

Greater Boston Area Updated Transmission Needs Assessment

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Section 1
Executive Summary

1.1 Objective

The objective of the study was to identify reliability-based transmission needs in the Greater Boston study area while considering the following:

- Future load growth
- Long-term system transfer needs
- A range of generation patterns
- Regional and local reliability issues
- All applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Corporation (NPCC) and ISO New England transmission planning reliability standards

The scope of the Needs Assessment performed for the Greater Boston area included evaluation of the reliability performance of the transmission system serving this area of New England for the 2018 and 2023 projected system conditions. The system was tested with all lines in and under N-1 and N-1-1 contingency conditions for a number of possible operating conditions with respect to related interface transfer levels and generating unit availability conditions. The study area defined as Greater Boston included the area known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston and parts of the areas south of Boston and a small area that is a part of the New Hampshire load zone. In broad terms the Greater Boston study area can be described as the communities north and east of Interstate 495 up to the New Hampshire Border, the city of Boston and some of the suburbs south of Boston. The study area encompasses the Boston RSP subarea with the addition of some load in the west and south outside of the Boston RSP subarea. To account for the load and to describe the study area, the term Boston RSP subarea is used in general throughout the report even though a small portion of the study area is outside of the Boston RSP Subarea.

As described in this report, the Needs Assessment identified certain areas of the system that failed to meet thermal, voltage and short-circuit criteria when subjected to testing in accordance with NERC, NPCC, ISO New England Inc. (ISO-NE), and Transmission Owner standards and criteria.[1]

[1] In many instances this report refers to results as being "violations". These instances are violations of the thermal, voltage and short-circuit criteria being used in the study.

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This Needs Assessment was the first step in the study process defined in accordance with the Regional Planning Process as outlined in Attachment K to the ISO-NE Open Access Transmission Tariff (OATT)2. In accordance with Attachment K, a Solutions Study will be conducted to develop and analyze potential transmission solutions for the needs identified in this analysis.

A working group led by ISO-NE, and consisting of members from ISO-NE, Northeast Utilities (NU), and National Grid has been studying the Greater Boston area since 2008. The results of the 2008 Needs Assessment were documented in the 2010 report titled "Greater Boston Area Transmission Needs Assessment" in July 2010. This report will be referred to as the 2010 Greater Boston Needs Assessment. In March 2012 the solutions study for the set of needs identified in the 2010 Greater Boston Needs Assessment was completed and a preferred solution was developed. This solution will be referred to as the March 2012 preferred solution. At this time New Hampshire Transmission (NHT) requested that a submarine HVDC cable (Sealink) from Seabrook to Boston be considered as an alternative to the preferred solution proposed by the working group. Subsequently, the Sealink alternative was studied in parallel to the March 2012 preferred solution. In February 2013 Footprint combined cycle cleared the Forward Capacity Auction 7 and with the addition of 674 MW of new resources in the Greater Boston study area there was a need to update the 2010 Needs Assessment. Hence, the Greater Boston working group, including NHT, reassessed the Greater Boston area transmission system. As part of the Planning Advisory Committee (PAC) process, stakeholders, which include generator owners, suppliers, load serving entities, energy efficiency entities, state regulators, and transmission owners, also provided input throughout the study process.

1.2 Method and Criteria

The Needs Assessment was performed in accordance with NERC TPL-001-4[3] Transmission System Standards[4], Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory # 1[5], "*Design and Operation of the Bulk Power System*", ISO New England Planning Procedure 3[6], "Reliability Standards for the New England Area Bulk Power Supply System," ISO New England Planning Procedure 5-3[7], "Guidelines for Conducting and Evaluating

[2] http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[3] http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf

[4] NERC TPL-001-04 also requires an evaluation of the power system one year, five years, and ten years out. This study only evaluated five years and ten years out load levels and system configurations however a critical load level assessment was conducted that identified the year of need.

[5] https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf

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

[7] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp05_3/pp5_3_final.pdf

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Proposed Plan Application Analyses", as well as the criteria found in Appendix E: Assessment Criteria – Steady State Thermal and Voltage Criteria of this report.

The results of the analysis provided in this report have been organized by subareas to facilitate geographic orientation of the information. A set of defined subareas was developed based on a review of the thermal and voltage violations. As a result the Greater Boston area results were grouped into eight subareas. A more detail explanation of the subareas can be found in section 5.1. The defined subareas include the following:

A. 345 kV and 115 kV Northern ties to Greater Boston
B. Waltham, Woburn and Lexington Area
C. Downtown Boston 115 kV cables
D. Sudbury, Marlboro and Northborough area
E. W. Medway, W. Walpole and Holbrook area
F. Boston, Golden Hills and Wakefield Junction area
G. 115 kV Lines North of Boston in Salem area and Near Tewksbury[8]
H. 115 kV Lines Near Tewksbury

1.3 Study Assumptions

A near-term (five-year) and longer-term (ten-year) planning horizon, as mandated by NERC, was used for this study based on the most recently available Capacity, Energy, Loads, and Transmission (CELT) report (2013) at the time the study was updated. This study was focused on the projected 2018 peak demand load levels for the five-year horizon and 2023 peak demand load levels for the ten-year horizon using the 2013 CELT forecast. The models reflected the following peak load conditions:

2018 System Load Level Tested:

- The summer peak 90/10 load level forecast of 32,615 MW for all of New England and 6,830 MW for Boston RSP subarea peak demands

2023 System Load Level Tested:

- The summer peak 90/10 load level forecast of 34,460 MW for all of New England and 7,210 MW for Boston RSP subarea peak demands

8 Sub-Area G (115 kV Lines North of Boston in Salem area and Near Tewksbury) was studied but, due to recent upgrades, which include the Salem Harbor retirement upgrades, and the addition of new resources this sub-area was found to no longer result in any reportable reliability issues.)

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The previous Needs Assessment report for this region of the system was based on the 2008 ISO-NE system load forecast. Subsequent to this assessment a number of transmission system and resource changes occurred. Please see the "Changes in Study Assumptions" in section 3.5 for a review of the chronology of events that affected the prior study results. These events lead to the conclusion that re-assessment of the area was necessary. This report describes the results of the updated Needs Assessment while preserving useful information that was provided in the original study report.

For the two load levels tested, demand resources (DR) in the form of active DR and passive DR that cleared the Forward Capacity Market (FCM) and forecasted Energy Efficiency as a part of the 2014 CELT forecast was modeled as load reductions. The details for these load reductions are included in section 3.1.12.

The existing Boston Import limit is approximately 4,175 MW under N-1-1 conditions based on the 2013 Regional System Plan[9]. However, no fixed transfer level was assumed for the purpose of testing the area's reliability. Instead the Boston Import transfer levels were driven by the various generating unit unavailability scenarios and are therefore the result of the sum of peak demand in the area minus on-line generating resources.

A total of 37 peak load cases and a total of four light load cases were modeled and used in all the N-0, N-1 and N-1-1 contingency testing which represented a number of possible generation dispatch and availability conditions. Variations and/or combinations of study area resources (Mystic, Kendall, HQ Phase II HVDC, as well as the proposed Footprint units[10]) versus variations of SEMA/RI, western New England, and northern New England generation were included in the system models tested. These dispatch conditions were also combined with interface transfer level variations to create a comprehensive set of possible system conditions.

Light load testing was also performed to assess high voltage conditions for the Greater Boston area. The testing resulted in a number of potential high voltage violations under N-1 and N-1-1 contingency conditions. Testing was performed for minimum load level of 8,500 MW and a summer off peak load level of 10,500 MW. Based on the current practice of changing the no-load tap position each season of certain transformers in the Greater Boston area, light or off peak loads during summer months could also introduce a voltage violation concern.

The cases tested are categorized throughout the report as design cases and retirement sensitivity cases. Design cases include reasonably expected generation unavailability with various New England system transfer stresses. In addition to the design cases with two critical

[9] http://www.iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docx

[10] Footprint consists of two units at the Salem Harbor 115 kV substation. They will be referred to collectively as "Footprint" or individually as Salem Harbor 5 and Salem Harbor 6

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units out of service, this study also includes limited testing with one critical unit out of service, recognizing that one generator out of service in the Boston RSP sub-Area may potentially highlight different issues than when there is more than one generator out of service, partly due to generator status-dependent system switching. A criteria violation in a design case constitutes a need that must be addressed by a proposed solution to meet criteria at the load level studied. Additional retirement sensitivity cases have been performed in response to stakeholder concerns. The Solutions Study intended to address the problems and concerns identified in this Needs Assessment will consider both design and retirement sensitivity cases to determine both the robustness of the proposed solutions and to identify the incremental upgrades associated with the sensitivities.

Design Cases

- **One Critical Unit Out of Service Cases**

  These cases assumed either Mystic 8 (345 kV), Mystic 9 (115 kV), Kendall, or one Footprint unit out of service, while simultaneously modeling a range of stressed conditions on the interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface.

- **Two Critical Units Out of Service Cases**

  Various combinations of Boston RSP subarea unit outages were studied. These included combinations of Mystic 7, 8 and 9 as well as Kendall and Footprint units out of service. These cases assumed unavailability of two critical units in the Boston RSP subarea out of service while simultaneously modeling a range of stressed conditions on the interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface. The Boston Import transfer level was above the existing N-1-1 limit for many of these cases.

A criteria violation in a design case in either a one critical unit or two critical units out of service case constitutes a need that must be addressed by a proposed solution.

Generation Retirement Sensitivity Cases

Generation retirement sensitivity case testing was performed based on stakeholder concerns that the older generating units or stations in the Boston RSP subarea could potentially retire from service in the near future or be subject to extended shutdown. This testing was limited to the oldest unit, Mystic 7, retired. Steady-state test results varied as a function of the system conditions modeled. A number of post-contingency overloads and voltage violations were observed in all of the various cases modeled and in many cases only the severity of the violations changed. There were also a number of post-contingency overloads and voltage violations that were only associated with specific system conditions.

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Study Assumption from Prior Greater Boston Needs Assessment Report

This updated Greater Boston Transmission Needs Assessment report includes a number of significant study assumptions that have been introduced since the Needs Assessment study for this area was first initiated in 2008. In general the study assumption changes include 1) updates to the system load forecast and demand resources for New England as well as the Boston RSP subarea; 2) changes in the available generating resources, including retirement of Salem 1-4 and the addition of Footprint (Salem 5 & 6); and 3) an update to the ratings and modeling assumption of certain underground cable systems in the Boston RSP subarea.

1.4 Specific Areas of Concern

1.4.1 Steady State Testing Results

The results of the analysis for all of the study work completed indicated that there were a number of design case thermal overloads and voltage violations for N-1 and N-1-1 conditions. There were no design case criteria violations for N-0 conditions.

The results of the steady-state testing varied as a function of the system conditions modeled. A number of post-contingency thermal overloads and voltage violations were observed in all of the various base cases modeled and in many cases only the severity of the violations changed. There were also a number of post-contingency thermal overloads and voltage violations that were only associated with specific system conditions.

1.4.2 Review of N-0 Testing

N-0 (also known as "all-lines-in") conditions were reviewed for the cases modeled. The results indicate that under all tested dispatch and transfer level conditions N-0 overloads were not observed given operational adjustments of the Boston area phase shifters. Additionally, there were no N-0 high or low voltage criteria violations observed.

1.4.3 Review of N-1 Testing

N-1 testing was performed for all the system conditions described above. A number of post-contingency violations seen in simulations were determined to be correctable through operational adjustments. The Boston area phase shifters, bus tie-breakers, HVDC runback and generation runback options are under the supervision of system operators and operators have the ability to mitigate a number of the problems initially identified. The stated operator actions can only be used to resolve overloads that are Long time emergency (LTE) rating violations but not Short time emergency (STE) rating violations.

Overall, by2023, N-1 contingency overloads were observed for elements within the Greater Boston area across the 69 kV, 115 kV and 345 kV transmission facilities. Some overloads were correctable through system adjustments but many are problems that will need to be addressed through a proposed solution. Retirement sensitivity case contingency overloads were similar to

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the design case problems in terms of the elements that were found to have overloads but were, in general, more severe than the design case results.

Table 1-1 below provides a summary of the total number of elements by subarea that had thermal LTE or STE violations under N-1 contingency conditions. The values shown include all 69 kV, 115 kV, 230 kV and 345 kV elements in the study area.

Table 1-1
Count of Number of Elements with N-1 Thermal Violations

Subarea	2018		2023	
	LTE[11] Overloaded Elements	STE Overloaded Elements	LTE[11] Overloaded Elements	STE Overloaded Elements
A	1	1	1	1
B	5	1	6	2
C	16	0	18	0
D	2	2	3	2
E	4	4	5	5
F	0	0	1	0
H	0	0	1	0

The table above excludes contingency overloads for the Y-151 line and for the 326 line. Overloads on these lines are mitigated [redacted]. The remaining elements that overload under N-1 conditions occur under various Greater Boston area contingencies for a number of Boston RSP subarea dispatch conditions. This specific element overload information is summarized in Section 5.1 below with detailed information provided in Section 5.2.2.

There were a limited number of voltage violations under N-1 conditions. Subarea D – Sudbury, Marlboro and Northboro and Subarea F – Boston, Golden Hills, and Wakefield Junction, both had a limited number of buses with low voltage violations under 2018 and 2023 peak load conditions.

Additionally under light load testing conditions, Subarea B – Boston, Golden Hills and Wakefield Junction, Subarea C – Downtown Boston 115 kV Cables, Subarea D - Sudbury, Marlboro and

[11] The count of elements that are overloaded beyond LTE ratings includes those elements that are also overloaded beyond STE ratings.

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Northboro, and Subarea E - Holbrook and West Walpole all had a limited number of buses with high voltage violations under minimum load and/or off peak load conditions.

1.4.4 Review of N-1-1 Testing

Initial element-out-of-service (N-1-1) testing included all 115 kV, 230 kV and 345 kV transmission lines as well as 345 kV autotransformers in the Greater Boston area that are considered Bulk Electric System (BES) elements. These element-out-of-service conditions were tested against the full set of contingencies used in the N-1 tests. These were tested for design cases and for retirement sensitivity cases that modeled retirement of Mystic Unit 7. N-1-1 testing was performed using an analytical tool that re-dispatched generation outside the Boston RSP subarea, modeled runback of generation inside the Boston RSP subarea, adjusted Phase II HVDC output and adjusted phase shifter settings within the Boston area to avoid overloads.

Table 1-2 below provides a summary of the total number of elements by subarea that had thermal LTE or STE violations under N-1-1 contingency conditions. The values shown include all 69 kV, 115 kV, 230 kV and 345 kV elements in the study area.

Table 1-2
Count of Number of Elements with N-1-1 Thermal Violations

Subarea	2018		2023	
	LTE[11] Overloaded Elements	STE Overloaded Elements	LTE[11] Overloaded Elements	STE Overloaded Elements
A	11	7	13	10
B	12	6	13	8
C	35	1	36	1
D	25	21	24	22
E	15	9	23	14
F	8	4	9	4
H	9	6	14	8

The table above excludes contingency overloads for the Y-151 line and for the 326 lines. Overloads on these lines are mitigated [redacted] The remaining elements that overload under N-1-1 conditions occur under various Greater Boston area contingencies for a number of Boston RSP subarea dispatch conditions. This specific element overload information is summarized in Section 5.1 below with detailed information provided in Section 5.2.2 below.

Additionally, there were a set of N-1 or N-1-1 events that resulted in consequential load loss that approached or exceeded 300 MW of customer load. These are load pockets within the

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system that are served by two transmission lines and the loss of both lines disconnects the load from the system. The mitigation of the following load interruptions under 2023 peak load conditions were identified as needs in the Greater Boston area:

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Table 1-3
2023 Consequential Load Loss for N-1-1 or N-1 Events

Load Pocket	Contingency	Consequential Load Loss
Norwood/Canton/South Randolph Load Pocket (N-1)	[redacted]	324 MW
Sudbury Load Pocket (N-1-1)	[redacted]	298 MW
Revere/Chelsea Load Pocket (N-1-1)	[redacted]	357 MW

1.4.5 Short Circuit Testing

The Greater Boston study area is known to have limited short circuit margin at multiple substations based on past studies. The limited short circuit margins have proven in the past to be a significant challenge to integrate new resources and represent a potential problem for the integration of additional transmission facilities into the area.

A short-circuit assessment was conducted for this study, the results indicated that two 115 kV stations in downtown Boston [redacted] had a total of 26 breakers that would be overdutied under 2018 system model conditions.

1.5 Statements of Need

The results of the assessment conducted of the Greater Boston area transmission performance against transmission reliability standards for the projected 2018 and 2023 system conditions in this study indicate that there are a significant number of thermal, voltage and short circuit violations across a number of subareas within the Greater Boston system. The Greater Boston area transmission system fails to meet the reliability criteria standards in several geographical subareas under the design case testing performed and measures should be developed to mitigate the problems identified. A determination of the year of need was established for each element that was found to be exposed to potential overloads under contingency conditions. Additionally the specific reliability violations for each element that could potentially be overloaded are summarized by study year and categorized as design or retirement sensitivity case violations in Section 5.1. The results of the year of need analysis can be found in Section 6.1 in Table 6-1 and Table 6-2.

The year of need assessment shown in Section 6.1 was based on evaluation of the year and load level that elements first fail to meet criteria under N-1 and under N-1-1 contingency conditions. This assessment found that 9 out of 14 elements failed to meet criteria under N-1 contingency conditions prior to 2013 and that 2 of the 14 elements had an initial year more than 5 years from 2013. Additionally, it was found that under N-1-1 contingency conditions 36 out of 48

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elements failed to meet criteria prior to 2013 and that 2 of the 48 overloaded elements had an initial year more than 5 years from 2013.

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Section 2
Introduction and Background Information

2.1 Study Objective

The objective of the study was to identify reliability-based transmission needs in the Greater Boston study area while considering the following:

- Future load growth
- Long-term system transfer needs
- A range of generation patterns
- Regional and local reliability issues
- All applicable North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Corporation (NPCC) and ISO New England transmission planning reliability standards

2.2 Area(s) Studied

The study area included all or part of several load zones that are considered to be collectively called the Greater Boston area for the purposes of this analysis. They included the load zone areas known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston, some of the load area south of Boston included in the Southeast Massachusetts load zone or SEMA load zone, and parts of the load area north of Boston included in the New Hampshire load zone (See Figure 2-1 and Figure 2-2). In broad terms the Greater Boston study area can be described as the communities north and east of Interstate 495 up to the New Hampshire Border, the city of Boston and some of the suburbs south of Boston. Quantifying the needs for Greater Boston area beyond the Boston RSP subarea allows for a comprehensive assessment of the Boston RSP subarea needs and for the potential that solutions developed to solve surrounding area needs are coordinated and designed to remedy multiple Boston RSP subarea needs, if possible. This study also coordinated with other surrounding area studies, such as New Hampshire and SEMA-RI. However, for accounting load and to describe the study area in general the term Boston RSP subarea is used in general through the report even though a small portion of the study area is outside the Boston RSP subarea.

The Greater Boston area is served by 345 kV, 230 kV, 115 kV and 69 kV transmission elements and substations. Existing generating units in the Boston RSP subarea range in size from 10 MW to 682 MW. Based on summer qualified capacity for FCA 7, these resources include a total of 1,952 MW at Mystic Station, 200 MW at Kendall Station (taking into account the partial Non-price retirement for FCA 8) and approximately 390 MW from a number of smaller units (<50 MW) for a total generation of 2,542 MW. Additionally, newly proposed units that have cleared the Forward Capacity Auction located within the Boston RSP subarea (Salem Harbor 5 and

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Salem Harbor 6) were included in the study. These units are proposed to be constructed at the existing Salem Harbor generating site. There are two proposed units each with a qualified capacity of 337 MW for a total generating qualified capacity of 674 MW[12] which was included in the resource mix for the Boson Import area. A list of the major units, units over 100 MW, serving the Greater Boston area that were included in the study is provided in Table 2-1 below. As discussed in Section 3.1.7, the peak load for the Boston RSP subarea in 2023 is projected to be 7,210 MW. In addition to the 3,216 MW of generation, there is 784 MW of active and passive demand resources available in the area through FCA-7 and additional forecasted EE for the years 2018-2023. The details of the DR modeled in the case are provided in Table 3-1.

Table 2-1
Major Greater Boston Area Generating Units (>100 MW)

Generating Units	Qualified Capacity[13]	Commercial Operation Year	Age (years)
Mystic 7	578	1975	39
Mystic 8	682	2003	11
Mystic 9	692	2003	11
Kendall CT	154	2002	12
Salem Harbor 5	337	2017[14]	N/A
Salem Harbor 6	337	2017[14]	N/A
TOTAL	**2780**		

[12] Footprint Combined Cycle or Salem 5 and 6 obtained a Capacity Supply Obligation of 674 MW in FCA 7 which establishes the maximum qualified capacity for subsequent auctions.

[13] Net of station service.

[14] Expected in-service year

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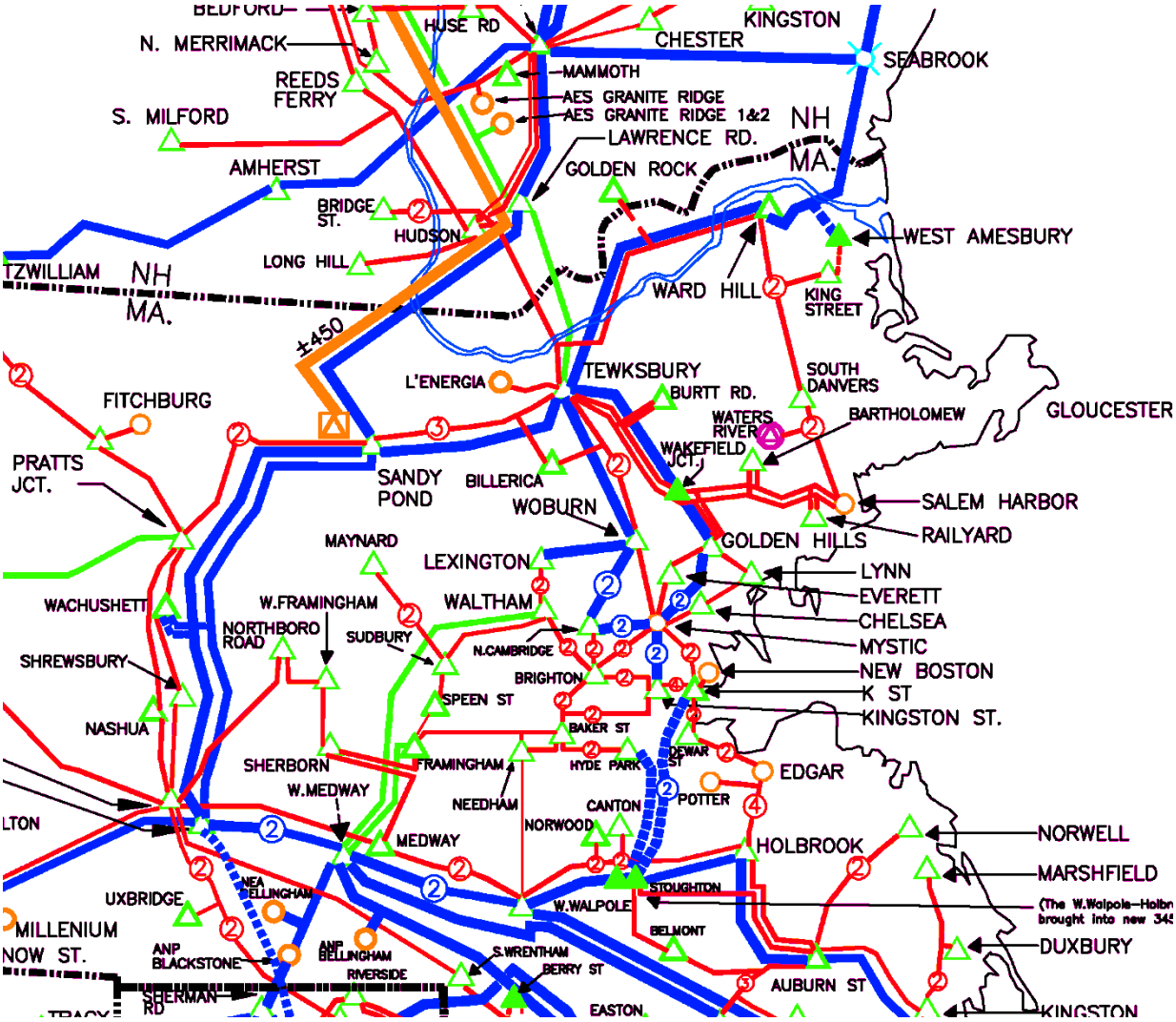


Figure 2-1
Greater Boston Area Map

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Figure 2-2
Greater Boston Area One Line Diagram (Including Related Interfaces)

2.3 Study Horizon

A five-year and ten-year planning horizon was used for this study based on the most recent CELT report. The study was focused on the projected 2018 peak demand load levels for the five-year horizon and 2023 peak demand load levels for the ten-year horizon utilizing the 2013 CELT forecast.

2.4 Analysis Description

This study evaluated the long term area reliability for the Greater Boston and surrounding areas through testing of the steady state system reliability performance. The system was tested under N-0 (all-facilities-in), N-1 (all-facilities-in, first contingency), and N-1-1 (facility-out, first contingency) conditions for a number of possible operating scenarios with respect to related interface transfer levels and generating unit unavailability conditions.

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The following types of analysis were performed:

- **Thermal Analysis** – studies to determine the level of steady-state power flows on transmission circuits under base case conditions and following contingency events.
- **Voltage Analysis** – studies to determine steady-state voltage levels and performance under peak load and light load base case conditions and following contingency events.
- **Short Circuit Analysis** – studies to determine the ability of substation equipment to withstand and interrupt fault current.

The thermal and voltage analysis were conducted at two different load levels; peak load and light load. The light load study was primarily conducted to assess high voltage violations in the Greater Boston area. The Greater Boston area is susceptible to high voltage problems due to the large number of underground cables in this part of the system.

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

The PowerGEM Transmission Analysis and Reliability Assessment (TARA) application15 version 7.10 was used to conduct all thermal contingency analysis presented in this report. This application allowed for optimization of phase shifter settings and generator redispatch to capture operational responses and processing of multiple base cases against a large number of contingencies.

The PTI program PSS/E version 32 was used for base case development.

Aspen version 11 was used for short-circuit evaluations.

[15] TARA (Transmission Adequacy and Reliability Assessment) is load flow software tool for identifying and analyzing transmission bottlenecks, DC (linear) & AC (non-linear) contingency analysis, Security Constrained Economic Dispatch (SCED), and Security Constrained Reliability Dispatch (SCRD).

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Section 3
Study Assumptions

3.1 Steady State Model Assumptions

3.1.1 Study Assumptions

The Greater Boston steady state models were developed to be representative of the long term projection of the 90/10 summer peak system demand level to assess reliability performance under heavy load conditions. The model assumptions included consideration of a wide range of Greater Boston area generation unit unavailability conditions as well as variations in surrounding area transfer level conditions. A comprehensive summary of the load levels, dispatch conditions and transfer levels can be found in the individual case summaries located in Section 10 of this report.

3.1.2 Source of Power Flow Case Models

The power flow study cases used in this study were obtained from the ISO-NE Model on Demand system with selected upgrades to reflect the system conditions in 2023. The load was modified in this model to obtain the 2018 load levels.

3.1.3 Transmission Topology Changes

The original Greater Boston Needs Assessment base cases were created in April 2012 and included all transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff, as of the March 2012 RSP Project Listing. However, in April 2013 the cases were modified to reflect the changes post Forward Capacity Auction (FCA-7). As a part of this process several additional transmission upgrades were added based on the March 2013 project listing were included in the base cases. A list of the upgrades included in the study cases can be found in Section 8.

3.1.4 Generation Assumptions (Additions & Retirements)

Generation projects with a FCM Capacity Supply Obligation as of FCA-7 were included in the study base case. A listing of the recent major new future projects cleared in FCA-1 through FCA-7 and not yet in-service is included below.

New Hampshire

- QP 251 – Laidlaw Berlin (Burgess) Biomass Energy Plant (FCA-4)

Massachusetts

- QP 089 – Cape Wind Turbine Generators (FCA-7)
- QP 196 – Northfield Mountain Uprate 88 MW (FCA-4, 6, and 7)
- QP 387-2 – Footprint (FCA-7)

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Rhode Island

- QP 233 – Ridgewood Landfill (FCA-2)

Connecticut

- QP 150 – Plainfield Renewable Energy Project (FCA-3)

A significant sized new unit was cleared in FCA-7 for the Boston RSP subarea and this new generation was modeled in the study cases. The unit is identified as Footprint (Queue Position #387-2), also known as Salem 5 & 6 Generation. This new generation was included in the Greater Boston area analysis as shown in Table 2-1 above. The plant consists of two combined cycle units configured as four generators. Each pair is to be made up of 203 MW and 134 MW generators. The total combined out of both units is modeled 674 MW in this assessment. These units are expected to be in service by June 1, 2016.

The existing Salem Harbor units 1 through 4 have retired and these units have been removed from all base cases used in the study.

Generation was modeled at its qualified capacity per FCA-7.

Retirement sensitivity cases capturing potential generation retirements were created to represent the potential retirement of a unit at Mystic Station. This possible retirement condition was evaluated under various transfer level conditions to assess the potential impact of such events on the future reliability of the system as compared to the systems performance absent the retirement of Mystic 7. The Solutions Study intended to address the problems and concerns identified in this Needs Assessment will consider the design cases to develop the base set of solutions and will identify the incremental upgrades associated with the Mystic 7 retirement sensitivity.

3.1.5 Explanation of Changes Not Included

All known system changes for the area under study were included in the study cases. Transmission upgrades that have not been fully developed and generation additions that have not cleared in the 2013 FCA-7 were not modeled due to the uncertainty concerning these proposed system additions.

