems; electrical equipment capacities are sometimes stated in MVA.
MVAR:	Megavolt Ampere Reactive - also called MegaVARS - measure of reactive power in alternating current circuits; shunt capacitor and reactor capacities are usually stated in MVARs.
MW:	Megawatt - a megawatt equals 1 million watts.
N-1:	A single event causing the loss of one or more elements (i.e., generator, transmission lines, bus section, etc.).
N-1-1:	Occurrence of two separate and unrelated outages within a short period of time.
NAAQS:	National Ambient Air Quality Standards.
NEEWS:	New England East-West Solution.
NEPOOL:	New England Power Pool.
NERC:	North American Electric Reliability Corporation.

NESC:	National Electrical Safety Code. The NESC is an ANSI standard that covers basic provisions for safeguarding of persons from hazards arising from the installation, operation, or maintenance of 1) conductors and equipment in electrical supply stations, and 2) overhead and underground electric supply and communication lines. It also includes work rules for the construction, maintenance, and operation of electric supply and communication lines and equipment.
NITHPO:	Narragansett Indian Tribal Historic Preservation Officer.
NO_x:	Nitrogen Oxides.
NPCC:	Northeast Power Coordinating Council.
NSTAR:	NSTAR Electric Company, Massachusetts-based, investor-owned electric and gas utility company. A wholly-owned subsidiary of Northeast Utilities.
NTAs:	Non-Transmission Alternatives.
NU:	Northeast Utilities.
O_3:	Ozone.
OATT:	Open Access Transmission Tariff.
OH:	Overhead - electrical facilities carried above-ground on supporting structures.
OPGW:	Optical ground wire – ground wire containing optical fibers.
PAC:	Planning Advisory Committee lead by ISO-NE.
Phase:	Transmission and distribution AC circuits are comprised of three conductors or bundles of conductors that have voltage and angle differences between them; each of these conductors (or bundles) is referred to as a phase.
$PM_{2.5}$:	Fine Particulate Matter.
Power Transformer:	A device that changes or transforms alternating current from one voltage to another voltage.
PPA:	Proposed Plan Application.
PP-3:	ISO-NE Planning Procedure 3, Reliability Standards for the New England Area Bulk Power Supply System.
PP-4:	ISO-NE Planning Procedure 4.
PVC:	Polyvinyl Chloride.
Reactive Power:	A component of power associated with capacitive of inductive circuit elements; its unit of measurement is the VAR.
Rebuild:	Replacement of an existing overhead transmission line with new structures and conductors, generally along the same alignment as the original line.
Reconductor:	Replacement of existing conductors with new conductors, and any necessary structure reinforcements or replacements.

Reinforcement:	Any of a number of approaches to increase the capacity of the transmission system, including rebuilding, reconductoring, uprating, conversion and conductor bundling methods.
RIDEM:	Rhode Island Department of Environmental Management.
RIDFW:	Rhode Island Division of Fish and Wildlife.
RIDOT:	Rhode Island Department of Transportation.
RIEDC:	Rhode Island Economic Development Corporation.
RIGIS:	Rhode Island Geographic Information System.
R.I.G.L:	Rhode Island General Law.
RIHPHC:	Rhode Island Historical Preservation & Heritage Commission.
RINHP:	Rhode Island Natural Heritage Program.
RINHS:	Rhode Island Natural History Survey.
RIRP:	Rhode Island Reliability Project.
ROD:	Record of Decision.
ROW:	Right-of-Way. Corridor of land within which a utility company holds legal rights necessary to build, operate, and maintain power lines.
Schist:	Light, silvery to dark, coarse to very coarse-grained, strongly to very strongly layered metamorphic rock whose layering is typically defined by parallel alignment of micas. Primarily composed of mica, quartz and feldspar; occasionally spotted with conspicuous garnets.
SEMA:	The Southeastern Massachusetts electrical zone.
SF_6:	Sulfur hexafluoride, a gas used as electrical insulation.
Shield Wire:	Wire strung at the top of transmission lines and intended to prevent lightning from striking the transmission circuit. These conductors are sometimes referred to as static wire or aerial ground wire and may contain glass fibers for communication use (refer to "OPGW").
Shunt Reactor:	An electrical reactive power device primarily used to compensate for the capacitance of high voltage underground transmission cables.
SHPO:	State Historic Preservation Officer.
SMP:	Soil Management Plan.
SNETR Study:	Southern New England Transmission Reliability Study (original report that identified the need for the NEEWS projects).
Splice:	A device to connect two or more bare conductors or to connect two or more insulated cables.
Steel Pole Structure:	Transmission line structure consisting of tubular steel pole(s) with arms or other components to support insulators and conductors.

Steel Lattice Tower:	Transmission line structure consisting of a freestanding framework tower.
Substation:	A fenced-in yard containing switches, power transformers, line terminal structures, and other equipment enclosures and structures; voltage changes, adjustments of voltage, monitoring of circuits and other service functions take place in the substation.
Switching Station:	Same as Substation except with no power transformers; switching of circuits and other service functions take place in a switching station.
SWPPP:	Stormwater Pollution Prevention Plan.
Terminal Point:	The substation or switching station at which a transmission line terminates.
Terminal Structure:	Structure typically located within a substation that ends a section of transmission line.
Terminator:	An insulated fitting used to connect underground cables to an overhead line or to a substation bus.
THPO:	Tribal Historic Preservation Officer.
TMDL:	Total Maximum Daily Load. Maximum allowed pollutant load to a water body without exceeding water quality standards.
Transmission Line:	An electric power line operating at 69,000 volts or more.
TO:	Transmission Owner.
TPL:	Transmission Planning Standards.
USDA:	United States Department of Agriculture.
USEPA:	United States Environmental Protection Agency.
USFWS:	United States Fish and Wildlife Service.
USGS:	United Stated Geological Survey.
VIA:	Visual Impact Assessment.
V / m:	Volts per meter - a measure of electric field strength.
VOC:	Volatile Organic Compound.
Voltage Collapse:	A condition where voltage drops to unacceptable levels and cascading interruptions of transmission system elements occur resulting in widespread blackouts.
Voltage:	Electric potential difference between any two conductors or between a conductor and ground.
Wire:	Refer to “Conductor”.
Working Group:	Transmission Planners from ISO-NE, National Grid and Northeast Utilities who collaborated to perform the SNETR and NEEWS studies.
WTGH(A):	Wampanoag Tribe of Gay Head (Aquinnah).

WTHPO:	Wampanoag Tribe of Gay Head (Aquinnah) Tribal Historic Preservation Officer.
XLPE:	Cross Linked Polyethylene. A type of underground cable insulation.

3 PROJECT NEEDS ANALYSIS

3.1 OVERVIEW

The IRP is one of four interrelated projects developed by ISO-NE, National Grid, and NU, to comprehensively address transmission system reliability issues in Southern New England. The IRP is designed to reinforce the interconnected transmission systems in Rhode Island, Massachusetts, and Connecticut so that they may continue to reliably serve Southern New England under a wide range of system conditions.

The need for IRP was first identified in the 2008 Needs Analysis (Appendix A), and was reconfirmed in the 2011 Needs Assessment (Appendix D) and then again in the *Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment* ("2012 Follow-Up Needs Analysis") (Appendix N).[1] The 2008 Needs Analysis found interdependent limitations on east-to-west power transfers across Southern New England and power transfers between Connecticut, southeast Massachusetts, and Rhode Island. The 2011 Needs Assessment confirmed these limitations while also finding constraints in transferring power from west-to-east across Southern New England. Under certain conditions for which the system must be planned, power generated in the west and needed in the east – or vice versa – cannot be reliably delivered. As discussed in Section 3.4 below, the 2012 Follow-Up Needs Analysis again reconfirmed the needs indicated in the prior analyses.

All three analyses focus on power transfers across New England. Only three 345 kV paths connect eastern and western New England. Depending on system conditions, the loss of one of these paths can have a significant impact on the loading of some of the other lines of the transmission system. When two out of the three paths are lost due to N-1-1 contingency events, the remaining 345 kV path and the underlying 115 kV network can experience large power flows resulting in numerous thermal overloads and voltage issues.

The 2011 Needs Assessment and 2012 Follow-Up Needs Analysis show widespread thermal overloads and voltage issues across the study area under a variety of system conditions for the N-1-1 contingencies tested.[2] Several 345 kV transmission lines in Rhode Island, central and western Massachusetts and Connecticut overload under certain conditions. Rhode Island in particular experiences severe overloads on its 115 kV system during certain N-1-1 events. A thermal transfer capability analysis determined that there will be insufficient generation and transmission resources:

[1] A copy of this report, redacted to avoid disclosure of CEII, is provided in the public record as Appendix N, and an unredacted copy will be provided to the EFSB and to eligible parties who have executed CEII Non-Disclosure Agreements.

[2] Contingencies, as specified by NERC, NPCC, and ISO-NE standards and criteria, are usually characterized as an event causing the loss of one or more system elements – generator, transmission line, bus section, etc. Sometimes a single contingency may cause the loss of two elements. A single event causing the loss of one or more elements is referred to as an "N-1" contingency event. The occurrence of two separate and unrelated outages within a short period of time is referred to as an "N-1-1" contingency event.

(1) to serve eastern New England load under N-1-1 conditions starting in 2011; (2) to serve western New England load under N-1-1 conditions starting in 2017-2018; and (3) to serve Connecticut load under N-1-1 conditions starting in 2014-2015.

Overall, the 2011 Needs Assessment identified reliability-based needs to:

1. Reinforce the 345 kV system into the West Farnum Substation for Rhode Island transmission system reliability (now);

2. Increase the transmission transfer capability from western New England and Greater Rhode Island into eastern New England (2011). With the retirement of Salem Harbor, there is a greater need for additional transmission transfer capability to eastern New England;

3. Increase the transmission transfer capability into the state of Connecticut (2014-2015); and

4. Increase the transmission transfer capability from eastern New England and Greater Rhode Island to western New England if additional resources are available in the exporting area (2017-2018).

The 2012 Follow-Up Needs Analysis confirmed the need identified in the 2011 Needs Assessment, as shown above. Additionally the need dates identified in the 2012 Follow-Up Needs Analysis, which are shown in Section 3.4.5 below, are very close to those identified in the 2011 Needs Assessment.

IRP addresses these four reliability needs by creating a new 345 kV transmission path between Massachusetts, Rhode Island, and Connecticut. This new path addresses existing constraints on the transfer of power from east-to-west and from west-to-east within New England. At the same time, it eliminates the potential for the identified transmission overloads in Rhode Island, and also provides needed import capability to Connecticut. IRP will also enable approximately 2,000 MW of generation along the Card Street to West Medway corridor, most of which is relatively new and efficient, to be called upon to serve load reliably in both eastern and western New England, as needed, over the long-term planning horizon.

IRP is designed so that the Southern New England transmission system will continue to adhere to NERC, NPCC, and ISO-NE standards and criteria. NERC develops and enforces mandatory reliability standards for transmission network planning and operations. The objective of the standards is to define the design contingencies and measures used to assess the adequacy of the transmission system performance. The standards are subject to approval by FERC and compliance is mandatory under federal law. The 2011 Needs Assessment and 2012 Follow-Up Needs Analysis were performed in accordance with the following NERC Transmission Planning Standards ("TPL") (with miscellaneous dates): TPL-001, TPL-002, TPL-003, and TPL-004; the NPCC *Regional Reliability Referenced Directory #1 - Design and Operation of the Bulk Power System,* dated

December 2009 ("NPCC Directory"); and the ISO-NE *Planning Procedure 3, Reliability Standards for the New England Area Bulk Power Supply System* dated March 2010 ("PP-3").

The following sections of this report contain a more detailed description of the transmission system and the need for the IRP and how that need has evolved over time. Section 3.2 provides a description of the Southern New England transmission system to provide context for the regional needs analysis. Section 3.3 follows with a summary of the analyses undertaken and the results and implications found in the 2011 Needs Assessment, showing a need to reinforce the transmission system in Southern New England. Section 3.4 summarizes the changes in assumptions used by ISO-NE in the 2012 Follow-Up Needs Analysis, specifically with respect to changes in load forecast and forecasted energy efficiency. This section also summarizes the results of the steady state thermal and voltage analyses using the new assumptions, and identifies the initial year of need for eastern New England, western New England, Rhode Island and Connecticut. Lastly, Section 3.5 considers the results and implications of the 2011 Needs Assessment and 2012 Follow-Up Needs Analysis in terms of the impacts on customers in Rhode Island.

3.2 THE NEW ENGLAND TRANSMISSION SYSTEM

Transmission lines across New England and beyond are interconnected to form a transmission network, sometimes called a grid or a system. National Grid's transmission system is part of this interconnected transmission network. Thus, National Grid's transmission system in Rhode Island and Massachusetts is part of the larger New England area transmission system. The National Grid transmission system affects and is affected by the generation, load, and transmission configurations of the electric systems operated by neighboring utilities and in neighboring states.

FERC has designated all of New England as a single operating area, and has designated ISO-NE as the independent system operator for the New England control area. As such, ISO-NE is responsible for the reliable operation of New England's power generation and transmission system. ISO-NE also administers the region's wholesale electricity markets, and manages the comprehensive planning of the regional power system. New England's transmission system is planned to be fully integrated and seeks to use all regional generating resources to serve all regional load, independent of state boundaries, utility ownership, and utility service territories. The transmission network is operated as a tightly integrated grid. Therefore, the electrical performance of one part of the system affects all areas of the system.

3.2.1 The New England East–West Interface

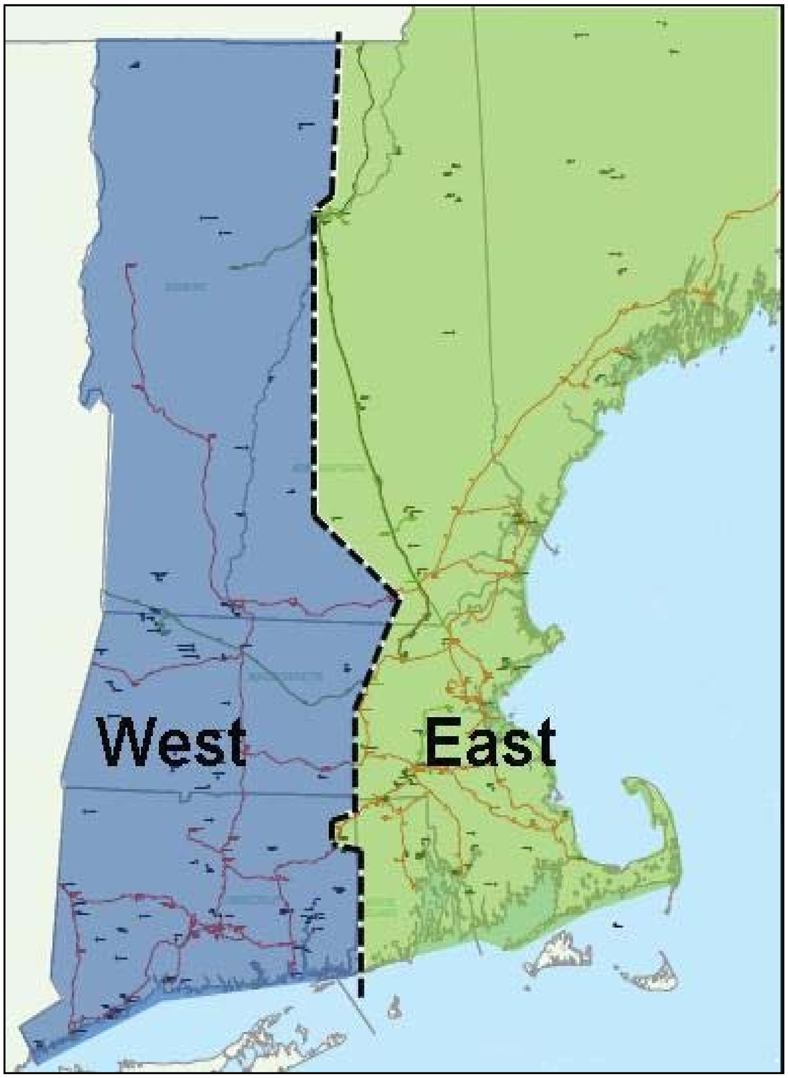
Historically, New England has been divided into two large operating areas, known as East and West, separated by the New England East-West Interface.[3] This interface, which largely corresponds to the boundaries of the service areas of major electric utilities, divides New England approximately in half,

[3] The term "interface" is used to describe both the imaginary boundary between two electrical operating areas and the set of transmission facilities that can be used to transfer power reliably, within defined limits, from one such area to another.

separating the major load centers of the southeast Massachusetts and Boston areas from those in the Connecticut area. This interface is important in that the New England transmission system performance is materially dependent on the power that flows across it. The New England East-West Interface roughly follows the Connecticut and Rhode Island border and then continues in a northerly direction through the rest of New England. The general location of this interface is depicted in Figure 3-1.

Figure 3-2 illustrates the 345 kV network in Southern New England, as it will be constituted with the completion of GSRP and RIRP, both of which are now under construction. Only three 345 kV transmission lines cross the New England East-West Interface: the 330 Line between the Card Street Substation and the Lake Road Switching Station in Connecticut; the 302 Line between the Millbury No. 3 Switching Station in Millbury, Massachusetts and the Carpenter Hill Substation in Charlton, Massachusetts; and, further to the north, the 380 Line between the Amherst Substation in Amherst, New Hampshire and the Scobie Pond Substation in Londonderry, New Hampshire. Two 230 kV transmission lines and a few 115 kV transmission lines also cross the interface. Most of these 230 kV and 115 kV transmission lines run long distances and have relatively low thermal capacity. Therefore, they do not add significantly to the transfer capability across the interface.

Figure 3-1: New England East-West Interface

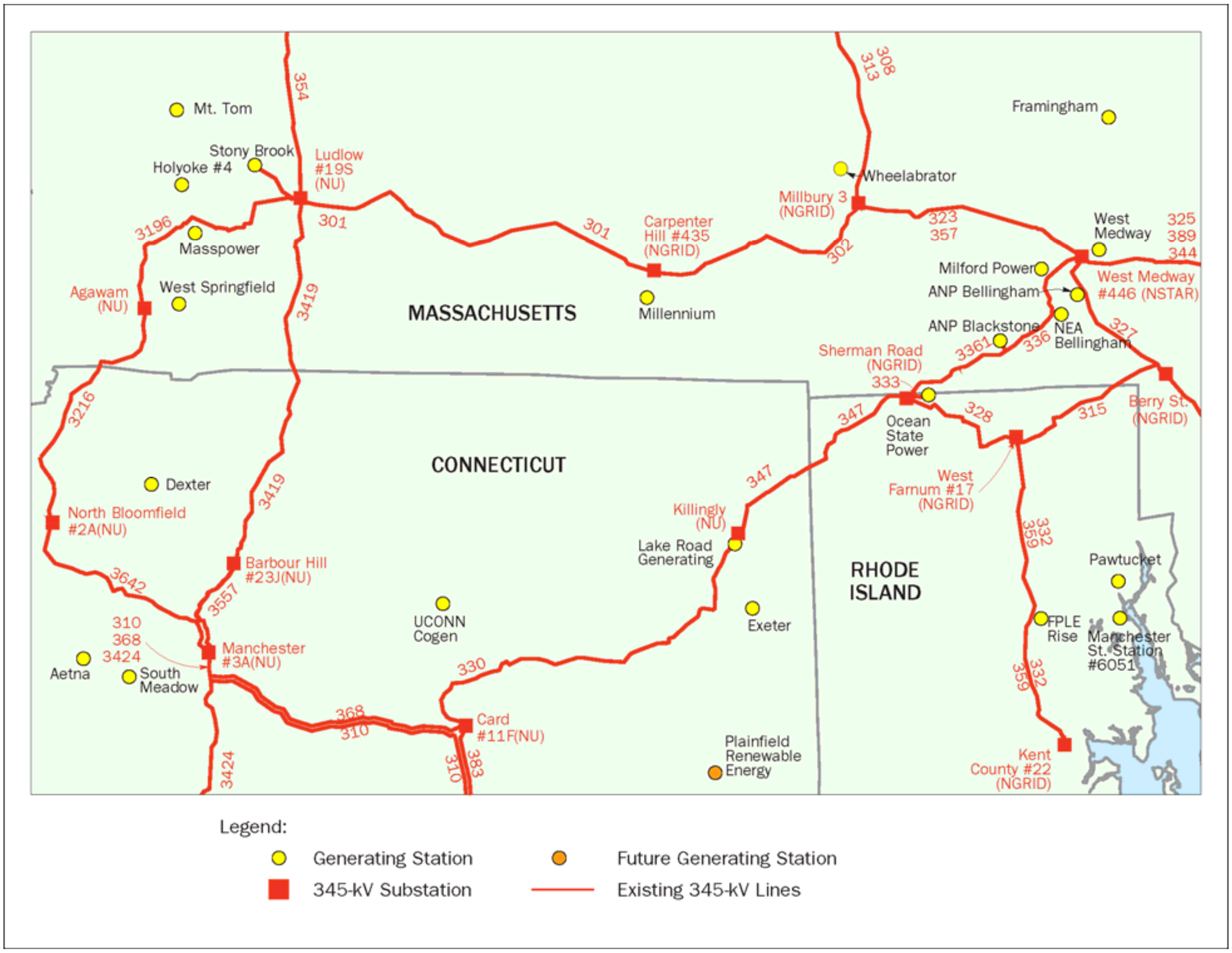


3.2.2 The 345 kV Card Street to West Medway Corridor

One of the three main paths across the New England East-West Interface is the transmission path along the Card Street to West Medway corridor. This corridor extends from CL&P's Card Street Substation in Lebanon, Connecticut to the Lake Road Switching Station and the Killingly Substation (both in Killingly, Connecticut), across the Connecticut/Rhode Island state border to National Grid's Sherman Road Switching Station in Burrillville, Rhode Island, and from there to NSTAR's West Medway Substation in Medway, Massachusetts. It provides the only direct 345 kV tie between Connecticut and Rhode Island,[4] and one of only two 345 kV ties between Rhode Island and Massachusetts.

[4] In addition, southeastern Connecticut is tied to southwest Rhode Island by a 115 kV transmission line of very limited capability.

Figure 3-2: 345 kV System - Geographic Overview



The Card Street to West Medway corridor serves as a super highway, transporting power from Connecticut resources to serve load in Rhode Island and southeast Massachusetts and also transporting power from southeast Massachusetts resources to Rhode Island and Connecticut load centers. This super highway connects four large efficient base load generating stations to the 345 kV transmission network at various locations along this transmission corridor (see Table 3-1).

Table 3-1: Generation Resources Located Between Card Street and West Medway Substations

Generating Station	Location	FCA-4 Summer Capacity Supply Obligation (MW)
Lake Road Generating	Dayville, Connecticut	752
Ocean State Power	Burrillville, Rhode Island	541
ANP Blackstone	Blackstone, Massachusetts	444
NEA Bellingham	Bellingham, Massachusetts	274
Total		**2,011**

Under various system conditions, the generating stations along the Card Street to West Medway corridor cannot all be dispatched at the same time because of the potential for overloading one or more of the transmission lines making up the New England East-West Interface in the event of a contingency.

3.3 2011 NEEDS ASSESSMENT

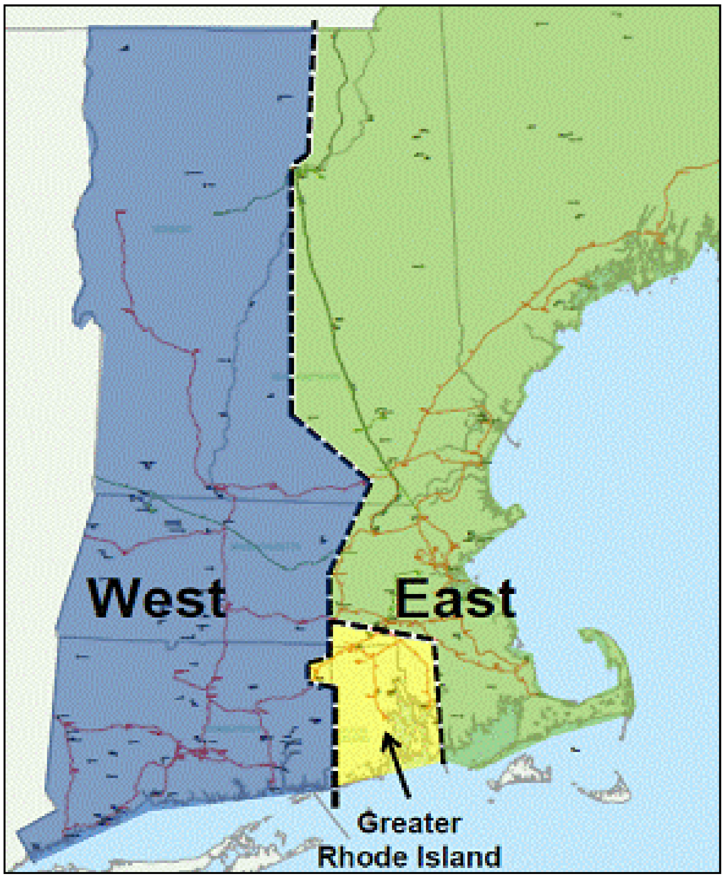
3.3.1 Study Description

As discussed in Section 1 of this Report, the Working Group first identified the need for new 345 kV transmission facilities to serve Southern New England in the 2008 Needs Analysis. After the 2008 Needs Analysis was completed, more than 2,000 MW of new generation resources and demand resources were added in Connecticut and other areas west of the New England East-West Interface. ISO-NE is required by Section 4.2(a) of Attachment K to its FERC-approved Open Access Transmission Tariff ("OATT") to update its needs assessments as new resources materialize through the FCA process. Therefore in 2009, ISO-NE undertook a reassessment of the need for IRP. The re-evaluation of IRP was substantially completed in the summer of 2010, presented to the PAC in August and November of 2010, and finalized in April 2011.