Additionally, as a part of the case refresh in April 2013, certain transmission projects that are electrically located a significant distance away from the study area and were not expected to have a significant impact on the study area were not included in the model. The following highlight a few prominent projects that were excluded:

- The Pittsfield-Greenfield Solution (RSP ID: 1208-1210, 1221-1226)
- Advanced SWCT – Line 8300 Reconfiguration (RSP ID: 1246)
- Advanced SWCT – Glenbrook to South End 115 kV Cable (RSP ID: 1228)

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There are also Non-Price Retirement (NPR) requests from FCA-8 that were not removed from the load flow or short circuit base cases as their determination was made following completion of the analyses supporting this assessment. The units requesting NPR were not considered as having an impact on any of the identified needs for the Greater Boston area. Vermont Yankee and Brayton Point units requested NPRs in FCA-8 but were not removed from the thermal base case models.

Finally, the New England East West Solution (NEEWS) – Central Connecticut Reliability Project components (RSP ID: 576, 1114, 1372, 1373) have PPA approval but are being replaced with the Greater Hartford Central Connecticut projects and are excluded.

3.1.6 Load Forecast Information (including assumptions concerning energy efficiency, interruptible loads, etc.)

The 2013 ISO-NE system load forecast was used as a basis for the demand levels modeled in the study. As of 2012 load modeling for the New England network model is based on forecasted loads as well as forecasts in energy efficiency, passive demand reductions and active demand reductions. The values reported in the 2013 CELT report were used to develop the 2023 and 2018 network load models that were included in the study. Table 3-1 and Table 3-2 below show the aggregate amount of active and passive demand resources modeled in the 2018 and 2023 cases. A more detailed breakdown of demand resource assumptions can be found later in section 3.1.12 showing all forms of demand reductions including availabilities for the different years. Demand Resources were not explicitly modeled in either minimum load level or summer off-peak load level testing as they are already incorporated into the load levels being examined.

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Table 3-1 2018 and 2023 DR Modeled in the Basecases

Load Zone	2018 Passive DR (DRV MW) [16]	2018 Active DR (DRV MW)	Total 2018 Available DR (Modeled MW) [17]	2023 Passive DR (DRV MW)[16]	2023 Active DR (DRV MW)	Total 2023 Available DR (Modeled MW) [17]
Maine	182	295	425	230	295	476
New Hampshire	101	61	155	144	61	200
Vermont	159	63	218	233	63	296
Northeast Massachusetts & Boston	456	82	546	682	82	784
Southeast Massachusetts	250	87	333	362	87	451
West Central Massachusetts	314	160	458	450	160	601
Rhode Island	189	74	258	281	74	355
Connecticut	474	324	756	590	324	879
New England	**2,125**	**1,146**	**3,149**	**2,972**	**1,146**	**4,042**

Table 3-2 New England Demand Resource Performance Assumptions

Region	Passive DR	Energy Efficiency	Active DR	RTEGs
New England	100%	100%	75%	0%

3.1.7 Load Levels Studied

The 2023 90/10 summer peak load level was tested. These cases were based on the 2013 CELT report (See Section 7) forecast summer peak 90/10 load level of 34,460 MW for all of New England and the Boston RSP subarea loads were modeled based on a forecasted peak demand level of 7,210 MW[18] or 20.9% of the New England demand which is consistent with area load peak demand assumptions of 20% to 21%. The CELT forecast in Section 7 only has loads until 2022 and the load growth rate from 2021 to 2022 was used to derive the 2023 loads.

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

[17] Modeled DR in case includes 100% of Passive DR and 75% of Active DR. The DRV Values are scaled up by 5.5% to account for avoided distribution losses. Modeled MW = 1.055x(100% of Passive DRV + 75% of Active DRV)

[18] The Boston Import area load was derived based on the definition of BOSTON RSP Subarea in the CELT Report.

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The 2018 90/10 summer peak load level was tested. These cases were based on the 2013 CELT report forecast summer peak 90/10 load level at 32,615 MW for all of New England and the Boston RSP subarea loads were modeled based on a forecasted peak demand level of 6,830 MW.[19]

Additionally, light load analysis was conducted and this analysis included modeling of system loads at minimum levels as well as under summer off peak load levels. Minimum load levels have been trending in the downward direction and a system load level of 8,500 MW has been established as the most appropriate load level to study when conducting minimum load level analysis. This load level was used for the assessment of minimum load level voltage performance of the Greater Boston area. Based on the current practice of changing the no-load tap position each season of certain transformers in the Greater Boston area, light or off peak loads during summer months could also introduce a voltage concern. Off peak loads were tested at the minimum load level historically seen during summer month periods (New England load at 10,500 MW). Results are included for both the minimum load level and the summer off peak load level conditions.

3.1.8 Load Power Factor Assumptions

Load power factors consistent with the each of the Transmission Owner's planning practices for establishing power factor for loads in the Greater Boston area were assumed for the load model data. The appropriate load power factor was used for each of the load levels modeled.

Peak load power factor was modeled based on the data submitted by the Transmission Owners. Light load high voltage testing was performed at a .998 p.u. leading power factor across New England with the exception of .978 p.u. lagging power factor for NSTAR load in downtown Boston and unity power factor for the NSTAR suburban load.

3.1.9 Transfer Levels

While the current Boston Import N-1 limit is in the range of 4,600 to 4,900 MW, for the purposes of testing the area's reliability, no fixed transfer level was assumed. Instead Boston Import area transfer levels were driven by the various generating unit availability scenarios and are therefore the result of the sum of peak demand in the area minus on-line generating resources. The Boston Import transfer levels for 2023 that were included in the testing ranged from a low of 3,259 MW to a high of 5,075 MW. Additionally cases were run to test a range of interface transfer levels for both the North-South interface and the SEMA/RI interface. The North-South interface levels for 2023 ranged from a high of 2,785 MW to a low of 1,620 MW and the SEMA/RI export values ranged from 2,496 MW to a low of 1,242 MW.

[19] The 2013 Boston Import area load was derived in the same manner as the 2018 values.

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Other relevant interfaces that play a role in the area under study are listed below along with their current maximum transfer level ranges based on the 2013 Federal Energy Regulatory Commission (FERC) 715[20] report for the 2018 system:

- Phase II Import: [redacted]
- East-West: [redacted]
- West-East: [redacted]
- New Brunswick – NE: [redacted]
- Highgate – NE: [redacted]
- Northern New England (NNE) – Scobie +394: [redacted]

New York-New England and other external interfaces were allowed to float within acceptable limits.

Table 3-3 below provides a summary of the transfer levels modeled in all base cases for the significant interfaces associated with the Greater Boston area. Descriptions of the system conditions are shown in Table 3-4.

[20] http://www.iso-ne.com/system-planning/transmission-planning/ferc-form-no-715-reports

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Table 3-3
2018 and 2023 Significant Interface Modeled Transfer Levels

Case Title and Year	East-West	Boston Import	North-South	SEMA/RI - NE	PHASE II Import
[redacted]	2317	3438	2779	2496	2000
[redacted]	2479	3259	2721	2495	2000
[redacted]	2001	3788	2726	2496	2000
[redacted]	36	3787	2729	2493	0
[redacted]	1987	3802	2725	2495	2000
[redacted]	23	3799	2729	2492	0
[redacted]	2020	3778	2781	2496	2000
[redacted]	1947	3838	2724	2496	2000
[redacted]	1428	4370	2727	2496	2000
[redacted]	1686	4124	2784	2496	2000
[redacted]	1311	4488	2727	2495	2000
[redacted]	1672	4137	2783	2495	2000
[redacted]	735	5072	2728	2494	2000
[redacted]	-429	3438	2759	1816	0
[redacted]	-288	3258	2720	1792	0
[redacted]	606	3790	2717	1243	2000
[redacted]	-813	3787	2718	1790	0
[redacted]	589	3804	2716	1242	2000
[redacted]	-827	3800	2718	1789	0
[redacted]	1168	3780	2753	1795	2000
[redacted]	1109	3840	2752	1794	2000
[redacted]	591	4372	2757	1793	2000
[redacted]	859	4125	2756	1819	2000
[redacted]	473	4489	2757	1791	2000
[redacted]	844	4138	2756	1817	2000
[redacted]	-108	5073	2758	1787	2000
[redacted]	-184	3434	1649	1812	1400
[redacted]	-3	3253	1650	1813	1400
[redacted]	-1230	3776	1646	2488	0
[redacted]	-1246	3793	1647	2487	0
[redacted]	159	3772	1622	2494	1400
[redacted]	101	3831	1623	2493	1400
[redacted]	-424	4363	1619	2492	1400
[redacted]	-185	4118	1622	2492	1400
[redacted]	-541	4480	1619	2490	1400
[redacted]	-197	4129	1622	2491	1400
[redacted]	-1125	5064	1647	2485	1400
[redacted]	2733	3260	2756	2674	2000
[redacted]	2894	3080	2698	2673	2000
[redacted]	2418	3609	2702	2674	2000
[redacted]	458	3608	2708	2673	0
[redacted]	2404	3623	2702	2674	2000

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Case Title and Year	East-West	Boston Import	North-South	SEMA/ RI - NE	PHASE II Import
[redacted]	445	3620	2708	2672	0
[redacted]	2437	3599	2758	2674	2000
[redacted]	1847	4191	2704	2675	2000
[redacted]	2364	3659	2701	2675	2000
[redacted]	1731	4308	2704	2674	2000
[redacted]	2105	3945	2761	2674	2000
[redacted]	2091	3957	2761	2674	2000
[redacted]	1158	4892	2706	2673	2000
[redacted]	46	3259	2763	1998	0
[redacted]	186	3079	2724	1974	0
[redacted]	1080	3611	2720	1425	2000
[redacted]	-336	3608	2723	1972	0
[redacted]	1064	3624	2720	1424	2000
[redacted]	-350	3620	2723	1971	0
[redacted]	1640	3600	2755	1975	2000
[redacted]	1065	4192	2760	1974	2000
[redacted]	1581	3660	2755	1975	2000
[redacted]	948	4309	2761	1973	2000
[redacted]	1332	3946	2759	1999	2000
[redacted]	1318	3958	2759	1998	2000
[redacted]	370	4892	2763	1969	2000
[redacted]	291	3254	1654	1994	1400
[redacted]	471	3074	1654	1995	1400
[redacted]	-754	3597	1653	2670	0
[redacted]	-770	3613	1653	2669	0
[redacted]	632	3592	1656	2674	1400
[redacted]	51	4183	1653	2673	1400
[redacted]	574	3652	1655	2674	1400
[redacted]	-66	4300	1653	2671	1400
[redacted]	289	3938	1656	2673	1400
[redacted]	277	3949	1656	2672	1400
[redacted]	-648	4883	1653	2667	1400

Table 3-4 below includes a list of the specific set of base cases (N-0 condition) studied along with a brief description of what conditions the case was intended to represent.

Table 3-4
Summary of System Conditions Modeled

Case Title	Case Description
[redacted]	[redacted]
[redacted]	[redacted]

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Case Title	Case Description
[redacted]	[redacted]

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Case Title	Case Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Additionally, light load (minimum load and summer off peak) level testing included modeling of transfer level conditions appropriate to this load level. The assessment included modeling the North-South transfers at a reduced level, high and low West-East transfers and modeling of Hydro Quebec Phase II at 0 MW and 500 MW.

3.1.10 Generation Dispatch Scenarios

A total of 37 cases were modeled for each of the two study years and used in all the N-1 and N-1-1 contingency testing for the peak load testing which represented a number of possible generation dispatch and availability conditions. The cases all have a major Boston RSP subarea unit out of service as a base condition. The cases are organized by surrounding interface transfer levels. One set is based on high North-South transfers along with high SEMA/RI export levels, the second set is based on high North-South transfers with low SEMA/RI export levels and the final set is based on low North-South transfers with high SEMA/RI export levels.

Based on operational experience, it was assumed that approximately 80% of the fast start units in the Boston RSP subarea were modeled as being in-service.

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In addition, combinations of study area resources (Mystic, Kendall, and Footprint) as well as units in close proximity to the Boston RSP subarea (Fore River and HQ Phase II HVDC) were adjusted versus variations of SEMA/RI, western New England, and northern New England units in the system models tested. These dispatch conditions were also combined with the North-South and SEMA/RI interface transfer level variations to create a comprehensive set of possible reliability assessment system conditions.

The cases tested are categorized throughout the report as design cases and retirement sensitivity cases. Design cases include reasonably expected generation unavailability with various New England system transfer stresses. Included in the set of design cases with two critical units out of service were cases with one critical unit out of service, recognizing that one generator out of service in the Boston RSP subarea may potentially highlight different issues than when there is more than one generator out of service, partly due to unit status-dependent system switching [redacted] A criteria violation in a design case constitutes a need that must be addressed by a proposed solution to meet criteria at the load level studied. Additional retirement sensitivity cases representing generation retirement/extended shutdown cases have been tested as well to be consistent with NERC planning criteria. The Solutions Study intended to address the problems and concerns identified in this Needs Assessment will consider both design and retirement sensitivity cases to determine both the robustness of the proposed solutions and to identify the incremental upgrades associated with the sensitivities.

PEAK LOAD DISPATCH CONDITIONS

Design Cases

- **One Critical Unit Out of Service Cases**
  These cases assumed Mystic 8, Mystic 9, Kendall CT, Salem Harbor 5 or Salem Harbor 6 out of service, while simultaneously modeling a range of stressed conditions on the interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface.

- **Two Critical Units Out of Service Cases**
  These cases assumed conditions where two critical units are out of service which included various combinations of Mystic7, Mystic 8, Mystic 9, Kendall CT and Salem Harbor 5 or 6 out of service. In addition to assuming two critical units in the Boston RSP subarea out of service the New England system interfaces adjacent to the Boston RSP subarea were modeled with a range of stressed conditions on the interfaces which included the North-South interface, SEMA/RI interface and the East-West interface. The Boston Import transfer level was above the existing limit for these cases.

Generation Retirement Sensitivity Cases

Generation retirement case testing was performed based on stakeholder concerns that the older generating units or stations in the Boston RSP subarea could retire from service in the

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near future or be subject to extended shutdown. Any needs and resulting solution development will be evaluated with consideration of this possibility.

- **Mystic 7 Retirement Sensitivity**

  These cases assumed the retirement of the Mystic 7 generation. Study cases included two critical units ([redacted] out of service with related interface transfer levels within their respective defined limits. The Boston Import transfer level was above the existing limit for these cases.

Summary of Generation Dispatch Conditions Modeled

The following tables show the unit unavailability and dispatch levels for major generation associated with the Boston RSP subarea and the transfer level conditions for the Boston RSP subarea and related interfaces as modeled for 2023 and 2018 shown in Table 3-5. The numbers in Table 3-5 include the total output of the generators which consists of the qualified capacity and the station service load.

Table 3-5
2018 and 2023 Modeled Generation Dispatch Conditions

Case Title	Fore River	KENDALL CT	MYSTIC			Salem Harbor	
			7	8	9	5	6
[redacted]	697	158	601	698	706	337	0
[redacted]	697	0	601	698	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]0	697	158	601	698	706	0	0
[redacted]	697	0	0	698	706	337	337
[redacted]	697	158	0	0	706	337	337
[redacted]	697	158	601	0	706	337	0
[redacted]	697	158	601	0	0	337	337
[redacted]	697	158	601	698	0	337	0
[redacted]	697	158	0	0	0	337	337
[redacted]	697	158	601	698	706	337	0
[redacted]	697	0	601	698	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	706	0	0
[redacted]	697	0	0	698	706	337	337
[redacted]	697	158	0	0	706	337	337
[redacted]	697	158	601	0	706	337	0

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[redacted]	697	158	601	0	0	337	337
[redacted]	697	158	601	698	0	337	0
[redacted]	697	158	0	0	0	337	337
[redacted]	0	158	601	698	706	337	0
[redacted]	0	0	601	698	706	337	337
[redacted]	697	158	601	0	706	337	337
[redacted]	697	158	601	698	0	337	337
[redacted]	697	158	601	698	706	0	0
[redacted]	697	0	0	698	706	337	337
[redacted]	697	158	0	0	706	337	337
[redacted]	697	158	601	0	706	337	0
[redacted]	697	158	601	0	0	337	337
[redacted]	697	158	601	698	0	337	0
[redacted]	697	158	0	0	0	337	337

LIGHT LOAD DISPATCH CONDITIONS

Light load dispatch conditions were similar for both the minimum load level modeling and the summer off-peak load level modeling. Light load level analysis included modeling of dispatch conditions that are appropriate for this load level. The generation dispatch conditions listed below were modeled for the light load level analysis.

- All Major Boston RSP subarea generation out of service
- Pilgrim and Seabrook generators out of service
- Reduced eastern New England generation
- All pumped hydro units off-line

Minimum load testing was based on the following dispatches:

1. Phase II on at 500 MW with low SEMA/RI export and low North-South transfers
2. Phase II on at 500 MW with medium SEMA/RI export and low North-South transfers
3. Phase II off with low SEMA/RI export and low North-South transfers

In addition the summer off-peak load level cases were tested with the following modifications to Dispatch 1 above:

1. Seabrook on
2. Pilgrim on

3.1.11 Reactive Dispatch Assumptions

Peak Load Assumptions

All area reactive resources were assumed available and dispatched if conditions called for their dispatch. Reactive output of units was constrained to defined limits and shunt reactive

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resources were dispatched as conditions called for. A summary of the reactive output of units and shunt devices connected to the transmission system that play a significant role in the study area can be found in the generation summary tables included in Section 10 and a list of shunt reactive devices modeled in the Boston RSP subarea area can be found in Table 10-2 in Section 10 below.

Light Load Assumptions

The following system adjustments were used for both the minimum load level and summer off-peak load level testing.

[redacted]

NSTAR Autotransformer Taps

The no load taps on the following NSTAR autotransformers were adjusted to match the light load setting:

[redacted]

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[redacted]

3.1.12 Demand Resource Assumptions

Demand Resources (DR) were modeled in the base cases consistent with current practices for inclusion of demand resources. Demand Resources were modeled in peak load base cases as detailed in Table 3-6 and Table 3-7 below. The passive and active demand reductions are constant for the 2018 and 2023 system conditions. The differences for the two study years' is based on energy efficiency forecasts. In Table 3-6 below the variable forecasted energy efficiency for 2018 and 2023 is lumped together with the fixed passive demand reductions through FCA-7 to provide the total passive DR that was modeled for the years 2018 and 2023.

Table 3-6 2018 and 2023 Passive DR Values: DR through FCA #7 and EE Forecast

Load Zone	Passive DR[21] (FCA-1-7 DRV MW) [22]	EE Forecast (2017-2018 DRV MW) [22]	EE Forecast (2017-2023 DRV MW)[22]	Total 2018 Passive DR (DRV MW) [22]	Total 2023 Passive DR (DRV MW)[22]
Maine	159	23	71	182	230
New Hampshire	80	21	64	101	144
Vermont	125	34	108	159	233
Northeast Massachusetts & Boston	341	115	341	456	682
Southeast Massachusetts	194	56	168	250	362
West Central Massachusetts	245	69	205	314	450
Rhode Island	142	47	139	189	281
Connecticut	417	57	173	474	590

[21] Passive DR includes passive DR cleared through FCA #7 as well as forecasted Energy efficiency for the study year

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

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New England	1,703	422	1,269	2,125	2,972

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

Dispatch Zone	Active DR (FCA-1-7) DRV (MW)
Bangor Hydro	56
Maine	207
Portland, ME	32
New Hampshire	49
New Hampshire Seacoast	12
Northwest Vermont	38
Vermont	25
Boston, MA	62
North Shore Massachusetts	20
Central Massachusetts	51
Springfield, MA	31
Western Massachusetts	78
Lower Southeast Massachusetts	18
Southeast Massachusetts	69
Rhode Island	74
Eastern Connecticut	53
Northern Connecticut	100
Norwalk-Stamford, Connecticut	45
Western Connecticut	126
New England Total	1,146

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

There are a number of Special Protection Systems (SPS) that are designed to operate in and around the Greater Boston study area. These SPSs have, in some cases, been in service for a significant period of time.[23] Each of these SPSs was either modeled directly or taken into consideration when reviewing results. Table 3-8 below lists the SPSs that potentially affect the Greater Boston transmission system.

[23] [redacted] have been in service since prior to1990.

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Table 3-8
Greater Boston Area Special Protection Systems

SPS Name	SPS Action Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[24] The "stability" mode for [redacted] was not modeled in the study.

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3.1.14 Explanation of Operating Procedures and Other Modeling Assumptions

The Greater Boston area transmission power flows are managed on a daily basis through the use of generation dispatch and phase shifting transformers located at [redacted]. The phase shifters are located on the 115 kV systems inside the Boston RSP subarea and are set to balance power flows under normal conditions and are adjusted to post contingency, as necessary.

For the purposes of the contingency testing conducted as part of this study, phase shifters were adjusted to angles expected to work best for post contingency conditions based on phase shifter optimization analysis included in the power flow testing application. These settings were not representative of pre-contingency phase shifter positions. Rather they were set to post contingency angles, within an appropriate operating range of the phase shifters to minimize potential overloads following a contingency. This avoided reporting of overloads for which phase shifter action would serve as the mitigating measure. Further adjustment of the phase shifters was also found to be effective at relieving other overloads post-contingency for overloads that did not exceed STE ratings for elements on the Greater Boston transmission system. It should be noted that phase shifter tap settings were adjusted to unit specific values to accurately model the actual tap settings available on each phase shifting transformer.

Generation adjustments were also modeled in the analysis to reflect system adjustments that could occur between outages under N-1-1 contingency conditions. These adjustments were primarily limited to [redacted]. The adjustments were limited to a total of 1,200 MW across the New England system to reflect consistency with operating reserve constraints. The units listed in Table 3-11 were included in the set of units used for system adjustments between contingencies. Units that are shown with an adjustment type of "Full Dispatch" were allowed to vary their dispatch either up or down if on-line in the case whereas units that are shown with an adjustment type of "Back-Down Only" could only reduce output in response to potential overloads. It should be noted that the unit adjustment process used in the analysis attempts to correct for all overloads that are the results of an initial element outage followed by any one of the subsequent contingencies included in the analysis. The analysis may result in adjustments that allow some elements to overload in an effort to relieve overloads for a number of other elements. The results provided are the best overall system adjustments needed to minimize the total number of overloads for all second level contingencies.

As stated in Section 3.1.11, for the purposes of conducting voltage assessments it is important to note that a number of autotransformers in the Greater Boston area have their no-load tap positions adjusted each season to better optimize the voltage performance of the system between peak load conditions and shoulder period (Spring and Fall) load conditions.

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Table 3-9
Units That Were Allowed to Adjust Between Contingencies

Unit Name	Adjustment Type	Unit Name	Adjustment Type
Boston Units		**Western NE Units**	
Framingham Jets	[redacted]	New Haven Harbor	[redacted]
Kendal Jet	[redacted]	Lake Road 1	[redacted]
L Street Jet	[redacted]	Montville 6	[redacted]
Mystic Jet	[redacted]	Westbrook C1, C2 & ST	[redacted]
W Medway Jet 1, 2 & 3	[redacted]	C. Cove	[redacted]
MATEP 3	[redacted]	**Northern NE Units**	
MATEP Diesels	[redacted]	Granite GT	[redacted]
MBTA Jet	[redacted]	Newington G	[redacted]
Waters River J1	[redacted]	Merrimack ST & CT	[redacted]
Mystic 7	[redacted]	MIS C1, C2 & ST	[redacted]
Mystic 8	[redacted]	**SEMA/RI Units**	
Mystic 9	[redacted]	Cherry Street Diesels	[redacted]
Salem Harbor 5	[redacted]	Fitchburg	[redacted]
Salem Harbor 6	[redacted]	Canal 2	[redacted]
Kendal ST & CT	[redacted]	Brayton Point 3	[redacted]
HVDC Terminals		**Greater Boston Units**	
Phase 2 HVDC 1 Terminal	[redacted]	Fore River	[redacted]
Phase 2 HVDC 1 Terminal	[redacted]	ANP Bellingham	[redacted]
CSC Terminal	[redacted]	Ipswich Diesels	[redacted]
		Marblehead	[redacted]

Additionally, operator initiated system adjustments were assumed to be available as mitigating measures for certain conditions. In some cases closing of bus tie breakers that are normally operated open or that can be opened under certain dispatch conditions were assumed to be viable operator responses to certain overloads under appropriate conditions. [redacted]

3.2 Stability Modeling Assumptions

3.2.1 Study Assumptions

Not Applicable.

3.3 Short Circuit Model Assumptions

3.3.1 Study Assumptions

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The short circuit analysis assumptions used for this study are consistent with those used for all other studies for this region of the New England system. The case that was developed was intended to be representative of the transmission and generation system configuration that would be in place by 2018.

3.3.2 Short Circuit Model

The study model was based on the ISO-NE's 2013 Master Short Circuit case updated with the addition of generators and transmission lines expected to be in service by 2017. The case used was developed from Round 8 of the New England Short-Circuit database release. A listing of the system topology changes included in the short circuit model is shown in Table 8-2 included in Section 8.

3.3.3 Contributing Generation Assumptions (Additions & Retirements)

The generation model included new generation that cleared FCA-7 as well as PPA approved generators in the vicinity of the study area. In particular this included a new plant (Footprint) to be sited at the existing Salem Harbor plant location. Additionally, units requesting non-price retirements in FCA-8 were not removed from the case as these requests were still under review at the time the analyses supporting this study. This included the Vermont Yankee, Norwalk Harbor 1 & 2, and Brayton Point 1, 2, 3, & 4 units. These units were modeled as in service and running for the short-circuit analysis.

3.3.4 Generation and Transmission System Configurations

A significant system configuration factor was that the testing assumed [redacted].

3.3.5 Boundaries

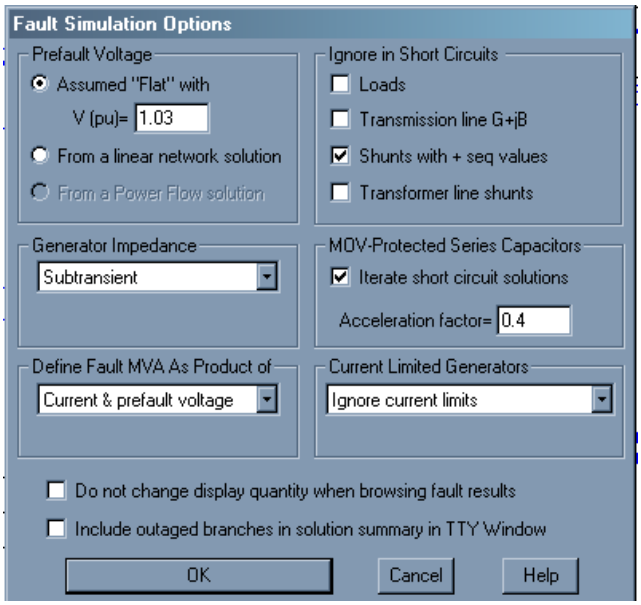
Case boundaries were consistent with the New England short-circuit database model assumptions and no additional equivalent source models were added to the case.

3.3.6 Other Relevant Modeling Assumptions

The following options were set with respect to the fault simulation options:

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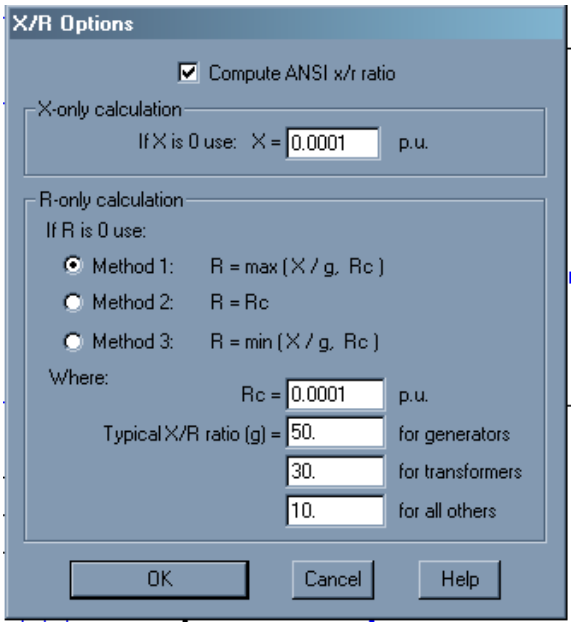
The pre-fault voltage was set to 1.03 for National Grid and NSTAR buses and 1.05[25] for Public Service of New Hampshire (PSNH) buses as per respective company-specific practices.

[25] The Planning Technical Guide states that the pre-fault voltage for the PSNH system should be 1.04. Since no overdutied breakers were seen in the PSNH system the analysis was not redone with the lower pre-fault voltage

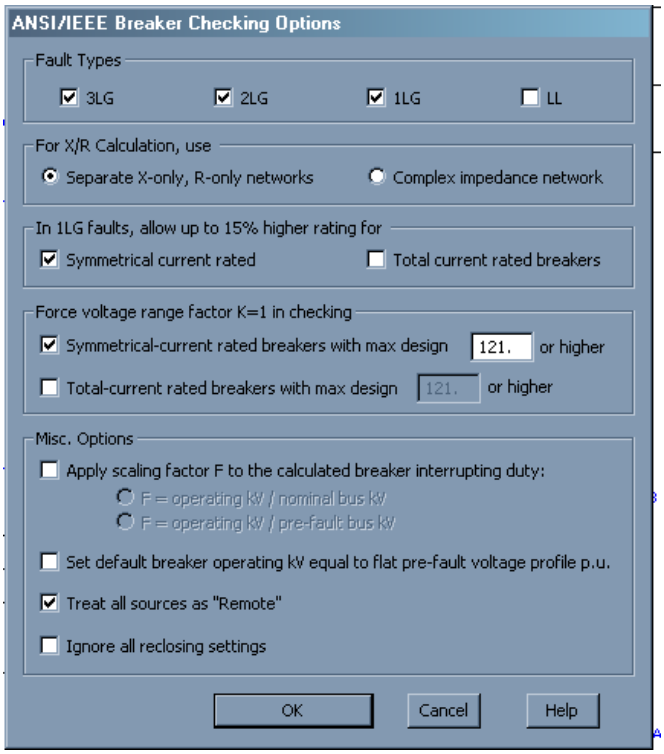
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The following options were set with respect to the X/R options:



The following provides assumptions used for the Breaker Rating Module:



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3.4 Other System Studies (such as Transient Network Analysis, Harmonic Analysis, Equipment Assessments, etc.)