The objective of the 2011 Needs Assessment was to update the analysis of the reliability-based transmission needs identified in the 2008 Needs Analysis, specifically with respect to the IRP component of NEEWS. The Working Group updated the analysis of system needs for the Southern New England transmission system using a study area consisting of the three Southern New England states: Massachusetts, Rhode Island, and Connecticut. For purposes of this study, the Southern New England transmission system was split into three sub-areas (eastern New England, western New England, and Greater Rhode Island) based on relatively weak transmission system connections among these sub-areas.[5] The three sub-areas are shown in Figure 3-3 below. The Greater Rhode Island area was treated as part of western New England when evaluating eastern New England reliability, and was treated as part of eastern New England when evaluating western New England reliability. This treatment reflects existing constraints on the delivery of generation located in Greater Rhode Island, both when moving power eastward as well as when moving power westward.

[5] These sub-areas were defined for the purpose of the 2011 Needs Assessment, and should not be confused with the thirteen sub-areas of the region's bulk electric power system used by ISO-NE for modeling and planning purposes.

Figure 3-3: New England Sub-Areas



The 2011 Needs Assessment identified and addressed three general areas of concern:

- **Transmission Planning Standards and Criteria:** The study assessed the ability of the transmission system serving eastern New England, western New England, Greater Rhode Island, and Connecticut to comply with NERC, NPCC, and ISO-NE transmission planning standards and criteria over the 10-year planning horizon.
- **Transmission Transfer Capability:** The study assessed the ability of existing and planned FCA-cleared generation located in western New England to serve load in eastern New England, and the ability of existing and planned FCA-cleared generation located in eastern New England to serve load in western New England, given the existing transmission constraints.
- **Salem Harbor Non-Price Retirement Requests:** The study assessed the impact on transmission system reliability of the proposed 2014 retirement of the Salem Harbor Generating Station (approximately 750 MW).

To address compliance with transmission planning standards and criteria, as well as the impact of the Salem Harbor Generating Station retirement, the Working Group undertook a series of detailed steady state load flow analyses. These analyses assessed compliance with thermal and voltage standards under base case conditions and following contingency events, for five scenarios: a West-to-East Scenario, an East-to-West Scenario, a Connecticut Reliability Scenario, a Rhode Island Reliability Scenario, and a Salem Harbor Retirement Scenario. The methodology, assumptions, and results of the steady state thermal and voltage analyses are summarized in Section 3.3.2 below and are set forth in detail in pages 41-57 of the 2011 Needs Assessment.

As part of the 2011 Needs Assessment, ISO-NE also undertook a Transmission Transfer Capability Analysis to determine whether the transmission system could serve load reliably under three scenarios: an eastern New England Import Scenario, a western New England Import Scenario, and a Connecticut Import Scenario. The methodology, assumptions, and results of the transmission transfer capability analysis are summarized in Section 3.3.3 below and are set forth in detail in pages 65-71 of the 2011 Needs Assessment.

Finally, the 2011 Needs Assessment included an Extreme Contingency Analysis, involving limited stability studies to examine how the transmission system would perform per the NERC, NPCC, and ISO-NE Standards and Criteria. A generator torsional impact ("Delta-P") analysis was also performed involving limited studies to determine the mechanical stress put on local generators during system contingency events. The results of the Delta-P testing are set forth in detail in pages 58-60 of the 2011 Needs Assessment and the results of the extreme contingency testing are set forth in pages 57-58 of the 2011 Needs Assessment.

3.3.2 Steady State Analysis

The 2011 Needs Assessment was performed in accordance with the NERC, NPCC, and ISO-NE planning standards and criteria in the 10-year planning horizon. The steady state voltage and loading criteria, solution parameters, and contingency specifications used in the analysis are consistent with these documents.

A total of four base cases, representing a number of possible generation dispatch and availability conditions, were modeled for study years 2015 and 2020. These four cases were used to study five possible scenarios: the East-to-West Scenario, the West-to-East Scenario, the Connecticut Reliability Scenario, the Rhode Island Reliability Scenario, and the Salem Harbor Retirement Scenario. For each scenario, the system was tested with all transmission lines in-service (N-0) and under N-1 and N-1-1 contingency events for 2015 and 2020 load conditions. System adjustments allowed in power-flow simulations between the first and second contingency for N-1-1 events are listed in ISO-NE PP-3.

3.3.2.1 Steady State Analysis Assumptions

The assumptions used in the steady state modeling are set forth in detail in Section 3 of the 2011 Needs Assessment, and are summarized below.

Load Forecast Assumptions

In accordance with ISO-NE planning practices, the modeled load was based on the summer peak 90/10 demand forecast in ISO-NE's 2010 CELT Report. These values were 31,810 MW for all of New England in 2015 and 33,555 MW in 2020 (system losses included). In comparison, the summer peak 90/10 demand forecast in the 2011 CELT Report is 31,705 MW for 2015 and 33,750 MW for 2020. The change between the 2010 and 2011 CELT forecast is less than 1%.

Demand Resource Assumptions

Demand resources ("DR"), both passive and active, were modeled in the base case as capacity resources at the levels of the most recent FCA – in this instance, FCA-4. The amounts of demand resources modeled in the 2015 and 2020 base cases are listed in Tables 3-2 and 3-3 below.[6]

In comparison, cleared passive DR values for the years 2014-2015 from FCA-5 were up by 2.9% from the FCA-4 values, while the cleared active DR values went down by almost 15% from FCA-4 values. In aggregate, cleared DR (both active and passive DR) in FCA-5 went down by approximately 4.5% compared to the FCA-4 values.

Table 3-2: FCA-4 Passive DR Values

Load Zone	Passive DR Values (MW)
Maine	152
Vermont	72
Northeast Massachusetts and Boston	263
Southeast Massachusetts	140
West Central Massachusetts	150
Rhode Island	85
Connecticut	424

Table 3-3: FCA-4 Active DR Values

Dispatch Zone	Active DR Values (MW)	Dispatch Zone	Active DR Values (MW)
Bangor Hydro	76	Springfield, Massachusetts	36
Maine	203	Western Massachusetts	45
Portland, Maine	135	Lower Southeast Massachusetts	65
New Hampshire	64	Southeast Massachusetts	106
New Hampshire Seacoast	10	Rhode Island	77
Northwest Vermont	35	Eastern Connecticut	48
Vermont	19	Northern Connecticut	63
Boston, Massachusetts	212	Norwalk-Stamford, Connecticut	70
North Shore Massachusetts	83	Western Connecticut	208
Central Massachusetts	86		

6 Appendix A of the 2010 CELT Load Forecast in Table 7-4.

Base Case Transmission and Generation Assumptions

All transmission projects with ISO-NE PPA approvals as of the June 2010 Regional System Plan Project listing were included in the base case load flows for steady state modeling. These projects included two NEEWS projects - the GSRP and the RIRP. The CCRP, which is being re-evaluated, was not included. IRP was not included either as it was the subject of the study.

The base case included all existing generators and all new generators that have accepted a Forward Capacity Market ("FCM") Capacity Supply Obligation as of the FCA-4, with the exception of the Vermont Yankee Nuclear Plant, which was excluded from the base case because of the significant uncertainty concerning its continued operation after 2012.

The Salem Harbor Generating Station, located in Salem, Massachusetts, was assumed to be in service in the base case, and modeled as out-of-service only in the Salem Harbor Retirement Scenario. In May 2011, the owners of the Salem Harbor Generating Station confirmed that it will be retired in 2014. ISO-NE has directed the New England transmission owners not to include Salem Harbor Generating Station in any future reliability studies for any year after 2014.

Generation Dispatch Cases

Four generation dispatch cases were developed to reflect a range of possible stressed conditions on the Southern New England transmission system. These dispatch cases are shown in Table 3-4.

Table 3-4: Generation Dispatch Scenarios

Scenario	Generators Out-of-Service
New England West-to-East	• Hydro-Quebec Phase II • Seabrook Generating Station
New England East-to-West and Connecticut Reliability	• Millstone Units 2 and 3 • Berkshire Power (as a proxy for EFORD)[2]
Rhode Island Reliability	• RISE Generating Station • Franklin Square / Manchester Street 09 Combined Cycle
Salem Harbor Retirement[1]	• Hydro-Quebec Phase II • Seabrook Generating Station

[1] The base case for this scenario assumes that all generation at Salem Harbor Generating Station is retired in 2014, and that New Brunswick import levels are increased to compensate.
[2] EFORD – equivalent demand forced outage rate

The New England East-to-West and West-to-East Scenarios stressed transfers in each direction across the New England East-West Interface to determine the capability needed on the bulk transmission system to serve demand on either side of the interface. The Salem Harbor Retirement Scenario replicated the New England West-to-East Scenario for a base case that reflects the retirement of the Salem Harbor Generating Station and a corresponding increase in the import level from New Brunswick in order to compensate.

The Rhode Island Reliability and Connecticut Reliability Scenarios stressed conditions in local areas to determine the capability needed on the transmission system to serve demand in the local area. To accomplish this, the Rhode Island Reliability Scenario modeled two Rhode Island generators out-of-service. The Connecticut Reliability Scenario was modeled using the same generator dispatch case as was used for the New England East-to-West Scenario; however, for the Connecticut Reliability Scenario, the Connecticut load zone[7] was used as the region under study.

Each of the four generation dispatch cases assumes that the two largest generating units or supply sources in the area of interest are out-of-service. These cases were developed in compliance with ISO-NE's PP-3 and the standards set forth in NPCC's Directory which require that reliability assessments be based on load and generating conditions that reasonably stress the system. In the 2011 Needs Assessment, and in many other area studies conducted under PP-3, the system was stressed using base cases that have the largest and most critical generating units or stations in an area unavailable. Assuming the unavailability of more than one generating unit recognizes that units may be out-of-service over an extended period of time for any one of a number of reasons, such as economics, equipment failure, fuel supply, or maintenance.[8] Furthermore, in coming years, heightened environmental restrictions on fossil-fueled generating stations could affect the continuous operation of generating units or result in the closure of one or more units at a generating station.

In general, modeling existing generators as out-of-service in planning studies is not conducted simply to assure that the system will be able to do without those generators in specific system conditions, but rather to test the performance of the system under stresses that it may be required to withstand, whether from the unavailability of those specific generators or for other reasons. Generating units assumed to be unavailable or otherwise out-of-service should not be confused with the loss of a generating unit as a contingency. The former is a base case assumption – the system as represented before any contingency is applied. The latter is one of many contingencies specified by the NERC, NPCC, and ISO-NE standards, criteria, and procedures.

3.3.2.2 Steady State Results – Overview

Overall, the steady state analysis found numerous thermal overloads and a lesser number of voltage performance issues across New England under N-1 and N-1-1 contingency events. These transmission system performance issues occurred under all generator dispatch scenarios: when the system attempted to deliver power from western New England to serve load in eastern New England; when it attempted to deliver power from eastern New England to serve load in western New England; and when supplying load under stressed conditions to Connecticut and Rhode Island. Overall, thermal overloads and voltage performance issues increased substantially in number

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[7] The Connecticut load zone is electrically defined in Table 2-5 of the 2011 Needs Assessment.

[8] Historically, multiple generating units have been unavailable in New England even on peak days. ISO-NE notes that there have been five occasions over the past ten years when 2,500 MW or more of generation has been out of service during the peak day of June, July, or August.

between 2015 and 2020. Additionally, the number of thermal overloads under the New England West-to-East Scenario increased substantially under the Salem Harbor Retirement Scenario.

Figure 3-4 provides a graphic summary of the thermal overloads under N-1 conditions in 2020; similarly, Figure 3-5 provides a graphic summary of the thermal overloads under N-1-1 conditions in 2020. The worst case loading levels are shown for each transmission line that is loaded to 95% or more of its thermal capability under at least one contingency. Performance issues resulting from the Salem Harbor Retirement Scenario are not depicted in Figures 3-4 and 3-5.

3.3.2.3 Results: New England West-to-East Scenario

The New England West-to-East Scenario, with the Hydro Quebec Phase II high-voltage direct-current ("HVDC") line and the Seabrook Generating Station assumed to be out-of-service, illustrates the effect of high New England west-to-east transfers to serve demand in the east with generation from the west. A summary of the results of the N-1 and N-1-1 contingency analyses are shown in Table 3-5 below. Detailed results are contained in Tables 5-1, 5-6, 5-7, 5-8, and 5-9 in the 2011 Needs Assessment.

As shown in Table 3-5, under N-1 conditions, there are no thermal overloads in 2015, although four different transmission system elements would be loaded between 95% and 100%. By 2020, six elements would be overloaded and an additional two would be loaded between 95% and 100%. The N-1 study indicated no voltage performance issues.

The N-1-1 contingency analysis shows 19 overloaded elements in 2015, with an additional four elements loaded between 95% and 100%; by 2020, 36 elements are overloaded and an additional six are loaded between 95% and 100%. In addition, the analysis shows three voltage performance issues under N-1-1 conditions in 2015 and six in 2020.

Table 3-5: Thermal Overloads and Performance Issues: New England West-to-East Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
2015	4	0	0	4	19	3
2020	2	6	0	6	36	6

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

Figure 3-4: New England N-1 Thermal Overload Summary

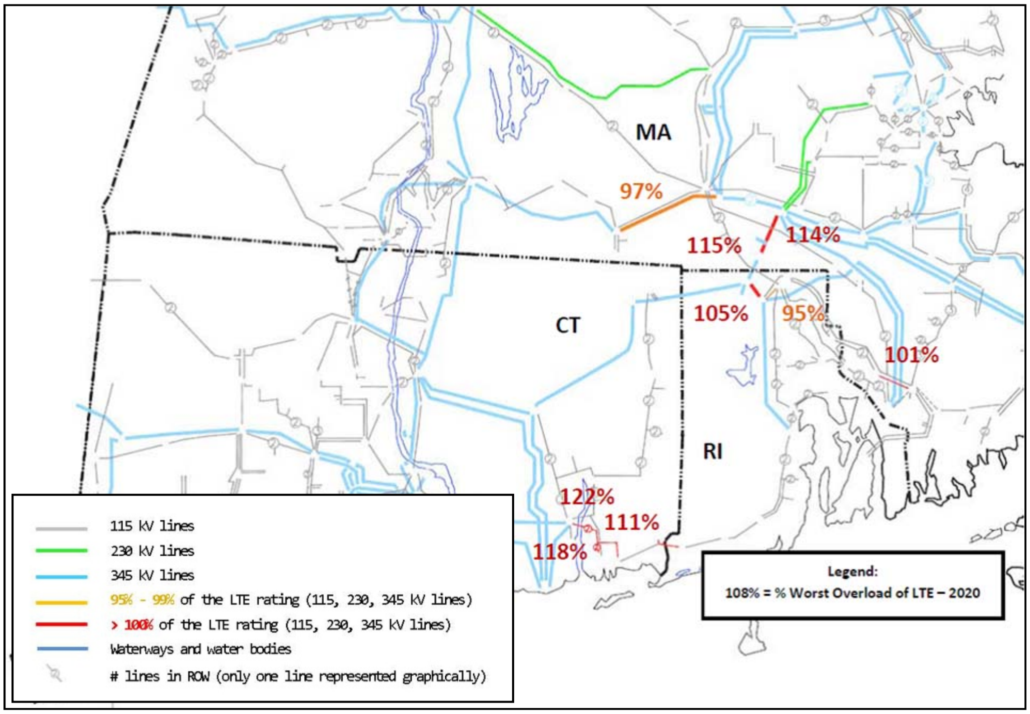
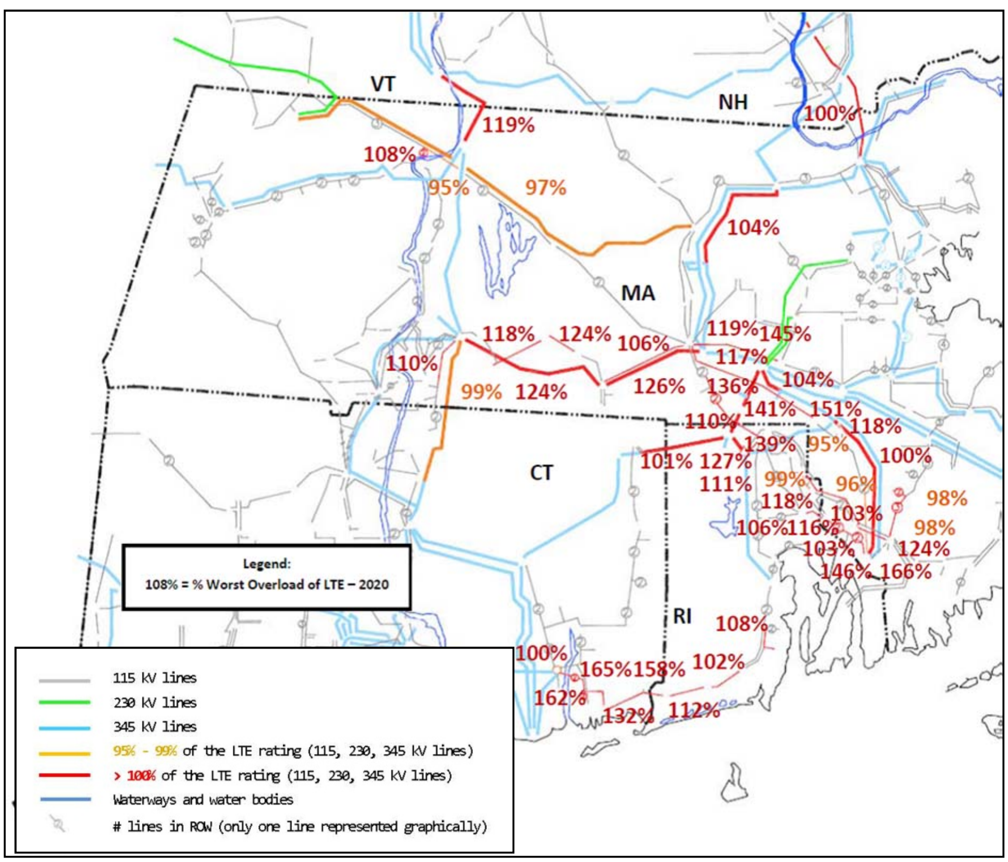


Figure 3-5: New England N-1-1 Thermal Overload Summary



3.3.2.4 Results: New England East-to-West Scenario

The New England East-to-West Scenario, with the Millstone Units 2 and 3 assumed to be out-of-service and the Berkshire Power Plant modeled offline to reflect the EFORD for western Massachusetts generation, illustrates the effect of high New England east-to-west transfers to serve demand in the west with generation from the east. A summary of the results of the N-1 and N-1-1 contingency analyses is shown below in Table 3-6; detailed results are contained in Tables 5-2, 5-10, 5-11, and 5-12 in the 2011 Needs Assessment.

As shown in Table 3-6, no thermal or voltage performance issues were observed in western New England under N-1 contingency conditions in 2015. However, by 2020, one element is loaded to 97% of its thermal capability under N-1 contingency conditions.

Under N-1-1 contingency conditions, thermal overloads occur on two transmission lines in western New England in 2015, and three additional elements are loaded to within 95% to 100% of their ratings. By 2020, ten transmission lines are overloaded and two additional elements are loaded to within 95% to 100% of their ratings. In addition, the N-1-1 study showed four voltage performance issues in 2020.

Table 3-6: Thermal Overloads and Performance Issues: New England East-to-West Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
2015	0	0	0	3	2	0
2020	1	0	0	2	10	4

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.3.2.5 Results: Connecticut Reliability Scenario

The Connecticut Reliability Scenario uses the same generator dispatch case as the New England East-to-West Scenario; however, the Connecticut load zone, rather than western New England, was used as the region under study. A summary of the results of the N-1 and N-1-1 contingency analyses is shown below in Table 3-7; detailed results are contained in Tables 5-15 and 5-16 in the 2011 Needs Assessment.

As shown in Table 3-7, the Connecticut load zone experiences no thermal or voltage issues under N-1 conditions in either 2015 or 2020. Under N-1-1 conditions, a single voltage performance issue is identified in 2015; by 2020, three thermal elements are overloaded, and one is loaded to within 95% to 100% of its rating, and three voltage issues are identified.

Table 3-7: Thermal Overloads and Performance Issues: Connecticut Reliability Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
2015	0	0	0	0	0	1
2020	0	0	0	1	3	3

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.3.2.6 Results: Rhode Island Reliability Scenario

The Rhode Island Reliability Scenario was used to assess load serving capability in Rhode Island. This scenario stressed conditions in the Rhode Island load zone by reducing Rhode Island generation to require the system to deliver generation resources from outside the sub-area. In particular, the RISE Generating Station and the Manchester Street 09 combined cycle unit were assumed to be out-of-service. A summary of the results of the N-1 and N-1-1 contingency analyses is shown below in Table 3-8; detailed results are contained in Tables 5-3, 5-13, and 5-14 in the 2011 Needs Assessment.

As shown in Table 3-8, Rhode Island experiences no thermal or voltage performance issues under N-1 conditions in 2015. In 2020, a single thermal element overloads under N-1 conditions.

Under N-1-1 contingency conditions, thermal overloads occur on five elements in 2015, with an additional two elements loaded to within 95% to 100% of their rating. By 2020, eight transmission system elements are overloaded under N-1-1 conditions, with an additional three elements loaded to within 95% to 100% of their ratings.

Table 3-8: Thermal Overloads and Performance Issues: Rhode Island Reliability Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
2015	0	0	0	2	5	0
2020	0	1	0	3	8	0

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.3.2.7 Results: Salem Harbor Retirement Scenario

The New England West-to-East Scenario, as described in Section 3.3.2.3, was re-analyzed for the retirement of Salem Harbor Generating Station, scheduled for 2014. To compensate for the permanent loss of the Salem Harbor generator, imports from New Brunswick were assumed to increase. A summary of the results of the N-1 and N-1-1 contingency analyses is shown below in

Table 3-9; detailed results are contained in Tables 5-4, 5-5, 5-17, 5-18, 5-19 and 5-20 in the 2011 Needs Assessment.

A comparison of Tables 3-5 and 3-9 demonstrates that the retirement of the Salem Harbor Generating Station will worsen the thermal and voltage concerns identified in the New England West-to-East Stress Scenario. In 2020, under N-1 conditions, the number of potentially overloaded elements increases from six to seven, and the number of voltage performance issues increases from none to two. Under N-1-1 conditions, potentially overloaded elements increase from 36 to 38, while voltage performance issues increase from six to nine.

Table 3-9: Thermal Overloads and Performance Issues: Salem Harbor Retirement Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
2020	2	7	2	7	38	9

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.3.3 Transmission Transfer Capability Analysis

3.3.3.1 Purpose

Transfer capability is the measure of the ability of interconnected transmission systems to transfer power in a reliable manner from one area to another. The ability of the transmission system within a defined area to reliably serve customer demands is predicated on the amount of local generation available and the capacity of the transmission network to import power from the surrounding areas. A system that can accommodate large power transfers generally allows lower system reserve requirements, provides adequate emergency backup of supply resources, permits economic interchange of power, and assures the system will remain reliable under contingency conditions.

The Working Group performed a set of transmission transfer capability analyses for eastern New England, western New England, and Connecticut to identify the required transfer capability into each of these sub-areas. This analysis involved two steps: determining the transmission transfer capability across each interface and then comparing projected area peak load with area generation and potential imports to assess resource adequacy.

3.3.3.2 Determining Transmission Transfer Capabilities

Transfer capability across a specific interface depends on the power flow that all the transmission elements crossing the interface can carry without exceeding thermal capability, causing system instability, or exceeding voltage limits under various contingency conditions.

Since system conditions such as load and the amount and location of available generation can vary significantly from day to day and from hour to hour, transfer capabilities across an interface are properly expressed as a range of values. This range of values will always be much lower than the sum of the thermal capacities of all of the transmission elements that make up the interface. That is, the system must be designed for the potential contingent loss of any single element of the interface, and for the overlapping loss of a second element within thirty minutes of the first. When such contingent events occur, the power that was flowing on the element lost from service automatically flows over the remaining elements of the interface. Accordingly, system operators monitor the power flow on each element of the interface, as well as the total power flow across the interface, in order to make sure that the interface will not become overloaded in the event of a contingency. When power flow on one or more elements of the interface, or on the interface as a whole, approaches the limit of their capability, generation may be re-dispatched to reduce the flow on that element or elements.

For the 2011 Needs Assessment, the Working Group used the Siemens PTI Program Managing and Utilizing System Transmission ("MUST") computer program to determine transfer limits for eastern New England, western New England, and Connecticut under both N-1 and N-1-1 conditions. Details of this analysis can be found in Section 5.2.6 of the 2011 Needs Assessment. The Working Group concluded that, under N-1-1 conditions, the import limit range for eastern New England is 1,250 to 1,350 MW. Under N-1-1 conditions, the import limit range for western New England is 2,250 to 3,000 MW, and the import limit range for Connecticut is 1,750 to 2,400 MW.

3.3.3.3 Assessing Resource Adequacy

Having established the import limit ranges for eastern New England, western New England, and Connecticut, ISO-NE assessed resource adequacy for each area by summing up the total resources available within that area (local generation plus demand response, minus generation outages) and then subtracting the resource requirement of that area (area load minus imports). If there is a surplus (positive value) afterwards, then the import region has sufficient resources in a given year. If there is a deficit (negative value) afterwards, then the import region has insufficient resources in a given year.

The transmission transfer capability analysis shows that there will be insufficient resources to serve eastern New England load under N-1-1 conditions starting in 2011. Further, there will be insufficient resources to serve western New England load under N-1-1 conditions starting in 2017-2018, and there will be insufficient resources to serve Connecticut load under N-1-1 conditions starting in 2014-2015. Specifically:

- Transfer capability from western to eastern New England is already deficient in 2011 by 446 to 546 MW. This deficiency will grow to between 1,762 to 1,862 MW in 2020 without transmission system improvements. With the impending retirement of the Salem Harbor Generating Station, the need for additional eastern New England import capability will be even greater.

- A need for additional transfer capability from eastern to western New England can be reasonably forecasted to occur between 2017 and 2018. This need would be advanced if any generation resources in western New England retire.
- A need for additional transmission transfer capability into Connecticut can be reasonably forecasted for between 2014 and 2015. This need would be advanced if any generation resources in Connecticut retire.