Not applicable for this study.

3.5 Changes in Study Assumptions

There have been a significant number of changes in study assumptions and system topologies since the Needs Assessment was first initiated in late 2008. The following is a summary of the most significant changes that have occurred followed by a chronology of reports provided to the Planning Advisory Committee (PAC).

3.5.1 Changes in Load Forecast

Since 2008 load forecast data has changed in a slightly downward direction. However the New England system peak demand load level forecast over this time period has decreased by less than 4%. The table below provides a summary of the 90/10 summer peak demand forecast for 2018 for each of the CELT forecasts published from 2008 through 2013.

Table 3-10
CELT Report Load Forecast History

CELT Forecast Year	2018 90/10 New England Summer Peak
2008 CELT Report	33,830 (extrapolated)
2009 CELT Report	33,235
2010 CELT Report	32,895
2011 CELT Report	32,955
2012 CELT Report	32,675
2013 CELT Report	32,615

The most significant change in study scope since 2008 is the study horizon. In 2008 the study horizon ended in 2018. The current assessment has a study horizon that ends in 2023. A summary of the changes in load modeling assumptions from the initial study to the current study is provided in Table 3-11 below:

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Table 3-11 Comparison of Greater Boston Study Load Forecast Assumptions

Assumption Metric	Initial Needs Assessment (July 2010)	Updated Needs Assessment (July 2013)
Study Horizon Yr.	2013 / 2018	2018 / 2023
Load Forecast Basis	2008 CELT 90/10 Summer	2013 CELT 90/10 Summer
New England Peak Load	2013 - 32,410 MW 2018 - 33,830 MW	2018 - 32,615 MW 2023 - 34,460 MW
Boston RSP subarea Peak Load	2013 - 6,460 MW 2018 - 6,900 MW	2018 - 6,830 MW 2023 - 7,210 MW
NEMA/BOSTON Loadzone DR	300 MW through FCA2	457 MW[26] through FCA7
Additional Energy Efficiency	None	2018 – 124 MW 2023 – 369 MW[27]

3.5.2 Changes in System Resources and Topology

Other significant changes in study conditions were the changes in system topology that have occurred since the study was first initiated. The availability of generation resources for the study area was among the most significant changes. In 2010 Dominion announced its intention to retire Salem Harbor units 1 through 4 from the system reducing generation resources for the area by some 750 MW, a reduction of over 20% in area resources. As a result of this announced retirement, additional upgrades have been placed in service to address potential reliability concerns for the area. These changes triggered the need for a full reassessment of area needs.

Subsequent to this announcement a new resource was proposed and ultimately cleared the in FCA-7 which would effectively replace the generation retired at Salem Harbor with new generation. The new generating facility has a qualified capacity of 674 MW. This new generation addition once again changed the resources of the Greater Boston area requiring a full reassessment of area needs.

Other system topology changes also occurred with additions of new step down facilities as well as implementation of system upgrades that were more urgent such as the need to upgrade the Lexington-Trapelo Rd.-Waltham 115 kV lines (320-507/508).

3.5.3 Changes in System Modeling

[26] The DR number is calculated by adding 8% transmission and distribution losses to the NEMA/BOSTON Passive DR and Boston and North shore Dispatch zone active DR from Table 3-6 and Table 3-7 respectively.

[27] The Forecasted EE number obtained by adding 8% transmission and distribution losses to the NEMA/BOSTON EE forecast number from Table 3-6.

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An additional significant study adjustment was the change in system modeling of underground cable systems in the Boston RSP subarea[28]. The design typically used by NSTAR for its underground transmission system includes the construction of companion circuits in a common duct bank where two circuits share cooling fluids in order to maximize thermal cooling capabilities. This construction technique relies on pumping facilities and in some cases heat exchanger facilities to improve the thermal performance of both circuits by circulating cooling fluid from one circuit to the other and back in a looped manner.

One significant consequence of this design is the change in thermal capabilities of a circuit when its companion circuit is out of service. In many cases loss of a companion circuit results in loss of coolant circulation and, consequently, a reduction in thermal cooling. This means that, for modeling purposes, the rating of an underground circuit changes when its companion circuit is out of service requiring the use of alternative rating tables. A modeling change was developed by ISO-NE to capture this change in rating. The process called for a revision to the circuit model to include alternate versions of each underground cable as well as revision to all associated contingency files to use the appropriate cable model depending on the contingency that was being simulated. This change in modeling more accurately captures the thermal capability of underground cables during outage events.

An additional change also occurred related to the ratings used for underground transmission facilities in the NSTAR system. As a follow-up to ISO-NE's request for single line in-service ratings, NSTAR also re-rated underground cables based on new rating practices and to ensure consistency with ISO-NE rating procedure requirements. The new ratings used in the base case models were all based on a 12-hour LTE rating methodology consistent with ISO-NE rating procedures.

A full explanation of the methodology developed to capture this system characteristic is included in Section 12 of this report. Section 12 also includes a summary of the updated ratings that have been developed for the applicable cable pairs showing the companion cable in-service and out-of-service ratings.

There was also a change in assumptions concerning N-1-1 testing. Prior assessments were based on a general practice that included all lines that interconnect two or more BPS stations as the initial element to be taken out of service in N-1-1 testing. This approach changed to be more expansive and the study was modified to include all BES elements in the study area.

3.5.4 Chronology of Needs Assessment Study Effort

The Greater Boston Needs Assessment study progress has been routinely reported at PAC meetings. A chronology of the reports provided to the PAC is shown in Table 3-12 below:

[28] See April 2013 PAC presentation available at http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

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Table 3-12 Chronology of Greater Boston Study PAC Reviews

PAC meeting date	Discussion topic	Presentation or Report Title[29]
May 20, 2008	Initial announcement of starting Needs Assessment and study scope	Northeast Massachusetts / Greater Boston Transmission Needs Assessment – Study Scope
Jan 21, 2009	Needs Assessment Study status update including initial N-1 results	Greater Boston Transmission System Needs Assessment – Study Results
Jul 16, 2009	Needs Assessment Study Results; Announced of commencement of Solutions Study	Greater Boston Transmission System Needs Assessment Review and Solution Study Initiation
Dec 16, 2009	Revisit Needs Assessment for generator retirement/delist scenarios	Greater Boston Needs Assessment (Status Update)
Mar 18, 2010	Update on Needs Assessment and review of options for potential solutions	Greater Boston Needs Assessment Solutions Status Update (ISO presentation) Greater Boston Transmission Reliability Assessment and Preliminary Discussion of Alternatives (NSTAR presentation)
July 8, 2010	Needs Assessment Report posted to ISO-NE web site	Greater Boston Area Transmission Needs Assessment
Dec 16, 2010	Needs Assessment and Solutions Study update	Greater Boston Study Needs Assessment/Solution Study Status Update
Jun 30, 2011	Needs Assessment and Solutions Study update	Greater Boston Study Needs Assessment/Solution Study Status Update
Jan 18, 2012	Solutions Study update on preliminary preferred solution	Greater Boston Study Needs Assessment/Solution Study Status Update
Mar 14, 2012	Solutions Study update on preliminary preferred solution; NHT proposes HVDC as alternative which ISO-NE agrees to study	Greater Boston Study Needs Assessment/Solution Study Status Update
Feb 12, 2013	Solutions Study update	Greater Boston Solutions Study Status Update
April 2013	NSTAR led discussion on changes to the underground cable ratings	NSTAR Underground Cable Ratings Update
July 9, 2013	Needs Assessment updated with the latest load forecasts and FCA results and Solutions Study update	Greater Boston 2023 Needs Assessment and Solutions Study Status Update
Nov 20, 2013	Solution Study Update	Greater Boston 2023 Solutions Study Status Update

[29] The PAC presentations are available at http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

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PAC meeting date	Discussion topic	Presentation or Report Title[29]
June 19, 2014	Disclosure of Cost Estimate for the "AC Plan" and "HVDC Plan"	Greater Boston Solutions Study Update
November 18, 2014	Greater Boston Solutions Study Update	Greater Boston 2023 Solutions Study Status Update

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Section 4
Analysis Methodology

4.1 Planning Standards and Criteria

The applicable NERC, NPCC and ISO-NE criteria were tested as part of this evaluation. A description of each of the NERC, NPCC and ISO-NE standard tests that were included in all studies used to assess system performance are shown in Table 4-2 in Section 4.3.2.

4.2 Performance Criteria

4.2.1 Steady State Criteria

The Needs Assessment was performed in accordance with NERC TPL-001-4 Transmission System Standards, NPCC "Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System", dated 04/20/12 the ISO New England Planning Procedure 3, "Reliability Standards for the New England Area Bulk Power Supply System," the ISO New England Planning Procedure 5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses", as well as criteria found in Section 11.

NERC Reliability Standards require that the system thermal and voltage levels remain within applicable limits after the events as described in "Table I. Transmission System Standards – Normal and Emergency Conditions" of the NERC Reliability Standard TPL001-4.

Steady State Thermal and Voltage Limits

A summary of the criteria used to assess system performance for thermal and/or voltage violations used in the study are included in Section 11.

Steady State Solution Parameters

The pre-contingency and post-contingency solution parameters that were used for adjustment of area interchange, adjustment of load tap-changing transformers (LTCs), static var devices (SVDs, including automatically-switched capacitors) and phase angle regulators (PARs) were modeled as described below.

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Table 4-1
Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Pre-contingency	Disabled	Stepping	Locked[30]	Regulating
Post-contingency	Disabled	Stepping	Locked	Regulating

4.2.2 Stability Performance Criteria

Not Applicable.

4.2.3 Short Circuit Performance Criteria

The criteria used to determine short circuit duty adequacy was consistent with recognized industry standards. ISO-NE Planning Procedure 3, Section 3.3 states "The New England bulk power supply system shall be designed to ensure equipment capabilities are adequate for fault current levels with all transmission and generation facilities in-service for all potential operating conditions." These procedures were used in the evaluation of fault duties as compared to interrupting capability of all applicable equipment.

There were internal Transmission Owner standards that provided additional guidance extending beyond these standards which included such consideration as assumptions concerning the appropriate pre-fault voltage conditions. Pre-fault voltage conditions were established by the Transmission Owners based on their experience for the particular areas under study.

4.2.4 Other Performance Criteria (as appropriate)

Not Applicable.

4.3 System Testing

4.3.1 System Conditions (Sensitivities) Tested (including operating and equipment condition assumptions)

System-condition-testing included evaluation of system performance under a number of generating unit outage conditions as well as unit retirement scenarios, variations in related

[30] Boston Area PARs set to optimized settings

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transfer and area import level conditions, as well as a significant number of line/transformer out of service conditions.

4.3.2 Steady State Contingencies / Faults Tested

Contingencies in each of the following NERC, NPCC and ISO-NE reliability criteria categories were tested as part of this evaluation.

Table 4-2
Summary of NERC, NPCC and ISO-NE Category Contingencies to be Tested

Contingency Type	NERC Type	NPCC D-1 Section	ISO-NE PP-3 Section	Tested in This Study
All Facilities in-service	P0	5.4.2.b	3.2.b	Yes
Generator (Single Unit[31])	P1.1	5.4.1.a	3.1.a	Yes
Transmission Circuit	P1.2	5.4.1.a	3.1.a	Yes
Transformers	P1.3	5.4.1.a	3.1.a	Yes
Shunt Devices	P.1.4	5.4.1.a	3.1.a	Yes
Single Pole DC line	P.1.5	5.4.1.a	3.1.a	Yes
Element w/o Fault	P2.1	5.4.1.d	3.1.d	Yes
Bus Section	P2.2	5.4.1.a	3.1.a	Yes
Breaker Failure	P.2.3, P.2.4, P4	5.4.1.e	3.1.e	Yes
Double Circuit Tower	P.7.1	5.4.1.b	3.1.b	Yes
Bipolar DC line	P.7.2	5.4.1.f	3.1.f	Yes

Additionally, to cover NERC TPL 001-4 P3 and P6, and NPCC and ISO-NE criteria, N-1-1 testing was performed as follows:

- An initial contingency of a transmission circuit or generator in the study area was taken
- System adjustments were performed between contingencies
- All the contingencies in Table 4-2 were applied as second contingencies

The details of all the contingencies tested are provided in Section 12.

4.3.3 Stability Contingencies / Faults Tested

Not applicable.

[redacted]

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4.3.4 Short Circuit Faults Tested

Short circuit faults were evaluated for three phase, phase to ground and double line phase to ground fault conditions. The assessment evaluated the maximum fault duty that would be seen from these types of fault conditions for each circuit breaker in the study area. Fault duties were evaluated at the following major Greater Boston Area stations:

Table 4-3
Greater Boston Area Stations Considered for Short Circuit

Station	Station	Station
Andrews Square 115 kV	Kingston 345 kV	Seabrook 345 kV
Baker Street 115 kV	K-Jet2 13.8kV	Seabrook 24.5 kV
Brighton 115 kV	K Street 115 kV	Sherborn 115.kV
Burlington 115 kV	K Street 345 kV	Shrewsbury 69 kV
Canton 115 kV	Lexington 115 kV	Slayton Hill 115 kV
Chelsea 115 kV	Lexington 345 kV	Speen St 115 kV
Colburn Street 115 kV	Lynn115 kV	Stoughton 345 kV
Deer Island 115.kV	Maplewood 115 kV	Sudbury 115 kV
Dewar Street115 kV	Maynard 115.kV	Tewksbury 115 kV
Dover 115 kV	Medway 115 kV	Tewksbury 230 kV
E Holbrook 115 kV	Merrimack 115 kV	Tewksbury 345 kV
E Methuen 115 kV	Mystic 345.kV	W Boylston 115 kV
E Cambridge 115.kV	Mystic115 kV	W Methuen 115 kV
Edgar 115 kV	N Cambridge 115 kV	Wachusett 115 kV
Everett 115 kV	N Cambridge 345 kV	Wakefield Jct 115kV
Fitch 69 kV	Needham 115.kV	Wakefield Jct 345kV
Framingham 115 kV	Northboro Road 115 kV	Walpole 115 kV
Golden Hills 115 kV	North Quincy 115 kV	Waltham 115 kV
Greendale 115 kV	Pratts Junction 115 kV	Ward Hill 115 kV
Hartwell 115 kV	Read Street 115 kV	Ward Hill 345 kV
Holbrook 115 kV	Revere 115 kV	W Framingham 115 kV
Holbrook 345 kV	Rolfe Avenue 115 kV	W Medway 345 kV
Hyde Park 115 kV	S Danvers 115 kV	Woburn 115 kV
Hyde Park 345 kV	Salem Harbor 115 kV	Woburn 345 kV
Kendall 115 kV	Sandy Pond 115 kV	W Walpole 115 kV
Kingston 115 kV	Sandy Pond 345 kV	W Walpole 345 kV

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Section 5
Results of Analysis

5.1 Overview of Results

The results of the steady-state analysis for all of the study work completed indicated that there no N-0 overloads or voltage violations. However, there were a number of overloads and voltage violations for N-1 and N-1-1 conditions. The results of the short-circuit work indicated there were a number of breakers overdutied and a number with limited short-circuit margin.

The results shown in sections 5.2.1 through 5.2.3 below include results for thermal overloads (STE violations are designated by "STE" after the overload percentage), low voltage violations and high voltage violations (see Section 11 for voltage criteria). The low voltage criteria analysis was based on peak load conditions. Due to the operating practice of changing no-load taps on autotransformers for some of the units in the Boston RSP subarea high voltage criteria assessments were conducted for both minimum load conditions, occurring in the Spring and Fall, and off-peak load conditions, occurring during Summer off-peak periods.

An overview of the results of the testing performed has been organized by subareas within the study area. The set of the defined subareas was developed based on a review of the thermal and voltage violations that were specific to particular areas within the Greater Boston study area. As a result the Greater Boston area results were grouped into eight subareas. These include the following subareas:

A. 345 kV And 115 kV Northern Ties to Greater Boston
B. Waltham, Woburn and Lexington Area
C. Downtown Boston 115 kV Cables
D. Sudbury, Marlboro and Northborough Area
E. W. Medway, W. Walpole and Holbrook Area
F. Boston, Golden Hills and Wakefield Junction Area
G. 115 kV Lines North of Boston in Salem Area and Near Tewksbury[32]
H. 115 kV Lines Near Tewksbury

The geographic location of the defined subareas in which these concerns were observed is shown in Figure 5-1 below.

[32] Sub-Area G (115 kV Lines North of Boston in Salem Area and Near Tewksbury) was studied but, due to recent upgrades, which include the Salem Harbor retirement upgrades, and the addition of new resources this sub-area was found to no longer result in any reportable reliability issues.)

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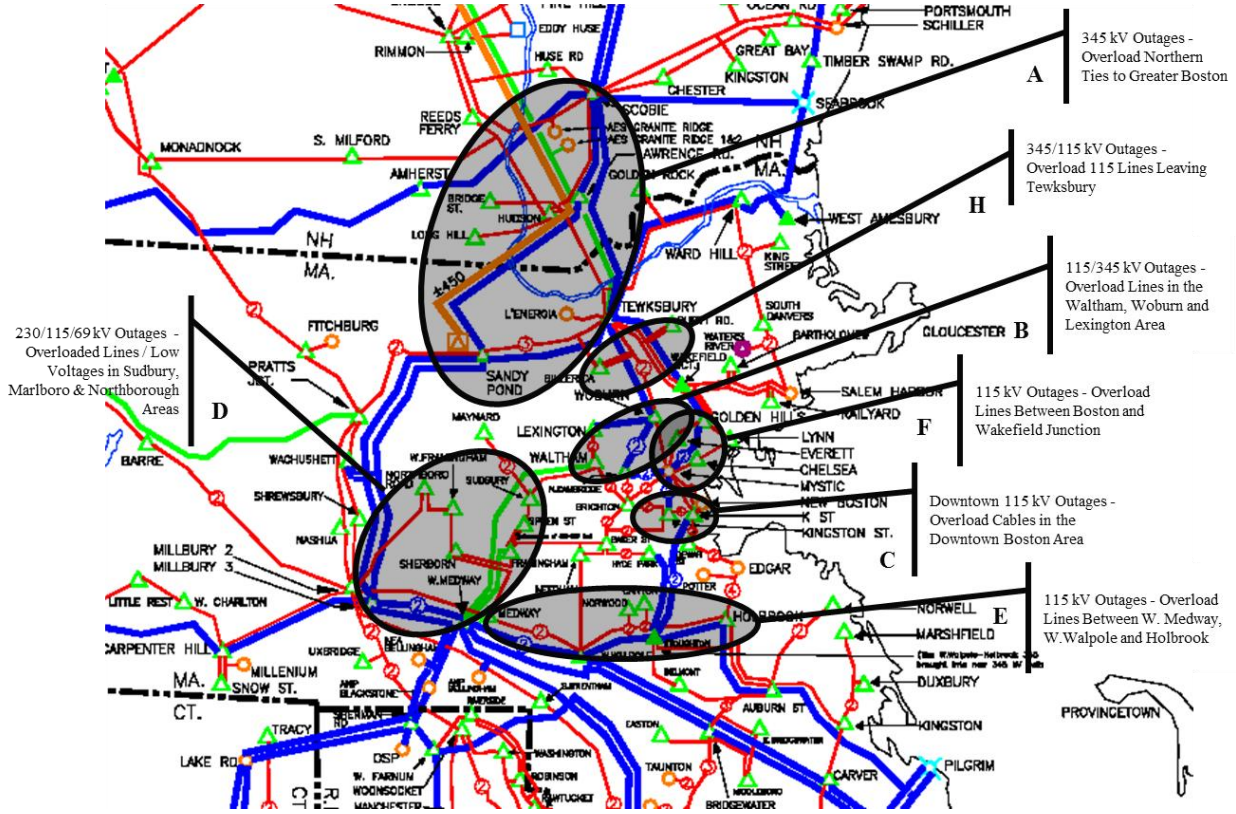


Figure 5-1
Greater Boston Subareas of Concern

A brief summary of each of the problems found in the subareas for the design case and retirement sensitivity case conditions is provided below in Table 5-1 through Table 5-7. Further explanation of the worst case observed thermal and voltage violations is included in Sections 5.2.1 through 5.2.3 below. Complete results of N-0, N-1 and N-1-1 testing are documented in the tables included in Section 13.

An additional designation which helped group common elements within each subarea was also developed for reporting purposes. A designation of C-7, for example, was indicative of grouping of the 324 and 372 cables, both of which run from Mystic to Kingston stations within Subarea C. Similarly a designation of C-5 is a grouping of the 110-510, 110-511, 514-510 and 514-511 cables which collectively interconnect the Baker St., Brighton and Kingston stations within Subarea C. Circuits were grouped together in this manner to ensure all like elements, in terms of common paths, were reported together. This report grouping was developed at the beginning of the Greater Boston study and, as the study results have changed over time, there are some

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elements that are no longer showing overloads. For example, the element grouping designated as A-6 was established for the G-133E and G-133W circuits which in earlier studies were reported as overloaded but do not currently show any overloads. Consequently, there may be element designations that are no longer included in the overloaded element reports and are therefore not included in the tables or descriptions shown below.

Subarea A - 345 kV and 115 kV Northern Ties to Greater Boston

Table 5-1 Subarea A - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
A – 345 kV and 115 kV Northern Ties to Greater Boston	Design Case Violations	No Violations	[redacted]	[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]

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Subarea B – Waltham, Woburn and Lexington Area

Table 5-2 Subarea B - N-0, N-1, and N-1-1 Steady State Violations



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Subarea C - Downtown Boston 115 kV Cables

Table 5-3 Subarea C - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
C – Downtown Boston 115 kV Cables	Design Case Violations	No Violations	[redacted]	[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]

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Subarea D - Sudbury, Marlboro and Northborough Area

Table 5-4 Subarea D - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
D – Sudbury, Marlboro and Northborough Area	Design Case Violations	No Violations	[redacted]	[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]

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Subarea E – W. Medway, W. Walpole and Holbrook Area

Table 5-5 Subarea E - N-0, N-1, and N-1-1 Steady State Violations



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Sub Area	Case Category	N-0	N-1	N-1-1
				[redacted]

Subarea F - Boston, Golden Hills and Wakefield Junction Area

Table 5-6 Subarea F - N-0, N-1, and N-1-1 Steady State Violations

Sub Area	Case Category	N-0	N-1	N-1-1
F – Boston, Golden Hills and Wakefield Junction Area	Design Case Violations	No Violations	[redacted]	[redacted]
	Additional Retirement Sensitivity Case Violations	No Violations	[redacted]	[redacted]

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Subarea H – 115 kV Lines North of Boston in Salem Area and Near Tewksbury

Table 5-7 Subarea H - N-0, N-1, and N-1-1 Steady State Violations



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5.2 Steady State Performance Criteria Compliance

Steady state test results varied as a function of the system conditions modeled. A number of post-contingency overloads and voltage violations were observed in all of the various base cases modeled and in many cases only the severity of the violations changed. There were also a number of post contingency overloads and voltage violations that were only associated with specific system conditions. A high level summary of the results for the conditions that were modeled is provided in Figure 5-1 above.

5.2.1 N-0 Thermal and Voltage Violation Summary

N-0 conditions were reviewed for the cases modeled. The results indicate that under the dispatch scenarios and transfer levels studied no N-0 condition thermal overloads or voltage violations were observed.

5.2.2 N-1 Thermal and Voltage Violation Summary

N-1 testing was performed for all of the system condition models described in Section 3 above. The results of overloaded lines and voltage violations can be found in the tables included in Appendix G. An overview of the results of N-1 testing is provided below. It should be noted that a number of pre and post contingency concerns seen in simulations were determined to be mitigated through phase shifter response. The operation of the Boston RSP subarea phase shifters are under the supervision of system operators and they routinely evaluate the pre and post contingency conditions of the system to determine the most appropriate phase shifter response to potential overloads. The exact process, response and phase shifter settings that operators use was not included in the study. However, evaluations were performed to determine if phase shifter adjustments could mitigate identified overloads and, in those cases where such actions were viable, overloads shown in model simulations that could be mitigated were not included in the results reporting.

The Holbrook and West Walpole subarea (subarea-E) within the Greater Boston area was found to include the potential for loss of consequential load[33] in excess of 300 MW [redacted]. While there are currently no specific standards that limit the magnitude of consequential load loss, this level of load loss violates the level noted in the draft ISO-NE Load Interruption Guide[34]. [redacted].

[33] Consequential Load Loss is the interruption of loads that are directly supplied by the faulted elements or affected area. This is usually associated with a radial element but it may be associated with loads fed directly from a network element or from lines on common circuit structures or load lost due to isolation of multiple elements as a result of breaker failures.

[34] See http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2011/load_interruption.pdf

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Test results for 2018 and 2023 base case conditions indicated a number of problems that could not be corrected through system adjustments (such as Phase Shifter adjustment,, HVDC output adjustment or SPS actions). The results are reviewed from two perspectives; design level and retirement sensitivity conditions. A summary of the design level system conditions is provided which provide the results that are based on the reliability standard requirements for generator dispatch and transfer level conditions. Additionally, a summary is provided for retirement sensitivity conditions that consider plant retirement conditions.

There were a limited number of voltage violations under N-1 conditions. Subarea D – Sudbury, Marlboro and Northboro and Subarea F – Boston, Golden Hills, and Wakefield Junction, both had a limited number of buses with low voltage violations under 2018 and 2023 peak load conditions.

Additionally under light load testing conditions, Subarea B – Boston, Golden Hills and Wakefield Junction, Subarea C – Downtown Boston 115 kV Cables, Subarea D - Sudbury, Marlboro and Northboro, and Subarea E - Holbrook and West Walpole all had a limited number of buses with high voltage violations under minimum load and/or off peak load conditions.

N-1 Overloads and Voltage Violations by Subarea

The summaries provided in the following tables identify the worst case overloads for system elements for modeled conditions grouped by the subarea that the elements are located in. In many cases overloads occurred for more than one system modeled condition. Only the worst case overloads are listed here in the interest of avoiding repetitive reviews. The worst case overloads due to contingencies reported are organized by the year that was tested and by the category of modeled condition (i.e. Design Cases or Retirement Sensitivity Cases) that the overload occurred for. The element overload summaries for design conditions are indicated with the designation “Des” (i.e. one or two units out of service modeled conditions) and overloads occurring for retirement sensitivity conditions are indicated with the designation “Sen” (i.e. generator retirement) overloads. The tables identify the contingency that caused the worst case overload and the percent overload that was observed. Additionally a high level map shows the location of overloaded elements has been included for each of the subareas. Only the converged cases are reported in the detailed discussion of each subarea. A discussion of divergent cases is included at the end of this section. Please refer to the results tables provided in Appendix I for a full listing of all overload conditions that were observed. Additionally, Appendix G includes a summary table of all overload conditions for each subarea.

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Subarea A - 345 kV and 115 kV Northern Ties to Greater Boston

Cases in which transfer levels across the North-South interface were at high levels resulted in overloads on 345 kV lines north of the Boston RSP subarea. [redacted]



Figure 5-2 Subarea A Design (White) and Sensitivity (Shaded) Case Overloaded Elements

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Worst Case Thermal Violations for Subarea A

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
A-1	Y-151 Line	Pelham to Power St. 115 kV line (formerly Hudson) section	Des	[redacted]	238	[redacted]	245
			Sen	[redacted]	256	[redacted]	265
		Pelham to Dracut Junction 115 kV line	Des	[redacted]	206	[redacted]	212
			Sen	[redacted]	223	[redacted]	230
There was an issue observed in association with the loss of [redacted] The acceptability of this loading level ([redacted]) will need to be investigated to ensure that the conductor and terminations can withstand this level of loading f[redacted]							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
A-2	337 Line	Sandy Pond to Tewksbury 345 kV Line	Des	None		None	
			Sen	[redacted]	104	[redacted]	109
This line overloads for [redacted]abrook. The most severe overload observed was for [redacted]rload. The overloads shown in this table are based on operation of [redacted] and are at a level that may be corrected through other system adjustments (such as back down of the Sandy Pond terminal or additional northern resources). [redacted]. Taking such actions may stress the reserves available on the system to compensate for this loss of source.							

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Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
A-3	394 Line	Seabrook to Ward Hill 345 kV line section	Des	[redacted]	111	[redacted]	113
			Sen	[redacted]	107	[redacted]	109
[redacted]							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
A-5	Sandy Pond Xfm	Sandy Pond 345/115 kV autotransformer	Des	None		None	
			Sen	None		[redacted]	103
[redacted]							

This condition only arose in 2023 under retirement case scenarios and may be mitigated through back down of Phase II.

Worst Case Voltage Violations for Subarea A

There were no design case or sensitivity case voltage violations reported for subarea A.

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Subarea B – Waltham, Woburn and Lexington Area

The Waltham, Woburn and Lexington areas include 345 kV and 115 kV facilities that interconnect the stations between these three locations. There were a number of autotransformer and 115 kV line overloads and voltage violations for this area of the system. Overloads observed in this area were influenced by dispatch and transfer level conditions but were not a function of any specific set of conditions.



Figure 5-3 Subarea B N-1 Design (White) and Sensitivity (Shaded) Case Overload Elements

Worst Case Thermal Violations for Subarea B

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
B-2	Woburn Xfm	Woburn 345/115 kV autotransformer	Des	[redacted]	105	[redacted]	109
			Sen	None		None	
[redacted] Overloads were not seen in the retirement sensitivity cases. The overloads are only seen in the cases with Mystic 9 in-service. Since all the retirement sensitivity cases have Mystic 9 OOS this overload was not observed in those cases.							

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Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
B-3	533-508 Line	Lexington to Hartwell Ave 115 kV Line	Des	[redacted]	None	[redacted]	104
			Sen	None		None	
[redacted] The overload is only seen for the cases with [redacted] the violation is not seen in the retirement sensitivity cases.							