3.4 2012 FOLLOW-UP NEEDS ANALYSIS

3.4.1 Study Description

Pursuant to its obligations under Section 4.2(a) of Attachment K to its FERC-approved OATT, in March, 2012, ISO-NE undertook a “follow-up” to the 2011 Needs Assessment, issuing a report entitled “Follow-up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment” (“2012 Follow-Up Needs Analysis”). This report was presented to the PAC and was posted on the ISO-NE website as a final report on September 21, 2012.

According to ISO-NE, the objective of the 2012 Follow-Up Needs Analysis was to update the needs identified in the 2011 Needs Assessment based on changes in assumptions, specifically with respect to changes in load forecast and forecasted energy efficiency. Key changes in assumptions included:

- Use of load forecast information from the 2012 CELT Report. The 2011 Needs Assessment was based on load forecast information from the 2010 CELT Report.
- Use of study year 2022 for the 10-year horizon. The 2011 Needs Assessment used a study year of 2020.
- Use of results from FCA-6 (Capacity Period June 1, 2015-May 31, 2016), the most recent Forward Capacity Auction. FCA-4 results were used in the 2011 Needs Assessment.
- Use of longer-term energy efficiency forecasts as published in the 2012 CELT Report to project energy efficiency from the end of the FCA-6 capacity period through the year 2022. No longer-term energy efficiency forecast was used in the 2011 Needs Assessment.
- Changes in generation dispatch assumptions, including:
  - Revised assumptions for wind power output;
  - Revised hydro power assumptions based on the ongoing Vermont/New Hampshire, Pittsfield/Greenfield and Greater Hartford/Central Connecticut reliability studies;
  - Salem Harbor, AES Thames, Bridgeport Harbor 2, Somerset 6, Somerset Jet 2, Holyoke 6 & 8, Bio Energy, Potter Diesel, and Ansonia were assumed out of service in the base

case due to multiple delist bids/retirements/interconnection queue withdrawals. These units were assumed all available in the 2011 Needs Assessment.

ISO-NE performed steady state analyses (thermal and voltage) for 2022 summer peak load conditions using these revised assumptions. The methodology, assumptions, and results of the steady state thermal and voltage analyses are summarized below and are set forth in detail in pages 16-44 of the 2012 Follow-Up Needs Analysis. The 2012 Follow-Up Needs Analysis was performed in accordance with the NERC, NPCC, and ISO-NE planning standards and criteria in the 10-year planning horizon.

A total of three design cases and two sensitivity cases, representing a number of possible generation dispatch and availability conditions, were modeled for the 2022 study year and tested under N-0 and N-1 contingency events. System adjustments allowed in power-flow simulations for analyzing needs are listed in ISO-NE PP-3. The base cases are described in Section 3.4.2.4.

Based on the steady state analysis, ISO-NE identified a need for additional resources under each of four scenarios: an Eastern New England scenario, a Western New England scenario, a Connecticut scenario, and a Rhode Island scenario. ISO-NE then performed a Critical Load Level Analysis to identify the initial year of need for each scenario. Based on the Critical Load Level Analysis, ISO-NE determined that the needs identified in the Rhode Island and Eastern New England scenarios exist at current load levels, and the needs identified in the Western New England and Connecticut scenarios exist in the 2016-2017 timeframe.

3.4.2 Steady State Analysis Assumptions

The steady state assumptions used in the 2012 Follow-Up Needs Analysis are set forth in detail in Section 3 of that document, and are summarized below.

3.4.2.1 Load Forecast Assumptions

In accordance with ISO-NE planning practices, the modeled load was based on the summer peak 90/10 demand forecast in ISO-NE's 2012 CELT Report. This value was 34,130 MW for all of New England in 2022 (system losses included).

A summary of the load modeled in the 2022 case compared with the 2020 case from the 2011 Needs Assessment is shown in Table 3-10.

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

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

Note that the Study Year load forecast for New England load is 575 MW higher in the 2012 Follow-Up Needs Analysis than it was in the 2011 Needs Assessment. This is due primarily to the fact that the Study Year for the 2012 Follow-Up Needs Analysis is 2022 – two years later than the Study Year used in the 2011 Needs Assessment. The extra two years of load growth result in increased Study Year loads. The 2012 CELT forecast (used in the 2012 Follow-Up Needs Assessment) is roughly comparable to the 2010 CELT forecast (used in the 2011 Needs Assessment) on a year-on-year basis; for example, the 2020 summer peak load level of 33, 555 MW from the 2010 CELT forecast (see Table 3-10 above) is very close to the 2020 summer peak load forecast of 33,405 from the 2012 CELT Report.

3.4.2.2 Demand Resource Assumptions

Demand resources were modeled in the base case as capacity resources at the levels of the most recent FCA (in this instance, FCA-6), with additional energy efficiency resources as forecast in the 2012 CELT. The additional energy efficiency resources forecasted in the 2012 CELT Report are classified as passive DR. Thus, the demand resource values for each year are comprised of three elements: passive DR from FCA-6, additional passive DR in the form of energy efficiency resources projected in the 2012 CELT Report; and active DR from FCA-6.

The passive demand resource values from FCA-6 are listed in Table 3-11.

Table 3-11: FCA-6 Passive DR Values

Load Zone	CELT DRV[9] (MW)
Maine	146
New Hampshire	78
Vermont	115
Northeast Massachusetts & Boston	318
Southeast Massachusetts	176
West Central Massachusetts	210
Rhode Island	129
Connecticut	389

In addition to passive DR, ISO-NE included forecasts of energy efficiency through the ten-year horizon in the CELT Report. The amounts modeled in the cases are listed in Table 3-12. These values were added to the passive DR totals cleared through FCA-6 to determine a total passive DR value for the year 2022.

Table 3-12: Additional Forecasted EE Values through 2022[10]

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

Finally, the active demand resource values from FCA-6 are listed in Table 3-13.

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

[10] The 2012 CELT only provides EE forecast values through 2021. The EE forecast for year 2022 was assumed to be identical to the EE forecast for year 2021.

Table 3-13: FCA-6 Active DR Values

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

3.4.2.3 Net New England Load Assumptions

"Net load" is a term that represents a load forecast net of anticipated demand-side resources. ISO-NE developed a net load forecast for use in the 2012 Follow-Up Needs Analysis. A comparison of the net load from the 2011 Needs Assessment and net load from the 2012 Follow-Up Needs Analysis is provided in Table 3-14.

Table 3-14: Comparison of Net New England Load Between 2011 and 2012 Needs Assessments

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

As can be seen from Table 3-14, the 2022 Net Load used in the 2012 Follow-Up Needs Analysis is approximately 370 MW below the 2020 Net Load Used in the 2011 Needs Assessment. Primary drivers of this change included:

- Use of the 2012, rather than the 2010, CELT load forecast;
- Use of the results of FCA-6 rather than FCA-4, resulting in higher levels of passive demand resources and lower levels of active demand resources;
- Higher forecasted energy efficiency, and
- Termination of undelivered active and passive demand resources.

3.4.2.4 Base Case System Changes

Transmission projects with ISO-NE PPA approval as of the March 2012 RSP Project Listing[11] have been included in the study base cases. The base cases also included the most recent updates to the NEEWS RIRP and GSRP projects after their May 2012 revised PPA approval. The CCRP, which is being re-evaluated, was not included in the study base case. IRP was not included either, as it was the subject of the study.

The base cases included all existing generators and all new generators that have accepted an FCM Capacity Supply Obligation as of the FCA-6 for the commitment period (June 1, 2015 – May 31, 2016). Consistent with the 2011 Needs Assessment, the Vermont Yankee Nuclear Station in Vernon, Vermont (604 MW) was assumed out of service as a base case condition for all East-to-West stressed cases due to uncertainty surrounding the continued operation of the plant. However, Vermont Yankee was modeled as available when a proxy unit in the west was needed for the West-to-East stressed cases. In addition, updated assumptions were used to determine base case wind and hydro power output.

A list of Non-Price Retirement Requests and a discussion of FCM delisted units included in the base cases is provided on pages 18 - 19 of the 2012 Follow-Up Needs Analysis.

3.4.2.5 Generation Dispatch Cases

ISO-NE created generation dispatch cases for four areas of concern: Eastern New England (West-to-East Stress), Western New England (East-to-West Stress), Connecticut (East-to-West Stress), and Rhode Island. ISO-NE also developed two sensitivity cases: one for the Eastern New England case and one for the Western New England and Connecticut cases. These five dispatch cases were used to reflect a range of possible stressed conditions on the Southern New England transmission system, as shown in Table 3-15 below.

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

Table 3-15: Generation Dispatch Scenarios

Scenario	Area(s) of Concern	Generation Dispatch
West to East (design)	Eastern New England	• Hydro Quebec Phase II OOS • Seabrook Generating Station OOS • New Brunswick import at 700 MW
East to West (design)	Western New England Connecticut	• Millstone Units 2 and 3 OOS • Berkshire Power OOS as EFORD
Rhode Island Reliability (design)	Rhode Island	• RISE Generating Station OOS • Franklin Square / Manchester 09 OOS
West to East (sensitivity)	Eastern New England	• Hydro Quebec Phase II OOS • Seabrook Generating Station OOS • New Brunswick import at 0 MW
East to West (sensitivity)	Western New England Connecticut	• Millstone Units 2 and 3 OOS • West Springfield 3 OOS as EFORD

The New England East-to-West and West-to-East Scenarios stressed transfers in each direction across the New England East-West Interface. The Rhode Island and Connecticut Scenarios stressed conditions in local areas to determine the capability needed on the transmission system to serve demand in the local area. To accomplish this, the Rhode Island Reliability Scenario modeled two Rhode Island generators out-of-service. The Connecticut Reliability Scenario was modeled using the same generator dispatch case as was used for the New England East-to-West Scenario; however, for the Connecticut Reliability Scenario, the Connecticut load zone[12] was used as the region under study.

3.4.3 Steady State Analysis Results

ISO-NE conducted steady state load flow analysis to identify needs in each of the areas of concern in 2022. The results for each area of concern are presented below.

3.4.3.1 Eastern New England (New England West-to-East Scenario)

The New England West-to-East Scenario, with the Hydro Quebec Phase II high-voltage direct-current ("HVDC") line and the Seabrook Generating Station assumed to be out-of-service, illustrates the effect of high New England west-to-east transfers to serve demand in the east with generation from the west. The results of the 2022 cases for N-1 and N-1-1 contingency analyses are summarized in Table 3-16 below, assuming imports from New Brunswick at 700 MW (base case) and at 0 MW (sensitivity case).

As can be seen in Table 3-16, potential thermal overloads are seen under N-1 contingencies, and both thermal overloads and voltage performance issues are seen under N-1-1 contingencies, regardless of the New Brunswick import level chosen. The number of thermal overloads increases at the lower

[12] The Connecticut load zone is electrically defined in Table 2-5 of the 2011 Needs Assessment.

New Brunswick import level. Detailed results are contained in Section 5 of the 2012 Follow-Up Needs Analysis.

Table 3-16: 2022 Thermal Overloads and Performance Issues – New England West-to-East Scenario

Case	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
NB import @ 700 MW	1	2	0	9	10	2
NB import @ 0 MW	2	3	0	4	21	2

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.4.3.2 Western New England (New England East-to-West Scenario)

The New England East-to-West Scenario, with the Millstone Units 2 and 3 assumed to be out-of-service and the Berkshire Power Plant modeled offline to reflect the EFORD for Western Massachusetts generation, illustrates the effect of high New England east-to-west transfers to serve demand in the west with generation from the east. A summary of the results of the N-1 and N-1-1 contingency analyses is shown below in Table 3-17 for cases with Berkshire Power out-of-service representing EFORD (base case) and with West Springfield 3 out-of-service representing EFORD (sensitivity case).

As can be seen in Table 3-17, thermal overloads are seen under N-1-1 contingencies only, regardless of the unit selected to model forced outages. The number of potential thermal overloads is greater with the West Springfield unit out of service. Detailed results are contained in Section 5 of the 2012 Follow-Up Needs Analysis.

Table 3-17: 2022 Thermal Overloads and Performance Issues – New England East-to-West Scenario

Case	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
BERK OOS	0	0	0	2	7	0
WSP3 OOS	0	0	0	5	3	0

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.4.3.3 Connecticut (New England East-to-West Scenario)

Connecticut reliability is modeled using the same generator dispatch case as for Western New England; however, the Connecticut load zone, rather than Western New England, was used as the region under study. A summary of the results of the N-1 and N-1-1 contingency analyses is shown below in Table 3-18 for cases with Berkshire Power out-of-service and with West Springfield 3 out-of-service.

As can be seen in Table 3-18, thermal overloads are seen under N-1-1 contingencies only, regardless of the unit selected to model forced outages. The number of potential thermal overloads is greater with the West Springfield unit out of service. Detailed results are contained in Section 5 of the 2012 Follow-Up Needs Analysis.

Table 3-18: 2022 Thermal Overloads and Performance Issues – Connecticut Reliability Scenario

Case	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
BERK OOS	0	0	0	3	3	0
WSP3 OOS	0	0	0	4	1	0

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.4.3.4 Rhode Island

The Rhode Island Reliability Scenario was used to assess load serving capability in Rhode Island. This scenario stressed conditions in the Rhode Island load zone by reducing Rhode Island generation to require the system to deliver generation resources from outside the sub-area. In particular, the RISE Generating Station and the Manchester Street 09 combined cycle unit were assumed to be out-of-service. A summary of the results of the N-1 and N-1-1 contingency analyses are shown below in Table 3-19.

As can be seen in Table 3-19, certain N-1-1 contingencies result in voltage collapse on the Rhode Island transmission network. Under these circumstances, the steady state model does not solve, and therefore does not identify the thermal overloads that could also result from this contingency. Table 3-19, therefore, understates the number of thermal overloads that may result from N-1-1 contingencies. Detailed results are contained in Section 5 of the 2012 Follow-Up Needs Analysis.

Table 3-19: 2022 Thermal Overloads and Performance Issues – Rhode Island Reliability Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95%-100%[1]	Thermal Overloads	Voltage Performance Issues
2022	0	0	0	> or = to 1 (see above paragraph)	> or = to 2 (see above paragraph)	collapse

[1] Although transmission lines loaded between 95% and 100% are not technically overloaded, they are indicative of problems that may occur just beyond the study horizon.

3.4.3.5 Summary

ISO-NE's steady state analysis demonstrates that:

- Certain N-1-1 contingencies could lead to voltage collapse in Rhode Island;
- When serving Eastern New England from the west, thermal overloads are seen under N-1 contingencies, and thermal overloads and voltage performance issues are seen under N-1-1 contingencies;
- When serving Western New England from the east, thermal overloads are seen under N-1-1 contingencies; and
- When serving Connecticut from the east, thermal overloads are seen under N-1-1 contingencies.

3.4.4 Critical Load Level Analysis

Based on its steady state load flow analysis, ISO-NE identified potential thermal overloads and/or voltage issues in each of the four areas of concern under N-1 or N-1-1 conditions for the study year of 2022. ISO-NE then undertook a critical load level analysis to identify the initial date of need for each of the four areas of concern. This critical load level analysis was based on a focused set of analyses for the study year 2017 for selected contingencies associated with the thermal overloads and combined with linear extrapolation.

3.4.4.1 Methodology

To assess the initial year of need in each area of concern, ISO-NE selected the worst case contingency pairs and thermal violations seen in the 2022 results and simulated those same contingency pairs at a 2017 load level. A linear extrapolation of 2017 and 2022 load levels was then used to determine the load level at which the overloads would be first seen. This load level was then compared to forecasted net load levels for the years 2012 to 2022 to determine the year in which the overloads would first be seen. No topology changes were assumed when reducing load from a 2022 load level to a 2017 load level.

As an initial matter, ISO-NE needed to determine the 2017 net load in each of the four areas of concern. Anticipated net loads for the eight New England load zones were determined by deducting the net DR from the CELT Report load forecast. Table 3-20 provides the net loads in New England and the eight load zones for the 2012-2022 horizon.

Table 3-20: Net Loads (MW) 2012-2022

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

Using the above table, the net loads in the four areas of concern were determined. Since Connecticut and Rhode Island are stand-alone load zones, these loads were readily available. However, eastern New England and western New England areas are a combination of the different load zones. The western New England area consists of the Vermont load zone, the Connecticut load zone and parts of the West Central Massachusetts ("WCMA") load zone (56.5%) and parts of the New Hampshire load zone (7.8%). The eastern New England load zone consists of the Maine and Northeastern Massachusetts/Boston ("NEMA Boston") load zones, the remainder of the WCMA load zone (43.5%), a majority of the Southeastern Massachusetts ("SEMA") load zone (79.3%) and the New Hampshire load zone (92.2%). A part of the SEMA load zone (20.7%) is in the Greater Rhode Island subarea in addition to the Rhode Island load zone. Using these factors, ISO-NE calculated the net load for the 2012-2022 forecast horizon, in the four areas of concern, as shown in Table 3-21.

Table 3-21: Net Area Loads (MW) 2012-2022

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

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

3.4.4.2 Results

Details of the critical load level analysis, including the identity of the worst-case contingency pairs for each area of concern, can be found in Section 6 of the 2012 Follow-Up Needs Analysis.

- **Eastern New England:** Based on extrapolation from projected critical element loadings in eastern New England at 2017 and 2022 load levels, ISO-NE concluded that the critical element for this area will be loaded to 100% when net eastern New England load reaches 13,915 MW. As can be seen in Table 3-21, load in eastern New England reached this load level prior to 2012. Thus, there is an existing need to address violations of planning criteria at current load levels.

- Western New England: Based on extrapolation from projected critical element loadings in western New England at 2017 and 2022 load levels, ISO-NE concluded that the two critical elements for this area will be loaded to 100% when net western New England load reaches 10,914 MW and 10,988 MW, respectively. A comparison with Table 3-21 indicates that this load level should be reached in 2016 or 2017. Thus, there is a need to address violations of planning criteria beginning in 2016/2017.

- Connecticut: Based on extrapolation from projected critical element loadings for Connecticut at 2017 and 2022 load levels, ISO-NE concluded that the two critical elements for this area will be loaded to 100% when net Connecticut load reaches 7,609 MW and 7,670 MW, respectively. A comparison with Table 3-21 indicates that this load level should be reached in 2016 or 2017. Thus, there is a need to address violations of planning criteria beginning in 2016/2017.

- Rhode Island: Because the critical contingency pair for Rhode Island did not converge in 2022, ISO-NE was not able to use linear extrapolation to determine the critical load level.

Therefore, ISO-NE re-ran the critical contingency pair at 2012 load levels. This resulted in a projected thermal overload, leading ISO-NE to the conclusion that the initial year of Rhode Island need is prior to 2012.

3.4.5 2012 Follow-Up Needs Analysis: Conclusions

In its 2012 Follow-Up Needs Analysis, ISO-NE determined that:

- The results of the eastern New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier. With generation retirements, the need for additional eastern New England transmission transfer capability is greater.
- The results of the western New England reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen in the 2016-2017 timeframe. The need for additional transmission transfer capability is advanced if generation resources in western New England retire.
- The results of the Rhode Island reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen at 2012 load levels or earlier.
- The results of the Connecticut reliability analysis indicate that there are violations of planning criteria under the assumptions and system conditions modeled with the first violation seen in the 2016-2017 timeframe. The need for additional transmission transfer capability is advanced if generation resources in Connecticut retire.

Based on these findings, ISO-NE concluded that its 2012 steady state and critical load-level analyses continue to indicate a need to:

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

3.5 NEED IMPLICATIONS FOR RHODE ISLAND

The 2011 Needs Assessment and 2012 Follow-Up Needs Analysis confirm the needs shown in the 2008 Needs Analysis. The 2011 Needs Assessment first documented a previously unrecognized problem of insufficient transmission facilities to allow New England resources in the west to serve load needs in the east. While ISO-NE's analysis focuses on Southern New England as a whole, particularly on the need to improve the integration of the electric supply system serving the three Southern New England states and enhance the reliability of the transmission system for the benefit of the entire New England area, it also demonstrates the need for additional transmission facilities to specifically benefit the Rhode Island transmission system and to provide reliable power to the residents and businesses of Rhode Island.

The limitations of the Rhode Island transmission system are characterized by:

- limited ties to the New England 345 kV transmission system;
- limited generation; and
- a relatively large pocket of load southwest of Providence.

As can be seen in Figure 3-2, there are a limited number of 345 kV ties between the Rhode Island transmission system and the New England 345 kV transmission system.

Maintaining Rhode Island's connection to the larger New England 345 kV transmission system is of particular importance in light of the fact that Rhode Island also has limited generation resources, particularly in the relatively large pocket of load located southwest of Providence.

Because of these factors, on a heavy load day, the Rhode Island transmission system can experience significant transmission line overloads and low system voltages under certain N-1-1 contingencies. The IRP would address this issue by creating new 345 kV transmission paths into Rhode Island, both from the east (via the new 366 Line from the Millbury No. 3 Switching Station) and from the west (via the new 341 Line from the Lake Road Switching Station). With these new 345 kV lines in place, the thermal overloads and low system voltages that could have occurred in the previously described scenario are eliminated.

3.6 CONCLUSION

The IRP has been under study by the Working Group for over eight years, during which time the evolving analyses have taken into account multiple changes in system conditions. The 2011 Needs Assessment and 2012 Follow-Up Needs Analysis reinforced that this three-state project is necessary for New England transmission system reliability. N-1 steady state analysis showed thermal overloads and performance issues. N-1-1 steady state analysis testing showed widespread thermal overloads and performance issues across the study area. The 2011 Needs Assessment and 2012 Follow-Up Needs Analysis concluded that there will be inadequate resources to reliably serve anticipated load in eastern New England by 2011; in western New England by 2017/18; and in Connecticut by 2014/2015. Additionally, west-to-east thermal and voltage performance issues will become worse with the retirement of the Salem Harbor Generating Station. At the same time, the Project will resolve the multiple reliability issues within Southern New England.

5 PROJECT ALTERNATIVES

5.1 INTRODUCTION

This section describes the alternatives considered to address the needs identified in the 2011 Needs Assessment. The evaluation process involved multiple distinct assessments, each of which is discussed below. First, the Working Group consisting of National Grid, NU, and ISO-NE undertook a detailed assessment of alternative transmission solutions. The Working Group process culminated in the release of the 2012 Solution Report (included as Appendix E).

In parallel with the development of the 2012 Solution Report, National Grid and NU engaged an expert consultant, ICF, to study the potential for non-transmission alternatives ("NTAs") such as new generation, energy efficiency, demand response programs, and distributed generation, either alone or in combination, to address the needs identified in the 2011 Needs Assessment. National Grid also engaged POWER Engineers to evaluate alternatives to constructing some or all of the proposed Project underground. Finally, the Company assessed and compared all of the available options for meeting the identified need. National Grid's overriding goal throughout the planning and design phases of the Project has been to select the alternative that best meets the Project need, with a minimum impact on the environment, at the lowest possible cost.

As discussed in Section 3.4, in the spring and summer of 2012, ISO-NE undertook a "follow-up" to the 2011 Needs Assessment, issuing the 2012 Follow-Up Needs Analysis. As a complement thereto, ISO-NE also undertook a follow-up to the 2012 Solution Report, issuing a report entitled *Follow-Up Analysis to the 2012 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Solution Study Report* dated September 21, 2012 ("2012 Follow-Up Solution Report"). The 2012 Follow-Up Solution Report was posted on the ISO-NE website as a final report on September 21, 2012. A copy of this report is provided as Appendix O.[1]

Section 5.2 discusses the alternative of taking no action at all to improve the Southern New England electric transmission system. Section 5.3 describes the Working Group process and the analysis of various overhead transmission alternatives, and Section 5.4 presents a summary of the 2012 Follow-Up Solution Report, including the additional studies performed and the results thereof. Section 5.5 describes potential NTAs. Sections 5.6 and 5.7 describe alternative overhead routes using new ROWs and the existing Project ROWs respectively. Section 5.8 describes the Company's consideration of underground transmission alternatives. Section 5.9 describes alternatives to the expansion of the Sherman Road Switching Station.

[1] A copy of this report, redacted to avoid disclosure of CEII, is provided in the public record as Appendix O, and an unredacted copy will be provided to the EFSB and to eligible parties who have executed CEII Non-Disclosure Agreements.

5.2 NO ACTION ALTERNATIVE

Under the No Action Alternative, no improvements would be made to the existing electric supply system serving Southern New England. The Company would not pursue any new facilities or resources, but instead would continue to rely upon the existing system configuration.

The No Action Alternative was rejected because it would not resolve the regional electric reliability problems that ISO-NE and the transmission system owners have been studying for nearly eight years. Under the No Action Alternative, the electric supply system in the region, particularly in Massachusetts, Rhode Island, and Connecticut, would not comply with national and regional reliability standards and criteria. Compliance with these standards is mandatory under federal law. In addition, the No Action Alternative would be inconsistent with ISO-NE's determination that the IRP is needed to fully integrate generation resources with loads throughout Southern New England by relieving existing transmission constraints on the transfer of power from east to west and from west to east across the region. Furthermore, under the No Action Alternative, the thermal and voltage issues that presently exist at current load levels would continue and would be exacerbated by future increases in power demand. Accordingly, the Company rejected the No Action Alternative because it would not provide a solution to the existing and projected transmission reliability needs in the New England service area.

5.3 ELECTRICAL ALTERNATIVES

5.3.1 The NEEWS Working Group – Identification of Transmission Alternatives

As documented in the 2012 Solution Report, the Working Group identified five alternative transmission line solutions that could resolve the reliability issues identified in the 2011 Needs Assessment. These alternative transmission options, which are variants of Options A and C-2 from the 2008 Solution Report, were designated as Options A-1, A-2, A-3, A-4, and C-2.1.[2]

Interstate Options A-1, A-2, A-3, and A-4 connect the Millbury No. 3 Switching Station in Massachusetts, the West Farnum Substation and/or the Sherman Road Switching Station in Rhode Island, and the Card Street Substation and the Lake Road Switching Station in Connecticut. These four options are identical within Connecticut, but have different configurations in Massachusetts and Rhode Island.