Ref	Element ID	Element Description		2018 Loading		2023 Loading Contingency	2023 Loading % LTE
B-5	211-514 Line	Woburn to Mystic 115 kV Line	Des	[redacted]	195	[redacted]	204
			Sen	None		None	
[redacted] The overloads are only seen in the cases with Mystic 9 in-service. Since all the retirement sensitivity cases have Mystic 9 OOS this overload was not observed in those cases. Loading above 152% LTE are also STE violations for this line.							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
B-6	282-520 / 282-521 Lines	Brighton to Watertown 115 kV line section	Des	[redacted]	128	[redacted]	131
			Sen	[redacted]	104	[redacted]	109
		Waltham to Watertown 115 kV line section (only 282-521 circuit)	Des	[redacted]	102	[redacted]	107
			Sen	[redacted]	115	[redacted]	115
The table above indicates the worst case contingency violation on different segments of the 282-520 and 282-521 lines for the design and sensitivity cases. Most contingency overloads on these lines can be mitigated through phase shifter adjustment. Some contingencies result in isolation of the phase shifters and in these cases there are no mitigating operator actions available. The worst case contingency that cannot be mitigated through operator action is for a [redacted]							

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Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
B-8	346 / 365 Lines	Woburn to N. Cambridge 345 kV	Des	None		None	
			Sen	[redacted]	114	[redacted]	120
Loss of either 346 345 kV line from Woburn to N. Cambridge or the companion 365 345 kV line [redacted] This only occurs for retirement case scenarios.							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
B-9	338 Line	Tewksbury to Woburn 345 kV	Des	None		None	
			Sen	None		[redacted]	102
[redacted] results in overload of the 338 line. This only occurs for the 2023 retirement case scenarios.							

Worst Case Low Voltage Violations for Subarea B

There were no design case or sensitivity low voltage violations reported for subarea B.

Worst Case High Voltage Violations for Subarea B

Table 5-8 Worst Design Case High Voltage Violations for Subarea B

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
Waltham	**230**	[redacted]	1.0554	N/A
Waltham	**115**	[redacted]	1.0733	N/A

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Subarea C - Downtown Boston 115 kV Cables

Overloads for this segment of the Greater Boston area were in some cases (i.e. C-1, C-2, and C-3) associated with specific transfer levels of either high Boston Import or high North-South transfers. The 115 kV cables [redacted] were the most severely overloaded under certain dispatch conditions. The remaining overloads were observed across a wide range of transfer level and dispatch conditions.



Figure 5-4 Subarea C N-1 Design (White) and Sensitivity (Shaded) Case Overloaded Elements

Worst Case Thermal Violations for Subarea C

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
C-1	329-510/511	Mystic - Somerville 115 kV section	Des	[redacted]	109	[redacted]	113
			Sen	[redacted]	N/A	[redacted]	N/A
		Brighton – Somerville 115 kV section	Des	[redacted]	103	[redacted]	106
			Sen	[redacted]	106	[redacted]	109

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The overloads from Mystic to Somerville overload for [redacted]. These overloads are only seen for the dispatches [redacted] are restricted to the design cases. However, for the segment between Brighton and Somerville overloads are observed for [redacted]. The overloads for the retirement cases are slightly higher than the overloads for the design cases.

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
C-3	385-511	High St. – K Street 115 kV section	Des	[redacted]	115	[redacted]	120
			Sen	[redacted]	120	[redacted]	126
		Kingston – High St. 115 kV section	Des	[redacted]	137	[redacted]	143
			Sen	[redacted]	142	[redacted]	149

The worst case overloads occur for [redacted] er. This overload can be mitigated for most contingencies by [redacted]. The worst case contingency that cannot be resolved through operator action is [redacted]

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
C-4	250-516/517	K Street - Chatham 115 kV section	Des	[redacted]	119	[redacted]	125
			Sen	[redacted]	135	[redacted]	142
		Mystic – Hawkins 115 kV section	Des	[redacted]	141	[redacted]	141
			Sen	None		None	

These lines overload for [redacted]. The overloads occurred for a number of design case dispatch conditions as well as for the retirement sensitivity cases. [redacted].

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Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
C-5	110-510/511	Baker St. – Washington St. 115 kV section	Des	[redacted]	120	[redacted]	113
			Sen	[redacted]	105	[redacted]	109
		Colburn – Washington St. 115 kV section	Des	[redacted]	101	[redacted]	102
			Sen	None		[redacted]	101
The loading on the 110-510/511 lines is [redacted]. These overloads are all below STE ratings and operator adjustment post contingency can correct them.							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
C-7	324 or 372	Mystic – Kingston 345 kV cables	Des	[redacted]	115	[redacted]	116
			Sen	None		None	
[redacted]. The overloads only occurred for design cases with Mystic 9 out of service and with Mystic 7 and 8 in-service. This was not seen for the retirement cases since Mystic 7 and 8 are out of service.							

Worst Case Low Voltage Violations for Subarea C

There were no design case or sensitivity low voltage violations reported for subarea C.

Worst Case High Voltage Violations for Subarea C

Table 5-9 Worst Design Case High Voltage Violations for Subarea C

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
K Street	**345**	[redacted]	N/A	1.0556

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Subarea D - Sudbury, Marlboro & Northborough Area

The Sudbury, Marlboro and Northborough area overloads were, for the most part, driven by isolating loads onto facilities with limited capacity. There was minimal sensitivity to the dispatch conditions modeled.

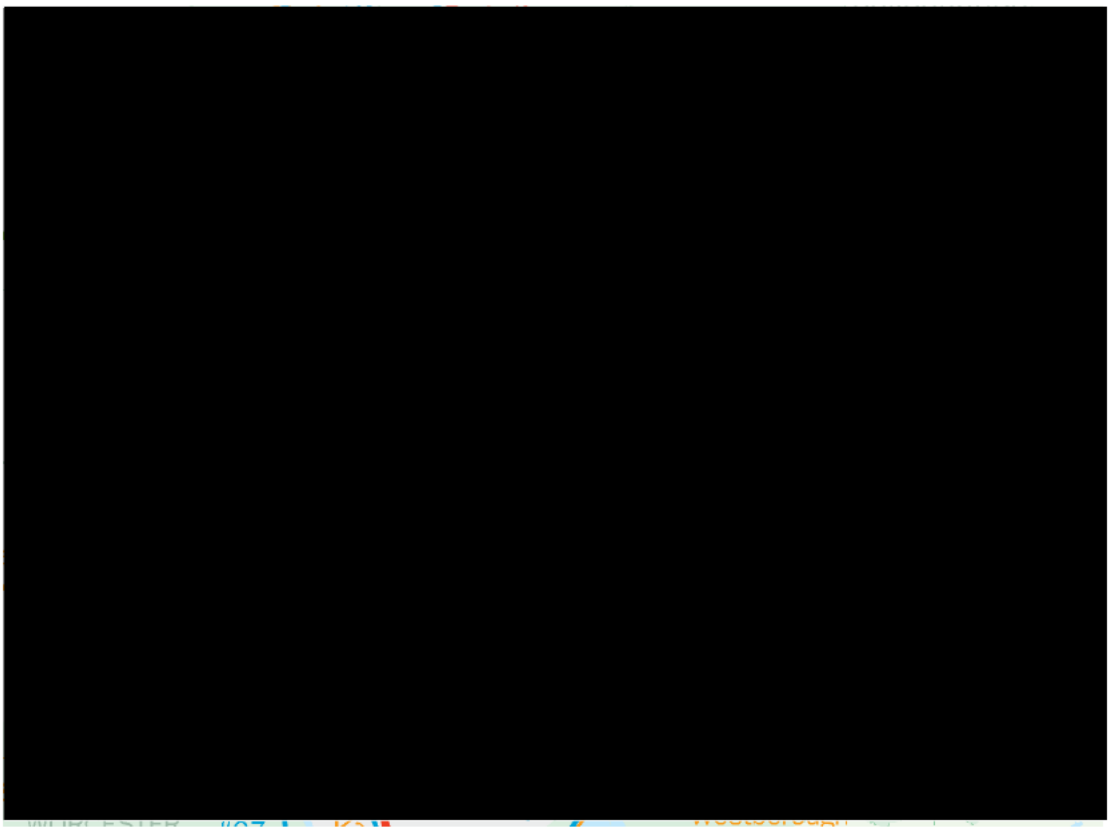


Figure 5-5 Subarea D N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea D

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
D-1	W-23	Fitch Rd to Woodside 69 kV	Des	None		[redacted]	105
			Sen	None		[redacted]	104
This line overloads for [redacted].							

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Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
D-3	W-23W	Woodside to MWRA and MWRA to Northborough Road 69 kV line sections	Des	[redacted]	113	[redacted]	119
			Sen	[redacted]	113	[redacted]	117
This line overloads for [redacted] between Woodside and MWRA and between MWRA and Northborough Rd in conjunction with [redacted]. Loading above 104% of LTE are also a STE violation for this line.							

Worst Case Low Voltage Violations for Subarea D

Table 5-10 Worst Case Low Voltage Violations for Subarea D

Bus Name	Base kV	Contingency	2018 DES	2018 SEN	2023 DES	2023 SEN
Sudbury	**115**	[redacted]	0.9278	0.927	0.9146	None
		[redacted]	None	None	None	0.9116
Speen Street	**115**	[redacted]	None	None	None	0.9197
		[redacted]	0.9432	None	None	None
		[redacted]	None	0.9432	0.9301	None

Worst Case High Voltage Violations for Subarea D

Table 5-11 Worst Design Case High Voltage Violations for Subarea D

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
Sudbury	**115**	[redacted]	1.0697	N/A
Speen Street	**115**	[redacted]	1.0622	N/A

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Subarea E - Holbrook and W. Walpole Area

The Holbrook and W. Walpole area overloads were primarily associated with dispatch conditions with Fore River running. These overloads are not mitigated through [redacted]

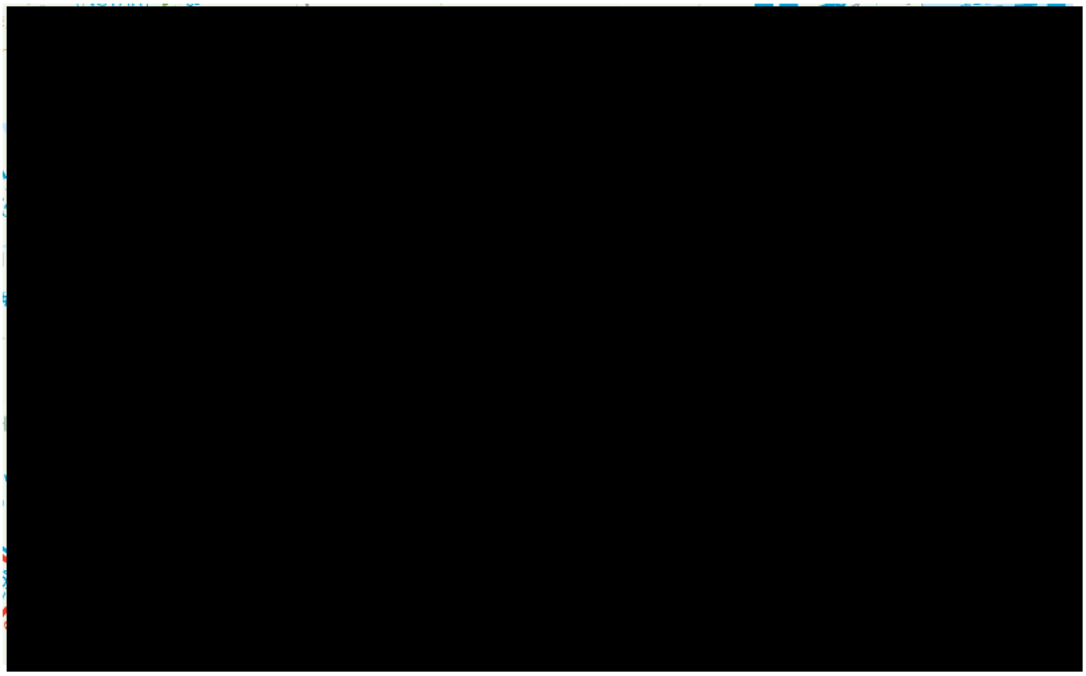


Figure 5-6 Subarea E N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea E

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
E-1	447-508	Holbrook to S. Randolph 115 kV section	Des	[redacted]	108	[redacted]	111
			Sen	[redacted]	107	[redacted]	109
		Canton to S. Randolph 115 kV section	Des	None		[redacted]	101
			Sen	None		None	
These lines overload for a [redacted] This forces higher flows on 447-508 from the Holbrook end of the line. Loadings above 100% of LTE are also STE violations for this line.							

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Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
E-10	148-522XY	Dover to Needham 115 kV	Des	None		[redacted]	100 +
			Sen	None		[redacted]	101
Under sensitivity retirement cases the line overloads [redacted] However, the loading is below STE and the overload can be mitigated by adjusting the Baker Street PS.							

Worst Case Low Voltage Violations for Subarea E

There were no design case or sensitivity case low voltage violations reported for subarea E.

Worst Design Case High Voltage Violations for Subarea E

Table 5-12 Worst Design Case High Voltage Violations for Subarea E

Bus Name	Base kV	Contingency	Summer Off Peak	Min Load
Hyde Park	**345**	[redacted]	1.0552	1.0579
Stoughton	**345**	[redacted]	None	1.0562
West Medway	**230**	[redacted]	1.0578	None
Baker Street	**115**	[redacted]	1.0551	None

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Subarea F - Boston, Golden Hills and Wakefield Junction Area

Golden Hills and Wakefield area overloads were observed for a number of contingency events and under a number of transfer level conditions.

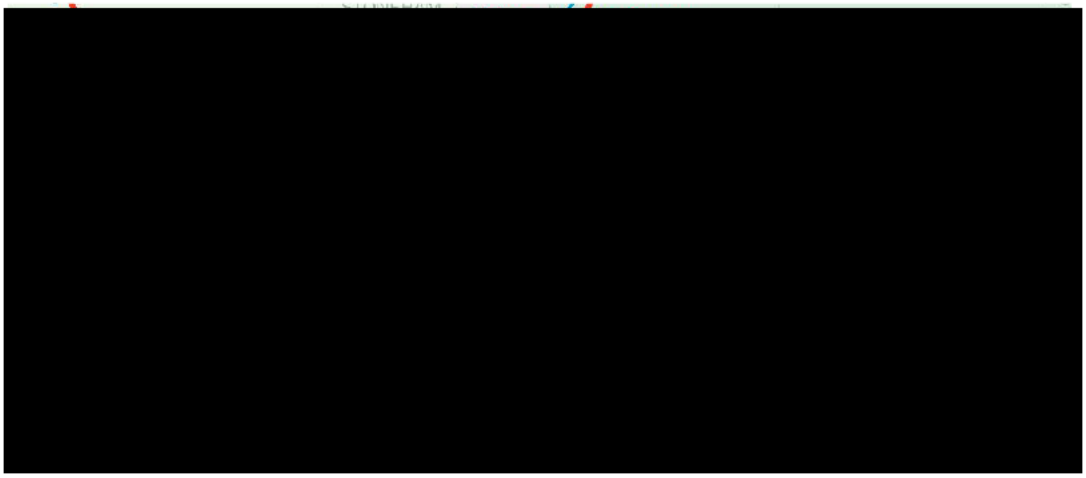


Figure 5-7 Subarea F N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea F

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
F-4	349 X/Y	Wakefield Junction – Mystic 345 kV cable	Des	None		None	
			Sen	[redacted]	105	[redacted]	108
This line overloads for [redacted] ne under retirement case scenarios.							

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
F-6	Q-169	GE River to Lynn 115 kV line section	Des	None		[redacted]	100+
			Sen	None		[redacted]	104
		RESCO/Saugus to GE River 115 kV line section	Des	None		None	
			Sen	None		[redacted]	103
This line overloads due to [redacted] primarily under retirement case scenarios in 2023. Marginal overloads are seen for the design cases in 2023.							

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Table 5-13 Worst Case Low Voltage Violations for Subarea F

Bus Name	Base kV	Contingency	2018		2023	
			DES	SEN	DES	SEN
Chelsea	**115**	[redacted]	0.9178	0.9126	0.8974	0.8708

Worst Design Case High Voltage Violations for Subarea F

There were no design case high voltage violations reported for this subarea.

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Subarea H – 115 kV Lines Near Tewksbury

Area H was primarily impacted by the unavailability of generation in the Boston RSP subarea under retirement sensitivity conditions.

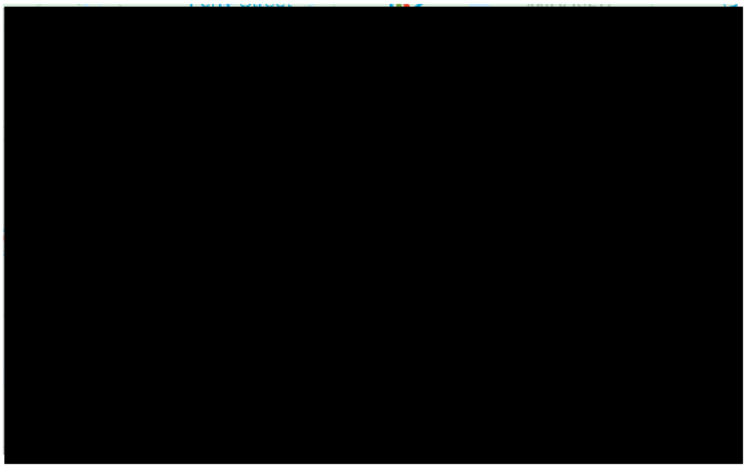


Figure 5-8 Subareas H N-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Worst Case Thermal Violations for Subarea H

Ref	Element ID	Element Description		2018 Loading Contingency	2018 Loading % LTE	2023 Loading Contingency	2023 Loading % LTE
H-2	M-139 Line	Tewksbury to Billerica 115 kV line section	Des	None		[redacted]	101
			Sen	[redacted]	103	[redacted]	107
This line overloads for [redacted].							
This line overloads under sensitivity retirement conditions for [redacted]							

Worst Case Low Voltage Violations for Subarea H

There were no design or sensitivity case low voltage violations reported for subarea H.

Worst Design Case High Voltage Violations for Subarea H

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There were no design case high voltage violations reported for subarea H.

5.2.3 N-1-1 Thermal and Voltage Violation Summary

Initial element-out-of-service (N-1-1) testing included all 115 kV, 230 kV and 345 kV transmission lines as well as 345 kV autotransformers in the Greater Boston area that are considered Bulk Electric System ("BES") elements. These element-out-of-service conditions were tested against the full set of contingencies used in the N-1 tests. These were tested for design cases and for retirement sensitivity cases that modeled retirement of Mystic Unit 7. Testing of the system included use of an analytical tool that used a re-dispatch of New England generation, back-down of Boston RSP subarea generation and adjustment of the Boston RSP subarea phase shifters in an attempt to avoid overloads. These cases were evaluated using LTE ratings as they represented post-contingency, post-system adjustment conditions. Additionally, testing included evaluation of post-second contingency phase shifter adjustments, HVDC terminal adjustments and fast start unit back-down to mitigate each specific contingency pair where operator intervention was viable (i.e. overloads do not exceed STE ratings). Those contingencies that resulted in STE violations show the percentage of STE ratings and are indicated by noting "STE" after the overload percentage values.

Testing was also performed to assess the impact of possible generation retirement sensitivities on the element-out-of-service condition of the system. Mystic Unit 7 retirement was tested for N-1-1 conditions. Each of the retirement sensitivity cases included an assumption that Mystic 8 and 9 were unavailable. The results of thermal violations that were not seen in any other analysis are included in each area section described below.

Cases where overload conditions were found to exist that were unique to N-1-1 contingencies or had higher loading under N-1-1 conditions are reported by subarea below. This includes summary tables for design and retirement sensitivity cases. The list of the element-out-of-service conditions that were tested can be found in Table 12-2 included in Appendix F. The full results of thermal violations can be found in Appendix G.

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Subarea A - 345 kV and 115 kV Northern Ties to Greater Boston



Figure 5-9 Subarea A N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-2	337	Sandy Pond – Tewksbury 345 kV	Mystic 7	[redacted]	DES	<100%	109
			[redacted]	[redacted]	SEN	115	122
This line overloads for [redacted]. The [redacted] as it would see overload conditions for the first contingency and this action further aggravates the overload condition on the 337 line. Loadings above 107% LTE are also STE violations for this line. Note that even though there are no overloads reported for the 2018 load level for the design cases, the line depends on generation rejection with [redacted] to avoid STE overloads in 2018. [redacted].							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-3	394	Seabrook – Ward Hill 345 kV	[redacted]	[redacted]	DES	105	107
			[redacted]	[redacted]	SEN	108	113
This line overloads for loss of resource in Boston or loss of import capability into Boston followed by [redacted]. For the 2023 retirement case the worst case condition is different. [redacted]. Loadings above 100% LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-5	Sandy Pond Auto	Sandy Pond 345 kV to 115 kV autotransformer #1	[redacted]	[redacted]	DES	133	136
			[redacted]	[redacted]	SEN	140	140
The Sandy Pond Auto #1 overloads for [redacted] Loadings above 127% LTE are also STE violations and [redacted]							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-8	A-253	Dunbarton Tap to Merrimack 230 kV	[redacted]	[redacted]	DES	118	124
			[redacted]	[redacted]	SEN	112	113
The 230 kV line from Merrimack to Dunbarton Tap overloads for loss of the [redacted] For the National Grid portion of the line loadings above 106% LTE are also STE violations. For the NU portion of							

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the lines loadings above 100% LTE are also STE violations. The [redacted] sensitivity cases have lower violations than the design cases since all the retirement sensitivity cases have Phase II in-service. The worst case loadings for the design cases are seen with [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-9	B-202S	Dunbarton Tap to North Litchfield 230 kV	[redacted]	[redacted]	DES	108	113
			N/A	N/A	SEN	None	None
The 230 kV line from Dunbarton Tap to North Litchfield overloads for [redacted]. For the NATIONAL GRID portion of the lines loadings above 106% LTE are also STE violations. For the NU portion of the lines loadings above 100% LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-10	I-135	Fitzwilliam to Flagg Pond (NU section)	[redacted]	[redacted]	DES	101	107
			N/A	N/A	SEN	None	None
The initial segment of the I-135 line from Fitzwilliam to Flagg Pond overloads for [redacted] This only occurs for [redacted]. Since the Mystic 7 retirement sensitivities have Phase 2 in-service, we do not see this overload. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
A-13	N-214	N. Litchfield to Tewksbury 230 kV	[redacted]	[redacted]	DES	None	111
			N/A	N/A	SEN	None	None
The 230 kV line from N. Litchfield to Tewksbury overloads for [redacted] Since the Mystic 7 retirement sensitivities have Phase 2 in-service, we do not see this overload. Loadings above 109% of LTE are also STE violations for this line.							

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Worst Case Low Voltage Violations for Subarea A

There were no design case low voltage violations reported for subarea A.

Table 5-14 Worst Case Low Voltage Violations for Subarea A

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Tewksbury	115	[redacted]	[redacted]	None	None	None	0.9405
West Amesbury	115	[redacted]	[redacted]	None	None	None	0.9354

Worst Case High Voltage Violations for Subarea A

Table 5-15 Worst Design Case High Voltage Violations for Subarea A

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Tewksbury	345	[redacted]	[redacted]	None	1.0698
Ward Hill	345	[redacted]	[redacted]	None	1.0618
	115	[redacted]	[redacted]	None	1.0593
West Amesbury	345	[redacted]	[redacted]	None	1.0569
	115	[redacted]	[redacted]	None	1.0574

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Subarea B – Waltham, Woburn and Lexington Area



Figure 5-10 Subarea B N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-1	391-508	Burlington - Hartwell 115 kV line	[redacted]	[redacted]	DES	112	124
			N/A	N/A	SEN	None	None
Loss of the [redacted] followed by loss of [redacted] overloads this line. Flows over 115 kV lines into [redacted] are increased as flows from [redacted] line are increased due [redacted] resulting in the overload of this line. These conditions occur when [redacted] is in service and [redacted] is opened. Since Mystic 9 is out of service for the Mystic 7 retirement sensitivity cases this line does not overload for those cases. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-2	Woburn Xfmr	Woburn 345/115 kV autotransformer	[redacted]	[redacted]	DES	150	158
			[redacted]	[redacted]	SEN	108	111
Loss of the [redacted] fault overloads this transformer. Flows into [redacted] bus are increased as flows from [redacted] line are increased due to [redacted] resulting in the overload of this line. These conditions occur when [redacted] in service and the [redacted] is opened. Loadings above 127% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-3	533-508	Lexington – Hartwell 115 kV	[redacted]	[redacted]	DES	152	167
			[redacted]	[redacted] e	SEN	None	100+

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Loss of [redacted] followed by loss of [redacted] r fault overloads this line. Flows over 115 kV lines into [redacted] are increased as flows from [redacted] line are increased due to [redacted] resulting in the overload of this line. Loading above 100% of LTE are also STE violations for this line.

For the [redacted] sensitivities the line only overloads for the 2023 conditions with [redacted] as the first contingency followed by the loss of [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-5	211-514	Woburn - Mystic 115 kV	[redacted]	[redacted]	DES	266	277
			[redacted]	[redacted]	SEN	156	165
The 211-514 Woburn to Mystic 115 kV cable overloads for loss of a number of initial contingencies (worst case was [redacted] followed by loss of [redacted] fault. Flows over this cable can be mitigated in many cases by [redacted] There are cases where Mystic 9 is running and due to short circuit constraints the bus tie cannot be closed therefore overloads are still present. For retirement sensitivity cases loss of [redacted] followed by loss of [redacted] results in overloads and these cannot be mitigated through operator actions. Loadings above 152% of LTE are also STE violations for this line. For the Mystic 7 retirement sensitivities the highest overloads are seen with [redacted] as the first contingency followed by [redacted].							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-6	282-520 / 282-521 (segment #1)	Brighton - Watertown 115 kV cable section	[redacted]	[redacted]	DES	204	216
			[redacted]	[redacted]	SEN	185	199
	282-520 / 282-521 (segment #2)	Watertown to Waltham 115 kV cable section	[redacted]	[redacted]	DES	185	185
			[redacted]	[redacted]	SEN	184	203

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The Brighton to Watertown section of the 282-520/521 cables occurs for conditions when [redacted]. For the segments from Waltham to Watertown the highest overloads are seen with [redacted]. Loadings above 155% of LTE are also STE violations for these cables.

There are a number of additional overloads reported that can be corrected through operator adjustment of [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-7	358	Mystic to North Cambridge 345 kV	[redacted]	[redacted]	DES	141	146
			[redacted]	[redacted]	SEN	131	139
	351	Mystic to North Cambridge 345 kV	[redacted]	[redacted]	DES	118	122
			[redacted]	[redacted]	SEN	116	123
These lines overload for loss of the [redacted] followed by a [redacted].							
Under retirement scenario conditions the [redacted] overloads for loss of the [redacted] followed by loss of [redacted]. The 358 line overloads for loss of the [redacted]							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-8	346/365	North Cambridge – Woburn 345 kV	[redacted]	[redacted]	DES	151	151
			[redacted]	[redacted]	SEN	203	214
These lines overload with [redacted] V out of service followed by a single contingency that removes either the [redacted]. Loadings above 178% of LTE are also STE violations for these cables.							
Retirement scenario conditions resulted in STE violations for these cables.							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
B-9	338	Tewksbury – Woburn 345 kV	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	None	106
This line has the highest overload for [redacted] out of service followed by [redacted] The overload was only seen for the 2023 retirement sensitivity cases.							

Table 5-16 Worst Case Low Voltage Violations for Subarea B

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Woburn	**345**	[redacted]	[redacted]	None	None	None	0.7957
	115	[redacted]	[redacted]	None	None	None	0.9472
		[redacted]	[redacted]	None	None	0.9346	None
Lexington	**345**	[redacted]	[redacted]	None	None	None	0.7951
		[redacted]	[redacted]	None	None	0.9403	0.9118
	115	[redacted]	[redacted]	None	None	None	0.7889
Burlington MA	**115**	[redacted]	Woburn #106	None	None	None	0.7892
		[redacted]	[redacted]	0.9219	0.9303	0.9025	0.9151
		[redacted]	[redacted]	0.9240	0.9436	0.9084	0.9240
Hartwell	**115**	[redacted]	[redacted]	None	None	None	0.7892
		[redacted]	[redacted]	0.9219	0.9303	0.9025	0.9151
		[redacted]	[redacted]	0.9171	0.9375	0.9002	0.9165
Trapelo Road	**115**	[redacted]	[redacted]	None	None	None	0.7876
Waltham	[redacted]	[redacted]	[redacted]	None	None	0.9362	None

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		[redacted]				
		[redacted]	None	0.9439	None	0.9292
		[redacted]	None	None	None	0.8322
	115	[redacted]	0.9246	None	0.8966	None
		[redacted]	None	0.9419	None	0.9217
		[redacted]	None	None	None	0.7916
Watertown	115	[redacted]	None	None	None	0.7927

Table 5-17 Worst Design Case High Voltage Violations for Subarea B

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Woburn	345	[redacted]	[redacted]		1.0728
Waltham	230	[redacted]	[redacted]	1.0729	
	115	[redacted]	[redacted]	1.0614	
			[redacted]		1.0586
Lexington	345	[redacted]	[redacted]		1.0686
	115	[redacted]	[redacted]	1.0553	
			[redacted]		1.0552
Trapelo Road	115	[redacted]	[redacted]	1.0573	
			[redacted]		1.0567
Watertown	115	[redacted]	[redacted]	1.0623	
			[redacted]		1.0596

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Subarea C - Downtown Boston 115 kV Cables



Figure 5-11 Subarea C N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea C

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-1	329-510/511 (Section #1)	Mystic – Somerville section of the 115 kV Cables			DES	126	144
					SEN	<100	109
	329-510/511 (Section #1)	Brighton – Somerville section of the 115 kV Cables			DES	127	127
					SEN	123	138
The Somerville to Mystic segment of these cables overload for							

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followed by [redacted] The section from Brighton to Somerville overloads for [redacted] followed by the loss of [redacted]

Under retirement sensitivity case conditions loss of [redacted]

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-2	329-512/513	Kingston – Brighton 115 kV Cables	[redacted]	[redacted]	DES	121	126
			[redacted]	[redacted]	SEN	106	108
These lines overload for loss of [redacted]. For design cases loss of [redacted]. Under retirement case scenarios loss of [redacted]							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-3	385-510	Kingston – K Street 115 kV Cables	[redacted]	[redacted]	DES	113	123
			[redacted]	[redacted]	SEN	115	125
	385-511		[redacted]	[redacted]	DES	162	168
			[redacted]	[redacted]	SEN	158	171
The worst case overloads on the 385-510 line occur for loss of [redacted]. The overloads are typically							

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[redacted]. The highest overloads for the design cases are seen for the loss of [redacted]. For the retirement cases the [redacted]

The worst case overloads on the 385-511 line occur for the loss of [redacted]. These overloads are typically from [redacted] with the worst case second contingency being the loss of [redacted] For design cases loss of [redacted] followed by [redacted] overloads the 385-510. Under retirement case scenarios loss of [redacted] overloads the 385-511 line.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-3	385-513	Kingston – K Street 115 kV Cables	[redacted]	[redacted]	DES	143	146
			[redacted]	[redacted]	SEN	101	102
This line overloads for loss of [redacted] followed by a [redacted]. The worst case design overloads occur for the dispatches with Mystic 9 out of service, and since all the retirement sensitivity cases have Mystic 9 in-service the retirement sensitivity overloads are lower than the design cases.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-4	250-516/517	Mystic – K Street 115 kV Cables	[redacted]	[redacted]	DES	136	141
			[redacted]	[redacted]	SEN	161	169
Under design conditions these lines overload for loss of [redacted] These overloads occur when [redacted] is out of service and [redacted]. It may be possible to mitigate the overload by [redacted]. However this action may introduce other overloads. Under retirement scenario conditions loss of [redacted] results in the highest overload for the 250-516 cable in 2023. For 2018 the worst case overload is for the loss of [redacted]							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-5	110-510/511	Washington St. Tap to Baker St.115 kV cable section	[redacted]	[redacted]	DES	141	148
			[redacted]	[redacted]	SEN	195	188
		Washington Tap to Brighton 115 kV cable section	[redacted]	[redacted]	DES	104	119
			[redacted]	[redacted]	SEN	150	152
		Washington tap to Colburn 115 kV cable section	[redacted]	[redacted]	DES	132	145
			[redacted]	[redacted]	SEN	102	108
	514-510/511	Colburn to Kingston 115 kV cable section (514-510/511)	[redacted]	[redacted]	DES	138	143
			[redacted]	[redacted]	SEN	None	105

The flow on these cables is controlled by [redacted] and overloads that do not exceed STE rating can be mitigated through operator action. Loadings above 157% of LTE are also STE violations for these cables. However, all the violations above take phase shifter action into consideration and report the violations that are still observed after Phase shifter adjustments.

Loss of [redacted] result in the highest overloads under design case conditions on the Washington Street tap to Baker Street section. Loss of [redacted] results in the highest overload of these cables under retirement sensitivity case conditions. The retirement scenario conditions result in STE violations for these lines and phase shifter adjustment would not be an operational alternative to correct this loading.

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-7	324 / 372	Mystic to Kingston 345 kV	[redacted]	[redacted]	DES	117	119
			N/A	N/A	SEN	None	None
Loss of [redacted] results in overload of these cables. These overloads occur when [redacted] is out of service and the [redacted]. Since both Mystic7 and 8 are out of service for the Mystic 7 retirement sensitivity cases, these overloads are not observed.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
C-8	329-530/531	Brighton to N. Cambridge 115 kV	[redacted]	[redacted]	DES	129	135
			N/A	N/A	SEN	None	None
Loss of [redacted] isolates all N. Cambridge load on the single remaining 115 kV circuit. The overload only occurs for cases [redacted] is unavailable and hence is not seen for the retirement sensitivity since all the retirement sensitivity cases have [redacted] in-service.							

Table 5-18 Worst Case Low Voltage Violations for Subarea C

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Brighton	**115**	[redacted]	[redacted]	None	None	None	0.7958
Somerville	**115**	[redacted]	[redacted]	None	None	None	0.7986
Kingston	**345**	[redacted]	[redacted]	None	None	None	0.7974
	115	[redacted]	[redacted]	None	None	None	0.7992
Carver	**115**	[redacted]	[redacted]	None	None	None	0.7975
Scotia Street	**115**	[redacted]	[redacted]	None	None	None	0.7957

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High Street	115	[redacted]	None	None	None	0.7995
K Street	345	[redacted]	None	None	None	0.9417
	115	[redacted]	None	None	None	0.8017
Mystic	345	[redacted]	None	None	None	0.7974
	115	[redacted]	None	None	None	0.8023
	[redacted]	[redacted]	None	None	0.9188	None
Chatham	115	[redacted]	None	None	None	0.8036
Hawkins	115	[redacted]	None	None	None	0.8030
Colburn	115	[redacted]	None	None	None	0.7956
North Cambridge	345	[redacted]	None	None	None	0.7969
	115	[redacted]	None	None	None	0.7953

Table 5-19 Worst Design Case High Voltage Violations for Subarea C

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Mystic	345	[redacted]	[redacted]		1.0751
	115	[redacted]	[redacted]	1.0591	
		[redacted]	[redacted]		1.0571
Brighton	115	[redacted]	[redacted]	1.062	
		[redacted]	[redacted]		1.0593
K Street	345	[redacted]	[redacted]	1.0832	
	345	[redacted]	[redacted]		1.0861
	115	[redacted]	[redacted]	1.0652	
	115	[redacted]	[redacted]		1.0627
Chatham	115	[redacted]	[redacted]	1.0605	

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			1.0577
Colburn	115		1.0606
			1.0632
Hawkins	115		1.0601
			1.0576
High Street	115		1.0644
			1.0617
Kingston	345		1.0749
Carver Street	115		1.0638
			1.0611
Kingston	115		1.0642
			1.0615
North Cambridge	345		1.0745
	115		1.058
			1.0648
Scotia Street	115		1.0602
			1.063
Somerville	115		1.06
			1.0578

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Subarea D - Sudbury, Marlboro and Northborough Area



Figure 5-12 Subarea D N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea D

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-1	W-23	Fitch Rd - Woodside 69 kV	[redacted]	[redacted]	DES	213	213
			[redacted]	[redacted]	SEN	212	212
Loss of [redacted] overloads on the W-23 69 kV line. Loadings above 108% of LTE are also STE violations for this line.							

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An important consideration for this event is the severity of the overload. Loss of [redacted].

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-2	E-157	Millbury - Northboro Rd 115 kV	[redacted]	[redacted]	DES	131	136
			[redacted]	[redacted]	SEN	130	136
Loss of [redacted] results in overloads on the E-157 115 kV line. Loadings above 106% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-3	W-23W	Northboro Rd - Woodside 69 kV	[redacted]	[redacted]	DES	265	265
			[redacted]	[redacted]	SEN	264	264
Loss of [redacted] results in overloads on the W-23W kV line. Loadings above 104% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-4	X-24	North Grafton – Westboro 69 kV	[redacted]	[redacted]	DES	184	185
			[redacted]	[redacted]	SEN	181	183
Loss of [redacted] results in overloads on this line. Loadings above 108% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-5	433-507	Framingham – Speen St. 115 kV	[redacted]	[redacted]	DES	136	137

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		[redacted]r			
	[redacted]	[redacted]	SEN	137	137
Loss of [redacted] results in overloads on this line. Flows into Boston RSP subarea are seen on this line and loss of [redacted] supply into Boston RSP subarea results in overloading of the this line. Loadings above 100% of LTE are also STE violations for this line.					

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-6	282-507	Waltham - Sudbury 115 kV	[redacted]	[redacted]	DES	105	110
			[redacted]	[redacted]	SEN	106	112
Loss of [redacted] overloads the 282-507 Waltham to Sudbury 115 kV line due to the increased loading from [redacted] Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	240-508	Sherborn - Framingham 115 kV	[redacted]	[redacted]	DES	108	108
			[redacted]	[redacted]	SEN	102	110
Loss of [redacted] results in overloads on the 240-508 115 kV line. [redacted]. In 2023 under retirement sensitivity case conditions or loss of [redacted] is more severe than [redacted] Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	274-509	Medway -	[redacted]	[redacted]	DES	101	106

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		Sherborn 115 kV	[redacted]	[redacted]		
			[redacted]	[redacted]	SEN	None	110
Loss of [redacted] results in overloads on the 274-509 115 kV line. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	455-507	Sherborn – W. Framingham 115 kV	[redacted]	[redacted]	DES	132	137
			[redacted]	[redacted]	SEN	132	137
Loss of [redacted] results in overloads on the 455-507 115 kV line. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-7	513-507	Northboro Rd – W. Framingham 115 kV	[redacted]	[redacted]	DES	115	120
			[redacted]	[redacted]	SEN	115	121
Loss of [redacted] results in overloads on the 513-507 (connecting to D-156 on the NATIONAL GRID system) 115 kV line. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
D-9	N-40 A&B	Fitch Rd. to Pratts Junction 69 kV	[redacted]	[redacted]	DES	126	127
			[redacted]	[redacted]	SEN	125	126
Loss of [redacted] line results in overloads on the N-40 A&B 69 V line. Loadings above 108% of LTE are also STE violations for this line.							

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Table 5-20 Worst Case Low Voltage Violations for Subarea D

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Woodside	69	[redacted]	[redacted]	0.6032	0.6047	0.5939	None
Northboro Road	69	[redacted]	[redacted]	0.5445	0.5458	0.5321	None
	69	[redacted]	[redacted]	None	None	0.8971	None
MWRA	69	[redacted]	[redacted]	0.5574	0.5587	0.5459	None
North Grafton	69	[redacted]	[redacted]	0.8017	0.8019	0.7925	None
Westboro	69	[redacted]	[redacted]	0.5445	0.5458	0.5321	None
Framingham	230	[redacted]	[redacted]	None	None	None	0.9280
	115	[redacted]	[redacted]	0.9423	0.9347	0.9302	0.9087
	115	[redacted]	[redacted]	None	None	None	0.8951
Sherborn	115	[redacted]	[redacted]	None	None	None	0.9037
West Framingham	115	[redacted]	[redacted]	None	None	None	0.9245
Sudbury	115	[redacted]	[redacted]	0.8703	None	0.8335	None
	115	[redacted]	[redacted] B	0.9288	0.8917	0.8940	0.8695
	115	[redacted]	[redacted]	None	None	None	0.8126
Speen Street	115	[redacted]	[redacted]	0.8579	None	0.8212	None
	115	[redacted]	[redacted] B	0.9177	0.8796	0.8814	0.8566
	115	[redacted]	[redacted]	None	None	None	0.8365

Table 5-21 Worst Design Case High Voltage Violations for Subarea D

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Sudbury	115	[redacted]	[redacted]	1.1145	1.0686
Framingham	115	[redacted]	[redacted]	1.0594	
Speen Street	115	[redacted]	[redacted]	1.1135	1.0677

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Subarea E - Holbrook and W. Walpole Area

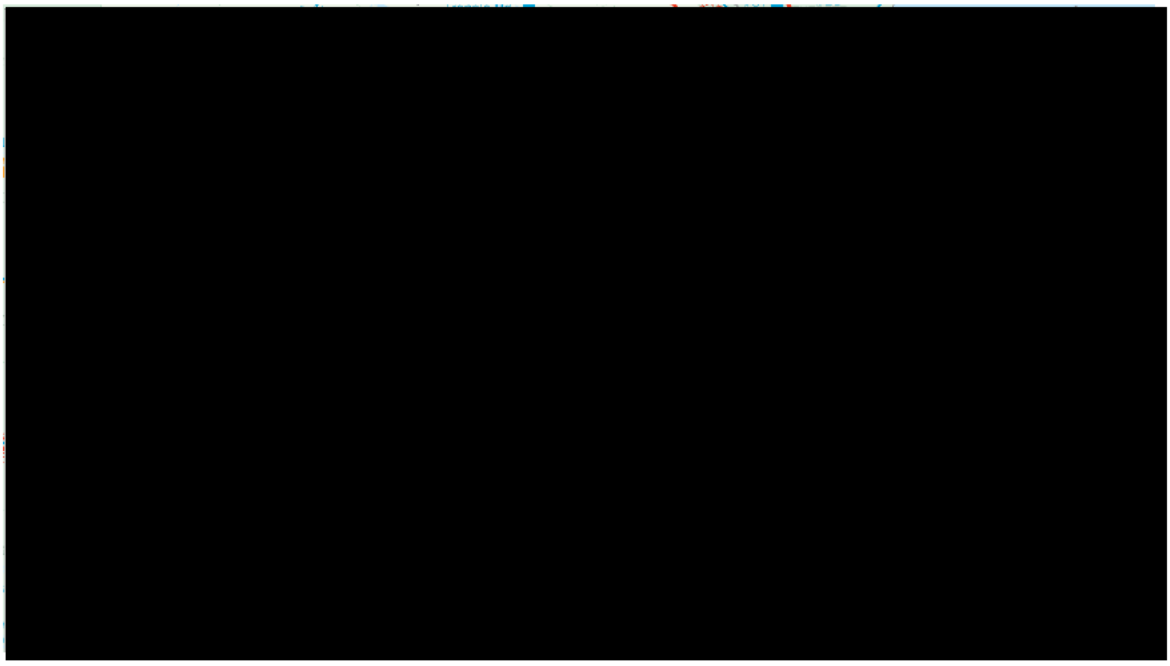


Figure 5-13 Subarea E N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea E

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-1	447-508/509	Holbrook – W. Walpole 115 kV	[redacted]	[redacted]	DES	118	125
			[redacted]	[redacted]	SEN	114	127
Loss of [redacted] overloads this line. The overload on this section of the line only occurs when Fore River generation in unavailable. Under retirement sensitivity case conditions loss of [redacted] overloads the Holbrook end of this line. Loadings above 100% of LTE are also STE violations for this line.							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	K Street autotrans formers	K Street 345 kV to 115 kV autotransformer #1 & #2	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	120	121
Loss of [redacted] results in overloads for these autotransformers in 2023. A different second contingency has the highest overloads for 2018 but both contingencies involve the loss of [redacted] The overloads only occur for the retirement scenario cases. Loss of [redacted] also overloads the autotransformers. Loadings above 110% of LTE are also STE violations for these transformers.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	3161	W. Walpole to Stoughton 345 kV	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	102	103
The loss of [redacted] overloads the 3161 line under retirement sensitivity case conditions. The combined loss of two northern import paths into Boston RSP subarea results in the overload of the southern lines which supply imports to Boston RSP subarea via [redacted] Other initial line out conditions that show overloads to a lesser degree include [redacted]							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	3162	Stoughton to K Street 345 kV	[redacted]	[redacted]	DES	None	101
			[redacted]	[redacted]	SEN	144	144
The loss of the [redacted] overloads the 3161 line. The combined loss of two northern import paths into Boston RSP subarea results in the overload of the southern lines which supply imports to Boston RSP subarea via [redacted].							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-4	3163	Stoughton to K Street 345 kV	[redacted]	[redacted]	DES	None	102
			[redacted]	[redacted]	SEN	146	146
The loss of [redacted] overloads the 3163 line. The combined loss of two northern import paths into Boston RSP subarea results in the overload of the southern lines which supply imports to Boston RSP subarea via [redacted].							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-5	Hyde Park autotransformer	Hyde Park 345 kV autotransformer #1	[redacted]	[redacted]	DES	107	108
			[redacted]	[redacted]	SEN	None	105
Loss of [redacted] result in overload of the Hyde Park autotransformer. Under retirement sensitivity case conditions loss of [redacted] also results on overload of these transformers. Loadings greater than 100% of LTE are also STE violations.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-6	282-602	W. Medway – Waltham 230 kV line	[redacted]	[redacted]	DES	None	104
					SEN	116	116
Loss of [redacted] results in an overload for this line. The combined loss of two import northern paths into Boston RSP subarea results in the overload of the all major import lines coming from the south.							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-6	456-522	W. Walpole to Dover 115 kV line	[redacted]	[redacted]	DES	None	None
					SEN	None	103
Loss of [redacted] results in an overload for this line under retirement sensitivity conditions. Loadings above 100% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-10	148-522XY	Dover to Needham 115 kV line	[redacted]	[redacted]	DES	None	112
			[redacted]	[redacted]	SEN	116	118
Loss of [redacted] overloads this line under design case conditions. Under retirement sensitivity case conditions loss of [redacted] overloads this line. However, the loadings are below STE and the overload can be mitigated by [redacted].							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
E-14	W. Medway 345A autotransformer	W. Medway 345 kV to 230 kV autotransformer	[redacted]	[redacted]	DES	None	None
					SEN	109	108
Loss of [redacted] overloads this autotransformer. The combined loss of two import northern paths into Boston RSP subarea results in the overload of the all major import lines coming from the south. This overload is only observed for the retirement cases.							

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Table 5-22 Worst Case Low Voltage Violations for Subarea E

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Norwood	115	[redacted]	[redacted]	None	None	None	0.9424
Walpole	115	[redacted]	[redacted]	None	None	None	0.9325
Baker Street	115	[redacted]	[redacted]	None	None	None	0.8080
Needham	115	[redacted]	[redacted]	None	None	None	0.8630
Medway	115	[redacted]	[redacted]	None	None	None	0.9334
Rocky Hill	115	[redacted]	[redacted]	None	None	None	0.9419
Hyde Park	115	[redacted]	[redacted]	None	0.9407	0.9398	0.8983
	115	[redacted]	[redacted]	None	None	None	0.8560
Dover	115	[redacted]	[redacted]	None	None	None	0.8936

Table 5-23 Worst Design Case High Voltage Violations for Subarea E

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Edgar	115	[redacted]	[redacted]		1.0604
Needham	115	[redacted]	[redacted]	1.0614	1.0617
Dover MA	115	[redacted]	[redacted]	1.0587	1.0588
Holbrook	345	[redacted]	[redacted]	1.0679	1.0789
	115	[redacted]	[redacted]		1.0632
Hyde Park	345	[redacted]	[redacted]	1.0867	
		[redacted]	[redacted]		1.0848
	115	[redacted]	[redacted]	1.0647	
		[redacted]	[redacted]		1.0663

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Stoughton	**345**	[redacted]	[redacted]	1.0852
		[redacted]	[redacted]	1.0835
Baker Street	**115**	[redacted]	[redacted]	1.0634
		[redacted]	[redacted]	1.0648
Canton	**115**	[redacted]	[redacted]	1.0569
West Medway	**230**	[redacted]	[redacted]	1.0572
East Weymouth	**115**	[redacted]	[redacted]	1.0607
Norwood	**115**	[redacted]	[redacted]	1.0569
South Randolph	**115**	[redacted]	[redacted]	1.0615
West Walpole	**345**	[redacted]	[redacted]	1.0554

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Subarea F - Boston, Golden Hills and Wakefield Junction Area



Figure 5-14 Subarea F N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea F

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-1	F-158N	Wakefield Junction – Maplewood 115 kV	[redacted]	[redacted]	DES	150	154
			[redacted]	[redacted]	SEN	182	208
Loss of [redacted] 023 results in an overload of this line. Under retirement sensitivity case conditions loss of [redacted] line also overload this line. Loadings above 106% of LTE are also STE violations. Under this outage scenario a significant amount of the flows on [redacted] will show up on the 115 kV lines feeding into the North Shore 115 kV system through [redacted]							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-2	F-158S	Maplewood – Everett 115 kV	[redacted]	[redacted]	DES	132	135
			[redacted]	[redacted]	SEN	162	184
Loss of [redacted] results in overloads of this line under design case conditions. Loadings above 107% of LTE are also STE violations. Loss of [redacted] ble results in an overload of this line under retirement sensitivity case conditions. Under this outage scenario a significant amount of the Boston imports from [redacted] is fed into the North Shore 115 kV system [redacted]. Substation. Loadings above 106% of LTE are also STE violations for this line.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-4	349 X/Y	Wakefield Junction – Mystic 345 kV Cables	[redacted]	[redacted]	DES	None	105
			[redacted]	[redacted]	SEN	113	123
Loss of [redacted] results in an overload of this line. Loadings above 123% of LTE are also STE violations.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
F-6	Q-169 (Section 2 in 2018) (section 3 in 2023)	Wakefield Junction – Lynn 115 kV line (Resco – Lynn section)	[redacted]	[redacted]	DES	110	116
			[redacted]	[redacted]	SEN	110	117
Loss of [redacted] results in an overload of this line under design case conditions and under 2018 retirement sensitivity case conditions. Under retirement sensitivity case conditions in 2023 loss of [redacted] result in overload of this line. Loadings above 105% of LTE are also STE violations.							

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Table 5-24 Worst Case Low Voltage Violations for Subarea F

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Golden Hills	115	[redacted]	[redacted]	None	None	None	0.8884
Wakefield Junction	115	[redacted]	[redacted]	None	None	None	0.9217
Melrose	115	[redacted]	[redacted]	None	None	None	0.8904
Maplewood	115	[redacted]	[redacted]	None	None	None	0.8350
Chelsea	115	[redacted]	[redacted]	0.8660	None	0.8509	0.8421
	115	[redacted]	[redacted]	None	None	None	0.8005
Revere	115	[redacted]	[redacted]	0.8742	None	0.8596	0.8507
	115	[redacted]	[redacted]	None	None	None	0.8053
Resco Saugus	115	[redacted]	[redacted]	None	None	None	0.8465
GE River	115	[redacted]	[redacted]	0.8983	None	0.8859	0.8770
	115	[redacted]	[redacted]	None	None	None	0.8214
Lynn	115	[redacted]	[redacted]	None	None	0.8975	0.8886
	115	[redacted]	[redacted]	None	None	None	0.8298

Table 5-25 Worst Design Case High Voltage Violations for Subarea F

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
Everett	115	[redacted]	[redacted]	1.0566	
		[redacted]	[redacted]		1.0575
Lynn	115	[redacted]	[redacted]		1.0564
Maplewood	115	[redacted]	[redacted]		1.0593
Wakefield	115	[redacted]	[redacted]B		1.0649
Golden Hills	115	[redacted]	[redacted]		1.0639

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Melrose	**115**	[redacted]	[redacted]	1.0639
Wakefield Junction	**345**	[redacted]	[redacted]	1.0746
	115	[redacted]	[redacted]	1.0664
GE River	**115**	[redacted]	[redacted] tor	1.0553
Resco-Saugus	**115**	[redacted]	[redacted]	1.0585

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Subarea H – 115 kV Lines Near Tewksbury



Figure 5-15 Subarea H N-1-1 Design Case (White) and Sensitivity (Shaded) Overloaded Elements

Thermal Violations for Subarea H

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-1	S-145E/T-146E	Railyard – Salem Harbor 115 kV	[redacted]	[redacted]	DES	129	129
			[redacted]	[redacted]	SEN	138	148
Loss of [redacted] es results in overload of the companion line. Reducing [redacted] prior to the second contingency would resolve this overload. This will not be treated as a need.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-1	S-145W/T-146W	N. Reading – Wakefield Junction. 115 kV	[redacted]	[redacted]	DES	117	129
			[redacted]	[redacted]	SEN	120	119
Loss of [redacted] results in overload of these lines in design cases. Under retirement sensitivity case conditions loss of [redacted] results in overloads on these lines. The design case overloads only							

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occur for [redacted] out of service. Loadings above 102% of LTE are also STE violations.

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-1	T-146	E. Tewksbury - Tewksbury 115 kV	[redacted]	[redacted]	DES	104	110
					SEN	None	None
Loss of [redacted] results in overload of these lines in design cases. The design case overloads only occur for [redacted] out of service. Loadings above 109% of LTE are also STE violations.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-2	M-139	Tewksbury – Pinehurst 115 kV	[redacted]	[redacted]	DES	121	127
			[redacted]	[redacted]	SEN	131	152
		Pinehurst – N. Woburn Tap 115 kV line section	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	101	124
Loss of [redacted] result in overloads for this line. Under retirement sensitivity case conditions for 2018 or loss of [redacted] result in overloads for this line. Loadings above 106% of LTE are also STE violations for this line.							

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Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-3	N-140 (211-504)	Tewksbury – Pinehurst 115 kV line section	[redacted]	[redacted]	DES	110	114
			[redacted]	[redacted]	SEN	115	135
		Pinehurst – N. Woburn Tap 115 kV line section	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	110	129
Loss of [redacted] results in overload of this line. The next section of this line also overloads for [redacted] under retirement sensitivity case conditions. Loadings above 106% of LTE are also STE violations.							

Ref	Element ID	Element Description	Element Out of Service	Contingency		2018 Loading	2023 Loading
H-5	K-137E/L138E	Sandy Pond to Littleton 115 kV line	N/A	N/A	DES	None	None
			[redacted]	[redacted]	SEN	116	116
Loss of [redacted] results in overloads on this line under retirement case scenario conditions. The loadings on K137E are around 116% and the loadings on the L138E are about 101%.							

Table 5-26 Worst Case Low Voltage Violations for Subarea H

Bus Name	Base kV	Element Out of Service	Contingency	2018		2023	
				DES	SEN	DES	SEN
Pinehurst	**115**	[redacted]	[redacted]	None	None	None	0.8718

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Table 5-27 Worst Design Case High Voltage Violations for Subarea H

Bus Name	Base kV	Element Out of Service	Contingency	Summer Off Peak	Min Load
King Street	115	[redacted]	[redacted]	1.0575	None
West Salem	115	[redacted]	[redacted]	1.0673	1.0575
Railyard	115	[redacted]	[redacted]B	1.0677	1.0564
Bartholomew	115	[redacted]	[redacted]B	1.0669	1.0593
Ipswich River	115	[redacted]	[redacted]	1.0629	1.0649
Middleton	115	[redacted]	[redacted]	1.0617	1.0639
South Danvers	115	[redacted]	[redacted]	1.0656	1.0639
Salem Harbor	115	[redacted]	[redacted]B	1.0677	1.0746
Woodchuck Hill	115	[redacted]	[redacted]	1.0607	1.0664

N-1/N-1-1 Load Isolation Conditions

There were a set of events that were noted as causing consequential load loss approaching or exceeding 300 MW of customer load. These are load pockets within the system that are only served by two transmission lines and the loss of both lines disconnects the load from the system. The following load pockets were identified in the Greater Boston area:

N-1 Load Interruption

- Norwood/Canton/South Randolph Load Pocket (within Subarea E)
  - Loss of [redacted] disconnects 313 MW of load in 2018 growing to 324 MW of load in 2023 (Due [redacted]

N-1-1 Load Interruption

- Sudbury Load Pocket (within Subarea D)
  - Loss of [redacted] disconnects 290 MW of load in 2018 growing to 298 MW of load in 2023 ([redacted])
- Revere/Chelsea Load Pocket (within Subarea F)

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- Loss of [redacted] disconnects 349 MW of load in 2018 growing to 357 MW of load in 2023 (Loss [redacted])

Divergent Case Conditions

Divergent cases occurred for a number of contingencies associated with 115 kV line outages in [redacted]. The following table provides the contingency pairs that resulted in non-convergent cases and the associated counts for the number of cases where each contingency pair resulted in non-convergence. A contingency pair with a count of 37 indicated that the particular contingency pair did not converge in any of the dispatches for a given year.

Table 5-28
2018 and 2023 Divergent Contingency Cases

Element Out of Service	Contingency	2018	2023
[redacted]	[redacted]T	0	2
[redacted]	[redacted]B	23	23
[redacted]	[redacted]	36	37
	[redacted]	37	37
	[redacted]	37	37
	[redacted]	37	37
	[redacted]	36	37
	[redacted]	34	37
	[redacted]	37	37
[redacted]	[redacted]	33	31
	[redacted]	37	36
	[redacted]	36	35
	[redacted]	34	29
	[redacted]	36	34
	[redacted]	30	37
	[redacted]	23	22
	[redacted]	36	36
	[redacted]	37	37
	[redacted]	34	31
	[redacted]	30	36
[redacted]	[redacted]	14	0
	[redacted]B	7	1
	[redacted]	7	0
[redacted]	[redacted]SB	1	1
	[redacted]	23	1
	[redacted]	1	1

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5.3 Stability Performance Criteria Compliance

Not applicable for this study.

5.3.1 Stability Test Results Summary

Not applicable for this study.

5.4 Short Circuit Performance Criteria Compliance

The short circuit breaker duty evaluation was performed for the 2018 model year. This assessment considers the short circuit fault duty seen by individual breakers for worst case faults under the modeled conditions. The modeled condition includes assumptions concerning breaker interrupting characteristics as well as assumptions concerning dispatch of generation is running. Breakers exceeding 100% fault duty are in violation of reliability standards.

5.4.1 Short Circuit Test Results Summary

Table 5-29 shown below is a summary of the results of a breaker evaluation study that considered the worst case breaker fault duty for each breaker in the study area as compared to the breaker's rated interrupting capability. The values shown in Appendix H are based on 2018 model conditions and show values in percent of breaker capability ratings.

Table 5-29 2018 Greater Boston Area Stations with Over Duty Breakers

Station	Breaker Duty
Mystic 115 kV	[redacted]
Kingston 115 kV	[redacted]
Brighton 115 kV	[redacted]
K Street 115 kV	[redacted]
West Medway 345 kV	[redacted]
Salem Harbor 115 kV	[redacted]
Wakefield Junction 115 kV	[redacted]

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Section 6
Conclusions on Needs Analysis

The results of the assessment conducted of the Greater Boston area transmission performance against transmission reliability standards for the projected 2018 and 2023 system conditions in this study indicate that there are a significant number of thermal and voltage violations across a number of subareas within the Greater Boston system. The Greater Boston area transmission system fails to meet established reliability criteria standards, and measures should be developed to mitigate the problems identified. The study has determined the specific year in which violations first emerge and based on this information system upgrades necessary to mitigate these violations in criteria should be implemented as soon as practical.