In contrast, Option C-2.1 connects the Millbury No. 3 Switching Station with the Carpenter Hill Substation in Massachusetts and the Manchester Substation in Connecticut. It also requires a

[2] The 2008 Options Analysis and 2008 Solution Report considered a number of alternative transmission line options to resolve the reliability issues identified in the 2008 Needs Analysis. Two of these options – Options A and C-2 – were determined to have better system performance, to be easier to construct, and to cost less than the other options. The transmission line options identified by the Working Group in 2011 are based on these two options. The Option A-1 variant of Option A is the recommended solution as proposed by NU, National Grid, NSTAR, and ISO-NE.

separate 345 kV connection between the Sherman Road Switching Station and the West Farnum Substation, both in Rhode Island.

These options are described below, and illustrated in Figure 5-1 to 5-5. Table 5-1 summarizes the key elements of each option. With the exceptions noted in the following sections, all new and rebuilt transmission lines in Massachusetts and Rhode Island are located in existing National Grid and NU ROWs.

Table 5-1: Summary of Primary Elements in Massachusetts, Rhode Island, and Connecticut

Primary Feature	Option A Series				Option C-2.1
	A-1	A-2	A-3	A-4	
Mileage of Components					
New 345 kV Transmission Line	74.7	72.2	74.7	83.7	84.1
Reconductor / Rebuild Existing 345 kV Transmission Lines	9.2	0.2	8.7	0	0
Reconductor / Rebuild /Uprate Existing 115 kV Transmission Lines	0	0	0	0	15.4
New Substations/Switching Stations					
Rebuild Switching Station at Sherman Road[1]	AIS	GIS	AIS	AIS	AIS
New Switching Station at Uxbridge	--	--	AIS	--	--
New 345 kV Switchyard at Carpenter Hill	--	--	--	--	Yes
Modified Substations/Switching Stations					
Upgrade the Millbury No. 3 Switching Station	Yes	Yes	Yes	Yes	Yes
Modifications to CT Stations (Card Street, Lake Road, Killingly)	Yes	Yes	Yes	Yes	--
Expand Manchester Substation	--	--	--	--	Yes
New Bay at the West Farnum Substation	--	--	--	Yes	--

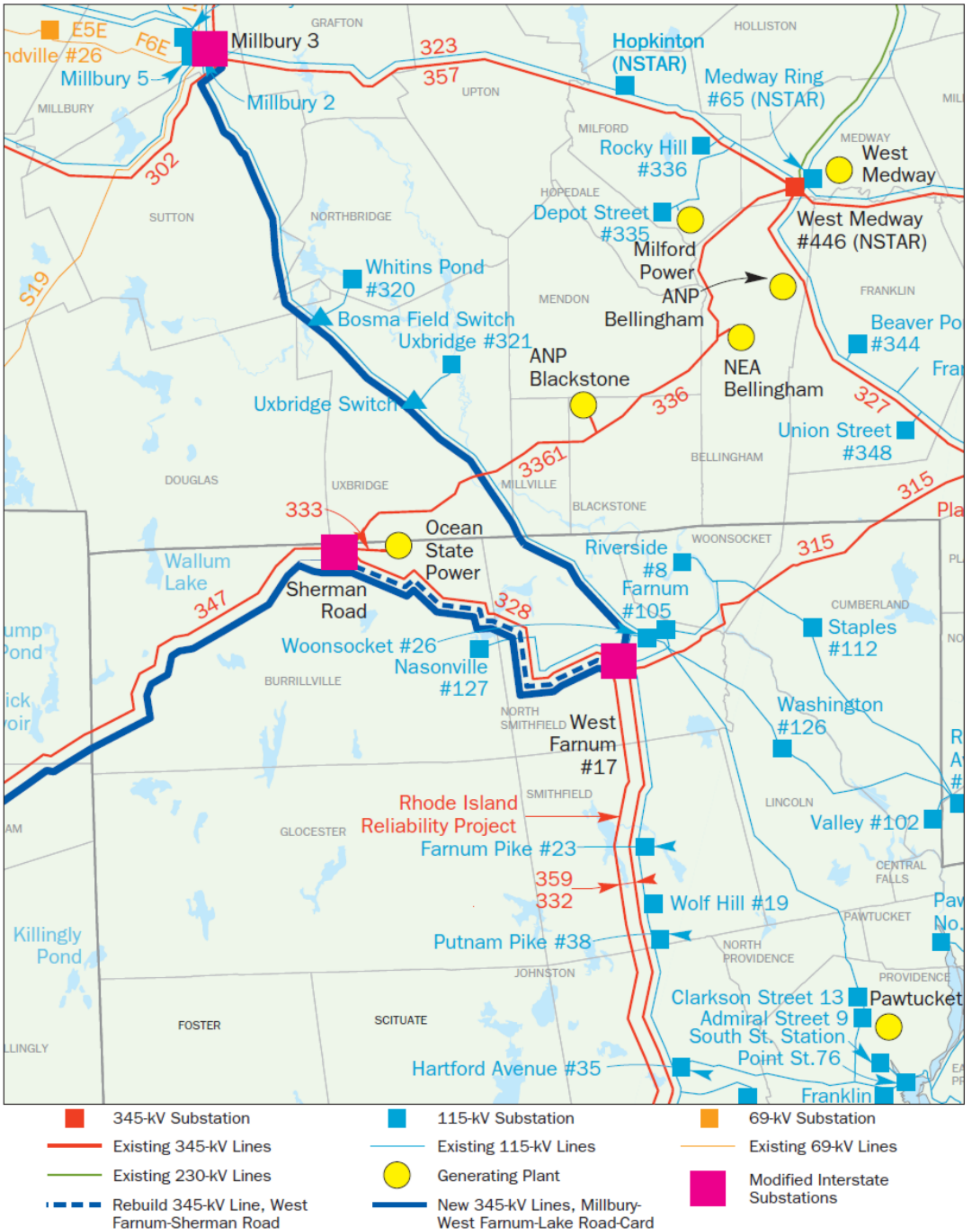
[1] Air-Insulated Switchgear ("AIS") is used at the Sherman Road Switching Station for Options A-1, A-3, A-4 and C-2.1. The more compact Gas-Insulated Switchgear ("GIS") is used for Option A-2 because an AIS would not fit on the site in this configuration. See Section 5.5 of the 2012 Solution Report.

5.3.2 Interstate Option A-1 (Proposed Project)

Option A-1, which is the proposed IRP, creates a new 345 kV connection between the Millbury No. 3 Switching Station, the West Farnum Substation, the Lake Road Switching Station, and the Card Street Substation and reinforces an existing 345 kV connection between the West Farnum Substation and the Sherman Road Switching Station. Option A-1 is illustrated in Figure 5-1. Key components of Option A-1 include:

- A new 20.2-mile 345 kV transmission line from the Millbury No. 3 Switching Station to the West Farnum Substation;
- A new 25.3-mile 345 kV transmission line from the West Farnum Substation to the Lake Road Switching Station;
- A new 29.2-mile 345 kV transmission line from the Lake Road Switching Station to the Card Street Substation;
- Reconstruction and reconductoring of the existing 328 345 kV transmission line between the Sherman Road Switching Station and the West Farnum Substation (approximately 9.2 miles) of; and
- Upgrades to the Millbury No. 3 Switching Station, the Lake Road Switching Station, and the Card Street Substation, and reconstruction of the Sherman Road Switching Station.

Figure 5-1: Option A-1 (Proposed Project)



Note: Common upgrades at W. Medway and on the 336 line are not shown on map.

5.3.3 Interstate Option A-2

Option A-2 creates a new 345 kV connection between the Millbury No. 3 Switching Station, the Sherman Road Switching Station, the Lake Road Switching Station, and the Card Street Substation and it also adds a new 345 kV connection between the West Farnum Substation and the Sherman Road Switching Station. Option A-2 is illustrated in Figure 5-2. Key components of Option A-2 include:

- A new 17.7-mile 345 kV transmission line from the Millbury No. 3 Switching Station to the Sherman Road Switching Station along existing National Grid and NSTAR ROWs;
- A new 16.2-mile 345 kV transmission line from the Sherman Road Switching Station to the Lake Road Switching Station;
- A new 29.2-mile 345 kV transmission line from the Lake Road Switching Station to the Card Street Substation;
- A new 9.2-mile 345 kV transmission line from the Sherman Road Switching Station to the West Farnum Substation;
- Rebuilding of 0.2 miles of the 345 kV transmission line from the Sherman Road Switching Station to Ocean State Power, both in Burrillville, Rhode Island; and
- Upgrades to the Millbury No. 3 Switching Station, the Lake Road Switching Station, and the Card Street Substation. The Sherman Road Switching Station would be rebuilt using GIS technology.

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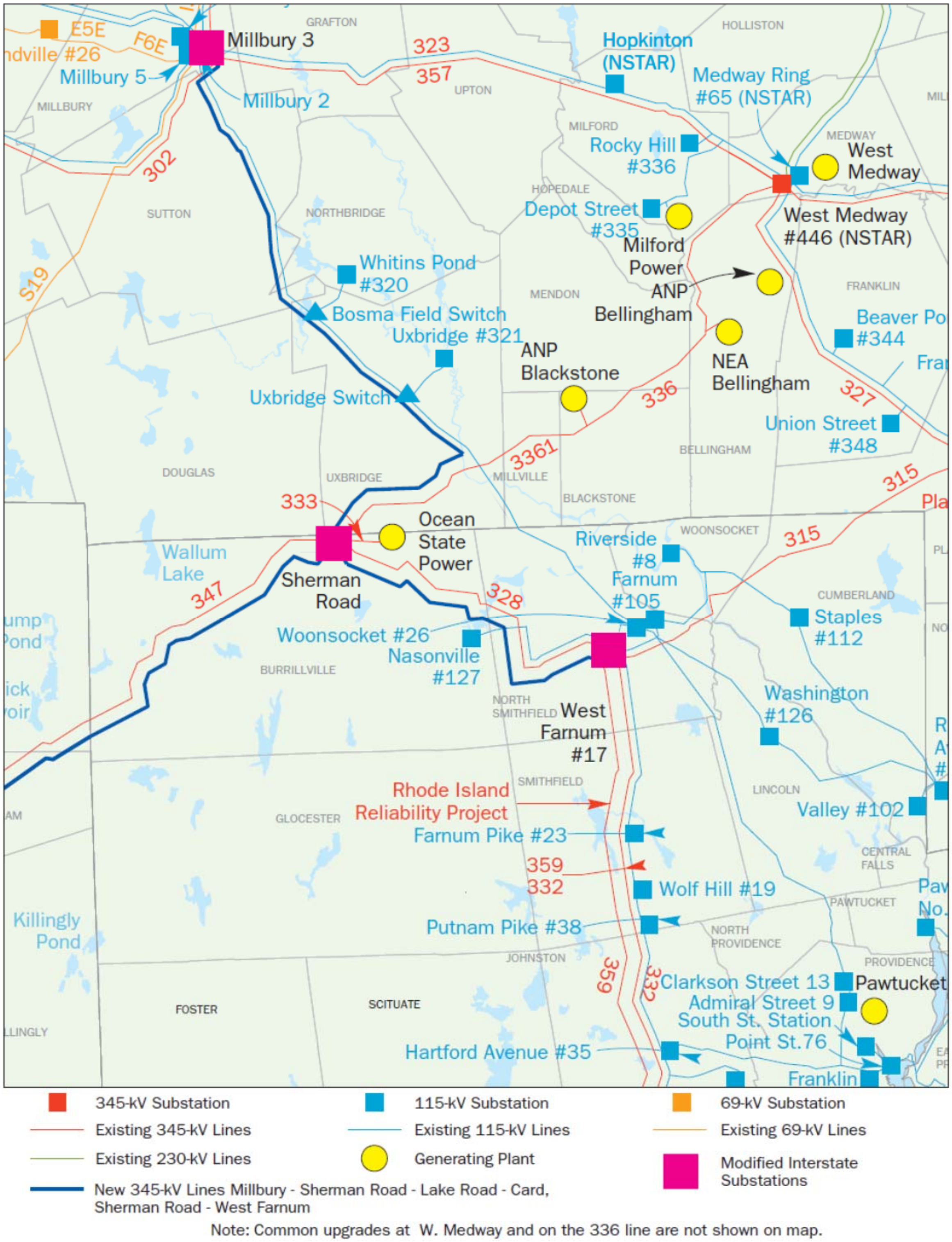
Figure 5-2: Option A-2



5.3.4 Interstate Option A-3

Option A-3 creates a new 345 kV connection between the Millbury No. 3 Switching Station, the West Farnum Substation, the Lake Road Switching Station, and the Card Street Substation, with a new switching station located in Uxbridge between the Millbury No. 3 Switching Station and the West Farnum Substation. The Uxbridge Switching Station also creates an interconnection with NSTAR's 3361 345 kV transmission line between the ANP Blackstone Substation and the Sherman Road Switching Station. Option A-3 is illustrated in Figure 5-3. Key components of Option A-3 include:

- A new 345 kV switching station in Uxbridge located at the intersection of National Grid's ROW and NSTAR's 3361 Line;
- A new 13.5-mile 345 kV transmission line from the Millbury No. 3 Switching Station to the new Uxbridge Switching Station;
- A new 6.7-mile 345 kV transmission line from the new Uxbridge Switching Station to the West Farnum Substation;
- A new 25.3-mile 345 kV transmission line from the West Farnum Substation to the Lake Road Switching Station;
- A new 29.2-mile 345 kV transmission line from the Lake Road Switching Station to the Card Street Substation;
- Increased conductor clearances on approximately 8.7 miles of existing 345 kV transmission lines between the Sherman Road Switching Station, the new Uxbridge Switching Station, and the ANP Blackstone Substation; and
- Upgrades to the Millbury No. 3 Switching Station, the Lake Road Switching Station, and the Card Street Substation, and reconstruction of the Sherman Road Switching Station.

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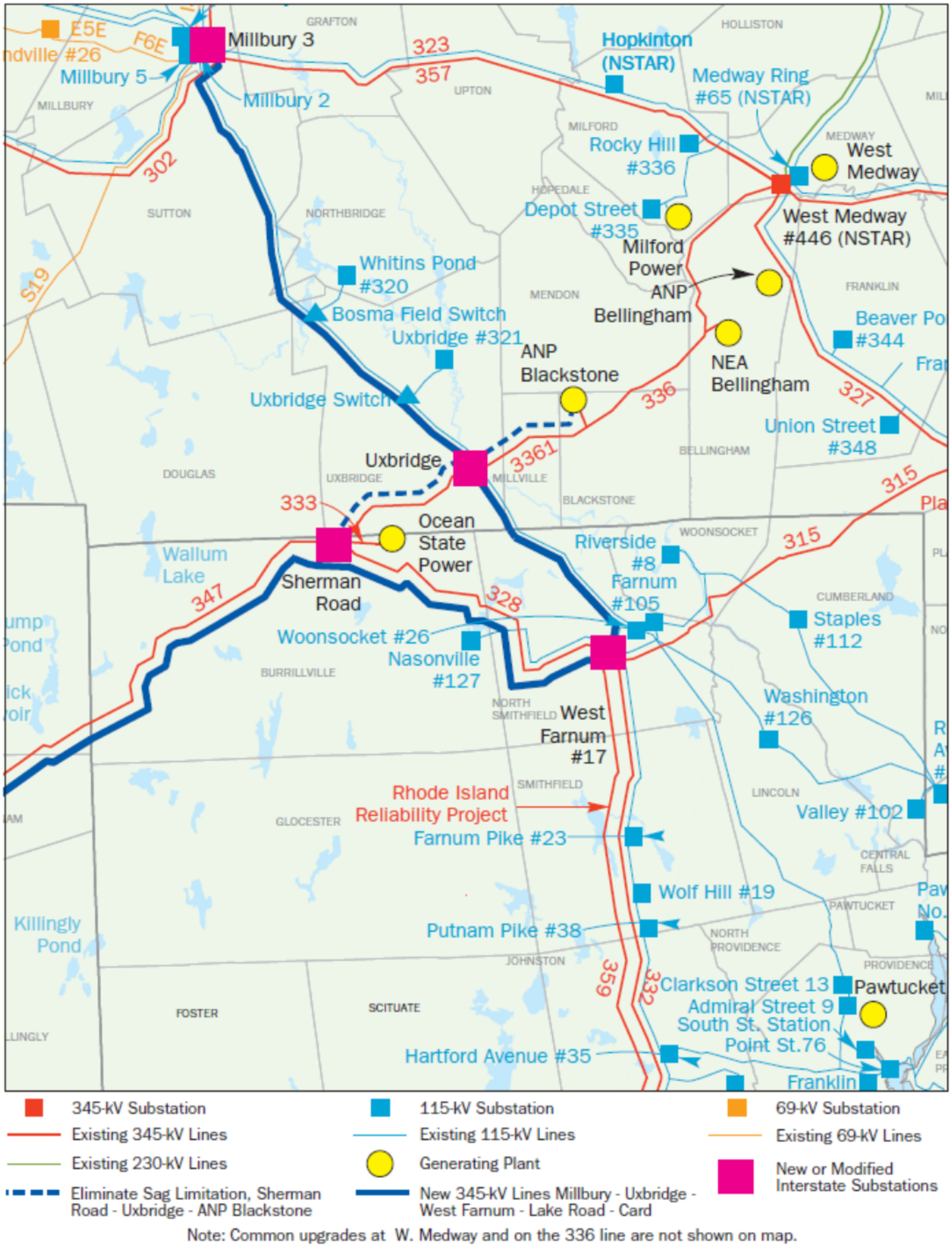
Figure 5-3: Option A-3

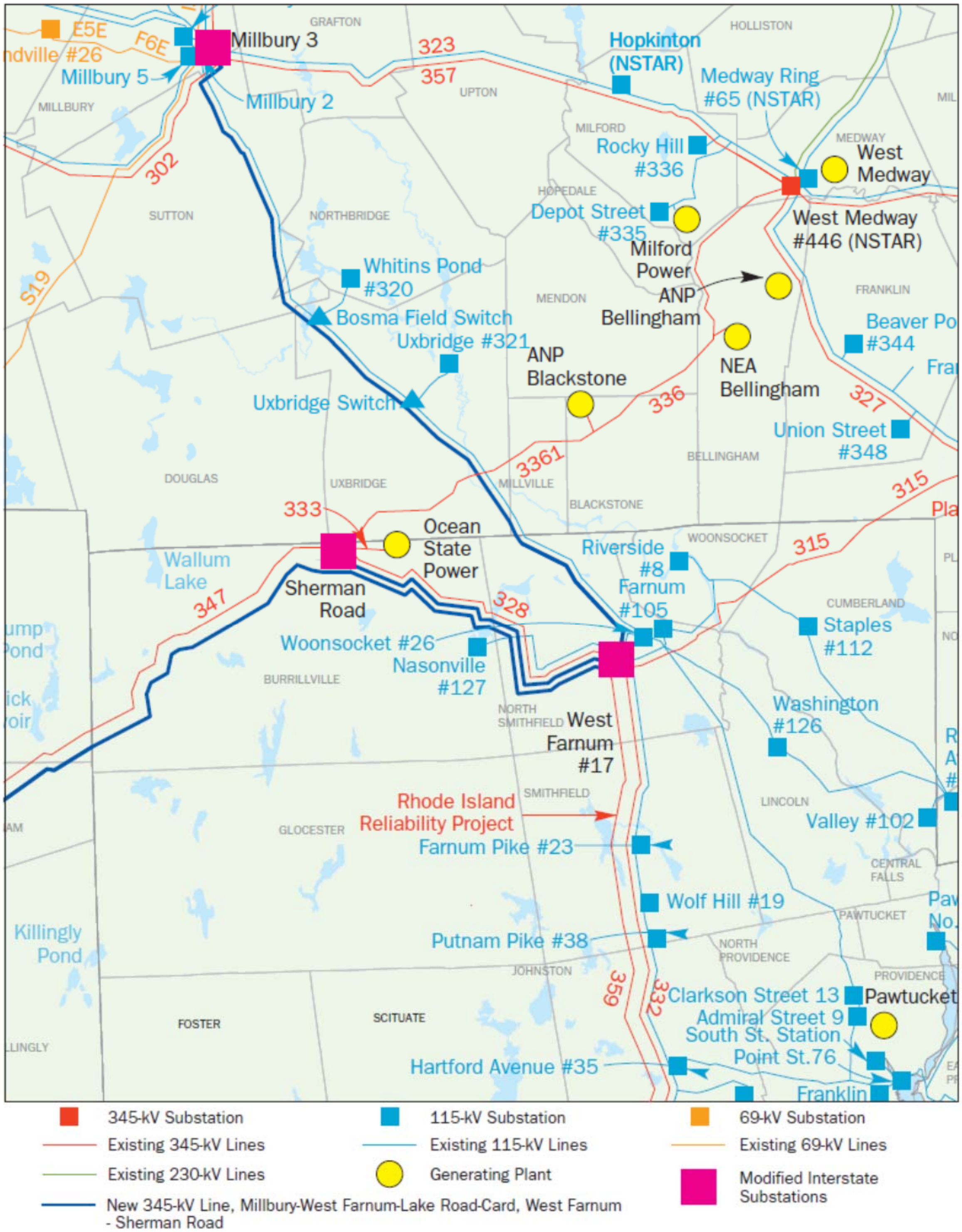


5.3.5 Interstate Option A-4

Option A-4 creates a new 345 kV connection between the Millbury No. 3 Switching Station, the West Farnum Substation, the Lake Road Switching Station, and the Card Street Substation. It also adds a new 345 kV transmission line between the West Farnum Substation and the Sherman Road Switching Station. Option A-4 is illustrated in Figure 5-4. Key components of Option A-4 include:

- A new 20.2-mile 345 kV transmission line from the Millbury No. 3 Switching Station to the West Farnum Substation;
- A new 25.3-mile 345 kV transmission line from the West Farnum Substation to the Lake Road Switching Station;
- A new 29.2-mile 345 kV transmission line from the Lake Road Switching Station to the Card Street Substation;
- A new 9.2-mile 345 kV transmission line from the West Farnum Substation to the Sherman Road Switching Station; and
- Upgrades to the Millbury No. 3 Switching Station, the Lake Road Switching Station, and the Card Street Substation, and reconstruction of the Sherman Road Switching Station.

Figure 5-4: Option A-4



Note: Common upgrades at W. Medway and on the 336 line are not shown on map.

5.3.6 Interstate Option C-2.1

Option C-2.1 creates a new 345 kV connection between the Millbury No. 3 Switching Station, the Carpenter Hill Substation, and the Manchester Substation in Connecticut. It also adds a new 345 kV connection between the West Farnum Substation and the Sherman Road Switching Station. Option C-2.1 is illustrated in Figure 5-5. Key components of Option C-2.1 include:

- A new 16.0-mile 345 kV transmission line from the Millbury No. 3 Switching Station to the Carpenter Hill Substation;
- A new 59.1-mile 345 kV transmission line from the expanded Carpenter Hill Substation to NU's Manchester Substation in Manchester, Connecticut;
- A new 9.2-mile 345 kV transmission line from the West Farnum Substation to the Sherman Road Switching Station;
- Upgrades to the Manchester Substation, the Carpenter Hill Substation, the Millbury No. 3 Switching Station, and the Sherman Road Switching Station; and
- Upgrades to various area 115 kV transmission lines.

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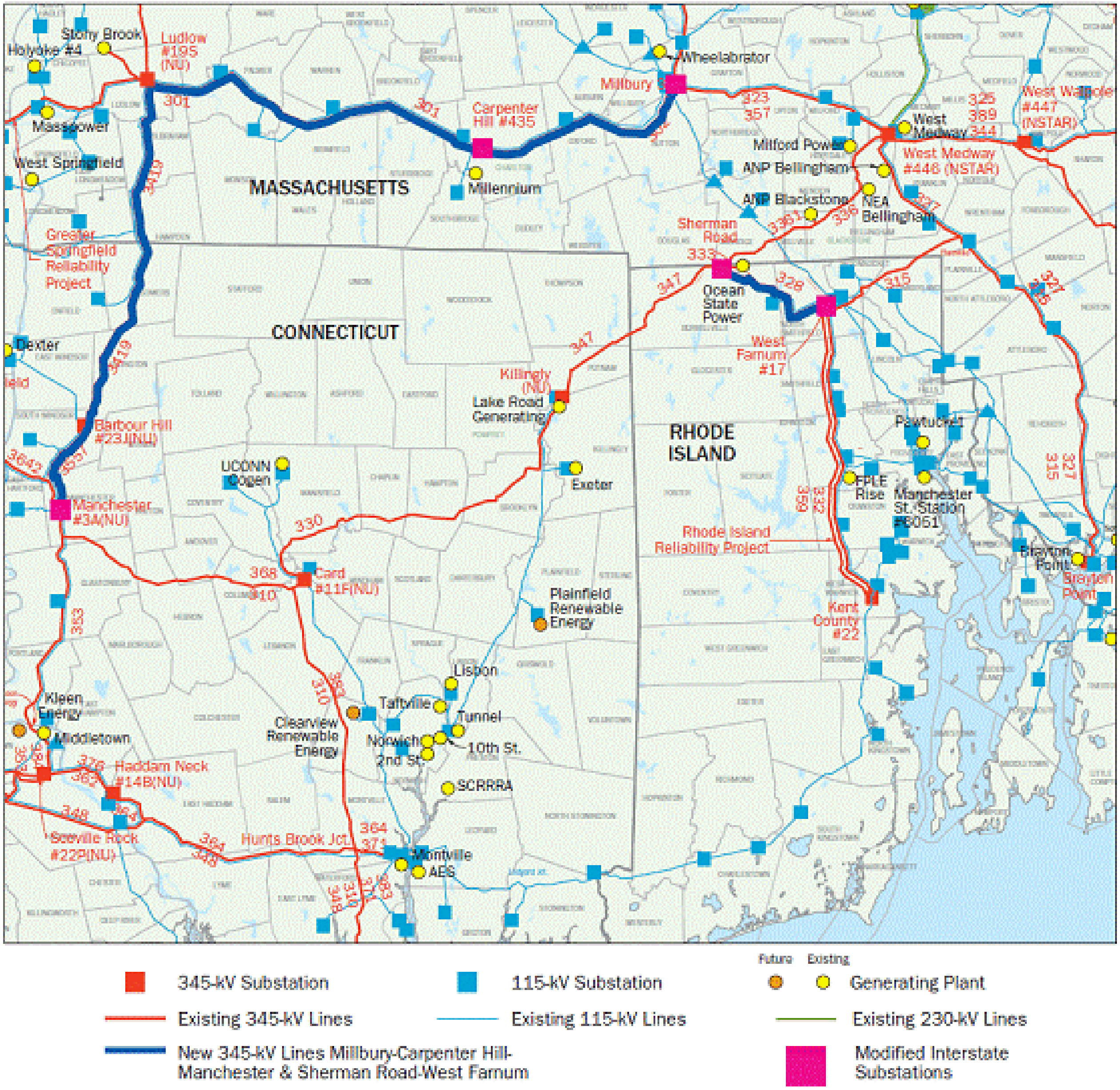
Figure 5-5: Option C-2.1



Note: Common upgrades at W. Medway and on the 336 line are not shown on map.

5.3.7 Assessment of Interstate Overhead Transmission Options

The Working Group undertook a comparison of the five overhead transmission options based on their electrical performance, cost, and impact on the natural and human environment. The Working Group evaluated the electrical performance of the five options under a broad range of system conditions and a variety of generation dispatches that stressed the transmission system. National Grid and NU were closely involved in this assessment, and ensured that it properly balanced reliability, cost, and environmental impacts. The Working Group's assessment is documented in the 2012 Solution Report, and is summarized below.

5.3.7.1 Electrical Performance

Electrical performance factors were used to compare the overall system benefits provided by each of the five options. The system upgrades associated with each option were designed to resolve all of the thermal and voltage issues identified in the 2011 Needs Assessment for the Southern New England transmission system over the 2015 to 2020 planning horizon. Each option was evaluated for its ability to improve the reliability and performance of the transmission system in the following areas:

- Improving the capability of the transmission system to move power into and within the load centers of Southern New England, specifically increasing the transfer capability across the following interfaces:
  - New England East-West interface
  - New England West-East interface
  - Connecticut import interface;
- Eliminating projected transmission line overloads and voltage performance issues following a contingency event;
- Providing acceptable short-circuit performance;
- Preventing degradation in stability performance during faults at major 345 kV switchyards in Southern New England;
- Minimizing generator torsional impact (Delta-P values) along the Card Street to West Medway corridor; and
- Maximizing ability for future expansion.

A detailed comparison of the electrical performance of the five options is provided in Section 7.2 of the 2012 Solution Report. In summary, the evaluation demonstrated that all five options would provide a level of electrical system performance that would meet design requirements for satisfying NERC, NPCC, and ISO-NE reliability standards and criteria. Options A-1, A-2, A-3, and A-4 provided generally comparable results with respect to transfer capability, transmission line loading, voltage performance, short-circuit impact, and generator torsional impact. Option C-2.1 was clearly inferior to the A-series options with respect to transfer capability, transmission line loading, and generator torsional impact, but performed better with respect to short-circuit impacts. Option A-1 was found to provide more system flexibility and expandability than any of the other options.

5.3.7.2 Cost

The Working Group prepared conceptual grade cost estimates (-25%/+50%) for each of the five IRP options, using a process consistent with ISO-NE procedures as defined in Attachment D of the ISO-NE Planning Procedure 4, *Procedure for Pool-Supported PTF Cost Review* ("PP-4").[3] Table 5-2 below summarizes the estimated cost of each option. Detailed cost estimates for each option are provided in Section 7.3 and Appendix I of the 2012 Solution Report (Appendix E).

Table 5-2: Conceptual Cost Estimates (in $ Millions) for Overhead Transmission Options (Massachusetts, Rhode Island, and Connecticut)

Option	Option A-1	Option A-2	Option A-3	Option A-4	Option C-2.1
Substations	$131	$168	$175	$148	$164
Transmission Lines	$411	$375	$378	$422	$550
Total	**$542**	**$543**	**$553**	**$570**	**$714**

Cost estimates in 2011 dollars

Options A-1, A-2, A-3, and A-4 are roughly comparable in cost, with Options A-1 and A-2 having the lowest cost estimate. Option C-2.1 is substantially more expensive than the other four options. Its estimated cost exceeds that of the A-Series options by $144 million to $172 million, or more than 25%.

5.3.7.3 Environmental Impacts

Section 7.4 of the 2012 Solution Report presents a two-stage comparison of the natural and human environmental impacts of the five overhead transmission line options. First, the A-series options are compared with Option C-2.1. Compared to the four A-series options, Option C-2.1 is longer overall and traverses more wetlands, watercourses, upland and wetland forests, parkland, and rare species habitat. Additionally, in Rhode Island, Connecticut, and Massachusetts, there are 942 residences within 500 feet of the C-2.1 centerline, as opposed to a range of 478 to 536 residences for the A-series options. Based on these factors, the 2012 Solution Report concludes that Option C-2.1 would have a greater potential for impacts to natural and human environmental resources than any of the A-series options.

Additional analysis was required to compare the four A-series options, due to their general similarities. This analysis evaluated potential for impacts in only Massachusetts and Rhode Island, since the four A-series options have identical facilities, and hence identical impacts, within Connecticut. Table 5-3 summarizes certain natural and human environmental characteristics of the

[3] http://www.iso-ne.com/rules_proceds/isone_plan/pp4_0_attachment_d.pdf

four A-series options that have the potential for environmental impacts within Massachusetts and Rhode Island.

Table 5-3: Environmental Impact of A-Series Options: Massachusetts and Rhode Island

Feature		Option A-1	Option A-2	Option A-3	Option A-4
New 345 kV Transmission Lines					
New 345 kV Transmission Line Length	Miles	37.9	35.6	37.9	46.9
Upland Forest Tree Removal	Acres	149.5	165.9	149.5	149.5
Wetland Forest Tree Removal	Acres	19.2	7.25	19.2	19.2
Upland Forest Tree Removal (Rare Species)	Acres	1.4	12.4	1.4	1.4
Forested Wetland Tree Removal (Rare Species)	Acres	2.1	0.6	2.1	2.1
Watercourse Crossings	Number	53	50	53	61
Parkland Traversed	Miles	2.1	2.1	2.1	3.2
Residences within 500 feet of Route Centerline	Number	319	265	319	319
Substations and Switching Stations					
Rebuilt Switching Station at Sherman Road		Yes	Yes	Yes	Yes
New AIS Switching Station at Uxbridge		No	No	Yes	No
Wetlands (permanently affected)	Acres	0.3	0.3	2.4	0.3
Upland Forest (permanently affected)	Acres	2.7	2.7	16.6	2.7

Source: Table 7-11 of 2012 Solution Report

As can be seen from Table 5-3, the work affecting the natural and human environment associated with the new 345 kV transmission line is identical for Options A-1 and A-3. However, the addition of a new 345 kV switching station on an undeveloped site in Uxbridge would create additional environmental impacts for Option A-3 relating to permanent wetland impacts and tree removal. Option A-1 is therefore superior to Option A-3 from the standpoint of natural and human environment impacts.

Table 5-3 indicates that the potential for natural and human environment impacts associated with the new 366 Line and substation work would be similar for Options A-1 and A-4, since they would occupy the same ROW. However, Option A-4 requires construction of a second new 345 kV transmission line, along a 9.2-mile ROW segment between Sherman Road and West Farnum. This would result in twice as many new foundations along this ROW segment, as well as additional work pads and roads to access structures for the second 345 kV transmission line, resulting in increased impacts to wetlands. Option A-1 is therefore superior to Option A-4 from the standpoint of natural and human environment impacts.

Table 5-3 indicates that the potential for natural and human environment impacts associated with Options A-1 and A-2 would be similar, with some features favoring A-1 and others favoring A-2.

One distinguishing difference between Options A-1 and A-2 is the work in rare species habitat. Along the Option A-2 route, for 3.4 miles of the NSTAR 3361 ROW between Sherman Road and Uxbridge, a presently-vegetated area approximately 75-feet wide would have to be cleared of trees to accommodate the new 345 kV transmission line. Much of this area is also within estimated habitat of rare species. Overall, development of Option A-2 would require 13.0 acres of tree removal within designated rare species habitat (12.4 acres of upland tree removal and 0.6 acres of wetland tree removal), while development of Option A-1 would require only 3.5 acres of tree removal within designated rare species habitat (1.4 acres of upland tree removal and 2.1 acres of wetland tree removal). The 12.4 acres of upland forest tree removal required by Option A-2 has much greater potential for taking of habitat and represents a serious environmental disadvantage as compared to Option A-1. Because preservation of known species habitat is a key concern of state regulatory agencies, the 2012 Solution Report concluded that Option A-1 is preferred from the standpoint of potential natural and human environment impacts.

5.3.8 Conclusions of the Working Group

Option A-1 emerged from the comparison process as the Working Group's preferred solution. In reaching this conclusion, the Working Group noted that its electrical performance testing demonstrated that the A-series options, as a group, performed slightly better than Option C-2.1. All the A-series options performed well electrically; however, future system expandability and flexibility considerations favored Option A-1 over the other A-series options.

The Working Group also noted that the A-series options are less expensive than Option C-2.1. Specifically, the estimated cost of Option C-2.1 is more than 25% greater than the estimated cost of the most expensive A-series option. The Working Group noted that the cost estimates for the four A-series options are within 5% of each other.

Finally, the Working Group concluded that Option A-1 is the preferred option from an environmental perspective. Option C-2.1 would have greater impacts on the natural and human environment than each of the A-series options. Option A-1 has a clear advantage over Option A-3, which requires a new switching station in Uxbridge, and over Option A-4, which requires the placement of two new 345 kV transmission lines along a 9.2-mile ROW segment between the Sherman Road Switching Station and the West Farnum Substation. The Working Group found that Options A-1 and A-2 have offsetting environmental advantages and disadvantages; however, Option A-2 would require 9.5 more acres of upland forest tree removal within designated rare species habitat than Option A-1. Overall, the reduced potential environmental impacts of Option A-1, combined with considerations of future system expandability, flexibility, and cost, led the Working Group to choose Option A-1 as the preferred IRP option.

5.4 2012 FOLLOW-UP SOLUTION REPORT

In the spring and summer of 2012, as a complement to the 2012 Follow-Up Needs Analysis, ISO-NE undertook a “follow-up” to the 2012 Solution Report (“2012 Follow-Up Solution Report”). The 2012 Follow-Up Solution Report was posted on the ISO-NE website as a final report on September 21, 2012. ISO-NE stated that the objective of the Follow-Up Solution Report was to identify regulated transmission solutions that address the needs identified in the 2012 Follow-Up Needs Analysis. A copy of this report is provided as Appendix O.

5.4.1 Study Assumptions

The study assumptions that were used for the 2012 Follow-Up Solution Report are the same as those that were used for the 2012 Follow-Up Needs Analysis. These assumptions are summarized in Section 3.4.2 of this report and detailed in Section 3 of the 2012 Follow-Up Solution Report.

5.4.2 Study Methodology

Because the needs identified in the 2011 Needs Assessment were seen again in the 2012 Follow-Up Needs Analysis, ISO-NE determined that the first step in the 2012 Follow-Up Solution Report was to revisit the alternatives considered in the 2012 Solution Report. Based on its prior analysis, ISO-NE determined that the A-series Options discussed above were superior to Option C-2.1, and that no other A-series option would provide a distinct advantage over Option A-1. ISO-NE then tested the major components of Option A-1 in an incremental manner to determine whether any component of Option A-1 could be deferred beyond the 10-year planning horizon.

In evaluating the different stages of Option A-1, only thermal and voltage analysis was performed. If the final solution had deviated from the complete Option A-1, additional transfer capability, stability analysis and delta P analysis would have been performed.

As a part of the 2012 Follow-Up Solution Report, ISO-NE tested the different components of Option A-1 in an incremental manner to determine whether any components of A-1 might be deferred. Table 5-4 identifies the components tested in each level of this incremental analysis. These combinations of components are referred to as Level 1, Level 2, Level 3 and Level 4 topologies. As can be seen in Table 5-4, the rebuilding of the Sherman Road Switching Station was included as a common upgrade for all topologies.

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Table 5-4: Solution Study Component Level Descriptions

Level	Component Descriptions
1	• Construct a new 345 kV line from the West Farnum Substation in Rhode Island to the Millbury No. 3 Switching Station in Massachusetts. • Rebuild of the Sherman Road Switching Station in Rhode Island
2	• All Level 1 components • Construct a new 345 kV line from the Lake Road Switching Station in Connecticut to the West Farnum Substation in Rhode Island
3	• All Level 2 components • Construct a new 345 kV line from the Card Street Substation to the Lake Road Switching Station in eastern Connecticut
4	• All Level 3 components • Rebuild the existing 345 kV line (328) between the Sherman Road Switching Station in Rhode Island to the West Farnum Substation in Rhode Island with higher capacity conductors

As discussed in Section 5 of the 2012 Follow-Up Solution Report,[4] the order in which the incremental analysis was performed was dictated by the results of the Follow-Up Needs Analysis. ISO-NE's first level of analysis included the addition of the new 345 kV line from Millbury to West Farnum, which addressed both the potential for voltage collapse, and the only N-1 violations identified in the Follow-Up Needs Analysis. For the second level of analysis, a 345 kV line from the Lake Road Switching Station to the West Farnum Substation was added to the elements in Level 1 to resolve certain contingency overloads between Connecticut and Rhode Island. For the third level of analysis, a new 345 kV line from the Card Street Substation to the Lake Road Switching Station was added to the elements in Level 2 to help resolve the N-1-1 overloads seen when moving power into western New England and Connecticut. For the fourth level of analysis, the 345 kV line from the Sherman Road Switching Station to the West Farnum Substation was rebuilt, as this line continued to overload under certain contingencies.

5.4.3 Steady State Study Results

ISO-NE conducted a steady-state analysis of each of the four transmission topologies listed above for each of three stress cases: Eastern New England Import, Western New England/Connecticut Import, and Rhode Island Import. The thermal and voltage issues associated with each stress case are summarized below. For each stress case the number of highly loaded transmission lines within the study area was recorded. A line was deemed to be highly-loaded when the flow on it was over 90% of its LTE rating after a contingency.

[4] ISO-NE has identified much of the information presented in Chapter 5 of the 2012 Follow-Up Solution Report as Critical Energy Infrastructure Information. In this summary, National Grid presents only information that ISO-NE has not identified as CEII.

5.4.3.1 Eastern New England Import

ISO-NE performed steady-state testing for the West-to-East Scenario with New Brunswick imports at 700 MW, and with New Brunswick imports at 0 MW. As discussed in Section 3.4.3, the 2012 Follow-Up Needs Analysis identified the potential for thermal overloads under N-1 contingencies, and for both thermal overloads and voltage performance issues under N-1-1 contingencies, in the absence of any new resources.

N-0 Results: No N-0 thermal or voltage issues were found in 2022 at either New Brunswick import level for any of the four transmission topologies.

N-1 Results: N-1 testing of the Level 1 topology identified a single thermal overload in 2022 when New Brunswick imports were assumed to be at 0 MW. In both cases, an additional element is loaded at over 90% of its LTE rating.[5] The results of the Level 1 analysis are presented in Table 5-5.

Table 5-5: 2022 Thermal Overloads and Performance Issues (N-1): Eastern New England Import (West-to-East Scenario)

Case	Level 1		
	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues
NB import @ 700 MW	1	0	0
NB import @ 0 MW	1	1	0

No heavily loaded lines, thermal overloads, or voltage issues were identified for Levels 2, 3 or 4 under N-1 contingencies. Thus, Level 2 improvements are sufficient to address N-1 contingencies for the West-to-East Scenario.

N-1-1 results

N-1-1 testing for the West-to-East Scenario found thermal overloads in 2022 for all four topologies, and at both New Brunswick import levels. Generally, overloads were worse when New Brunswick imports were assumed to be at 0 MW. The Level 4 topology resolved all overloads on 345 kV equipment; however, a single overload remained on 115 kV equipment which is resolved by the addition of a series breaker. Voltage performance issues were seen only with the Level 1 topology. The results of N-1-1 testing are summarized in Table 5-6 (for Level 1 and Level 2) and Table 5-7 (for Level 3 and Level 4).

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

Table 5-6: 2022 Thermal Overloads and Performance Issues (N-1-1): Eastern New England Import (West-to-East Scenario)

Case	Level 1			Level 2		
	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues
NB import @ 700 MW	7	4	0	3	0	0
NB import @ 0 MW	3	11	2	5	2	0

Table 5-7: 2022 Thermal Overloads and Performance Issues (N-1-1): Eastern New England Import (West-to-East Scenario)

Case	Level 3			Level 4		
	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues
NB import @ 700 MW	3	0	0	2	0	0
NB import @ 0 MW	5	2	0	5	1	0

Overall, for the West-to-East Scenario, Level 4 improvements (all elements of the IRP), and the addition of a series breaker, are required to resolve issues arising under N-1-1 contingencies.

5.4.3.2 Western New England/Connecticut Import

ISO-NE performed steady state testing for the East-to-West Scenario with EFORD represented alternately by Berkshire Power out-of-service, and by West Springfield 3 out-of-service. As discussed in Section 3.4.3, the 2012 Follow-Up Needs Analysis identified the potential for thermal overloads under N-1-1 contingencies under this scenario, in the absence of any new resources.

N-0 Results: No N-0 thermal or voltage issues or heavily loaded lines were found in 2022 for the Western New England and Connecticut Import stress case for any of the four topologies tested.

N-1 Results: No N-1 thermal or voltage issues were found in 2022 for any of the four topologies tested. However, a single 345 kV transmission line was found to be highly loaded in 2022 for the Level 1 and Level 2 topologies. These results are presented in Table 5-8.

Table 5-8: 2022 Thermal Overloads and Performance Issues (N-1): Western New England/Connecticut Import (East-to-West Scenario)

Case	Level 1			Level 2		
	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues
BERK OOS	1	0	0	1	0	0
WSP3 OOS	0	0	0	0	0	0

N-1-1 Results: N-1-1 testing for the East-to-West Scenario found thermal overloads and heavily loaded lines in 2022 for the Level 1 and Level 2 topologies. No thermal overloads or heavily loaded lines were identified for the Level 3 and Level 4 topologies. There were no voltage issues in the study area for any of the four topologies. The results the N-1-1 testing are summarized in Table 5-9.

Table 5-9: 2022 Thermal Overloads and Performance Issues (N-1-1): Western New England/Connecticut Import (East-to-West Scenario)

Case	Level 1			Level 2		
	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues	Elements Loaded 90%-100%	Thermal Overloads	Voltage Performance Issues
BERK OOS	3	6	0	4	5	0
WSP3 OOS	4	5	0	7	2	0

Overall, for the East-to-West Scenario, Level 3 improvements (all elements of the IRP with the exception of the 328 Line reconductoring) are required to resolve issues arising under N-1-1 contingencies.

5.4.3.3 Rhode Island Import

ISO-NE performed steady state testing for a single version of the Rhode Island Import Scenario. As discussed in Section 3.4.3, the 2012 Follow-Up Needs Analysis identified the potential for voltage collapse on the Rhode Island transmission system under N-1-1 contingencies under this scenario, in the absence of any new resources.

N-0 Results: No N-0 thermal or voltage issues were found in 2022 for the Rhode Island Import stress case for any of the four topologies tested. There were no highly loaded lines under N-0 conditions.

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

N-1-1 Results: No N-1-1 thermal or voltage issues were found in 2022 for the Rhode Island Import stress case for any of the four topologies tested.

Overall, for the Rhode Island Import Scenario, Level 1 improvements (the Millbury-to-West Farnum line) are sufficient to resolve the potential for voltage collapse arising under N-1-1 contingencies.

5.5 NON-TRANSMISSION ALTERNATIVES

National Grid and NU engaged an expert consultant, ICF, to assess the potential for NTAs to defer or displace the full IRP. ICF's assumptions, methodology and findings are discussed briefly below, and detailed in a report titled *Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Interstate Reliability Project* dated December 2011 ("NTA Report"). A copy of the NTA Report is attached as Appendix K.[6]

The NTA Report focused on relieving the numerous thermal overloads identified in the 2011 Needs Assessment using reasonably available NTAs, including generation in the ISO-NE New England Generation Interconnection Queue ("Interconnection Queue"), utility-funded energy efficiency, demand response programs, and distributed generation. As discussed below, ICF determined that the development of the Massachusetts, Rhode Island, and Connecticut generation currently in ISO-NE's Interconnection Queue, combined with aggressive pursuit of demand resources in Massachusetts, Rhode Island, and Connecticut would eliminate some but not all of the potential thermal overloads identified in the 2011 Needs Assessment. The NTA Report considered the possibility of addressing the resource shortfall with active demand response.[7] The report concluded that the resulting hypothetical NTA would require unprecedented levels of active demand resources and would have capital costs ranging from $15.1 billion to $43.5 billion, depending on the assumed cost of active demand response.

5.5.1 ICF Methodology

In order to determine whether the addition of new demand and/or supply resources could provide a reliability solution equivalent to that of the IRP, the effect of such additions were tested in the same way that the reliability performance issues were found in the first instance, and in the same way that the proposed transmission improvements have been proven to be a solution: by running power-flow models to determine if reliability performance issues would be eliminated by the addition of the extra resources. To accomplish this, ICF first obtained from ISO-NE the power flow simulation data used

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[6] A copy of the report, redacted to avoid disclosure of CEII, is provided in the public record as Appendix K, and an unredacted copy will be provided to the EFSB and to eligible parties who have executed CEII Non-Disclosure Agreements.

[7] Resources for reducing customer demand are classified as either "passive" or "active." Passive demand resources are principally designed to save electric energy use and are in place at all times without requiring direction from the ISO. They include energy efficiency measures and distributed generation. Distributed generation refers to small customer-owned generators, the output of which reduces demand for utility-supplied power. Active demand-response resources are designed to induce lower electricity use at times of high wholesale prices or when system reliability is jeopardized, by offering customers payments in return for reducing consumption.

to evaluate the need for the IRP. It then translated that data so that it would be compatible with ICF's own power-flow simulation software, which is different from that employed by ISO-NE. ICF ran the ISO-NE power flow cases on its software and determined that the results of the pre-IRP power-flow simulations agreed with those of the 2011 Needs Assessment and that the results of its post-IRP simulations agreed with those that ISO-NE had obtained in the course of preparing the 2012 Solution Report.

ICF then projected the generation and demand-side resources that could be made available in Southern New England within the 5- to 10-year planning horizon (2015 and 2020), and simulated the operation of the New England transmission grid assuming the non-transmission resources were substituted for the IRP. Three NTA options were examined – passive demand resources, including energy efficiency and passive distributed generation,[8] new generation, and a combination of new generation and passive demand resources. The potential NTAs were tested using power-flow simulations, under assumptions consistent with the 2011 Needs Assessment. The ICF analysis focused on evaluating the performance of the NTAs in eliminating thermal overloads. Additional modeling would be required to determine if any particular NTA resolved or aggravated the pre-IRP voltage performance issues.

The primary power flow cases assumed that the Salem Harbor Generating Station remains in service through 2020; the retirement of the Salem Harbor Generating Station was addressed in a sensitivity analysis. Thus, the results tend to understate the capacity additions or demand reductions required in eastern New England.

5.5.2 Critical Load Level Analysis

ICF began its assessment of NTAs by conducting a critical load level ("CLL") analysis for the Southern New England states. The CLL is the demand level above which reliability performance issues begin to occur. Above this load level, upgrades of the electric supply system would need to be made to continue to support demand. The identified reliability performance issues resolved by IRP occur in three different sub-regions – eastern New England, western New England, and Rhode Island - under three different and mutually exclusive dispatch scenarios. Therefore, ICF determined a reasonable estimate of the CLL for Southern New England by first determining a sub-regional CLL for each of the three sub-regions and then totaling them to develop an estimate of the Southern New England CLL.[9] ICF determined that the incremental demand reduction required to achieve the CLL for 2015 was 3,400 MW, which amounts to 15% of the peak load predicted for that year. For 2020, the required incremental demand reduction is 5,300 MW, which amounts to 22% of the 2020 predicted peak load.

[8] Energy efficiency programs and passive distributed generation (including passive renewables and distributed generation developed based on state net metering incentives) were included in ICF's estimates of passive demand resources.

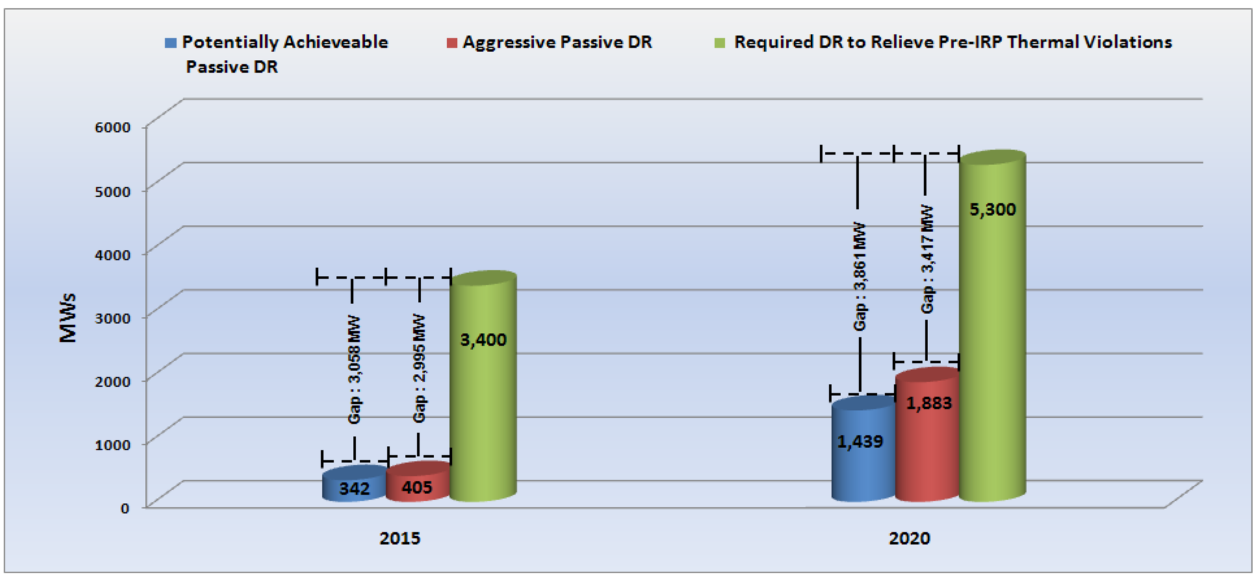
[9] ICF also conducted CLL analyses for Connecticut, treating the state first as an importing area and then as an exporting area. The Connecticut loads are included in the CLL for Western New England.