The specific set of criteria and standards that the transmission system serving Greater Boston fails to meet includes the following:

- NERC Reliability Standards TPL-001-4 Category P1, P2, P3, P4, and P6 performance requirements.
- NPCC Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System Section 5.4 Transmission Design Criteria requirements.
- ISO New England Planning Procedure No. 3 Reliability Standards For The New England Area Bulk Power Supply System Section 3.0 Area Transmission requirements.

6.1 Year of Need Assessment

An assessment of the initial year and load level that the system fails to meet the established criteria was performed based on evaluation of thermal overload conditions. This evaluation was performed for N-1 overloads and N-1-1 overloads under design case conditions. The process used was based on a linear projection of the load level at which overloaded elements first fail to meet criteria. The projection for each element with a thermal violation was derived by comparing the 2018 loading to the 2023 loading for specific contingency and dispatch conditions that resulted in the worst case thermal violation to establish a rate of change in loading. This rate of change was then used to calculate the load level at which an overload would first be seen. This process provides an approximation of when contingency based loading on specific elements will reach a threshold level and actual overloads may occur earlier or later than the results indicate. The results of this analysis are shown in Table 6-1 and Table 6-2 below. Please note that transmission cables that operate as a cable pair where both cables are overloaded only report loading data for the highest loaded element as these values were used in determining the year of need. The year of need is based on the loads for the Boston RSP subarea and the values shown in Tables 6-1 and 6-2 below represent the Boston RSP subarea loads.

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Table 6-1 Greater Boston N-1 Year of Need Assessment

Greater Boston Area N-1 Testing Year of Need Calcuation Results							
				LTE Loading for Year		Year of	Critical
Sub-Area	Element ID	Monitored Element	LTE Rating	Contingency	2018	2023	Need	Load Level
A-3	394	104127 SEABROOK 345 104128 NU_394_SBK 345 1	[redacted]	1	111	113	Pre-2013	4680
B-2	WOBURN 345A XFMR	110799 WOBURN 115 110756 WOBURN 345 1	[redacted]		105	109	2013	6463
B-3	533-508	110805 HARTWELL 115 110806 LEXINGTON 115 1	[redacted]		100	104	2018	6868
B-5	211-514	110799 WOBURN 115 110820 MYSTIC GIS 115 1	[redacted]		195	204	Pre-2013	2740
B-6	282-520 / 282-521	110811 WATERTWN 520 115 903019 282-520_BRTN 115 1A	[redacted]		128	131	Pre-2013	4075
C-1	329-510 / 329-511	110816 SOMERVIL 510 115 903025 329-510_MYST 115 1B	[redacted]		109	113	Pre-2013	5930
C-3	385-511	110832 KINGSTN ST A 115 903039 385-511_HIGH 115 1A	[redacted]		115	120	Pre-2013	5690
C-4	250-516 / 250-517	110818 MYSTIC MA 115 903013 250-516_HAWK 115 1B	[redacted]		141	141	Pre-2013	N/A
C-5	110-510 / 110-511	110854 WASH_TAP 510 115 903006 110-510_BAKR 115 1A	[redacted]		120	113	2032	7856
C-7	324 / 372	110766 KINGSTON ST 345 903005 372_MYST 345 2B	[redacted]		115	116	Pre-2013	N/A
D-1	W-23	113332 FITCH ROAD 69.0 114785 WOODSIDE 69.0 1	[redacted]		100	105	2018	6858
D-3	W-23W	114779 MWRA_W23W 69.0 114780 NBORO_W23W 69.0 1	[redacted]		113	119	Pre-2013	6003
E-1	447-508	110900 HOLBROOK 115 114765 S RANDLPH508 115 1	[redacted]		108	111	Pre-2013	5776
H-2	M139	113969 BILERCA 39_T 115 113987 TEWKSBURY 115 1	[redacted]		99	101	2020	6986

Table 6-2 Greater Boston N-1-1 Year of Need Assessment

Greater Boston Area N-1-1 Testing Year of Need Calcuation Results									
							LTE Loading for Year		Year of	Critical Load
Sub-Area	Element ID	Monitored Element	LTE Rating	Units Out	Line Out	Contingency	2018	2023	Need	Level (MW)
A-10	I135	104990 FITZWILLIAM 115 105001 NU_I135_NGR 115 1	[redacted]	1-2 Units	LN_394	[redacted]	101	107	2017	6789
A-13	N214	106013 N.LITCHFLD2 230 113955 TEWKSBURY 230 1		1-2 Units	LN_394		107	111	2021	7021
A-2	337	113950 SANDY POND 345 113951 TEWKSBURY 345 1		1-2 Units	GN_MYS9_CC_TIE_CLSD		103	109	2021	7082
A-3	394	104127 SEABROOK 345 104128 NU_394_SBK 345 1		1-2 Units	GN_MYS9_CC_TIE_CLSD		105	107	Pre-2013	5880
A-5	SANDY POND XFMR#1	113950 SANDY POND 345 114027 SANDY PD T1 99.0 1		1-2 Units	LN_394		133	136	Pre-2013	3347
A-8	A253	104111 MERRIMACK 230 104113 NU_A253_NGR 230 1		1-2 Units	LN_394		118	124	Pre-2013	5689
A-9	B202S	106011 DUNBARTAN TP 230 106013 N.LITCHFLD2 230 1		1-2 Units	LN_394		108	113	Pre-2013	6305
B-1	391-508	110804 BURLINGTN MA 115 110805 HARTWELL 115 1		1-2 Units	TF_WOBRN_345A		112	124	Pre-2013	6424
B-2	WOBURN 345A XFMR	110799 WOBURN 115 110756 WOBURN 345 1		1-2 Units	LN_533-508		150	158	Pre-2013	4462
B-3	533-508	110805 HARTWELL 115 110806 LEXINGTON 115 1		1-2 Units	TF_WOBRN_345A		152	167	Pre-2013	5563
B-5	211-514	110799 WOBURN 115 110820 MYSTIC GIS 115 1		1-2 Units	TF_KING_345B		266	277	Pre-2013	879
B-6	282-520 / 282-521	110811 WATERTWN 520 115 903019 282-520_BRTN 115 1B		1-2 Units	LN_282-521		204	216	Pre-2013	3586
B-7	351 / 358	110759 MYSTIC MA 345 903003 358_NCAMB 345 1B		1-2 Units	LN_338		141	146	Pre-2013	3500
B-8	346 / 365	110758 N. CAMBRIDGE 345 903000 346_WOBURN 345 1B		1-2 Units	LN_339		151	151	Pre-2013	N/A
C-1	329-510 / 329-511	110813 BRIGHTON A 115 903026 329-510 SOMR 115 1B		1-2 Units	LN 329-511		126	145	Pre-2013	6318
C-2	329-512 / 329-513	110830 KINGSTN ST W 115 903031 329-512_CARV 115 1B		1-2 Units	LN_385-512		121	126	Pre-2013	5212
C-3	385-510 / 385-511	110832 KINGSTN ST A 115 903039 385-511_HIGH 115 1A		1-2 Units	TF_MYST_345A		162	168	Pre-2013	2903
C-3	385-513	110830 KINGSTN ST W 115 903042 385-513 KST 115 2B		1-2 Units	LN 329-512		143	146	Pre-2013	1945
C-4	250-516 / 250-517	110842 CHATHAM 516 115 903015 250-516_KST 115 1B		1-2 Units	LN_250-517		135	141	Pre-2013	4181
C-5	110-510 / 110-511	110854 WASH_TAP 510 115 903006 110-510_BAKR 115 1A		1-2 Units	LN_3164		141	148	Pre-2013	4683
C-7	324 / 372	110766 KINGSTON ST 345 903004 324 MYST 345 1B		1-2 Units	LN 372		117	119	Pre-2013	3182
C-8	329-530 / 329-531	110815 N. CAMBRIDGE 115 903036 329-531_BRTN 115 1B		1-2 Units	TF_NCAM_345B		129	135	Pre-2013	4998
D-1	W-23	113332 FITCH ROAD 69.0 114785 WOODSIDE 69.0 1		1-2 Units	LN_455-507		213	213	Pre-2013	N/A
D-2	E157	113271 WYMNGRDN57 T 115 113275 E157 M165 J 115 1		1-2 Units	LN 455-507		131	136	Pre-2013	4227
D-3	W-23W	114779 MWRA_W23W 69.0 114780 NBORO_W23W 69.0 1		1-2 Units	LN_455-507		265	265	Pre-2013	N/A
D-4	X-24W	113339 N GRAFTON 69.0 114784 WESTBORO 69.0 1		1-2 Units	LN_E157W-W		184	185	Pre-2013	N/A
D-5	433-507	110870 FRAMINGHAM 115 110871 SPEEN STREET 115 1		1-2 Units	LN 394		136	137	Pre-2013	N/A
D-6	282-507	110810 WALTHAM PS 115 110872 SUDBURY 115 1		1-2 Units	TF_WMED_345B		105	110	Pre-2013	6429
D-7	240-508	110868 SHERBORN 115 110870 FRAMINGHAM 115 1		1-2 Units	LN_394		108	108	Pre-2013	2102
D-7	274-509	110866 MEDWAY 115 110868 SHERBORN 115 1		1-2 Units	LN_E157W-W		101	106	2017	6758
D-7	455-507	110868 SHERBORN 115 110869 W FRAMINGHAM 115 1		1-2 Units	LN_E157W-W		132	137	Pre-2013	4406
D-7	513-507	110869 W FRAMINGHAM 115 115027 NG513-507NST 115 1		1-2 Units	LN_E157W-W		106	111	Pre-2013	6348
D-9	N-40 A&B	113332 FITCH ROAD 69.0 113346 PRATTS JCT 69.0 1		1-2 Units	LN_455-507		126	127	Pre-2013	N/A
E-1	447-508 / 447-509	110895 WEST WALPOLE 115 110897 WALPOLE 509 115 1		1-2 Units	LN_451-536		118	125	Pre-2013	5885
E-4	3162	110862 K STREET 2 345 903062 3162_STGTN 345 1A		1-2 Units	LN_394		98	101	2021	7090
E-4	3163	110790 K STREET 1 345 903063 3163_STGTN 345 1A		1-2 Units	LN_394		99	102	2020	6946
E-5	HYDE PARK 345A XFMR	110791 HYDE PARK 115 110788 HYDE PARK 345 1		1-2 Units	LN_394		107	108	Pre-2013	5150
E-6	282-602	110789 WALTHAM 230 110794 W MEDWAY A 230 1		1-2 Units	LN_394		99	104	2019	6910
F-1	F158N	114410 GOLDNHL45-58 115 114412 MAPLEWOOD 115 1		1-2 Units	LN_349XY-1		150	154	Pre-2013	1895
F-2	F158S	114409 EVERETT 115 114412 MAPLEWOOD 115 1		1-2 Units	LN 349XY-1		132	135	Pre-2013	2736
F-4	349 XY	110759 MYSTIC MA 345 115017 NGR_349X_NST 345 1		1-2 Units	TF_WALTHM_PS		99	105	2019	6898
F-6	Q169	114430 GE RIVER69_T 115 114448 LYNN Q169 115 1		1-2 Units	LN_488-518		110	116	Pre-2013	6082
H-1	T146-1	113974 E TWKSBRY_46 115 113987 TEWKSBURY 115 1		1-2 Units	LN_349XY-1		104	110	2015	6577
H-1	S145E	114405 RAILYARD_45 115 114417 SALEM HARBOR 115 1		1-2 Units	LN_T146E		129	129	Pre-2013	N/A
H-1	T146W	113999 N READING 46 115 114485 WAKEFLD146 115 1		1-2 Units	LN 349XY-1		117	129	Pre-2013	6242
H-2	M139	113969 BILERCA 39_T 115 113987 TEWKSBURY 115 1		1-2 Units	LN_N140_504		121	127	Pre-2013	5405
H-3	N140	113962 PINEHURST 115 113987 TEWKSBURY 115 1		1-2 Units	LN_M139_503		110	114	Pre-2013	5991

Table 6-1 and Table 6-2 Notes:

1. Critical Load Level is a linear projection of the Boston RSP subarea load level for which the thermal violation first appears.

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2. Year of Need was limited to 2013 to capture the fact that system changes such as generation retirements and transmission system adjustments make linear projects before 2013 meaningless.

3. N/A was used for critical load level when the 2013 and 2018 facility loadings were approximately the same. A linear projection between two approximately identical points renders the result meaningless.

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Section 7
Appendix A: Load Forecast

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Table 7-1 2013 CELT Load Forecast

1.6 - Seasonal Peak Load Forecast Distributions

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2013	26470	26715	27045	27420	27840	28285	28735	29385	30135	30790
	2014	26900	27150	27485	27865	28290	28740	29200	29860	30620	31280
	2015	27410	27665	28005	28390	28825	29285	29750	30425	31185	31860
	2016	27910	28165	28515	28910	29350	29815	30295	30980	31740	32420
	2017	28325	28590	28940	29340	29790	30265	30750	31445	32210	32900
	2018	28675	28940	29295	29700	30155	30635	31125	31830	32615	33315
	2019	29025	29295	29655	30065	30525	31010	31505	32220	33010	33720
	2020	29345	29615	29980	30395	30860	31350	31855	32575	33380	34095
	2021	29670	29950	30315	30735	31205	31700	32210	32935	33755	34480
	2022	29970	30250	30625	31045	31520	32020	32535	33270	34105	34840
	WTHI (1)	**78.49**	**78.73**	**79.00**	**79.39**	**79.88**	**80.30**	**80.72**	**81.14**	**81.96**	**82.33**
	Dry-Bulb Temperature (2)	**88.50**	**88.90**	**89.20**	**89.90**	**90.20**	**91.20**	**92.20**	**92.90**	**94.20**	**95.40**
	Probability of Forecast Being Exceeded	**90%**	**80%**	**70%**	**60%**	**50%**	**40%**	**30%**	**20%**	**10%**	**5%**
Winter (MW)	2013/14	22025	22140	22235	22295	22445	22595	22765	22865	23080	23505
	2014/15	22205	22320	22420	22480	22630	22780	22955	23055	23255	23685
	2015/16	22385	22500	22595	22660	22810	22960	23135	23235	23440	23870
	2016/17	22540	22660	22755	22815	22970	23125	23295	23400	23620	24050
	2017/18	22680	22795	22895	22955	23110	23265	23440	23540	23780	24205
	2018/19	22800	22920	23020	23080	23235	23390	23565	23670	23920	24345
	2019/20	22915	23035	23130	23195	23350	23505	23685	23785	24045	24470
	2020/21	23030	23150	23250	23315	23470	23625	23805	23910	24160	24590
	2021/22	23145	23265	23365	23425	23585	23745	23920	24025	24280	24705
	2022/23	23255	23380	23480	23540	23700	23860	24040	24145	24395	24820
	Dry-Bulb Temperature (3)	**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

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Section 8
Appendix B: Upgrades Included in Base Case and Short Circuit Model

Table 8-1
Upgrades Included in Base Case Models

Maine	
Maine Power Reliability Program	MPRP - RSP ID: 1401-1472
Down East Reliability Improvement	RSP ID: 14
New Hampshire	
Second Deerfield 345/115 kV autotransformer Project	RSP ID: 277, 1137-1141
Rebuild Bellows Falls substation	RSP ID: 680
Western New Hampshire Solution	RSP ID: 1269-1275, 1346
Northern New Hampshire Solution	RSP ID: 1263, 1276
Central New Hampshire Solution	RSP ID: 1277-1278, 1300
Southern New Hampshire Solution	RSP ID: 1301-1304, 1306-1314, 1376, 1379
Seacoast New Hampshire Solution	RSP ID: 1316-1325
Massachusetts	
Auburn Area Transmission System Upgrades	RSP ID: 59, 887, 921, 919
Merrimack Valley / North Shore Reliability Project	RSP ID: 775-776, 782-783, 840
Long Term Lower SEMA Upgrades	RSP ID: 592, 1068, 1118. 1349-1351
Central/Western Massachusetts Upgrades	RSP ID: 924- 929, 931-932, 934-935, 937-950, 952- 955
NEEWS – Greater Springfield Reliability Project	RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105
Advanced NEEWS Interstate Projects	RSP ID: 1202, 1342
NEEWS – Interstate Reliability Project	RSP ID: 190, 1094, 1293
Salem Harbor Retirement Upgrades	RSP ID: 1257-1259
Rhode Island	
Greater Rhode Island Transmission Reinforcements	RSP ID: 484, 786, 788, 790-793, 913-918, 1098
NEEWS – Rhode Island Reliability Project	RSP ID: 795, 798-800, 1096-1097, 1099, 1106, 1109, 1331
NEEWS – Interstate Reliability Project	RSP ID: 794, 1233-1234, 1252, 1294-1298
Chase Hill	Crandall Street Substation RSP ID: 1253

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Connecticut	
NEEWS – Greater Springfield Reliability Project	RSP ID: 816, 1054, 1369-1371, 137
NEEWS – Interstate Reliability Project	RSP ID: 191, 802, 810, 1085, 1090-1091, 1235
Advanced NEEWS Interstate Projects	RSP ID: 1235, 1245
Northeast Simsbury Substation 115 kV Circuit Breaker Project	RSP ID: 1230
Millstone 345 kV Circuit Separation & SLOD SPS System Retirement	RSP ID: 1218
Line 1990 Asset Condition Replacement Project	RSP ID: 1229

Table 8-2 Model Changes Included in the 2017Short Circuit Base Case

File Name	Change
2017 MASTER CASE 20130624-Starting Case for Update(No Brkrs).OLR	Original 2013 base case sent out for review on 6/20/2013
2017 MASTER CASE 20130624-Add RIRP, CCRP, IRP&GSRP-01(No Brkrs).OLR	Added all NEEWS projects including: • IRP (Card-Lake Road 3271 line, Lake Road-West Farnum 341 line) • RIRP (West Farnum-Kent County 359 line, 3rd Kent County auto, reconductor G185, S171S, T172S) • CCRP (North Bloomfield-Frost Bridge 3208 line, 2nd Frost Bridge auto, reconductor 3533, add 2nd Beseck shunt reactor • GSRP (Ludlow-Agawam 3196 line, Agawam-North Bloomfield 3216 line, Manchester-North Bloomfield 3642 line, reconfigure 395 line, add 2 Agawam autos, 2nd North Bloomfield auto, build/reconductor 1230, 1314,1426, 1481, 1552, 1723, 1904, 1254, 1702, 1803, 1601, 1768/1821, 1781, 1782, 1845, 1556, 1645, 1784 lines). Note that these changes were already in the case, but were not in service. Added West Walpole-Carver line
2017 MASTER CASE 20130624-Add MPRP-02(Mystic, Kingston& WMedway Breakers).OLR	• Added entire MPRP project • Updated ANP Bellingham and Blackstone GSU impedances and 336/3361 line impedances
2017 MASTER CASE 20130624-ADD OTHER SEMA & RI UPDATES-03(Boston Area Breakers).OLR	• Added Medway peakers • Added Everett peakers • Added Plainfield CT gen • Placed Cape Wind in service with Kingston-Auburn and Kingston-Brook Street 115 kV line upgrades • Added replacement Holbrook auto
2017 MASTER CASE 20130630-Additional Gen Projects-04(BOSTON AREA BREAKERS).OLR	• Added Towantic QP384 • Added Brockton CC QP178 • Added Northfield uprates • Added Palmer Renewable QP273 • Added NH Laidlow Berlin Biomass QR251

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2017 MASTER CASE 20130701-Additional Transmission Projects-05(BOSTON AREA BREAKERS).OLR	• Added Salem Harbor RSP projects • Added Pittsfield-Greenfield Solution projects • Added National Grid Central Western MA projects
2017 MASTER CASE 20130702-06(NATIONAL GRID & NSTAR BRKRS).OLR	Removed Peabody generator
2017 MASTER CASE 20130806-07(NATIONAL GRID & NSTAR BRKRS).OLR	Corrected all Mystic GSU transformer zero-sequence impedances
2017 MASTER CASE 20130829-08(NATIONAL GRID & NSTAR BRKRS).OLR	• Removed AES Thames generator and GSU • Updated New Brunswick Equivalent (Note: The two equivalent sources were inadvertently omitted from this equivalent.) • Updated New York Equivalent • Corrected the Torrington terminal 115/69-kV autotransformer impedance (replacement) • Reconnected the A. L. Pierce generator at Wallingford that was inadvertently disconnected • Revised the Devon-Trumbull 1730 line impedances to match NX-9 data.
2017 MASTER CASE 20131117-09(NATIONAL GRID & NSTAR BRKRS).OLR	Corrected New Brunswick equivalent to add the two equivalent sources that were inadvertently omitted from Rev-08.

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Section 9
Appendix C: Case Summaries and Load Flow Plots

Select the following link to open the case summary file: [redacted]

Select the following link to open the case summary file: [redacted]

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Section 10
Appendix D: Generation Dispatch and Reactive Resources

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Table 10-1
2023 Greater Boston Area Generation Dispatch Summary

BusName	LFCaseName [redacted]
BOOTT HYDRO	
CANAL G1	
CANAL G2	
CPC LOWELL	
EDGAR GT1	
EDGAR GT2	
EDGAR ST	
FRAMINGHAM	
GE RIVER R&T	
GE RIVER S&U	
IPSWICH DSL	
KENDALL CT	
KENDALL JET	
L STREET JET	
LAWRENCE HYD	
LENERGIA CT	
LENERGIA ST	
MALDEN MLS_T	
MARBLEHEAD A	
MARBLEHEAD B	
MATEP 3	
MATEP_CC	
MATEP_DIESEL	
MBTA	
MYSTIC 7GT	

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BusName	[redacted]
MYSTIC 8ST	
MYSTIC 9ST	
MYSTIC GT 8A	
MYSTIC GT 8B	
MYSTIC GT 9A	
MYSTIC GT 9B	
MYSTIC JET	
NEWINGTON_G1	
NEWINGTON_S1	
OGDEN-MARTIN	
PERRY ST 3	
PILGRIM	
PUTNAM 2	
QP 387-2 5CT	
QP 387-2 5ST	
QP 387-2 6CT	
QP 387-2 6ST	
RESCO-SAUGUS	
SEABROOK_G1	
W MEDWAY J3	
W MEDWAY JET	
WATERS RVRJ1	
WATERS RVRJ2	
YARMOUTH #4	

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	LFCaseName
BusName	[redacted]
BOOTT HYDRO	
CANAL G1	
CANAL G2	
CPC LOWELL	
EDGAR GT1	
EDGAR GT2	
EDGAR ST	
FRAMINGHAM	
GE RIVER R&T	
GE RIVER S&U	
IPSWICH DSL	
KENDALL CT	
KENDALL JET	
L STREET JET	
LAWRENCE HYD	
LENERGIA CT	
LENERGIA ST	
MALDEN MLS_T	
MARBLEHEAD A	
MARBLEHEAD B	
MATEP 3	
MATEP_CC	
MATEP_DIESEL	
MBTA	
MYSTIC 7GT	

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BusName	[redacted]
MYSTIC 8ST	
MYSTIC 9ST	
MYSTIC GT 8A	
MYSTIC GT 8B	
MYSTIC GT 9A	
MYSTIC GT 9B	
MYSTIC JET	
NEWINGTON_G1	
NEWINGTON_S1	
OGDEN-MARTIN	
PERRY ST 3	
PILGRIM	
PUTNAM 2	
QP 387-2 5CT	
QP 387-2 5ST	
QP 387-2 6CT	
QP 387-2 6ST	
RESCO-SAUGUS	
SEABROOK_G1	
W MEDWAY J3	
W MEDWAY JET	
WATERS RVRJ1	
WATERS RVRJ2	
YARMOUTH #4	

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BusName	LFCaseName
BOOTT HYDRO	[redacted]
CANAL G1	
CANAL G2	
CPC LOWELL	
EDGAR GT1	
EDGAR GT2	
EDGAR ST	
FRAMINGHAM	
GE RIVER R&T	
GE RIVER S&U	
IPSWICH DSL	
KENDALL CT	
KENDALL JET	
L STREET JET	
LAWRENCE HYD	
LENERGIA CT	
LENERGIA ST	
MALDEN MLS_T	
MARBLEHEAD A	
MARBLEHEAD B	
MATEP 3	
MATEP_CC	
MATEP_DIESEL	
MBTA	
MYSTIC 7GT	

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BusName	[redacted]
MYSTIC 8ST	
MYSTIC 9ST	
MYSTIC GT 8A	
MYSTIC GT 8B	
MYSTIC GT 9A	
MYSTIC GT 9B	
MYSTIC JET	
NEWINGTON_G1	
NEWINGTON_S1	
OGDEN-MARTIN	
PERRY ST 3	
PILGRIM	
PUTNAM 2	
QP 387-2 5CT	
QP 387-2 5ST	
QP 387-2 6CT	
QP 387-2 6ST	
RESCO-SAUGUS	
SEABROOK_G1	
W MEDWAY J3	
W MEDWAY JET	
WATERS RVRJ1	
WATERS RVRJ2	
YARMOUTH #4	

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Table 10-2
Shunt Reactive Resources at 69 kV and Above for the Greater Boston Area

Greater Boston Needs Assessment Shunt Compensation Table											
Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive
3RIVERSN13_C	115	0	61.1	HEYWOOD RD_C	115	0	20	QUAKER HILL	115	0	5.4
AGAWAM_C	115	0	100.8	HG_CONVRTR_N	120	0	154	RAYMOND	115	0	5.4
AMHERST_C	345	0	50	HG_CONVRTR_S	115	0	140	REVERE_C	115	0	30
AMHERST_C	115	0	14.4	HYANNIS J_C	115	0	39	RILEY_C	115	0	30
AUGUSTA EAST	115	0	5.4	JACKMAN_C	115	0	26.68	ROCKY RIVR_C	115	0	25.2
BAKER ST_C1	115	0	53.6	K STREET 1_C	115	0	53.6	RUMFORD IP_C	115	0	25
BAKER ST_C2	115	0	53.6	K STREET 1_R	345	-89.42	0	S.GORHAM_C1	115	0	50
BARNSTABLE_C	115	0	35.3	K STREET 2_C	115	0	53.6	S.GORHAM_C2	115	0	50
BEAR SWP CAP	115	0	50	K STREET 2_R	115	-76	0	SACKETT_C	115	0	42
BEEBERIVER_C	115	0	39.9	K STREET 2_R	345	-89.42	0	SALEM HBR_C1	115	0	63
BELFAST	115	0	10.8	KEENE ROAD_C	115	0	15	SALEM HBR_C2	115	0	63
BELLOWSFLS_C	115	0	30	KENT CO._C2	115	0	63	SANDBAR_C	115	0	24.75
BERLIN CT_C	115	0	126	KENT CO._C56	115	0	144	SANFORD_C	115	0	30.6
BERLIN VT_C	115	0	24.75	KIMBALL RD_C	115	0	60	SCHILLER_C1	115	0	53.2
BRANDFORD_C	115	0	37.8	LARRABEE_C	115	0	30	SCHILLER_C2	115	0	53.2
BRUDIES ROAD	69	0	5.4	LEXINGTON_C	115	0	53.6	SEWALL ST	115	0	10.8
CANTON_C	115	0	50.4	LEXINGTON_R	345	-159.42	0	SINGER3165_R	345	-50	0
CAPE	115	0	10.8	LUDLOW_C	345	0	240	SINGER3280_R	345	-50	0
CAPE WIND_R1	115	-35	0	LYNDONVIL_C1	115	0	12.5	SINGER3619_R	345	-50	0

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Greater Boston Needs Assessment Shunt Compensation Table											
Bus Name	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**
CAPE WIND_R2	115	-35	0	LYNDONVIL_C2	115	0	12.5	SINGER3921_R	345	-50	0
CAPE WIND_R3	115	-35	0	MADBURY_C	115	0	53.34	SNDYPD HVDC1	345	-160	279
CAPE WIND_R4	115	-35	0	MAGUIRE RD_C	115	0	50.86	SNDYPD HVDC2	345	-320	279
CHELSEA_C	115	0	36.7	MANCHESTR_C1	115	0	151.2	SOUTHNGTN1_C	115	0	151.2
CHESTNUTHI_C	115	0	48.88	MANCHESTR_C2	115	0	151.2	SOUTHNGTN2_C	115	0	151.2
COOLIDGE_C1	115	0	25	MASHPEE_C	115	0	35.3	STARKS_C	115	0	36
COOLIDGE_C2	115	0	25	MASON_C1	115	0	50	STONY HIL_C1	115	0	25.2
COOLIDGE_R1	345	-59.92	0	MASON_C2	115	0	50	STONY HIL_C2	115	0	75.6
COOLIDGE_R2	345	-59.92	0	MERRIMACK_C	115	0	73.34	STOUGHTON_R1	345	-89.42	0
COOPER ML_C1	115	0	50	MERRIMACK_C2	115	0	36.67	STOUGHTON_R2	345	-89.42	0
COOPER ML_C2	115	0	50	MIDDLEBURY_C	115	0	22.9	STOUGHTON_R3	345	-89.42	0
CROWLEYS_C	115	0	50	MILLBURY_C1	115	0	63	STOUGHTON_R4	345	-159.42	0
CUMBERLAND_C	115	0	14.4	MILLBURY_C3	115	0	63	SUDBURY_C	115	0	49.47
DARIEN_C	115	0	37.8	MONROE_C1	230	0	63	SUROWIEC_C1	115	0	50
DETROIT	115	0	4.5	MONROE_C2	230	0	63	SUROWIEC_C2	115	0	50
DEVENS 1	69	0	3.6	MONTVILLE_C	115	0	100.8	SUROWIEC_C3	115	0	50
DEVENS 2	69	0	3.6	MOSHERS	115	0	10.8	TEWKSBURY_C1	115	0	63
DOVER MA_C	115	0	53.6	MYSTIC CT_C	115	0	50.4	TEWKSBURY_C2	115	0	63
E SHORE_C1	115	0	42	MYSTIC_C	115	0	53.6	TRENTON_C	115	0	10
E SHORE_C2	115	0	42	MYSTIC_R	115	-76	0	VERNON VT_R	345	-60	0
EAGLE_C1	115	0	50	MYSTIC_R	345	-159.42	0	VT YANKEE_C	115	0	60
EAGLE_C2	115	0	50	N CAMBRDG_R1	115	-76	0	W FRMNGHAM_C	115	0	54.4

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Greater Boston Needs Assessment Shunt Compensation Table											
Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive	Bus Name	Voltage (kV)	Min Reactive	Max Reactive
EDGAR_R1	115	-40	0	N CAMBRDG_R2	115	-76	0	W RUTLAND_C1	115	0	25
EDGAR_R2	115	-40	0	N RUTLAND_C	115	0	24.75	W RUTLAND_C2	115	0	25
ELM STREET	115	0	6	N.CAMBRIDG_R	345	-159.42	0	W RUTLAND_X	345	-60	0
EPPING TAP_C	115	0	10	N-BLOOMFLD_C	115	0	151.2	W.WALPOLE_R	345	-159.42	0
ESSEX_C34	115	0	24.3	NEW HAVEN_R	345	-59.92	0	WATERSIDE_C	115	0	37.8
ESSEX_C35_36	115	0	48.6	NORWALK-JC_R	345	-75.02	0	WEARE_C	115	0	26.6
ESSEX_C37	115	0	24.3	NORWALK-JD_R	345	-75.02	0	WEBSTER_C1	115	0	53.34
ESSEX_C38	115	0	24.3	NORWAY	115	0	7.2	WEBSTER_C2	115	0	53.34
ESSEX_C39	115	0	24.3	NORWLK3280_R	345	-50	0	WHITE LAKE_C	115	0	20
FALMOUTH T_C	115	0	35.3	NORWLK3921_R	345	-50	0	WILLISTON_C	115	0	25.2
FRAMINGHAM_C	115	0	53.6	NRTH HAVEN_C	115	0	42	WINGLANE_C	115	0	35.3
FRANKLIN-D_C	115	0	37.8	NTHBORO RD_C	115	0	54	WOBURN_R1	115	-76	0
FRANKLN SQ_C	115	0	63	NTHBORO RD_C	69	0	72	WOBURN_R2	115	-76	0
FROST BRG_C1	115	0	151.2	OAK HILL_C	115	0	26.66	WOBURN_R3	115	-76	0
FROST BRG_C2	115	0	100.8	OCEANRDE19_C	115	0	24.44	WOODLAND_C	115	0	28.8
GEORGIA_TP_C	115	0	24.75	OCEANRDU18_C	115	0	24.44	WYMAN HYD_C	115	0	36
GLENBROOK_C1	115	0	172.8	ORLEANS_C	115	0	13.57				
GLENBROOK_C2	115	0	158.4	ORRINGTON_C1	115	0	67				
GRANITE_C61	115	0	25	ORRINGTON_C2	115	0	67				
GRANITE_C62	115	0	25	ORRINGTON_C3	115	0	67				
GRANITE_C64	115	0	25	PLEASANT_C	115	0	28.8				
GRANITE_C66	115	0	25	PLUMTREE_C	115	0	88.2				
HADDAM_C	115	0	37.8	PLUMTREE_R	345	-75.02	0				

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Greater Boston Needs Assessment Shunt Compensation Table											
Bus Name	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**	**Bus Name**	**Voltage (kV)**	**Min Reactive**	**Max Reactive**
HARTFRD VT_C	115	0	25	PODICK_C	115	0	14.4				
HARTWELL_CAP	115	0	36.7	PRATTS JCT_C	115	0	63				
HARWICH_C	115	0	21.2	PRIDESCORNER	115	0	10.8				

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Section 11
Appendix E: Assessment Criteria – Steady State Thermal and Voltage Criteria

Table 11-1
Steady State Thermal Criteria

SYSTEM CONDITION	TIME INTERVAL	MAXIMUM ALLOWABLE FACILITY LOADING
Pre-contingency (all lines in)	Continuous	Normal rating
Post-contingency	Less than 15 minutes after contingency occurs	Short Time Emergency (STE) Rating[1]
	More than 15 minutes after contingency occurs	Long Time Emergency (LTE) Rating

[1] Post-contingency loading above LTE but below STE is considered acceptable as long as prompt system action (local phase shifter adjustment, generation runback, or special protection system-SPS operation) could reduce loading below LTE within 15 minutes.

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Table 11-2
Steady State Voltage Criteria

Transmission Owner	Voltage Level	Bus Voltage Limits (Per-Unit)	
		Normal Conditions	Emergency (Contingency) Conditions
Northeast Utilities	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
National Grid	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below[1]	0.95 to 1.05	0.90 to 1.05
Millstone/Seabrook	345 kV	1.00 to 1.05	1.00 to 1.05
VT Yankee/Pilgrim	345 kV	0.99 to 1.05	0.99 to 1.05
Sandy Pond	345 kV	1.00 to 1.05	1.00 to 1.05
Other Transmission Owners	230 kV and above	0.95 to 1.05	0.95 to 1.05

[1] Buses that are part of the Bulk Power System, and other buses deemed critical by National Grid Network Operations shall meet requirements for buses that are 230 kV and above.

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Section 12
Appendix F: Contingency List

12.1 Peak Load N-1 Contingency and Initial N-1-1 Contingency List

Table 12-1
Peak Load Contingencies Tested for All Cases and Sensitivities

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

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BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

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BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

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BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

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BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

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BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

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BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]	[redacted]							
[redacted]	[redacted]							
[redacted]	[redacted]							

Table 12-2 Initial Contingencies Applied for N-1-1 Peak Load Testing in All Cases and Sensitivities

Line Faults	Line Faults	Transformer Faults	Generator
[redacted]			

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12.2 Light and Minimum Load N-1 Contingency and Initial N-1-1 Contingency List

Table 12-3 Light and Minimum Load Contingencies Tested for All Cases and Sensitivities

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Table 12-4 Initial Contingencies Applied for N-1-1 Minimal and Light Load Testing in All Cases and Sensitivities



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12.3 Incorporating Dual Line Ratings for Cables with Common Circulation / Proximity

As a part of the post FCA 7 Greater Boston study changes to the ratings of underground cable facilities on the NSTAR transmission system have been included. An impact on the cable ratings that was previously not captured in the basecase models was the effect of the loss of a companion circuit on the rating of a cable. A companion underground circuit of circuit A is defined as a circuit B that shares the same duct bank with A, and may possibly have a common oil circulation. The common oil circulation would be such that oil flows from Station 1 to 2, through circuit A and returns back from station 2 to 1 via circuit B.

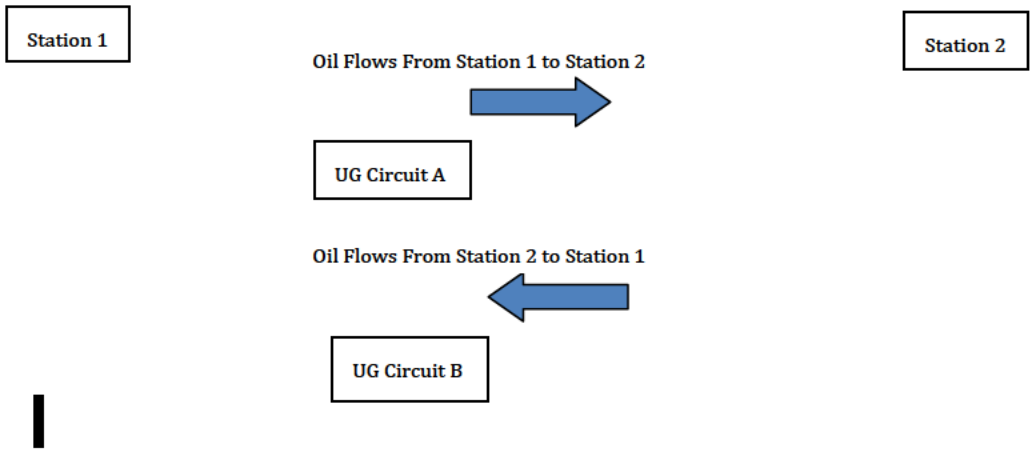


Figure 12-1 Illustration of Cables with Common Circulation

With a fault on one of the cables, for example Circuit B, the circulation will need to be interrupted to prevent the contamination of the circulation oil. The resultant loss of circulation for circuit A would tend to reduce the rating of the circuit. However, the fact that circuit B will be out of service, reduces the heat from an adjacent source that would tend to increase the ratings on circuit A. In calculating the line ratings post loss of the companion line both these factors will need to be accounted for.

For companion lines without a common circulation, the loss of the companion circuit, would only take out the adjacent heat source, and in general would increase the ratings on the line.

For each instance of such cables, ratings were calculated for both "Companion line in-service" and "Companion line Out-of-service". However, the power flow analysis software being employed by the study, does not account for conditional line ratings. Hence, a work around had to be developed to model the line ratings. The following example of the two 345 kV underground cables between

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Mystic and North Cambridge will serve as a demonstration of the methodology employed for this purpose.

The following Figure 2 demonstrates the existing model for 351 and 358. Each line has a set of ratings and impedances that matches the field data.

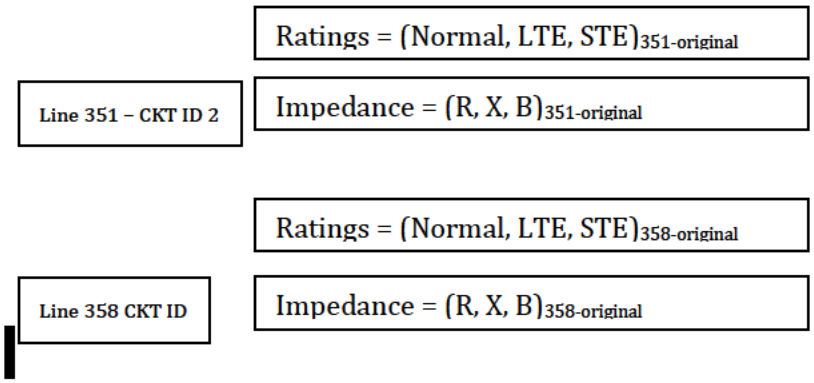


Figure 12-2 351 and 358 Existing Model

The following figure demonstrates the modifications made to the model to account for the two ratings. We call the ratings of 351 as: 351- with 358 In-service and 351-with 358 Out-of-service. Each line is divided into three segments with the circuit IDs ending with A, B and C. For line 351 which has an original circuit ID of 2, the ratings would be 2A, 2B and 2C. The 2C circuit has no ratings data but has the impedance data for the line. The segments 2A and 2B have two sets of ratings. The circuit 2A is normally closed and has the ratings assuming the companion line 358 is in-service. The circuit 2C is normally open and has the ratings assuming the companion line 358 is out-of-service.

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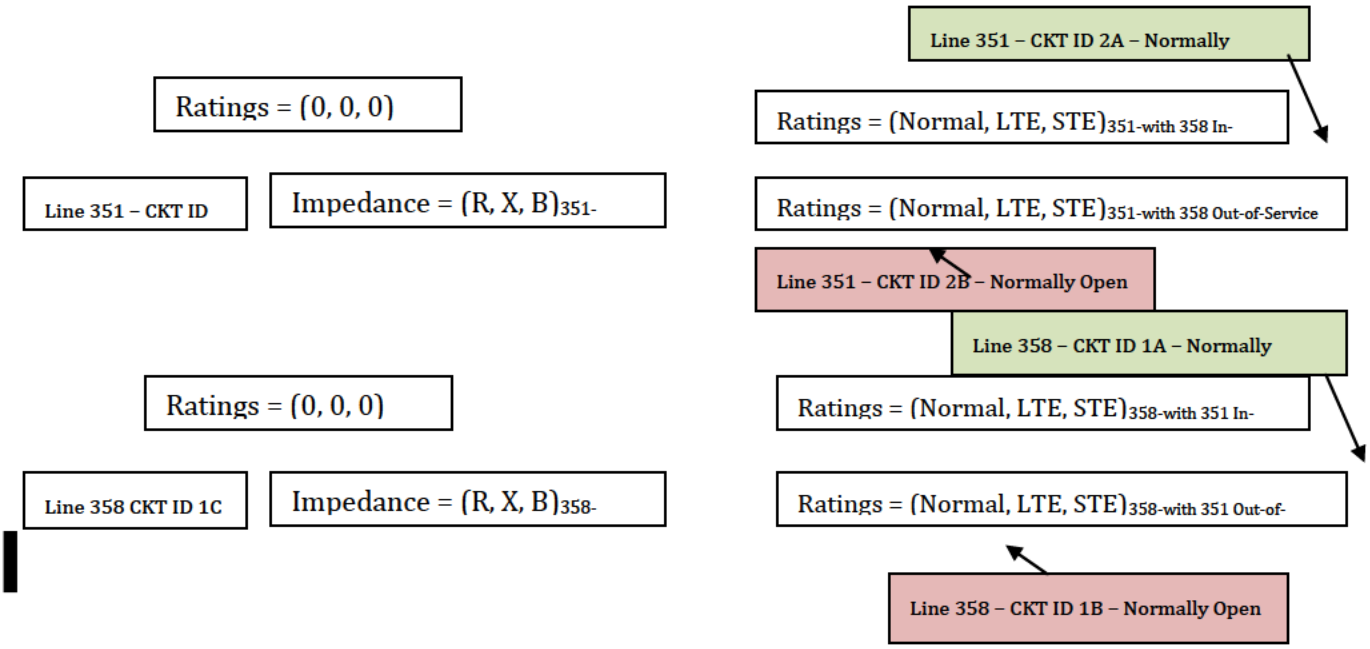


Figure 12-3 Illustration of modeling for 351 and 358

To see how the modeling works, it is best to observe the different scenarios that line 351 will be under.

1. 351 and 358 in-service
2. 358 out-of-service
3. 358 out-of-service + 351 out-of-service as the second contingency

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351 and 358 in-service

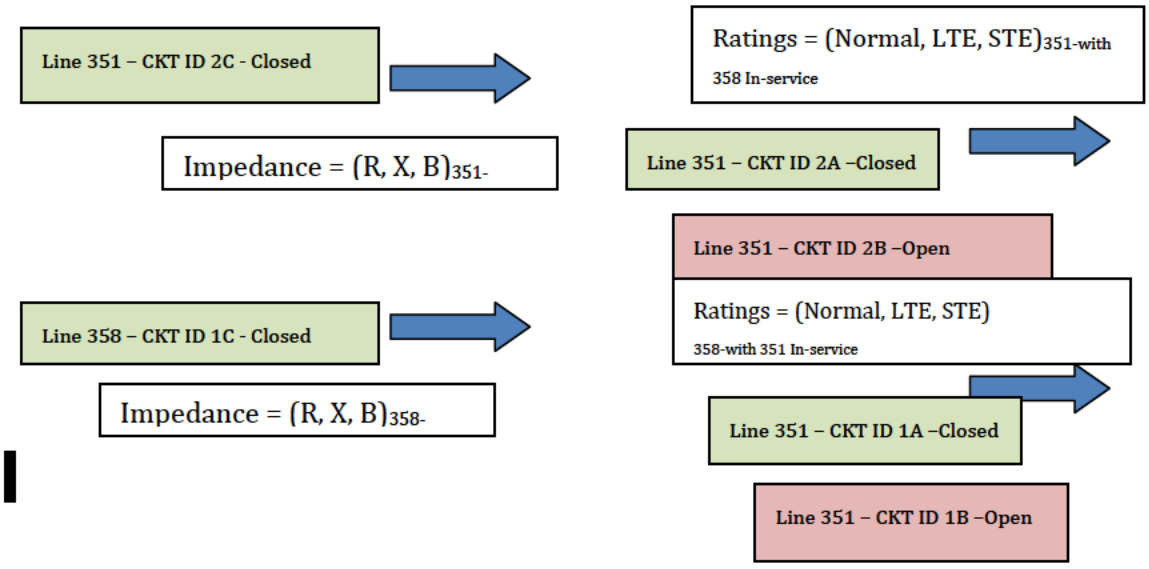


Figure 12-4 351 and 358 In-service

With 351 and 358 in-service, the circuit "C" stays in-service for both lines, and the circuits "A" stay in-service for both lines. As a result power flows on both lines and the ratings assume the companion line is in-service.

358 out-of-service

With 358 OOS, the circuits "C" and "A" of 358 are taken out of service. Additionally, the circuit "A" of 351 is taken out of service, and the circuit "B" of 351 is put into service. This results in the rating of line 351 to change to reflect the 358 out of service rating.

A similar change is done when 351 is taken out of service, to reflect the changed rating on 358.

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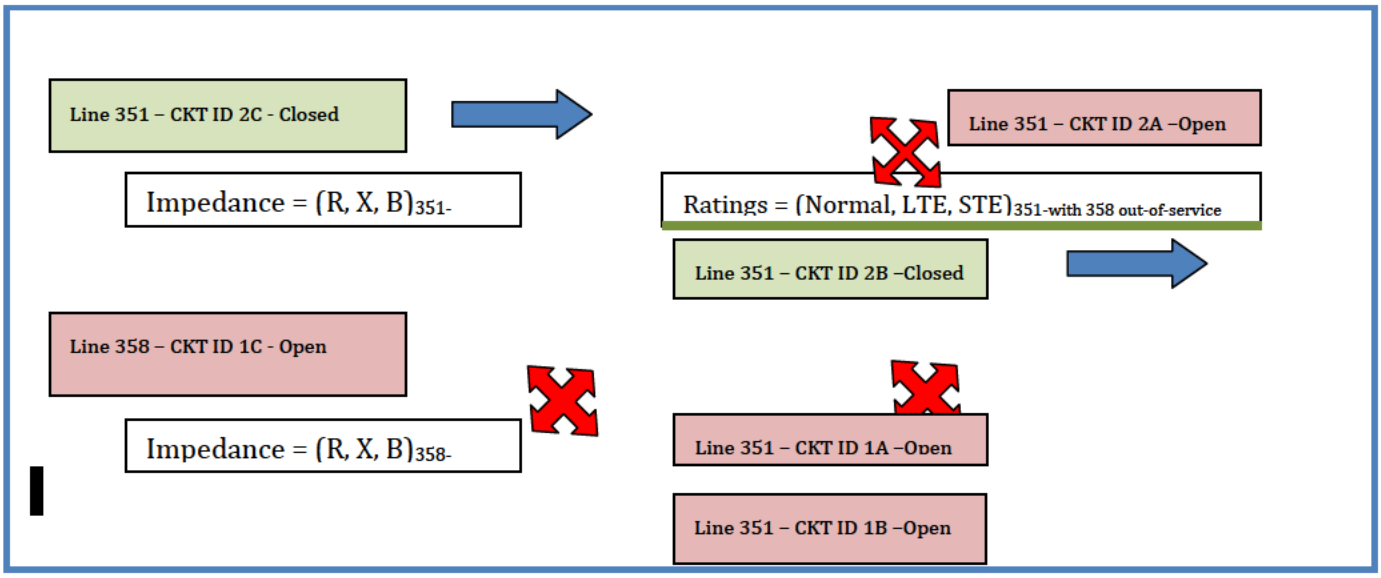


Figure 12-5 351 and 358 In-service

358 out-of-service followed by loss of 351

With 358 out of service, if 351 is lost as a contingency, then a similar action will be performed where the "A" and "C" circuits of 351 will be taken out of service, and the "A" circuit of 358 will be taken out of service and the "B" circuit will be put into service. Since this change will be incremental to the change in Figure 4 above, the net impact is demonstrated in Figure 5. The net result would be no flow on either 351 or 358 since the "C" circuits are out of service. The "B" circuits being in-service have no impact on the flows on the line.

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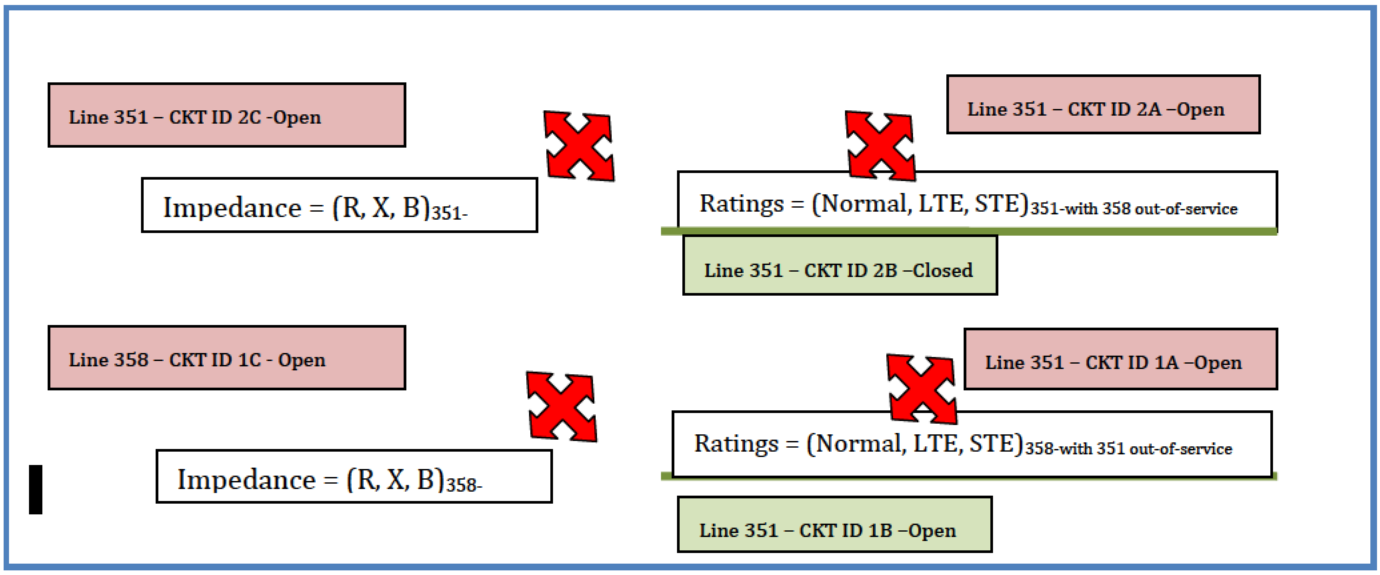


Figure 12-6 351 and 358 In-service

Hence based on the above 3 scenarios it has been demonstrated that the modified model would produce the system conditions required to be modeled under the different conditions. Changes will need to made to the contingency file to model the contingency as following

Loss of 351:

1. Take out 351 – Circuit 2C
2. Take out 351 – Circuit 2A
3. Take out 358 – Circuit 1A
4. Put in-service 358 – Circuit 1B

Thus, the previous definition of 351, "Take out 351 – Circuit 2", will be replaced by the four elements above in the contingency file to match the modified case.

Additional Buses Created:

In order to model the above line, for each line, a new bus needs to be added to model the "A", "B" and "C" circuits. These new buses need to be excluded from the monitor file since they are just dummy buses to model different line ratings and not actual points where physical equipment exists.

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Table 12-5 Greater Boston Area Updated Cable Pair Ratings

Line number	Terminal 1	Terminal 2	Proposed Ratings (Companion Cable in-service if applicable)			Proposed Ratings (Companion Cable out-of-service if applicable)		
			Normal	LTE	STE	Normal	LTE	STE
[redacted]								

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Line number	Terminal 1	Terminal 2	Proposed Ratings (Companion Cable in-service if applicable)			Proposed Ratings (Companion Cable out-of-service if applicable)		
			Normal	LTE	STE	Normal	LTE	STE

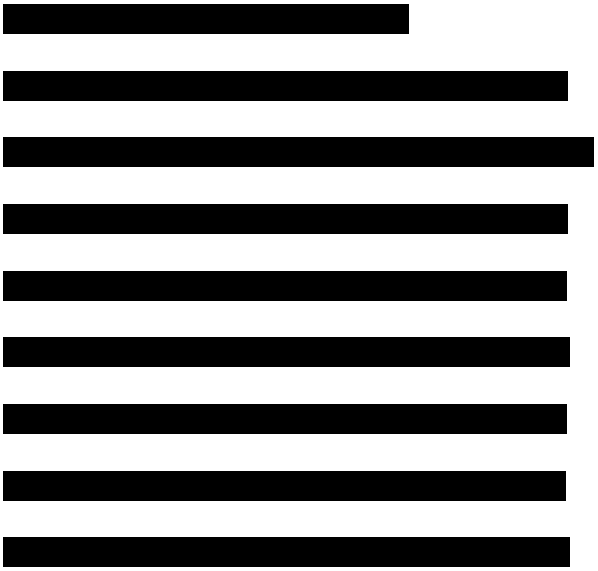
Line number	Terminal 1	Terminal 2	Proposed Ratings (Companion Cable in-service if applicable)			Proposed Ratings (Companion Cable out-of-service if applicable)		
			Normal	LTE	STE	Normal	LTE	STE
[redacted]								

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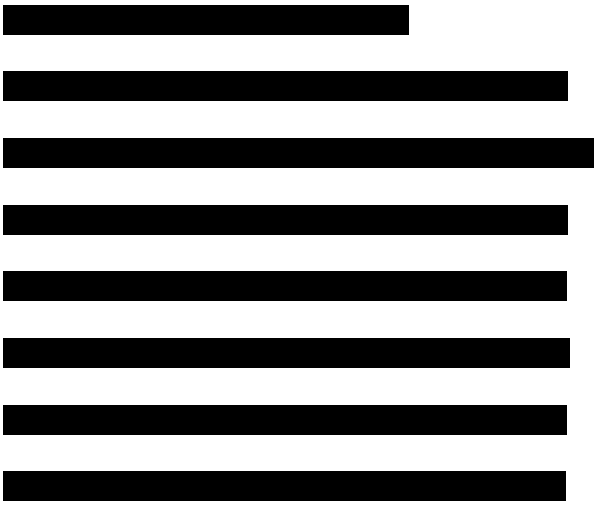
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Section 13
Appendix G: Contingency Results

2018 N-1 and N-1-1 Thermal Results



2023 N-1 and N-1-1 Thermal Results



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N-1 and N-1-1 Voltage Results

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Section 14 Appendix H: Short-Circuit Results

Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent
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Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent
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Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent
								345.kV			

Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent	Station	BREAKER	BKR Capability	Max DUTY in Percent
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Section 15
Appendix I: NERC Compliance Statement

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

This study provides a detailed assessment of Greater Boston area of New England's electric system performance for review of the system performance expected for years 2018 and 2023. This study shows performance for NERC Categories P1 through P7 as defined in the NERC TPL-001-4 standard. The results of this assessment are summarized in Section 5.1 (Page 48). This study uses normal operating procedures as illustrated by transfers, phase shifter settings and normal shunt compensation settings. Transfers are as shown in Section 3.1.9 (Page 21). Note that while firm transfers are not explicitly modeled or used in New England the system conditions used in this study are sufficiently stressed to ensure that reasonably expected transfer conditions across interfaces are being tested. The study includes reactive resources as shown in Section 10 Appendix D (Page 123). Long term planning studies consider 90/10 forecasts, stressed dispatches and line out conditions and the use of these assumptions historically provide sufficient operating margins to permit the performance of maintenance activities without jeopardizing the reliability of the system.

Critical Energy Infrastructure Information – Do Not Release

THIS DOCUMENT HAS BEEN REDACTED FOR CONFIDENTIAL INFORMATION AND CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Section 16
Appendix J: Summary of Results

See Section 5.1 of the report.

Critical Energy Infrastructure Information – Do Not Release

THIS DOCUMENT HAS BEEN REDACTED FOR CONFIDENTIAL INFORMATION AND CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Section 17
Appendix K: Base Case Load Flow Plots

Table 17-1 List of Base Case Load Flow Plots (w/ Links)

Case Title	2018 Plots	2023 Plots
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]



Critical Energy Infrastructure Information – Do Not Release

THIS DOCUMENT HAS BEEN REDACTED FOR CONFIDENTIAL INFORMATION AND CRITICAL ENERGY INFRASTRUCTURE INFORMATION (CEII).

Greater Boston Study Needs Assessment/Solution Study Status Update

PAC Meeting
January 18, 2012

Andrew Kniska
Lead Engineer, Transmission Planning

Agenda

- Background
  - Study History
  - Review of Preferred and Preliminary Preferred Upgrades
- Study Progress
- Solution Assessment Update
  - Western Suburbs
  - Downtown Boston

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Background

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Geographical Map of the Study Area



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Study History

- Needs Assessment scope presented to PAC in May 2008
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/index.html
- Initial needs presented to PAC in January 2009
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/index.html
- Detailed preliminary needs and Notification of Solution Study discussed at PAC in July 2009
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jul162009/index.html
- Needs Assessment Status Update in December 2009
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/dec162009/index.html

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Study History, *cont.*

- Needs Assessment/Solution Study Status Update and Preliminary Discussion of Alternatives presented at PAC in March 2010
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/mar182010/index.html
- Final "Greater Boston Area Transmission Needs Assessment" report posted in July 2010
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html

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Study History, *cont.*

- Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in December 2010
  - Grouped transmission solution alternatives into three areas
    - North of Boston
    - South of Boston
    - Central Area
  - Presented competing transmission alternatives for the areas to the north and south of Boston
  - Provided feasibility, cost, and technical assessment for the north and south competing transmission alternatives
  - Identified the preliminary preferred solutions for both the north and south areas
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/dec162010/index.html

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Study History, *cont.*

- Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in June 2011
  - Completed the "Needs Assessment" phase by presenting short-circuit assessment and critical load level assessment for the Boston Area
  - Identified the preliminary preferred solution for the Lexington – Waltham 115 kV reliability need
  - Discussed the impact of Salem Harbor Non-Price Retirement
    - Established the five line re-conductoring projects in the North Shore as the Preferred Solution
  - Provided an update to the Solutions Study

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Review of the North Solution

- Preferred Solutions
  - Re-conductoring North Shore 115 kV Lines
    - Y-151, B-154N, C-155N, S-145, and T-146
    - Received PPA approval
    - Construction underway to meet the in-service date of May 31, 2014
- Preliminary Preferred Solutions
  - Construct a 345 kV line Scobie-Tewksbury-Woburn
    - Open the Power St. to Pelham section of the Y-151 Line
  - Mystic to Wakefield Area
    - Construct a new 115 kV line between Wakefield and Everett
    - Re-conductor the Golden Hills to Everett F-158N & F-158S 115 kV Lines
    - Re-conductor Chelsea-Revere 128-518 115 kV line
    - Add a Chelsea 115 kV 54 MVAR Capacitor
  - Re-conductor the Tewksbury to Pinehurst M-139 & N-140 115 kV Lines

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Review of the South Solution

- Preferred Solution
  - Re-conductoring C-129N/201-502 and D-130/201-501 115 kV lines between Depot St. and Medway
    - Received PPA approval
- Preliminary Preferred Solution
  - Construct a new 115 kV line between West Walpole and Holbrook

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Review of the Central Solution

- Preferred Solution
  - Re-conductor the Lexington-Waltham 320-507/508 115 kV lines
    - Received PPA approval
    - Construction occurred in 4th Quarter 2011
    - Placed in-service in January 2012

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Study Progress

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Study Progress Since June 2011 PAC

- Continued the Central Area Solutions Study
  - Central Area Solution includes both the North and South area's preferred and preliminary preferred solutions
  - Further divided the Central Area into the Western Suburbs and Downtown Boston areas
    - Western Suburbs
      - Developed and studied transmission alternatives
      - Finalized the Preliminary Preferred Alternatives
    - Downtown Boston
      - Developed and currently studying transmission alternatives

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Study Progress, cont.