5.5.3 Assessment of Demand-Side Alternatives

After identifying the CLL for each sub-region and for Southern New England as a whole, ICF assessed whether it would be possible to reduce the peak demand to the CLL by relying entirely on demand resources. ICF analyzed the potential for incremental passive demand-side resources beyond those reflected in the 2011 Needs Assessment, which incorporated the demand measures embedded in the ISO-NE load forecasts and those procured through the ISO-NE FCA-4, held in August 2010.

Most demand resources result from programs sponsored by utilities under regulatory oversight. As such, they are subject to regulatory approvals at the state level, and also are frequently backed with state or ratepayer funding. Therefore, ICF first estimated achievable passive demand resource levels by examining the relevant programs in place in each of the three states in the study area and projecting two different potential future resource levels – a Reference DR Case and an Aggressive DR Case. The Reference DR Case assumed that utilities in each state would achieve incremental summer peak demand reductions equivalent to 100% of their current program goals each year until 2020. The Aggressive DR Case assumed that this level of summer peak demand reductions would be significantly exceeded. Neither case came close to reducing the demand level to the CLL. Figure 5-6 illustrates the gap between the CLL and the achievable passive demand resources for filling it.

Figure 5-6: Comparison of Achievable Incremental Passive DR to CLL Load Reduction in Southern New England – 2015 and 2020



5.5.4 Assessment of New Proposed Generation Alternatives

To determine if an NTA solution could be developed from new generation resources, ICF first reviewed the proposed projects in the Interconnection Queue as of April 1, 2011 to identify potential facilities in Southern New England that could be included in such a solution. The generation resources available in the Interconnection Queue, totaling 2,851 MW, were grouped into three categories based on their likelihood of being constructed:

- **Category 1:** Facilities with completed interconnection agreements (427 MW). These facilities have gone through various studies and all the steps in the approval process and were considered very likely to be developed.
- **Category 2:** Facilities with PPA approval in accordance with Section I.3.9 of the ISO-NE Transmission, Markets, and Services Tariff, excluding Category 1 facilities (1,904 MW).
- **Category 3:** All remaining facilities in the Interconnection Queue (520 MW). Units in Category 3 were considered to have the lowest probability of being developed.

Having identified and classified all potential generation resources in Southern New England, ICF undertook power-flow analyses to assess the ability of these resources to address the thermal conditions identified in the 2011 Needs Assessment. This analysis was performed first on a sub-regional basis to isolate the effects of alternate dispatch conditions; subsequently, sub-regional results were aggregated to determine the implications for Southern New England. In analyzing each sub-region, generation facilities from Category 1 were added to the 2015 and 2020 base power-flow cases, and the cases were analyzed under N-1 and N-1-1 contingency conditions similar to those analyzed in the 2011 Needs Assessment. The results were compared to those from the 2011 Needs Assessment, and any remaining or new thermal overloads were noted. If thermal overloads remained in any of the base power-flow cases, generation facilities from Category 2 were added to those cases and the contingency analysis and review of results repeated. The process was repeated with Category 3 resources if thermal overloads persisted after the addition of Category 2 resources.

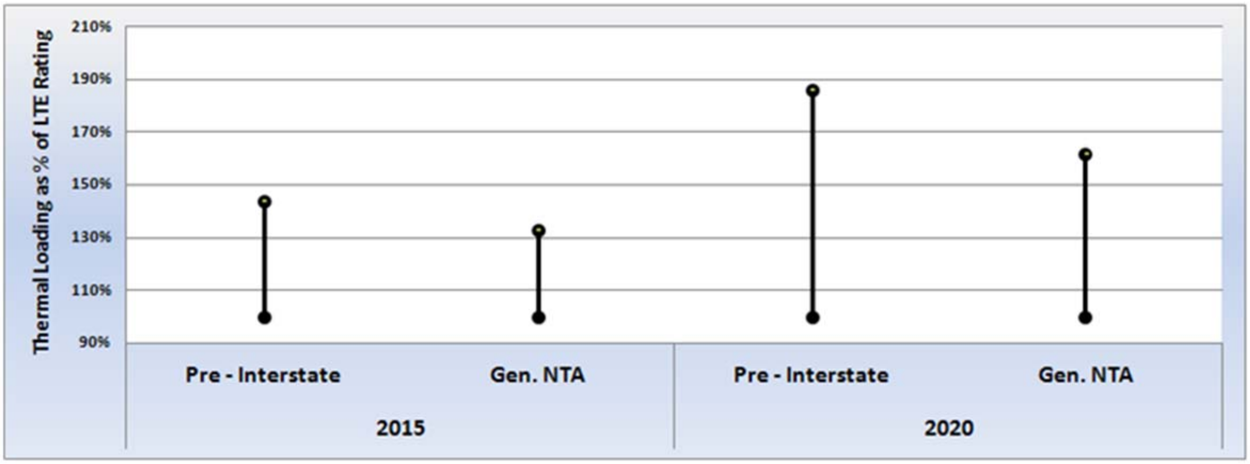
ICF modeled the Southern New England system with the addition of these generation resources, but without the IRP. The results of the simulation showed that no feasible generation NTA is available for Southern New England. The generation NTA would leave unresolved many of the thermal overloads addressed by the IRP. Table 5-10 summarizes the results of this simulation.

Table 5-10: Summary of Thermal Overloads for Generation NTA

Year	Number of Thermal Overloads			Number of Elements Overloaded		
	Needs Assessment	Generation NTA	% Reduction	Needs Assessment	Generation NTA	% Reduction
2015	206	90	56%	20	17	15%
2020	6,029	2,817	53%	53	31	42%

The severity of the remaining thermal overloads is shown in Figure 5-7. The generation NTA was more effective in reducing the number of overloads than the severity of overloads. Many of the most severe overloads still remained. In 2015, some transmission facilities exceeded their thermal limit ratings by 30%. In 2020, some thermal overloads were more than 60% higher than the rating of the facilities.

Figure 5-7: Range of Thermal Overloads in Southern New England – Generation NTA



5.5.5 Assessment of Combined Generation and Demand-Side Alternatives

Following its demand-side-only and generation-only analyses, ICF sought to develop a feasible NTA solution that combined generation with demand-side resources, including active demand response. As a first step, ICF supplemented the passive demand resources identified in its demand-side-only analysis with queued generation to develop a combined generation and passive demand resource NTA. ICF then analyzed the combination to determine if it would provide a feasible NTA solution. Having found that it would not, ICF considered whether the further addition of active DR resources could provide a solution. It determined that this would require an unprecedented level of growth in active DR resources, and that the cost of such an approach would be considerably higher than the cost of the IRP.

Table 5-11 summarizes the generation and passive demand resources used to develop two combination NTAs: the "Reference Combination NTA" and the "Aggressive Combination NTA". ICF used a sub-regional analysis to identify the generation and demand resources included in the combination NTAs. For each sub-region (Eastern New England, Western New England, and Rhode Island), ICF first assumed that all passive demand resources in the Reference DR case would be available, and then added generation as required to resolve the remaining thermal overloads in that sub-region. This resulted in the Reference Combination NTA. ICF repeated this process using the Aggressive DR case, resulting in the Aggressive Combination NTA.

Table 5-11: Reference and Aggressive Combination NTAs

Year	Reference Combination NTA		Aggressive Combination NTA	
	New Generation	New Passive DR	New Generation	New Passive DR
2015	896 MW	342 MW	896 MW	405 MW
2020	1,790 MW	1,439 MW	1,790 MW	1,883 MW

Power-flow simulations assuming the addition of these combinations of resources showed many remaining thermal overloads. Although the Reference Combination NTA reduced the number of thermal overloads compared to those shown in the 2011 Needs Assessment, in 2015, multiple contingencies would still cause 77 overloads on 16 facilities when the Reference Combination NTA is implemented. In 2020, there would still be 124 thermal overloads using the Reference Combination NTA. The results of the simulations are shown in Table 5-12.

Table 5-12: Summary of Thermal Overloads for Reference Combination NTA

Year	Number of Thermal Overloads			Number of Elements Overloaded		
	Needs Assessment	Combination NTA	Percent Reduction	Needs Assessment	Combination NTA	Percent Reduction
2015	206	77	63%	20	16	20%
2020	6,029	124	98%	53	19	64%

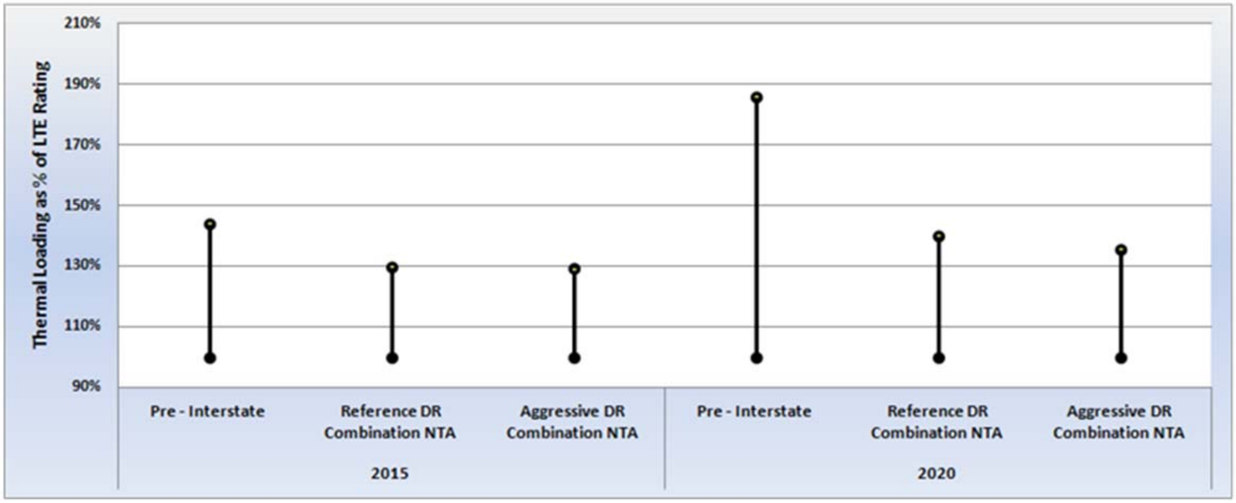
As shown in Table 5-13, the Aggressive Combination NTA slightly reduces the remaining thermal overloads as compared to the Reference Combination NTA.

Table 5-13: Summary of Thermal Overloads for Aggressive Combination NTA

Year	Number of Thermal Overloads			Number of Elements Overloaded		
	Needs Assessment	Combination NTA	Percent Reduction	Needs Assessment	Combination NTA	Percent Reduction
2015	206	72	65%	20	15	25%
2020	6,029	84	99%	53	17	68%

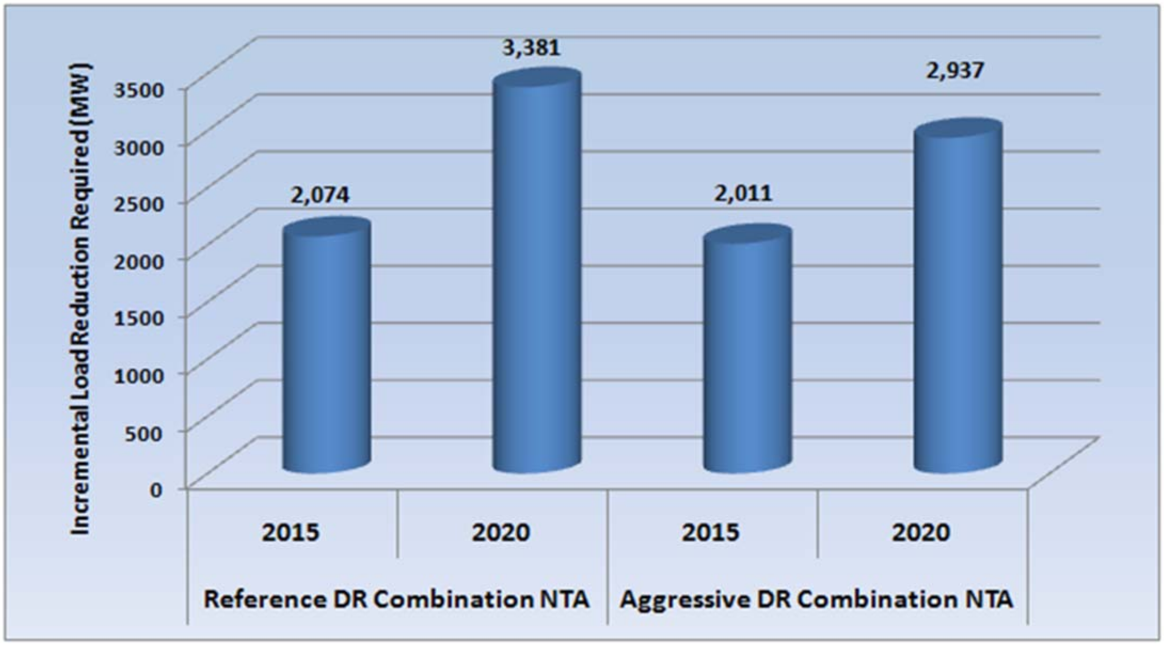
The severity of the thermal overloads is shown in Figure 5-8. The combination NTAs reduced the number of overloads significantly. They were also effective in reducing the severity of overloads. However, many severe thermal overloads still remained. For example, in both of the combination NTAs, some transmission facilities exceeded their Long-Term Emergency rating ("LTE") limits by approximately 30%.

Figure 5-8: Range of Thermal Overloads in Southern New England – Combination NTAs



ICF determined that a combination of generation assumed to be available by reason of its presence in the Interconnection Queue and potentially available passive demand resources would not provide a sufficient combination NTA. ICF then went on to consider whether the addition of potentially available active demand resources could enable a combination NTA to provide performance equivalent to that of the IRP. As it did in its CLL analysis, ICF determined the additional load reduction required to resolve all the thermal overloads that IRP addresses. ICF then estimated the additional active demand resource capacity that would provide the required load reduction. Figure 5-9 shows the load reduction that would be required from active demand resources to produce a combination NTA solution.

Figure 5-9: Combination Case Incremental Required Load Reduction to Achieve an NTA in Southern New England – 2015 and 2020



Estimating the level of active demand resources required to achieve this load reduction was challenging, because active demand resources, unlike traditional generators and energy efficiency measures, do not have a long track record from which future performance may be projected. ICF used the performance factors developed by ISO-NE for use in its 2011 FCA-5 to calculate the required amount of active demand resources in each sub-region, and then aggregated the sub-regional values to determine the values for Southern New England. Table 5-14 illustrates the level of active demand resources that would need to be available, in combination with the Aggressive Combination NTA, to produce an NTA solution. Higher levels of active demands resources would be required for the Reference Combination NTA.

Table 5-14: Active DR Required for the Aggressive Combination NTA

Parameter	Combination NTA 2015		Combination NTA 2020	
	No Derate	FCA-5 Derate	No Derate	FCA-5 Derate
FCA-5 (2014/15) Qualified Active Demand Response Resources (MW)[1]	1,102			
Incremental Active DR Required to Eliminate Thermal Overloads in the Combination Case (MW)	2,011	3,381	2,937	4,871
Total (cumulative) DR Required (MW)	3,113	4,483	4,039	5,973
Average Annual Percentage Growth	182%	207%	24%	33%

[1] The qualified resources from FCA-5 are used as a proxy for the total available demand response resources available for the summer of 2014 as of today. Total is shown for only the Massachusetts, Rhode Island, and Connecticut load zones, as the areas of concern. The total qualified Real Time Demand Response Resource for all of New England is 1,667 MW. Within Rhode Island, Connecticut, and Massachusetts load zones, 1,207 MW of capacity qualified; of this total, 105 MW were accepted for delist, resulting in qualified Real Time Demand Response Resources of 1,102 MW in Southern New England.

The capital costs required to achieve these unprecedented levels of active demand resources over 30 years is estimated to range from $8.5 billion to $37.3 billion, resulting in total capital costs of $15.1 billion to $32.7 billion for the Aggressive Combination NTA, and $18.7 billion to $43.5 billion for the Reference Combination NTA. Furthermore, in order to achieve these levels of active DR, the compound annual average growth rate in active DR would have to be between 24% and 33% until 2020. ICF did not view this as a realistic target. Accordingly, ICF concluded that potentially available active demand resources could not fill the gap, so that potentially available generation resources and active and passive demand resources are not sufficient to develop a feasible combination NTA solution.

5.5.6 Sensitivity Analyses

Following this analysis, ICF modeled two sensitivity scenarios. In one, it assumed the Salem Harbor Generating Station to be retired, in accordance with an announcement made by the owner and a directive from ISO-NE, both of which occurred after ICF began its work. Under this scenario, the performance of the combination NTAs were substantially worse, indicating the potential vulnerability of the NTA to the retirement of existing plants. In the other sensitivity scenario, ICF assumed the addition of a generic 1,400 MW incremental supply source in Tewksbury, Massachusetts. Even that very large resource increment, in addition to the Aggressive Combination NTA, did not eliminate all of the thermal overloads.

5.5.7 Conclusion – Non-Transmission Alternatives

Based on the findings of the ICF study, National Grid concluded that: (1) the construction of new ISO-NE queued generation would not meet the identified need; (2) aggressive implementation of demand-side management, including energy efficiency, distributed generation, and demand response programs would not meet the identified need; and (3) a combination of central generation and demand-side management would not meet the identified need. Moreover, even if a combination of

ISO-NE queued generation and demand-side management could be developed that was indeed able to meet the identified need, it would be substantially more costly than the IRP. Furthermore, implementation of an NTA, were one to exist, would be challenging, compared to implementation of IRP, as it would involve many parties, locations, and resources. Thus, any NTA that could be designed by including even more resources than were tested in the ICF studies would not be practical and feasible. Because none of the NTAs would meet the identified need at a reasonable cost, it was not necessary to analyze the environmental impacts associated with the NTAs and the Company did not bring these alternatives forward for further consideration.

5.6 ALTERNATIVE OVERHEAD ROUTES

To verify that no preferable alternative overhead routes exist for the new 345 kV transmission lines between the Rhode Island/Massachusetts border and the Rhode Island/Connecticut border, with an interconnection with the West Farnum Substation, National Grid examined the general vicinity and the orientation of east-to-west options for possible alternatives to the proposed route using the existing developed ROWs (Refer to Figure 5-10).

5.6.1 Public Streets and Highways

National Grid examined the use of public streets and highways for the proposed 345 kV transmission lines. The majority of the available road layouts would not be wide enough to accommodate an overhead 345 kV line while complying with applicable code clearances to adjoining property lines. As a result, this alternative would require the acquisition of new ROW along the edge of the existing roadways. This would add significantly to the cost and would delay the schedule of the Project. It would also cause impacts to and possible displacement of homes, businesses and other adjoining development and land uses. In addition, this alternative would render the new transmission line very visible along the commonly traveled roadways. Since there is a viable alternative using an existing, dedicated utility corridor that could be delivered in a timelier manner with lower impacts and costs, this option was rejected.

5.6.2 Use of Existing Pipeline Rights-of-Way

Existing pipeline ROWs were examined for co-location opportunities with the proposed transmission lines in Rhode Island. Three interstate pipelines were identified within the project area, including facilities operated by Algonquin Gas Transmission ("AGT"), Tennessee Gas Pipeline ("TGP"), and ExxonMobil Pipeline Company ("ExxonMobil").

AGT's facilities in the vicinity of the project deliver natural gas from the Cromwell and Chaplin Compressor Stations in Connecticut east to the Burrillville Compressor Station in Burrillville, Rhode Island. From the Burrillville Compressor Station, natural gas is delivered east to the Ocean State Power Generating Plant, and northeast to the AGT Bellingham Meter and Regulator Station. From this point natural gas is transported to the Boston and southeast Massachusetts service areas. AGT has a 75-foot ROW that contains two natural gas pipelines. There is an existing AGT pipeline crossing of the National Grid ROW located west of Wilson Trail in Burrillville, Rhode Island, and an approximate 1-mile longitudinal occupation with National Grid's ROW, in the vicinity of the Sherman Road Switching Station. Refer to Figure 2-2 map sheet 4, and map sheets 16-17 for these pipeline locations.

Co-location of a portion of the 341 Line along the AGT ROW was evaluated. An overhead route variation would start at the Sherman Road Switching Station and follow the AGT ROW west across Burrillville and into Connecticut, ending at the approximate location of the Chaplin Compressor Station in Chaplin, Connecticut. This route alternative would require National Grid to acquire additional new ROW (approximately 125 feet in width). This new ROW would require tree clearing and vegetation removal, and the construction of a new access road, as the access road along the AGT line would not support the equipment and vehicles needed to construct a new 345 kV transmission line. Since this overhead route alternative would require additional land acquisition, would result in additional impacts to the natural and social environments, and would increase project costs, it was removed from further consideration.

TGP's facilities in the project area deliver natural gas east to their Hopkinton Compressor Station in Hopkinton, Massachusetts. Pipeline systems from the Hopkinton Compressor Station transport natural gas to the Mendon Compressor Station in Mendon, Massachusetts, and then into Rhode Island, including one pipeline that runs south to the Cranston Sales Station in Cranston, Rhode Island, and a second pipeline that transports natural gas to the Ocean State Power Generating Plant in Burrillville, Rhode Island, and then loops back into the TGP main line. One of the TGP pipelines has an approximate 7-mile longitudinal occupation with National Grid's 341/328 transmission line ROW in the towns of North Smithfield and Burrillville (refer to Figure 2-2 map sheets 16A-28). TGP's permanent ROW varies in width and is typically 20 feet wide. The co-location of the TGP and National Grid facilities begins in the vicinity of the TGP pipeline crossing of the National Grid ROW at Matitty Road in North Smithfield and ends in the vicinity of the Sherman Road Switching Station in Burrillville, Rhode Island.

ExxonMobil operates a petroleum pipeline that delivers batched petroleum products from its facility distribution terminal in East Providence, Rhode Island, northwest to its distribution terminal in Springfield, Massachusetts. ExxonMobil's ROW varies in width from 16 feet to 33 feet and contains a single pipeline. ExxonMobil's pipeline occupies approximately 2.5 miles of shared longitudinal occupation with the 366 Line ROW, in the town of North Smithfield, north of the West Farnum Substation (refer to Figure 2-2 map sheets 33-39).

After consideration of the various pipeline ROW alternatives, National Grid determined that constructing the new 345 kV transmission lines parallel to existing TGP or ExxonMobil pipeline ROWs did not offer a distinct geographical route. In addition, use of any of the pipeline ROWs would require land acquisition, and would result in increased environmental impact and cost. Therefore these alternatives were not escalated for further study.

5.6.3 Massachusetts "Noticed Alternative" Route

The IRP, which includes facilities in Rhode Island, Massachusetts and Connecticut, requires approval from the EFSB, the MA EFSB, and the CSC. The MA EFSB process requires a utility to identify and compare two possible routes for the Project, including a Proposed Route and a Noticed Alternative Route. The MA EFSB regulations require that the alternative route must be both practical to build and geographically distinct from the proposed route.

National Grid has identified and developed a Noticed Alternative Route that extends from the Millbury No. 3 Switching Station in Millbury, Massachusetts, to the West Farnum Substation in North Smithfield, Rhode Island, along existing transmission ROWs that are distinct from the Proposed Route. The total length of this alternative route is approximately 37 miles, of which approximately eight miles would be in Rhode Island. As illustrated in Figure 5-10, the Noticed Alternative Route runs through the municipalities of Millbury, Upton, Grafton, Milford, Medway, Bellingham, Franklin and Wrentham, Massachusetts and continues through the communities of Cumberland, Woonsocket and North Smithfield, Rhode Island.

The Proposed Route and the Noticed Alternative Route would provide comparable system reliability and use similar overhead transmission line technologies. However, the Noticed Alternative Route is approximately 17 miles longer than the Preferred Route and would require reconstruction of existing 345 kV and 115 kV transmission lines in order to provide space for the new 345 kV transmission line within the corridor. As such, the cost of the Noticed Alternative Route from the Millbury No. 3 Switching Station to the West Farnum Substation is approximately three times the cost of the Proposed Route between the same substations. In addition, after a review of the environmental impacts along the Notice Alternative Route, National Grid determined that the impacts from the Noticed Alternative Route would be greater than the Proposed Route. Based on these analyses, National Grid concluded that the Proposed Route will meet the project need and reliability criteria at a lower cost to customers with less impact to the environment.[10]

5.6.4 Summary of Alternative Overhead Routes

After an evaluation of route alternatives, National Grid determined that the Proposed Route was preferable to use of public streets and highways, use of the pipeline ROWs, and the use of the Massachusetts Noticed Alternative Route.

5.7 OVERHEAD ALTERNATIVES USING THE EXISTING ROW

Several alternative configurations for constructing the Project within the existing National Grid ROWs were considered. Several different types of structures could be used to support the transmission line conductors. National Grid examined these possible alternatives in detail to

[10] If the MA EFSB were to order construction of the Noticed Alternative Route, National Grid would withdraw the portion of its Rhode Island Application covering the 366 Line, prepare a new Application for the 366 Line on the Noticed Alternative Route, and re-file with the EFSB.

determine the advantages and disadvantages of each, as compared to the proposed option of installing the Project on steel H-frame structures. National Grid assessed the impacts of several overhead design alternatives on Project cost, reliability, visibility of the structures, wetlands, and the level of disturbance caused by construction. The following sections describe the alternatives considered and their advantages and disadvantages.

5.7.1 Construct Interstate Using Davit-Arm Structures

As proposed, the Project will use direct buried weathering steel H-frame structures to support the conductors in a horizontal configuration along with two shield wires. As an alternative, National Grid evaluated using davit-arm structures to support the conductors, shield wire and OPGW. Each davit-arm structure would consist of a reinforced concrete caisson foundation mounted single shaft steel pole supporting the conductors in a davit-arm configuration. Two shield wires (one EHS and one OPGW) would be supported from arms extending from the top of the pole.

The davit-arm structure alternative was determined to have the following advantages and disadvantages relative to the proposed H-frame structure:

- Davit-arm structures would be approximately 35 feet taller than H-frame structures on average, and as such would be more visible.
- Davit-arm structures and H-frame structures would be relatively comparable in terms of their allowable span lengths, and as such, both designs would utilize approximately the same number of structures along the transmission line route.
- Davit-arm structures and H-frame structures are comparable in terms of their structural reliability.
- Davit-arm structures and H-frame structures are comparable in terms of their electrical reliability and performance.
- Davit-arm structures would have a narrower configuration than H-frame structures, utilizing less room on the ROWs and necessitating about 25 feet less tree removal than the proposed H-frame structures.
- Because davit-arm structures require large reinforced concrete caisson foundations, they would approximately double the required excavation for installation as compared to the use of direct buried H-frame structures, would significantly increase the level of access road improvements required for the Project, and increase the size and configuration of construction work pads required for installation of the caisson foundations and structures. The estimated footprint of the davit-arm structure is approximately 79 square feet per structure, whereas the direct embedded H-Frame structure has a footprint of approximately 48 square feet per structure.
- Davit-arm structures would be more expensive than the proposed H-frame configuration.

After considering the relative advantages and disadvantages of utilizing davit-arm structures, National Grid concluded that use of H-frame structures for the Project offered more advantages, created fewer impacts, and was a more cost-effective solution.

5.7.2 Construct Interstate Using Double-Circuit Davit Arm Structures

As an alternative to constructing the Project using H-frame structures, National Grid also evaluated use of a double-circuit structure to carry the new and existing transmission lines that also occupy the ROWs in Rhode Island. With this configuration, the two circuits would be constructed on a common structure. To achieve this configuration, the new line and an existing circuit would be constructed on a common single-shaft steel structure and the existing parallel transmission line would be removed from its present location. National Grid determined that the double-circuit structure alternative had the following advantages and disadvantages relative to the proposed H-frame structure:

- The use of double-circuit structures to combine two 345 kV circuits, such as those that occupy the 341 Line ROW, would not comply with transmission planning criteria and this would not meet the identified Project need.
- Double-circuit structures would be inferior to single-circuit H-frame structures in terms of their electrical reliability and performance. Common mode failure of double-circuit structures could result in loss of both lines. Double-circuit structures would increase the risk of a lightning strike or single transmission line fault causing both transmission lines to be interrupted simultaneously.
- Use of a double-circuit structure could reduce tree removal requirements in portions of the ROW.
- Double-circuit structures and H-frame structures would be relatively comparable in terms of their allowable span lengths, and as such, both designs would utilize approximately the same number of structures along the transmission line route.
- Double-circuit structures and single-circuit H-frame structures would be comparable in terms of their structural reliability.
- Each double-circuit structure would require a reinforced concrete caisson foundation, as opposed to the H-frame structures which would only require concrete foundations at points of line angle and dead-end locations. The additional foundations required for the double-circuit alternative would significantly increase the excavation and soil disturbance required for installation, and would increase the potential for impacts (access roads, construction pads, support work pads) to environmental resources.
- Double-circuit structures would typically be approximately 50 feet taller than single-circuit H-frame structures, and as such would be more visible.
- The larger and heavier steel structures required for a double-circuit transmission line, together with the need to get concrete trucks to each foundation location along the

transmission line route would significantly increase the level of access road improvements required for the Project, and the impacts associated with those improvements.

- The use of double-circuit structures would significantly increase the installed cost of the Project.
- Constructing a double-circuit transmission line would unnecessarily remove, retire and replace existing transmission line segments which are functioning adequately.

After considering the relative advantages and disadvantages of utilizing double-circuit structures, National Grid concluded that utilizing single-circuit H-frame structures for the Project offered more advantages, created fewer impacts, and was a much more cost-effective solution.

5.8 UNDERGROUND TRANSMISSION ALTERNATIVE

Because there are existing overhead transmission corridors between the Project endpoints, the Company focused primarily on overhead transmission alternatives that would meet the identified Project need, and that would utilize existing overhead transmission line corridors. Nevertheless, National Grid developed an underground alternative to compare with the potential overhead transmission line configurations for the IRP. Underground transmission lines typically have much higher installation costs than overhead transmission lines. Underground transmission cables, particularly long underground cables, have very different electrical characteristics than overhead transmission lines. This can lead to operational issues, and can require additional system reinforcements to address these issues. Construction techniques for underground transmission lines create different environmental impacts than overhead transmission line construction. Reliability issues associated with underground transmission lines are different than those associated with overhead transmission lines. In developing the underground alternative, the Company attempted to address these differences between overhead and underground transmission lines.

5.8.1 Selection of Potential Underground Routes

Within Rhode Island, there are portions of two 345 kV transmission lines associated with the Project. These lines are:

- The 366 Line from the West Farnum Substation to the Millbury No. 3 Switching Station; and
- The 341 Line from the West Farnum Substation to the Lake Road Switching Station.

National Grid developed underground alternatives for each of these transmission lines. The route development process for each line segment is discussed separately in the following sections.

5.8.2 West Farnum Substation to the Millbury No. 3 Switching Station

National Grid considered three potential underground routes for the 366 Line between the Millbury No. 3 Switching Station and the West Farnum Substation:

- The existing overhead transmission ROW between the Millbury No. 3 Switching Station and the West Farnum Substation;
- The Route 146 limited access highway corridor; and
- The existing public roadway network.

5.8.2.1 Existing Overhead ROW - Millbury No. 3 Switching Station to the West Farnum Substation

At a screening level, the Company considered both the advantages and disadvantages of utilizing the overhead ROWs for underground transmission line installation. The advantages of installing an underground transmission line along the existing overhead ROW corridor include use of an existing utility corridor, fewer traffic impacts during construction than if a roadway route were used, and a somewhat shorter route in this particular case. These factors might lead to slightly lower costs and lower human environment impacts than a roadway underground route.

However, the existing overhead ROWs between the Millbury No. 3 Switching Station and the West Farnum Substation is ill-suited for an underground transmission line for a number of reasons. The ROWs traverse multiple wetlands and wetland buffer zones, and crosses multiple waterbodies. With overhead construction, it is frequently possible to span wetlands and other sensitive resource areas. This has been demonstrated on these ROWs with the existing transmission lines, and is proposed for the new overhead transmission line. With underground construction, it is necessary to either trench the entire route, or to use trenchless techniques such as horizontal directional drilling (“HDD”). Trenchless installation techniques create additional design, construction, and economic issues, and have their own associated environmental issues. Underground transmission construction techniques have the potential to cause an increase in short and long term impacts to wetlands and other environmental resources along the overhead ROWs.

In addition to environmental resource issues, there is significant visible rock along portions of the ROWs, which would make constructing an underground transmission line difficult and costly. There are also areas of steep grade changes and rock cliffs that would make it difficult to install underground lines.

A substantial permanent access road would need to be constructed along the ROWs for purposes of construction and maintenance of an underground line, causing permanent impacts to the ROWs, and potentially affecting wetlands, stream crossings, rare species habitat, and other environmental resources.

Finally, National Grid does not own the majority of the overhead ROWs in fee, but rather holds easements. These easements generally do not include the right to install underground lines. Acquisition of the underground rights from numerous parties would significantly increase the timeframe for this alternative, and has the potential to increase cost of this routing alternative as well.

These constraints and considerations led National Grid to dismiss the existing overhead ROWs as a potential route for an underground transmission line.

5.8.2.2 Route 146 Limited Access Highway Corridor - Millbury No. 3 Switching Station to the West Farnum Substation

The Route 146 limited access highway alignment passes relatively close to the Millbury No. 3 Switching Station and the West Farnum Substation. As such, it represents a potential routing opportunity for an underground transmission line. On a screening level, National Grid examined use of this alignment. There would be several challenging issues with using this route for an underground transmission line:

- The RIDOT *Rules and Regulations for Accommodating Utility Facilities Within Public Freeway Rights-of-Way (2002)*, Rule 3.3, indicates the following restrictions on longitudinal co-locations: "Longitudinal installation of utility facilities within a Freeway right-of-way are permitted only when there is no feasible or prudent alternative to the installation of said facility." The proponent of the utility must demonstrate "That alternative locations are not available or cannot be implemented at reasonable cost, from the standpoint of providing efficient utility services in a manner conducive to safety, durability, and economy of maintenance and operations; that the accommodation will not adversely affect the design, construction, operation, maintenance or stability of the freeway; and that it will not interfere with or impair the present use or future expansion of the freeway."
- The Massachusetts Department of Transportation ("MassDOT") has similar restrictions for longitudinal utility installation along limited access highways.
- There are a number of areas where the Route 146 alignment passes through large rock-cut areas. Installing underground transmission through these areas would be difficult.
- There are a number of bridges in this alignment where Route 146 passes over local roads or streams/rivers. Such bridges are typically not designed to accommodate utility lines, so alternate means would be needed to traverse these areas.

Use of the Route 146 corridor as an underground transmission route was dismissed for these reasons.

5.8.2.3 Public Roadways – Millbury No. 3 Switching Station to the West Farnum Substation

There can be several advantages to installing an underground transmission line along the public roadway network, as compared to using the overhead ROWs or the Route 146 highway corridor for an underground transmission line. These relative advantages could include:

- Reduced impacts on the natural environment. By using the established roadway network, most construction would not directly impact wetlands or environmentally sensitive areas. Some construction could fall in areas where the roadway is within wetland buffer zones. In these cases, suitable environmental controls and BMPs would be employed to control sedimentation.

- There would likely be less rock removal with a roadway network route, since original road construction would have graded and removed a portion of the rock along the route. Roadway geometry generally is more suitable for underground transmission installation, since there would not be rock cliffs or other extreme grade changes to contend with.
- Access for ongoing maintenance is generally simpler within the roadway network.
- In general, rights for installation of underground facilities within the roadway network are obtained via a utility permit from a limited number of agencies (municipal Departments of Public Works, RIDOT, MassDOT, etc.)

There are some potential disadvantages to using the roadway network for an underground transmission line:

- During installation of the conduit and manhole system, there would be construction related impacts on vehicular traffic. There would also be some traffic impacts during cable installation and splicing, but these would be confined to manhole locations.
- In this case, the roadway route is somewhat longer than the overhead ROW route.

Overall, National Grid concluded that the roadway network provided fewer environmental and property acquisition issues, and had significant operational benefits as compared to installing an underground transmission line on the overhead ROW or along the Route 146 alignment. For these reasons, an underground route was developed using the existing public roadway network.

The underground route was developed as a reasonably direct connection between the West Farnum Substation and the Millbury No. 3 Switching Station, and should be considered as generally representative of a roadway underground route. Other roadway routes would be approximately the same length or longer, and would be expected to have similar costs, electrical issues, and environmental issues. In the event that an underground transmission solution became preferred, a more detailed routing analysis would be performed.

Starting at the West Farnum Substation, the representative underground route follows the overhead transmission ROW west for a short distance to the intersection with Route 5, proceeds north on Route 5 to Route 146A in Slatersville, and continues on Route 146A to the Massachusetts border (North Smithfield, Rhode Island and Uxbridge, Massachusetts). From there, the representative underground alternative route continues in Massachusetts along Route 146A in Uxbridge, Route 122 from Uxbridge to Millbury, and Route 122A in Millbury. In Millbury, the representative route would cross the Blackstone River and traverse a short section of the overhead ROW, ending at the Millbury No. 3 Switching Station. This route is shown in Figure 5-11. The total underground distance in Rhode Island would be 4.7 miles and within Massachusetts would be approximately 17.1 miles, for a total underground length of approximately 21.8 miles.

5.8.3 West Farnum Substation to the Lake Road Switching Station (Killingly, CT)

As with the Millbury to West Farnum transmission line, National Grid examined routing opportunities for an underground transmission line between the West Farnum Substation and the Rhode Island/Connecticut border (continuing in Connecticut to the Lake Road Switching Station). National Grid identified two potential routing opportunities for an underground transmission line:

- The existing overhead transmission ROW between the West Farnum Substation and the Rhode Island/Connecticut border; and
- The existing public roadway network.

5.8.3.1 Existing Overhead ROW - West Farnum Substation to the Lake Road Switching Station

As with the Millbury to West Farnum transmission line, the Company considered both the advantages and disadvantages of utilizing the overhead ROW for underground transmission line installation. The advantages of installing an underground transmission line along the existing overhead ROW corridor include use of an existing utility corridor, fewer traffic impacts during construction than if a roadway were used, and a somewhat shorter route in this particular case. These factors might lead to somewhat lower costs and lower impacts on the human environment than a roadway underground route.

However, the existing overhead ROW between the West Farnum Substation and the Rhode Island/Connecticut border is ill-suited for an underground transmission line for reasons similar to those discussed in Section 5.8.2.1. In particular the existing overhead ROW crosses multiple wetlands, wetland buffer zones, and water bodies; in addition there is significant visible rock along portions of the ROW, as well as steep grade changes and rock cliffs.

Moreover, as with the Millbury to West Farnum ROW, a substantial permanent access road would be required for construction and maintenance of an underground line potentially causing permanent impacts to wetlands, rare species and other environmental resources, as discussed in Section 5.8.2.1.

Finally, National Grid would have to acquire additional underground rights which would significantly increase the timeframe for this alternative, and has the potential to increase cost of this routing alternative as well. These constraints and considerations led National Grid to dismiss the existing overhead ROW as a potential route for an underground transmission line.

5.8.3.2 Public Roadways - West Farnum Substation to the Lake Road Switching Station

There are several potential advantages to installing an underground transmission line along the public roadway network, as compared to using the overhead ROW corridor. These relative advantages, which are discussed in greater detail in Section 5.8.2.3 above, include:

- Reduced impacts on the natural environment;
- Less rock removal;
- Easier access for ongoing maintenance; and
- Fewer property rights acquisition issues.

There are some disadvantages to using the roadway network for an underground transmission line, also discussed in Section 5.8.2.3:

- Construction related impacts during installation of the conduit and manhole system, on vehicular traffic; and
- In this case, the roadway route is longer than the overhead ROW route.

Overall, National Grid concluded that the roadway network provided fewer environmental and property acquisition issues, and had significant operational benefits as compared to installing an underground transmission line on the overhead ROW. For these reasons, an underground route was developed using the existing public roadway network.

The underground route was developed as a reasonably direct connection between the West Farnum Substation and the Rhode Island/Connecticut border, and should be considered as generally representative of a roadway underground route. Other roadway routes would be approximately the same length or longer, and would be expected to have similar costs, electrical issues, and environmental issues. In the event that an underground transmission solution became preferred, a more detailed routing analysis would be performed.

There were two major constraints in developing the roadway network route between the West Farnum Substation and the Rhode Island border.

- The overhead ROW corridor passes directly by the Sherman Road Switching Station in Burrillville. Although the proposed 341 Line will not initially connect to the Sherman Road Switching Station, there may be a future need to do this. The underground route was developed so that it would pass close to the Sherman Road Switching Station to provide the equivalent future capability.
- The route would enter NU service territory at the RI/CT border, continuing to NU's Lake Road Switching Station. National Grid and NU determined that the Route 44 crossing of the Rhode Island/Connecticut border (Glocester, Rhode Island to Putnam, Connecticut) was a suitable "meeting point" for the representative underground route.

With these constraints, a representative underground roadway route was developed. Starting at the West Farnum Substation in North Smithfield, the representative underground route follows Route 104 west to Route 7, follows Route 7 north, crossing into Burrillville, to West Ironstone Road. The route follows West Ironstone Road to Route 98 (Sherman Farm Road). At the West Ironstone Road and Route 98 intersection, the underground route is close to the Sherman Road Switching Station, satisfying one of the routing constraints.

The route then proceeds south on Route 98, entering Glocester, to Route 100. The route continues south on Route 100 to Route 44 in Chepachet, and continues on Route 44 to the Rhode Island/Connecticut border. From that point, NU developed a representative underground route in Connecticut, utilizing Route 44, a short section of an NU overhead transmission ROW, Route 21, Route 12, Attawaugan Crossing Road, and Old Trolley Road, ending at the Lake Road Switching Station. The total underground construction distance in Rhode Island would be 24.1 miles and within Connecticut would be approximately 9.0 miles, for a total underground length of approximately 33.1 miles. This route is shown on Figure 5-11.

5.8.4 Underground Cable Design

Two underground cable technologies were considered for an underground alternative to the overhead 345 kV transmission line: high pressure fluid filled ("HPFF") pipe type cable and solid dielectric cable.

HPFF pipe type cable consists of three single core paper-insulated fluid-impregnated cables. Metallic tapes and "skid wires" are added to the insulated cables for shielding and mechanical protection. The cables are installed in a coated steel pipe. The steel pipe is filled with a synthetic dielectric fluid, which is pressurized to approximately 200 pounds per square inch ("psi"). Pressurizing equipment, consisting of pumps, reservoirs, and associated controls, are required at one or both terminal ends of the cable.

Solid dielectric cable consists of a conductor insulated with an extruded solid material. At 345 kV, the insulation would be cross-linked polyethylene ("XLPE"). Additional layers are added to the insulated cables for shielding and mechanical protection. Solid dielectric cables are typically installed in a duct line consisting of several polyvinyl chloride ("PVC") conduits encased in concrete. Manholes are required at approximately 1,500 to 2,000 foot intervals to allow for splicing of the cables.

Underground alternating current ("AC") transmission cables have an electrical characteristic referred to as capacitance. The capacitance of transmission cables results in a "charging current", which means that it takes electrical current to "charge up" the cable before the cable can transmit useful power. For long AC underground transmission cables, the charging current reduces usable cable rating, and the capacitance can have significant effects on voltage control and system stability of the transmission system. Additional equipment is needed to address cable capacitance issues for the underground transmission alternative. This equipment includes shunt reactors and associated switches and circuit breakers installed at the terminal ends of the lines.

For the length of cable required for an underground alternative for the Project, the charging current would make pipe type cables impractical. With HPFF pipe type cable, almost all the cable rating would be used up in charging the cables, leaving little capacity for real power transfer. Solid dielectric cables have somewhat lower charging currents than pipe type cable, resulting in more useful capacity for real power transfer. The large quantity of dielectric fluid needed for pipe type cables and the operational and environmental issues associated with dielectric fluid maintenance were also considered to be significant disadvantages to a pipe type installation. For these reasons, the Company developed a solid dielectric system as the underground alternative to the Project.

5.8.5 Underground Alternative Design Requirements

Having selected a solid dielectric cable system for the underground alternative, National Grid then determined the required cable ratings through loadflow analysis. In order to satisfy the required ratings, it was determined that two sets of 3,500 kcmil copper 345 kV XLPE insulated cables would be needed, for both the 366 Line between the Millbury No. 3 Switching Station to the West Farnum Substation, and for the 341 Line from the West Farnum Substation to the Lake Road Switching Station. Underground transmission cables take much longer to repair than overhead transmission lines. A typical repair time for an overhead transmission line is measured in the one to two day timeframe. At 345 kV, underground transmission line repair times are measured in the one month or more timeframe. The Company determined that the reliability of the transmission system would be unacceptably compromised if either of the new transmission links were to be out of service for a month or more. In order to address the long repair times, a “3 cable per phase” system was developed using three sets of 3,500 kcmil copper XLPE insulated cables. Two sets of cables would be operated normally; a third set would be available to switch in for loss of one of the active cables.

Preliminary ratings for the “two active cables, one spare cable” system are shown in Table 5-15.

Table 5-15: Provisional Ampacity 2 sets 3,500 kcmil Copper XLPE 345 kV Cable

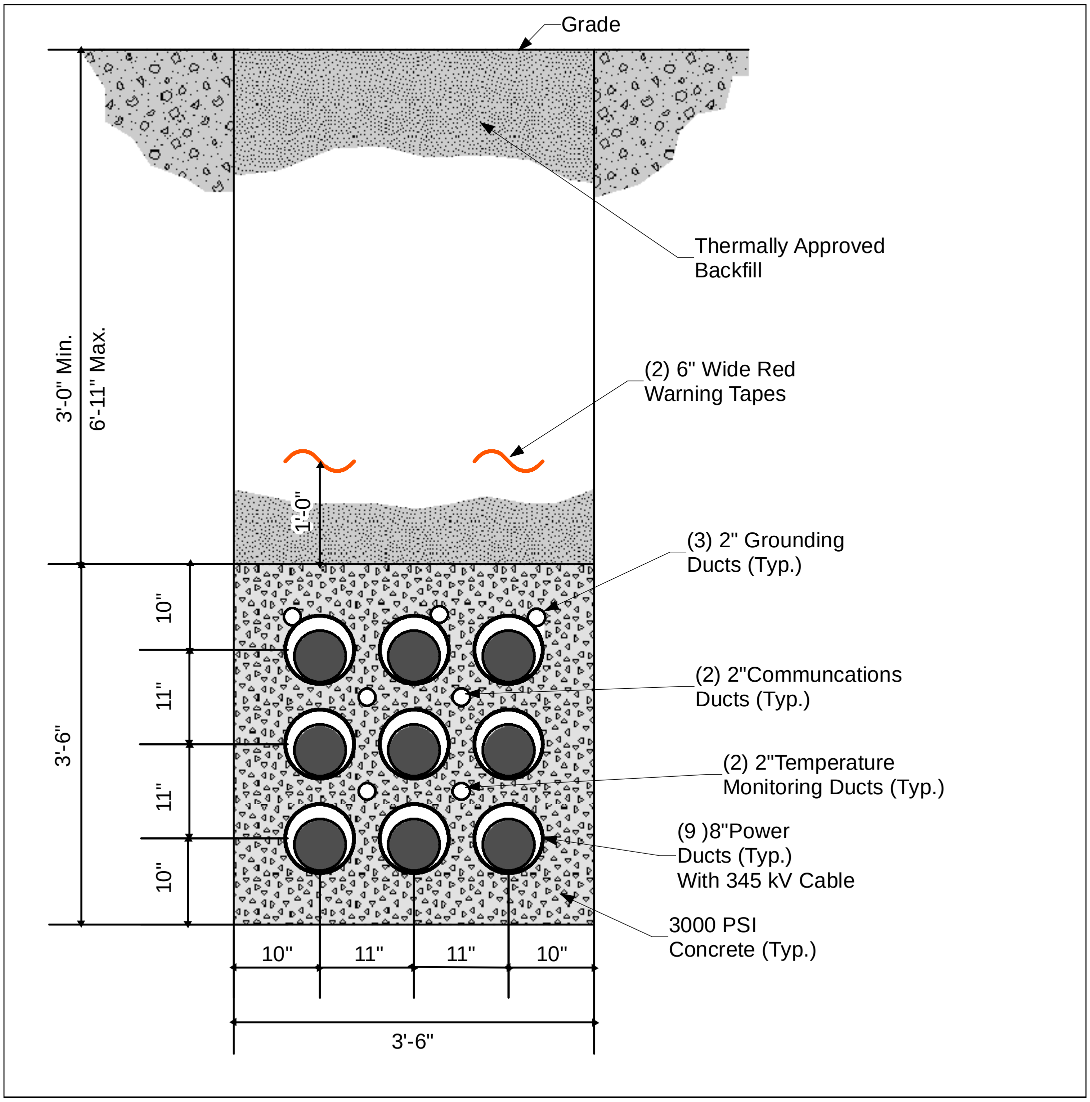
Rating	MVA	Amps
Normal Operating Condition @ 90˚ C Conductor Temperature	860	1450
12 Hour Emergency Condition @ 105˚ C Conductor Temperature	1200	2000

5.8.6 Description of Underground Construction

The solid dielectric underground transmission line alternative would consist of 9 insulated conductors installed in a duct and manhole system. The duct line would consist of nine eight-inch PVC conduits encased in concrete. Some smaller conduits would be installed for relaying, communication, and ground continuity cables. Cables would be installed one cable per duct, between manholes spaced at approximately 1,500 to 2,000 foot intervals.

A typical trench design would be 3.5 feet wide and 6.5 feet deep. The design depth would be 3.0 feet to the top of the duct line concrete encasement, but existing utilities could cause burial depth to vary along the route. In addition to the power conductors, the duct line would contain a ground continuity cable for shield grounding, and fiber optic cables which would be used for the communication and relaying requirements of the transmission system. A typical trench cross-section is shown in Figure 5-12.

Figure 5-12: 345 kV Underground Ductline Cross-Section



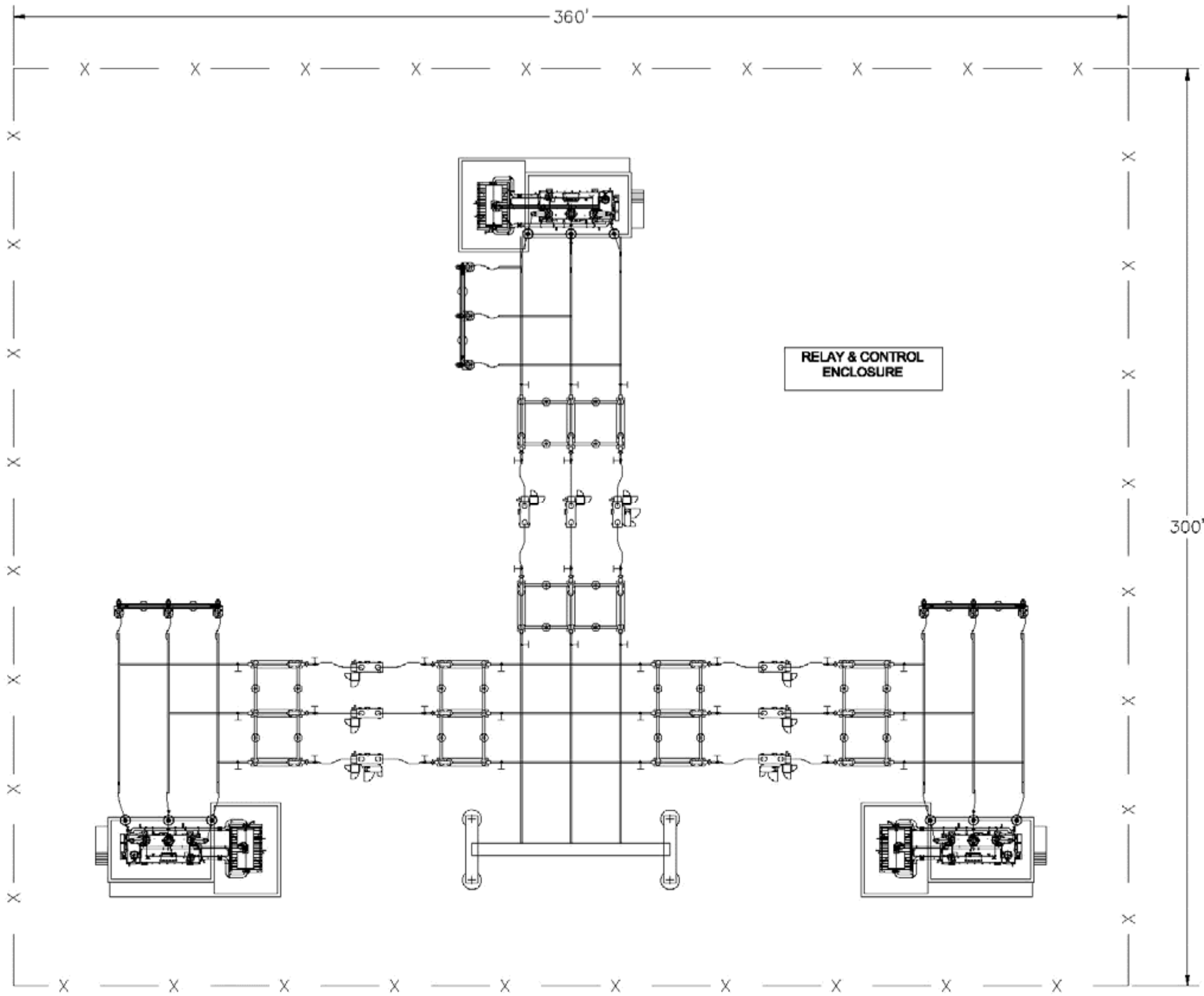
The typical construction progression for an underground installation would begin with the installation of precast concrete manholes. Excavation of the required trench would then commence. The PVC conduit would arrive in ten or twenty foot lengths and would be installed in the trench to form the duct bank. The assembled duct bank would be encased with concrete. The remaining backfill would be native soil or clean gravel. Roadways would be temporarily repaved as the construction progressed. Barriers and steel plates would be used along the trench route to provide protection and access ways for vehicles and pedestrians as necessary.

Once the manholes and duct lines were installed, the remaining construction activities would be confined to the terminals and manhole locations. These activities would consist of installing the cables in the conduits, splicing the cables at each manhole location and final testing. The ROW and streets would be restored following completion of construction.

At the terminal ends, the cables would rise above ground through riser structures. Because of cable charging issues and switching requirements, there would be significantly more equipment needed at the Millbury No. 3 Switching Station, at the West Farnum Substation, and at the Lake Road Switching Station for the underground alternative than there would be for the proposed Project. For the 366 Line between Millbury and West Farnum, this would include three additional circuit breakers and three 150 megavolt ampere reactive ("MVAR") shunt reactors, with associated buswork and protective equipment, at each end. For the 341 Line between West Farnum and Lake Road, this would include three additional circuit breakers and three 225 MVAR shunt reactors, with associated buswork and protective equipment, at each end. This additional equipment cannot fit in the existing yards at any of these substations. The Company developed a "Transition Station" design for the additional equipment needed for the underground alternative for use at the Millbury No. 3 Switching Station and at the West Farnum Substation. NU developed a similar transition station for use at the Lake Road Switching Station.

Each transition station would be approximately 300 feet by 360 feet. Transitions stations could be constructed as expansions of the existing substations, or as separate facilities near to the existing substations, connected by short overhead 345 kV transmission line segments. Figure 5-13 shows the 345 kV transition stations needed for the underground alternative. If the 366 and 341 Lines were both to be constructed underground, there would be a need for two of these transition stations at or near the West Farnum Substation.

Figure 5-13: 345 kV Overhead to Underground Transition Station



5.8.7 Underground Alternative Costs

National Grid prepared conceptual cost estimates for the 366 Line underground alternative between the Millbury No. 3 Switching Station and the West Farnum Substation and for the 341 Line between the West Farnum Substation and the Lake Road Switching Station. A comparison of overhead and underground facility construction costs is shown in Table 5-16. The underground estimates do not include land acquisition costs. There are other common Project costs that are not detailed in Table 5-16, but which are included in cost tables for the Project, as detailed in Section 4.8.

Table 5-16: Cost Comparison of Overhead and Underground Transmission Alternatives

Project Components	Proposed Project ($ Million)[1]	345 kV Underground Alternative ($ Million)[1]
366 345 kV Transmission Line, Millbury No. 3 Switching Station to the MA/RI Border	$67.4	$332.3
366 345 kV Transmission Line, MA/RI Border to the West Farnum Substation	$26.8	$109.3
Overhead to Underground Transition – 366 Line at the Millbury No. 3 Switching Station	$0.0	$15.3
Overhead to Underground Transition – 366 Line at the West Farnum Substation	$0.0	$15.8
Remove K11/L12 Towers in Massachusetts	$2.1	$0.0
Remove K11/L12 Towers in Rhode Island	$0.9	$0.0
Subtotal 366 Line Estimated Cost	**$97.2**	**$472.7**
341 345 kV Transmission Line, West Farnum Substation to RI/CT Border	$74.9	$498.0
Overhead to Underground Transition – 341 Line at the West Farnum Substation	$0.0	$15.8
341 345 kV Transmission Line, RI/CT border to Lake Road Switching Station (NU)	$41.9	$263.0
Overhead to Underground Transition – 341 Line at the Lake Road Switching Station (NU)	$0.0	$15.0
Subtotal 341 Line Estimated Cost	**$116.8**	**$791.8**
Total Project (RI, MA, and CT) Estimated Cost – Transmission Lines	**$214.0**	**$1,264.5**

[1] National Grid cost estimates in 2011 dollars. Connecticut (NU) estimates in 2010 dollars.

The total cost of the IRP from the Millbury No. 3 Substation to the West Farnum Substation, and from West Farnum to the Lake Road Switching Station is $214.0 million compared to $1,264.5 million for the underground alternative. The underground alternative represents a substantial increase in overall line cost over the Preferred Project Alternative.

5.8.8 Comparison of Underground and Overhead Alternatives

Underground and overhead transmission alternatives were compared on the basis of meeting the identified need, reliability, estimated costs, and environmental considerations.

5.8.8.1 Meeting the Identified Need

Both the underground and overhead transmission alternatives would meet the identified need of providing a new 345 kV connection between the Millbury No. 3 Switching Station and the West Farnum Substation and between the West Farnum and the Lake Road Switching Station. Both alternatives could be built with adequate capacity to meet present and future projected loads.

5.8.8.2 Reliability

Underground and overhead transmission technologies are both inherently reliable. However, the operational characteristics of underground transmission lines differ from those of overhead lines in several ways. These are discussed below.

Lengthy Outage Repair Times:

When an overhead transmission line experiences an outage, it can typically be repaired within 24 to 48 hours. In contrast, the failure of a 345 kV underground transmission cable can take a month or more to repair. During this time, the transmission system is exposed both to emergency loadings and to the loss of another transmission element, with possible loss of load. The spare cable included in the underground alternative design presented above would allow for rapid restoration of the cable system for the most common cable system failures (cable, splice, or termination failure). However, it might not address common mode failures such as a significant dig-in of the ductline. Thus, even with the spare cable circuit, there is still the possibility of extended outages with the underground alternative.

Effect on Reclosing:

Many faults on overhead transmission lines are temporary in nature. Often it is possible to "reclose" (re-energize) an overhead transmission line after a temporary fault, and return the transmission line to service with only a brief interruption. Faults on underground transmission cables are almost never temporary, and the cable must remain out of service until the problem is diagnosed and repairs can be completed.

Cable Capacitance:

Underground cables have significantly higher capacitance than overhead transmission lines, meaning that it takes reactive power (MVARs) to "charge up" the cable before the cable can transmit real power (MWs). This has several ramifications:

- Part of the cable's capacity is used up by the charging current, so larger conductors are needed to transmit an equivalent amount of power. These have been included in the system design described above.
- Capacitance can create voltage control problems, meaning that the voltage can get too high when the transmission system is at light load. If the 366 Line were constructed underground, it would require approximately 300 MVAR of cable charging per cable, or 600 MVAR for the two active cables of the three cable installation. In order to compensate for this cable capacitance, three 150 MVAR shunt reactors are needed at both the Millbury No. 3 Switching Station, and the West Farnum Substation. If the 341 Line were constructed underground, it would require approximately 450 MVAR of cable charging per cable, or 900 MVAR for the two active cables of the three cable installation. In order to compensate for this cable capacitance, three 225 MVAR shunt reactors are needed at both the West Farnum Substation and the Lake Road Switching Station. These have been included in the system design described above. Further reinforcements (such as breaker upgrades and protective relaying changes) may also be necessary, and would likely increase the cost of the underground alternative beyond the costs presented in Section 5.8.6.
- Cable capacitance causes higher switching transient voltages on the system (voltage "spikes" during switching). This can damage other system components, may trigger the need to replace surge arresters throughout the area, and complicates future system expansions.

Cable Reactance:

The underground cable would have a significantly lower series reactance than the overhead transmission lines that would operate in parallel with the cable. Consequently, there would be an unequal split of the power flow between the existing overhead transmission lines and the underground cables, with the underground cables "hogging" the load. Under future loading conditions, the underground cables could be operating at their thermal limit, while the overhead transmission lines would be operating well below their limits. This phenomenon limits operating flexibility on the transmission system and might trigger an earlier need for additional system reinforcements.

Ratings:

It is often difficult to match overhead transmission line ratings with underground cables. It is also much more difficult to upgrade ratings on underground lines should that become necessary in the future.

Overall, in this case, the underground alternative would be technically inferior due to the operational challenges associated with cable charging issues and longer repair times.

5.8.8.3 Environmental Considerations

The potential environmental impacts associated with the overhead and underground alternatives were compared. A complete discussion of the potential impacts associated with the proposed overhead alternative can be found in Section 8 of this Report.

The overhead transmission line will be constructed in an existing overhead ROW. Construction techniques would be used that would minimize impacts on the natural environment. Disturbed areas would be allowed to re-vegetate with low growing plant species, similar to existing vegetation within the cleared portions of the ROW.

In the case of the underground alternative, the majority of the construction would occur within existing roadways. Assuming an on-road route, most of the environmental impacts would be to the manmade environment, and would primarily occur during the construction of the lines. These would include significant temporary impacts on traffic during conduit and cable installation. The majority of the installation of an underground transmission system would be performed utilizing cut and cover techniques, where the roadway is excavated, the conduit and manhole system is installed, the trench is backfilled, and the roadway is repaved. For much of the route, the roadway is only two lanes wide. Lane closures with alternating traffic patterns would be required during construction. There would also be temporary noise impacts to the homes and businesses located along the roadway route from construction equipment and vehicles.

The underground route would cross a number of waterways and railroad tracks, including the Blackstone River and several small streams. Railroad tracks and limited access highways would be crossed by means of a pipe-jacking or jack and bore. With this technique, a steel or concrete sleeve (typically 2 to 5 feet in diameter) is hydraulically pushed under the roadway from a pit at one side of the roadway or railroad. The conduits for the electrical cables would then be installed in this larger sleeve.

Where the underground route would pass through buffer areas adjacent to wetlands, proper construction techniques and BMPs such as use of hay bales or other sedimentation barriers would be employed to protect those areas.

Wetlands and waterways would be crossed by installing the cables on bridges (if available and suitable) or by horizontal directional drilling. Horizontal directional drilling involves utilizing a steerable drill rig to create an underground pathway for the electrical conduits. However, this technique may result in frac-outs, which are unplanned releases of the bentonite clay drilling mud into the water body.

Substation expansions would be necessary in order to connect the 345 kV underground cables to the existing terminal substations. These expansions are needed to accommodate the additional facilities associated with the underground cables, primarily shunt reactors, circuit breakers, and the cable terminations. As shown in Figure 5-13, the additional equipment would require a fenced area approximately 300 by 360 feet. With setbacks and other clearance requirements, a 3 to 4 acre area would be needed. The transition from underground line to the substations could be done as an expansion of the existing substation yards, or as a separate transition station near the existing Millbury No. 3 Switching Station and the West Farnum Substation. The development of the substation expansion or a new transition station would, in most instances, require additional tree removal and grading to support the installation of the station, construction of a permanent access road, and construction of underground and overhead transmission line interconnections and facilities. Construction of new transition stations would impact vegetation, wetlands, wildlife habitats, and viewsheds surrounding the existing substation and switching station.

With the exception of the transition stations, there would be no visual impact associated with an underground line.

5.8.8.4 Electric and Magnetic Fields

Underground cables are equipped with metallic shielding, and have essentially no external electric fields. Underground cables do produce magnetic fields. Magnetic fields were calculated for the underground alternative. For an underground cable installed in public roads, the “edge of ROW” is not clearly defined, since the cable could be installed anywhere within the roadway alignment, and since road widths vary. Consequently, magnetic field calculations were made one meter above grade directly over the cable trench.

Anticipated Annual Average Load and Annual Peak Load in 2015 and 2020 were used in calculations. Magnetic field calculations were performed for both the 366 Line and the 341 Line, and are shown in Table 5-17. The magnetic fields drop off rapidly as distance from the cables increases.

Table 5-17: Magnetic Fields (mG) from Underground Alternative

Segment	2015	2020
366 345 kV Cable West Farnum Substation to Millbury No 3, Annual Average Loading	24	26
366 345 kV Cable, West Farnum Substation to Millbury No 3, Annual Peak Loading	36	33
341 345 kV Cable, West Farnum Substation to the Lake Road Switching Station, Annual Average Loading	15	18
341 345 kV Cable, West Farnum Substation to the Lake Road Switching Station, Annual Peak Loading	34	35

Source: Exponent (2012)

These magnetic field levels are roughly comparable to the edge of ROW magnetic fields associated with the proposed Project, as shown in Section 8.16 of this Report.

5.8.9 Underground Alternative Conclusions

Both the overhead and underground alternatives would meet the identified needs of the Project and would be expected to have high levels of reliability. The underground alternative has significant operational issues, longer restoration times, and voltage control issues that make it technically inferior to the proposed Project. Generally, the underground alternative on the public roadway network would have fewer environmental impacts than the preferred overhead alternative. There would, however, be greater temporary impacts to the public during construction. The significantly higher cost and the operational issues make the underground alternative much less preferred than the overhead alternative.

5.8.10 Underground Dips

During siting of overhead transmission lines, questions are often raised regarding the possibility of installing short segments of underground transmission line at discrete locations along the route. This type of short underground segment is often referred to as a "dip". The Company developed an estimated cost for a "generic" one mile underground dip. This underground dip would utilize 3 sets of 3,500 kcmil cu 345 kV XLPE cable in a concrete encased ductline. See Figure 5-12 (trench cross section).

At each end of the dip, there would be a transition station. This would be a fenced switching station, 300 feet by 360 feet (approximately 2.5 acres), and similar in appearance to an electrical substation. The transition station would terminate the overhead line, and would contain cable terminations, circuit breakers, shunt reactors, a control house, and accessory equipment. With buffers and setbacks, a 3 to 4 acre site would be needed at each end of the dip.

The cost of a one mile generic underground dip, utilizing similar assumptions as the underground alternative, is as follows:

Underground Cable:	$21.9 Million
<u>Transition Stations (2)</u>	$<u>26.1 Million</u>
Total:	$48.0 Million

The average overhead transmission line cost along the route is approximately $4.5 million per mile. For a 1 mile dip, the underground line represents more than a ten-fold increase in costs over the overhead line. An underground dip would expose the entire line segment to the underground transmission operational issues as discussed above. These include:

- Lengthy outage repair times for underground transmission cables;
- Effect on reclosing for temporary faults;
- Cable capacitance effects (less for dips);

- Cable reactance effects (less for dips); and
- Ratings – potential for future bottlenecks.

Underground dips represent a large cost increase and introduce operational disadvantages when compared to the proposed overhead line.

5.9 SHERMAN ROAD SWITCHING STATION ALTERNATIVES

As part of the Project, National Grid is proposing to reconstruct the Sherman Road Switching Station. The Sherman Road Switching Station interconnects four 345 kV transmission lines. This station, which has experienced a number of updates through the years, originated as an AIS in a straight bus configuration back in 1968, and was later updated to a ring bus configuration. A section of gas insulated station ("GIS") was installed to interconnect the Ocean State Generating Plant in 1989.

As identified in the 2012 Solution Report (Appendix E) the rebuild of the Sherman Road Switching Station is required in order to address thermal capacity issues, short-circuit duty related issues, asset conditions in the station, and to meet NPCC requirements.

Given the extent of changes required at the switching station, alternatives were developed and evaluated to determine the best solution that would meet the reliability needs identified. The alternatives were grouped based on the number of new elements being added into Sherman Road. Other factors included in the evaluation were construction time, outage requirements, construction sequencing, expansion capabilities, and environmental factors.

Examination of the existing Sherman Road property identified several factors that limit the extent to which the existing switching station could be expanded, including:

- The presence of two high pressure gas mains directly south of the existing station.
- Significant wetland areas to the north, west and east of the existing station.

After evaluating these existing constraints, it was determined that the existing station yard could be expanded to the northwest by an area of approximately 180 feet in width and 540 feet in length without causing significant environmental impacts. Expanding the existing station yard by any greater amount would cause more significant impacts to wetlands and potential cultural resource areas. A 180-foot by 540-foot expansion area is sufficient space to construct up to 2 new bays of 345 kV breaker-and-a-half AIS equipment, or up to 4 new bays of 345 kV breaker-and-a-half GIS equipment.

The 2012 Solutions Report examined numerous options for the Sherman Road Switching Station. Summarized below are the alternatives that are relevant for transmission Option A-1, the Proposed Project.

Alternative 1: Rebuild the existing station in place with air-insulated switchgear ("AIS")

This work would entail systematic equipment upgrades in each 345 kV ring position including circuit breakers, disconnect switches, structures, insulators and bus. All trenches and raceways would be replaced and a new control building will be installed to comply with NPCC requirements. In order to execute the various construction phases, a significant number of equipment outages would be required, and significant temporary arrangement measures would need to be taken in order to maintain the switching station operation. The outages may restrict operation of, or potentially remove from service, a number of generators in the area. The alternative of rebuilding the existing station in place has significant disadvantages:

- Increased exposures to reliability risks due to ring bus being opened during construction;
- Numerous and extended equipment outages would be required;
- Potential generation restrictions or forced generation outages;
- Extended construction durations; and
- Increased construction costs.

This alternative would also severely limit the potential for future switching station expansion. The future addition of a fifth transmission element would require the station to be changed from a ring bus configuration to a breaker-and-a-half configuration to meet the ISO Planning Procedure guidelines, which would again involve significant station changes and investment. The conceptual grade estimate for rebuilding the existing switching station in place is $38.0 million.

Alternative 2: Build a new gas-insulated station ("GIS")

The electrical configuration would be arranged as a modified breaker-and-a-half scheme using 345 kV GIS equipment including 345 kV breakers, disconnect switches, instrument transformers, structures, bus and other required accessories. The electrical work would entail adding a new GIS/Control building, associated yard equipment and transmission line termination structures to complete the new GIS station. A two-bay switchyard would be required and could be built in the expansion area to the northwest of the existing yard. All the work could be performed unimpeded until the element cutovers were made. Alternative 2 was estimated to cost $44.9 million.

Alternative 3: Build a new station with air-insulated switchgear ("AIS")

The work would entail building a completely new 345 kV AIS station in a breaker-and-a-half configuration consisting of 345 kV breakers, disconnect switches, instrument transformers, structures, bus and other required accessories. A new control building would also be installed. A two-bay switchyard would be built in the expansion area to the northwest of the existing yard. All the work could be performed unimpeded until the final element cutovers were made. Upon completion of all the cutovers, the existing yard equipment would be removed and the ground restored to the final elevation. Alternative 3 was estimated to cost $36.6 million including realignment of 347, 333, and 3361 transmission lines.

Table 5-18 summarizes the evaluation of the three alternatives.

Table 5-18: Sherman Road Alternatives

Comparison Factor	Alternative 1 Rebuild Existing Station in Place	Alternative 2 New GIS Station	Alternative 3 New AIS Station
Cost (Conceptual Grade[1] Estimate)	Medium Ring Bus- $38.0M	High 2-Bays - $44.9M	Low 2-Bays - $36.6M
Construction Time	Long – 24-36 Months	Standard – 18-24 Months	Standard – 18-24 Months
Outage Requirements	Very High Requirements High Risk Outages Long Duration Outages	Low Requirements Low Risk Outages Short Duration Outages	Low Requirements Low Risk Outages Short Duration Outages
Construction Sequencing	Construction will conflict with other components at West Farnum and Millbury	Minimal Conflicts	Minimal Conflicts
Expansion Capabilities	Difficult to Expand: Expansion requires reconfiguring from ring bus to breaker –and-a-half	Easy to expand: Up to 4 bays	Easy to expand: Up to 4 bays (after initial 2-bay build-out and removal of existing station)
Environmental Factors	Low Impact	GIS may not be considered carbon neutral	Medium Impact

Source: 2012 Solutions Report, Table 5-4, page 80.

[1] Estimates have a -25% / +50% degree of accuracy

Alternative 3, constructing a new 2-bay AIS Station, was determined to be the best solution for the Sherman Road Switching Station, based on lowest cost, low equipment outage requirements, minimal construction sequencing and outage difficulties, opportunity for future expansion, and minimizing environmental impacts given the constraints of the existing site conditions.

5.10 SUMMARY OF ALTERNATIVES AND CONCLUSIONS

In the development of the Project and selection of the preferred alternative, National Grid evaluated a variety of alternatives to the proposed action. Alternatives to the construction of the 345 kV transmission lines included a No Action alternative, electrical alternatives, non-transmission alternatives, alternative overhead routes, overhead alternatives using the existing ROW with different design configurations, an underground transmission line alternative, and alternatives for the modifications to the Sherman Road Switching Station.

The No Action alternative was rejected because it would not resolve the regional electric reliability problems identified by the ISO-NE and the transmission system owners, and therefore, the No Action alternative was not considered to be acceptable.

The Working Group identified five alternative transmission line solutions that could resolve the reliability issues identified in the 2011 Needs Assessment and the 2012 Follow-Up Needs Analysis. These electrical transmission alternatives included Options A-1, A-2, A-3, A-4, and C-2.1. Option A-1 (the proposed Project) was identified by the Working Group as the preferred IRP option. Option A-1 was determined to perform well electrically, would result in overall reduced potential environmental impacts, was the most cost effective solution, and offered future system expandability and flexibility.

The findings of the ICF study concluded that none of the non-transmission alternatives analyzed, including demand-side resources, generation, and a combination of generation and demand-side resources, would meet the identified project need at a reasonable cost.

National Grid also examined alternative routes for the overhead 345 kV transmission lines utilizing public streets and highways. In order to provide proper electrical safety clearances, additional ROW would have to be acquired along most public streets, potentially displacing homes, businesses, and adjoining land uses, and adding significant cost and time to develop the alternative. The visibility of this type of installation would be much greater than for the proposed project. This option was dismissed for these reasons.

National Grid considered siting the new 345 kV transmission lines parallel to one of the existing pipeline system ROWs. After careful consideration of these alternatives, National Grid determined that constructing the new 345 kV transmission lines parallel to existing pipeline ROWs did not offer advantages from land acquisition, environmental impact, or cost perspectives, over the preferred alternative.

National Grid evaluated the use of different design configurations within the existing ROW, including davit-arm and double-circuit structures for the new 345 kV transmission lines. National Grid concluded that utilizing single-circuit H-frame structures offered more advantages from an engineering design perspective, created fewer natural and social environmental impacts, and was a more cost-effective solution.

National Grid assessed the feasibility of underground lines as an alternative to an overhead route. National Grid concluded that the operational issues, longer restoration times, and voltage control issues, combined with the significantly higher cost of the underground alternative make it less preferred than the overhead route alternative.

Following an evaluation of the relative merits and disadvantages of the various transmission and non-transmission alternatives, the proposed action of constructing the new 366 and 341 345 kV transmission lines, reconstructing and reconductoring the existing 328 345 kV transmission line within the existing ROWs, and rebuilding the existing Sherman Road Switching Station, was determined to be preferable to the other alternatives.

The proposed overhead route alternative is superior to other routing alternatives because it:

- Utilizes existing ROWs dedicated to existing overhead transmission lines, thus avoiding acquisition of new ROW and reducing new environmental impacts;
- Minimizes tree clearing by making use of an existing cleared ROW currently occupied by decommissioned 69 kV structures for a portion of the 366 Line; and

- Is substantially less expensive than any of the routing alternatives considered.

An alternatives analysis was also performed to determine the best design solution for the proposed modifications to the existing Sherman Road Switching Station. Evaluation of the design alternatives showed that a new AIS would:

- Minimize construction time and outage difficulties for an existing switching station that serves as a "hub" for area transmission lines;
- Address the system reliability needs identified by the Working Group;
- Provide a cost effective solution; and
- Could be expanded to meet future needs of the transmission grid.

National Grid concluded that the construction of a new AIS switching station to the northwest of the existing yard and removal of the existing switching station is the preferred option.