- Central Area Solution Assessment also revealed an additional North Area need
  - Sandy Pond-Tewksbury 337 Line 345 kV overload
    - N-1-1 overload due to [redacted]
  - Competing transmission alternatives include a new 345 kV line or re-conductoring the existing line
    - Re-conductoring alternative estimate is approximately $19M
    - A parallel 345 kV line is estimated is approximately $73M
- Selected the re-conductoring alternative
  - The re-conductoring of the Sandy Pond–Tewksbury 337 345 kV line has been added to the North Area Preliminary Preferred Solution

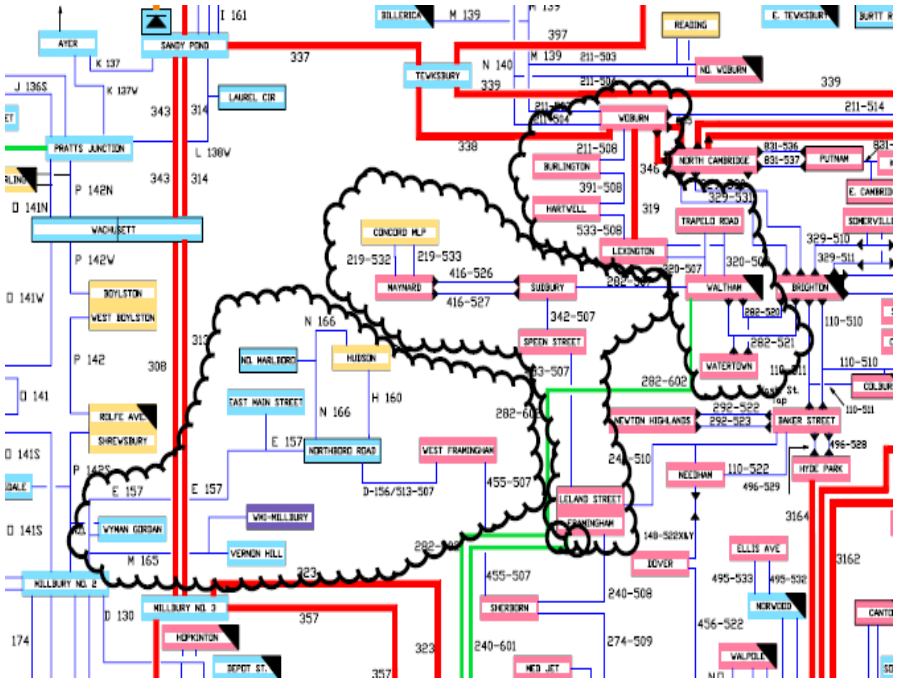
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Solution Assessment Update

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Western Suburbs Overview

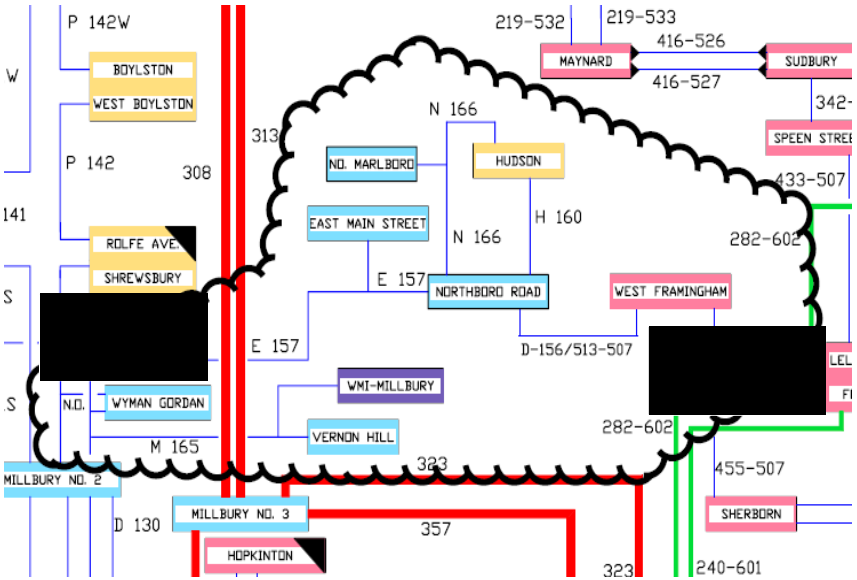
- The Western Suburbs consists of
  - Marlboro sub-Area
    - The 115 kV and 69 kV from Millbury towards Boston
  - Woburn-Waltham sub-Area
    - The 115 kV from Woburn to Brighton
  - Sudbury sub-Area
    - The 115 kV extending north from Framingham and west from Waltham



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Western Suburbs Needs

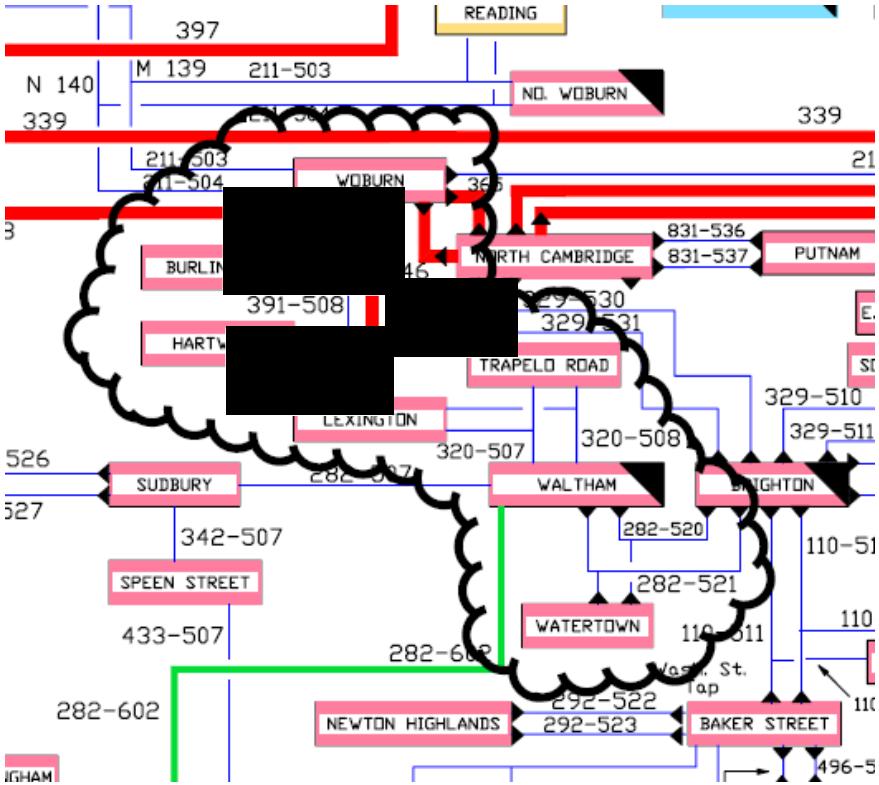
- Marlboro sub-Area
  - Overloads on the 69 kV system between Fitch Road and Northboro Rd substations
  - Thermal overloads include
    - E-157 Millbury to East Main St. 115 kV line
  - Low 115 kV and 69 kV voltages across the area
  - Marlboro Load Pocket
    - [redacted] causes voltage collapse on the 69 kV system
    - Loss of approximately 550 MW of load



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Western Suburbs Needs, *cont.*

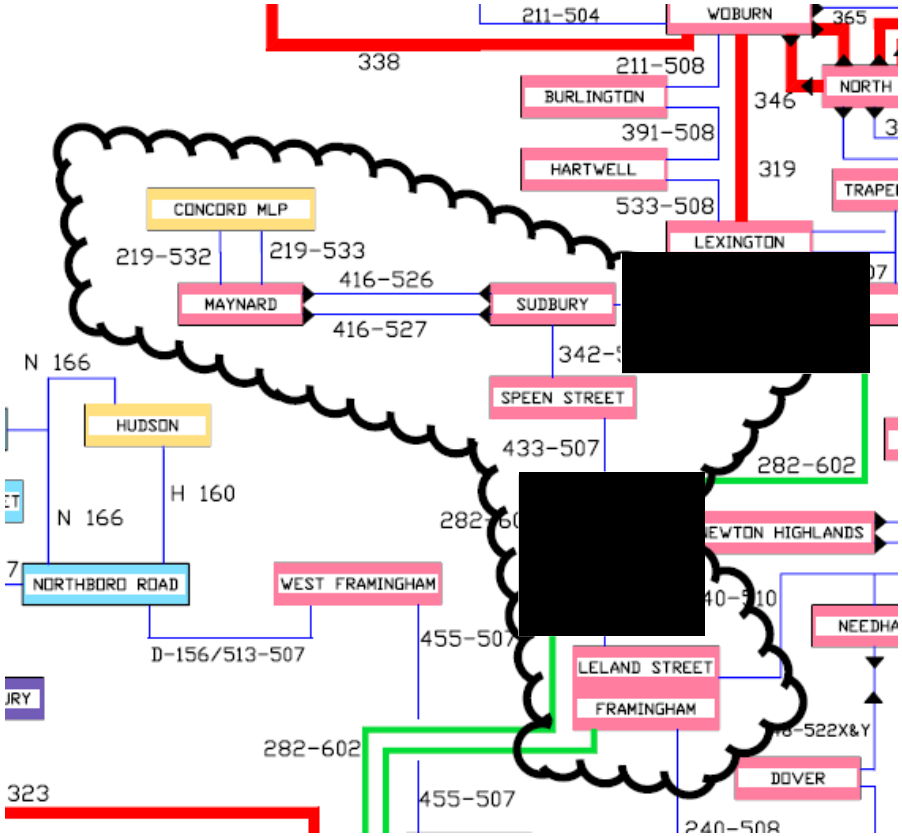
- Woburn-Waltham sub-Area
  - Thermal overloads
    - 282-520/521 Waltham to Brighton 115 kV line
    - Woburn 345/115 kV Autotransformer
    - 533-508 Lexington to Hartwell 115 kV line
  - Low 115 kV voltages in the Burlington and Hartwell areas
  - Burlington/Hartwell Load Pocket
    - Loss of approximately 220 MW of load



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Western Suburbs Needs, *cont.*

- Sudbury sub-Area
  - Thermal overloads
    - 433-507 Framingham to Speen St. 115 kV line
  - Sudbury load pocket
    - Loss of approximately 300 MW of load



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Western Suburbs Solutions Evaluation Process

- Transmission alternatives for each of the 3 Western Suburb sub-areas were developed
  - 2 for Marlboro, 2 for Woburn-Waltham and 2 for Sudbury
  - The 6 sub-area alternatives were then combined to form eight alternatives for the Western Suburb area
- Each of the 8 Western Suburbs alternatives was evaluated to assess overall system performance
  - Each Western Suburb alternative impacts the sub-Areas and the overall system performance
- Additional common upgrades such as line re-conductorings, equipment replacement, and double circuit tower (DCT) separations were added
- The system performance, cost and feasibility were then compared for each Western Suburb alternative to determine the Preliminary Preferred Upgrade for the Western Suburbs

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Marlboro sub-Area Cost Comparison

- Alternative 1
  - Converting the X-24 69 kV to 115 kV from Millbury to Northboro Rd.
    - Ancillary benefit of this alternative eliminates the need to refurbish X-24 Line due to asset condition
  - Re-conductor the 455-507 Northboro Rd. to Sherborn 115 kV Line
  - Re-conductor the E-157E Northboro Rd. to East Main St. 115 kV Line
  - Approximately $60M
- Alternative 2
  - Build a new Sudbury to Hudson 115 kV line
  - Refurbish the X-24 Millbury-Northboro Rd. 69 kV Line (cost TBD)
  - Approximately $41M

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Woburn – Waltham sub-Area Cost Comparison

- Alternative 1
  - Reconfigure the Waltham 115 kV Substation
    - Consists of breaker openings, line re-terminations, and the addition of breakers
    - The Waltham phase shifters will control the flow onto the 282-520/521 Waltham – Brighton 115 kV lines
    - Woburn – Lexington – Waltham – West Medway will be a free flowing path
  - Install a 2nd Woburn Auto
  - Construct a new 115 kV line between Woburn and Hartwell
  - Re-conductor
    - 211-508 Woburn-Burlington 115 kV Line
  - Terminal equipment upgrades
    - 320-507/508 Lexington-Waltham 115 kV lines
  - Approximately is $68M

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Woburn – Waltham sub-Area Cost Comparison, *cont.*

- Alternative 2
  - Install two new underground cables from Waltham to Brighton 115 kV
  - Re-conductor
    - 433-507 Framingham- Speen St. 115 kV Line
  - Approximately $115M

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Sudbury sub-Area Cost Comparison

- Alternative 1
  - Sudbury 230/115 kV autotransformer
  - Terminal equipment upgrades at West Medway for higher ratings on the 282-602 West Medway-Sudbury 230 kV line
  - Approximately $25M
- Alternative 2
  - Build a new Sudbury to Framingham 115 kV line
  - Sudbury 115 kV capacitor bank
  - Approximately $28M

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Common Upgrades to all Combinations

- Re-conductor
  - 533-508 Lexington-Hartwell 115 kV Line
  - E-157W Millbury-East Main Street 115 kV Line
  - W-23 Fitch Rd.-Woodside 69 kV Line
  - W-23W Woodside-Northboro Rd. 69 kV Line
- Woburn 345/115 kV Auto replacement
- Hartwell 115 kV 54 MVAR capacitor addition
- X-24 / E-157W double circuit tower (DCT) separation
- Approximately $22M

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Western Suburbs Comparison of Combinations

- Electrical performance
  - The eight combinations each satisfied the stated needs of the area
  - Ancillary benefits of various combinations such as reducing the size of a load pocket were considered
- Cost
  - The combinations were ranked in order of cost
  - The rankings revealed two combinations that were much lower in total cost than the other six
  - Of the two remaining combinations, the only difference in the combination of upgrades was a Sudbury 230/115 kV Auto versus a Sudbury-Framingham 115 kV line
- Feasibility
  - Determined that adding the Sudbury auto on an existing line was more feasible than adding a new 115kV line
    - The Sudbury 115kV Substation is adjacent to the West Medway-Waltham 230 kV line ROW

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Preliminary Preferred Solution for the Western Suburbs

- Marlboro sub-Area: Alternative 2 selected
  - Build a new Sudbury to Hudson 115 kV line
  - Refurbish the X-24 69 kV Line
- Waltham-Woburn sub-Area: Alternative 1 selected
  - Reconfigure the Waltham 115 kV Substation
  - Install a 2nd Woburn Auto
  - Construct a new line 115 kV Woburn to Hartwell
  - Re-conductor 211-508 115 kV line from Woburn-Burlington
  - Terminal equipment upgrades for the 320-507/508 Lexington-Waltham 115 kV lines

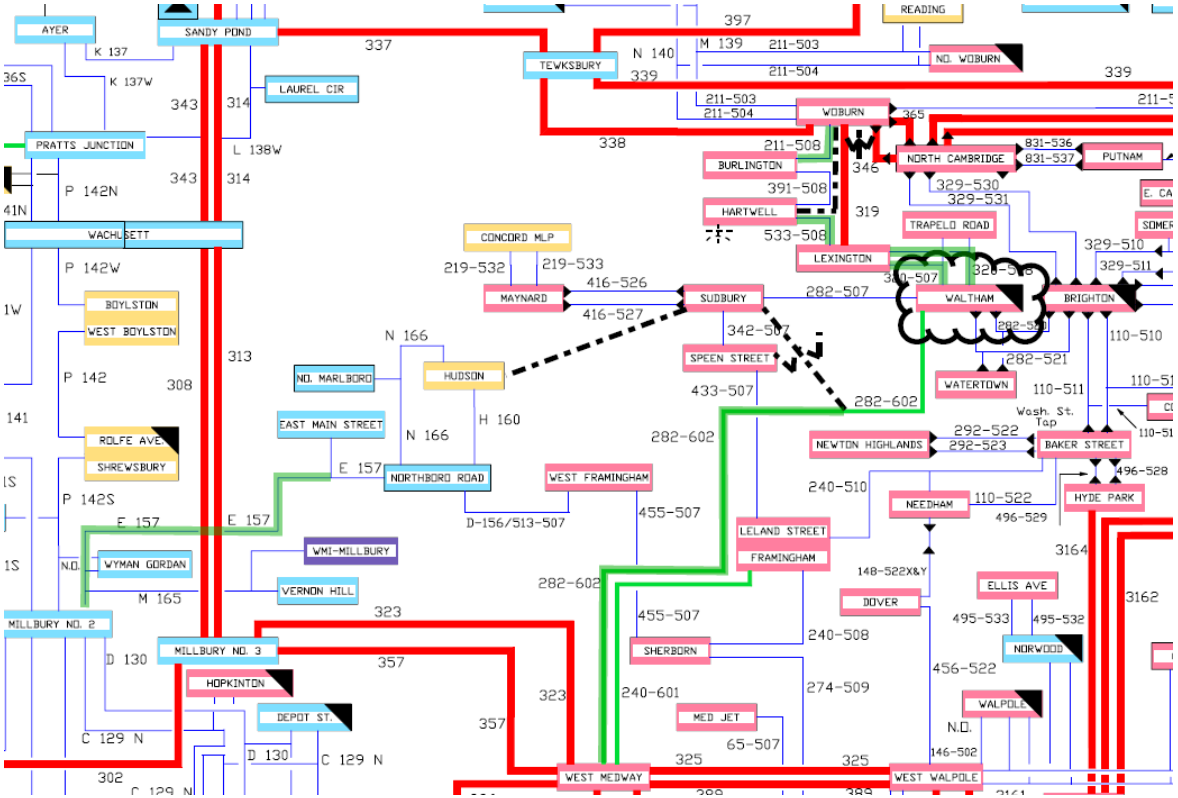
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Preliminary Preferred Solution for the Western Suburbs, *cont.*

- Sudbury sub-Area: Alternative 1 selected
  - Sudbury 230/115 kV autotransformer
  - Terminal equipment upgrades at West Medway for higher ratings on the 282-602 West Medway-Sudbury 230 kV line

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Western Suburbs Preferred Solution – One Line Representation



The Woburn Auto replacement, 69kV upgrades and the DCT separation are not shown

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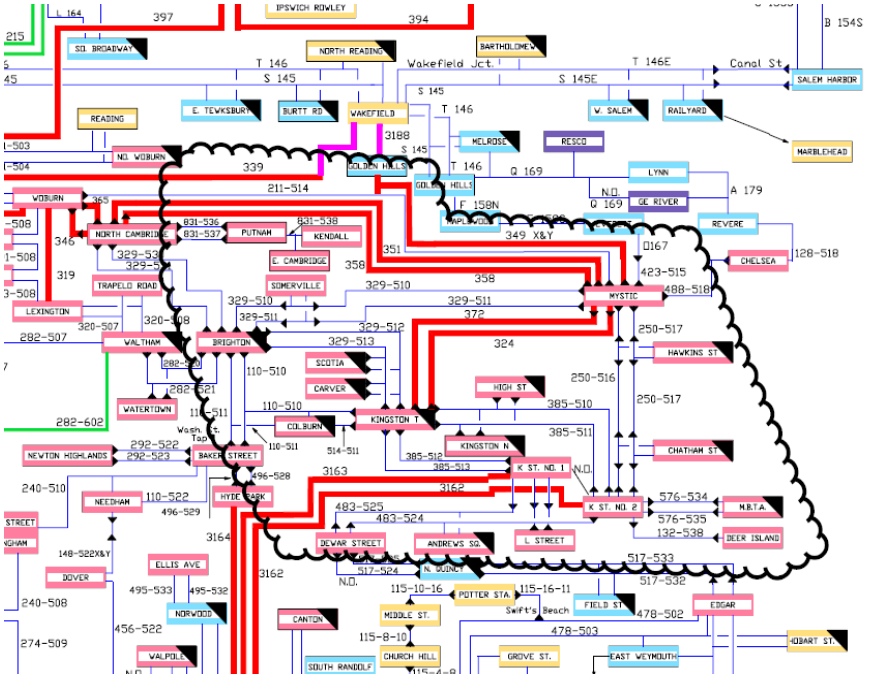
Western Suburbs Preliminary Preferred Solution Cost

- The overall cost for these upgrades is approximately $156M plus the cost of the X-24 Millbury-Northboro Rd. 69 kV refurbishment

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Downtown Boston Overview and Needs

- Numerous 115 kV cable overloads
- Short Circuit
  - [redacted]
  - Duty at Brighton 115 kV and K St. 115 kV between 90% and 100%



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Downtown Boston Solution Progress

- All potential solutions based on the preliminary preferred solutions for the North, South and Western Suburbs areas
- Started with a Short-Circuit Screening
  - Evaluated options to address base case short-circuit over-duties and potential over-duties introduced by central area upgrades
    - Splitting substations
    - Opening breakers and/or circuit switchers
    - Moving Mystic 9 generation to 345 kV
  - Developed four upgrade plans based on short circuit options noted above
- Added transmission to address remaining thermal issues
- Iterative process among:
  - Steady State Assessment
  - Stability Screening
  - Short-Circuit Assessment

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Potential Downtown Area Transmission Alternatives

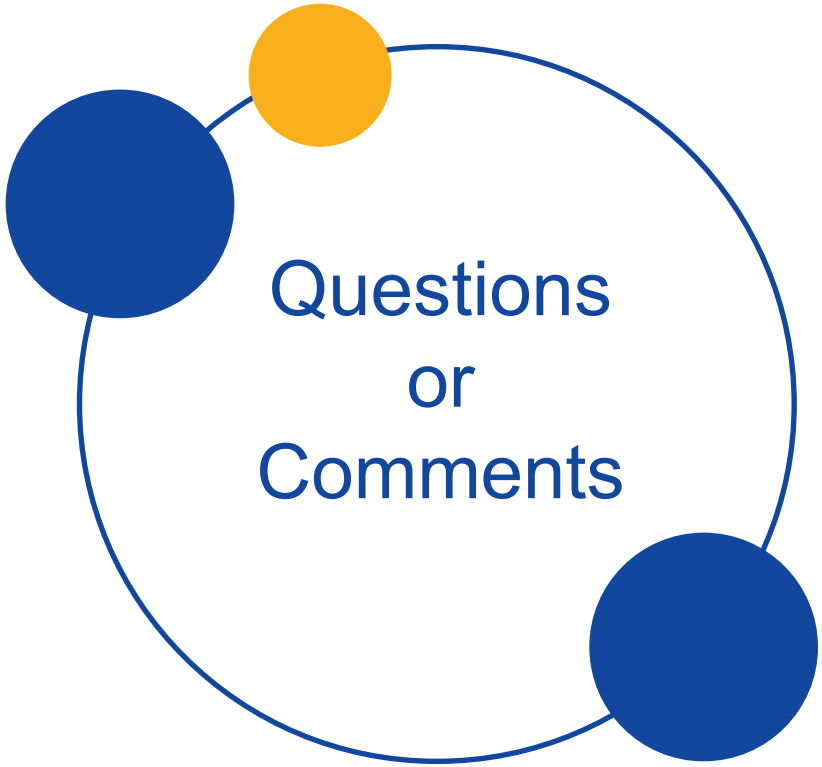
- Potential 345 kV line additions
  - Mystic-K St. 345 kV with K St. phase shifter
  - Wakefield-Ward Hill 345 kV
  - Wakefield-Woburn 345 kV
- Line re-conductorings
- The combination on short circuit options and transmission alternatives results in 12 variations of transmission topologies being evaluated

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Next Steps

- Finalize the Downtown Area Solution Assessment
- Selection of the preferred solutions for the remaining Downtown Area needs expected in the 2nd Quarter of 2012

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Greater Boston Study Needs Assessment/Solution Study Status Update

March 14, 2012 Planning Advisory Committee Meeting

Andrew Kniska
Lead Engineer, Transmission Planning

[redacted]

ISO new england

Purpose

- Present an update of the Greater Boston Study
  - Discuss the analysis of the Downtown sub-area since last presentation
- Present the complete Greater Boston Preferred Solution
  - Including updated cost estimates

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Agenda

- Provide a study review
  - Study Area
  - Study History
- Provide a Solution Study update
  - Downtown Boston Preferred Solution
- Present the complete Greater Boston Preferred Solution

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Study Review

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Geographical Map of the Study Area



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Study History

- Needs Assessment scope presented to PAC in May 2008
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/index.html
- Initial needs presented to PAC in January 2009
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- Detailed preliminary needs and Notification of Solution Study discussed at PAC in July 2009
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- Needs Assessment Status Update in December 2009
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Study History, *cont.*

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Study History, *cont.*

- Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in December 2010
  - Grouped transmission solution alternatives into three areas
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    - South of Boston
    - Central Area
  - Identified the preliminary preferred solutions for both the north and south areas
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Study History, *cont.*

- Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in June 2011
  - Completed the "Needs Assessment" phase by presenting short-circuit assessment and critical load level assessment for the Boston Area
  - Identified the preliminary preferred solution for the Lexington – Waltham 115 kV reliability need
  - Discussed the impact of Salem Harbor Non-Price Retirement
    - Established the five line reconductoring projects in the North Shore as the Preferred Solution
  - Provided an update to the Solutions Study
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2011/jun302011/index.html

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Study History, *cont.*

- Greater Boston Study Needs Assessment/Solution Study Status Update presented at PAC in January 2012
  - Grouped transmission solution alternatives for the Central Area into the Western Suburbs and Downtown Boston sub-Areas
  - Western Suburbs
    - Presented competing transmission alternatives
    - Provided feasibility, cost, and technical assessment
    - Identified the preliminary preferred solutions
  - Downtown Boston
    - Presented competing transmission alternatives
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/jan182012/index.html

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Solution Study Update

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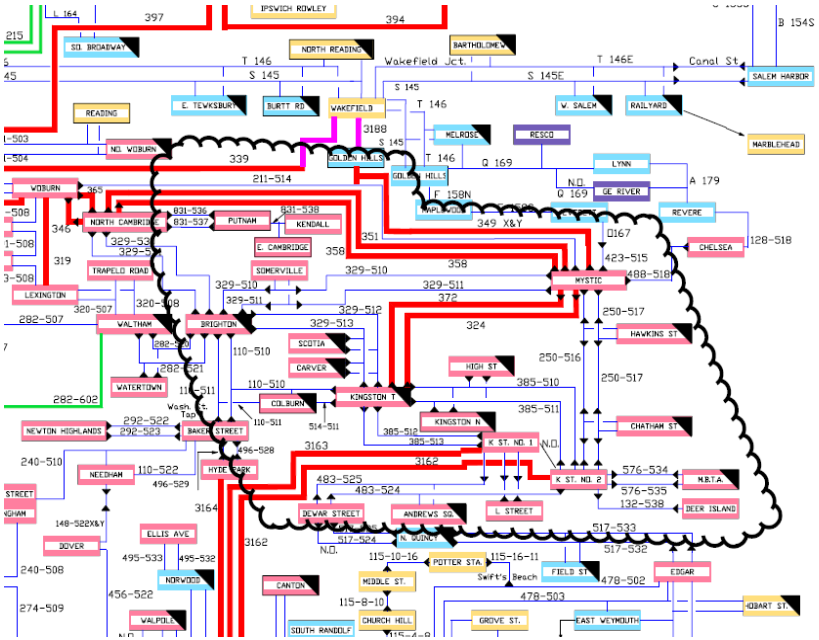
Study Progress Since January 2012 PAC

- Continued the Solution Study to determine the Downtown Boston sub-area upgrades
- Includes the North, South, and Western Suburbs preferred and preliminary preferred solutions

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Downtown Boston Overview and Needs

- Numerous 345 kV and 115 kV cable overloads
- [redacted]
  - Duty at Brighton 115 kV and K St. 115 kV between 90% and 100%



[redacted]

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Downtown Boston Solution Progress

- Started with a Short-Circuit Screening
  - Developed four upgrade plans based on initial short circuit evaluation
    - Plan 1 opens Mystic 115 kV downtown ties and closes K St. 115 kV bus tie
    - Plan 2 opens North Cambridge 115 kV downtown ties and splits the Kingston 115 kV bus
    - Plan 3 moves the Mystic generation to 345 kV and splits the Kingston 115 kV bus
    - Plan 4 opens the 115 kV ties between Mystic and K St. and two of the ties between Kingston and Brighton and closes the normally open K St. 115 kV bus tie
- Added transmission to address remaining thermal issues
- Iterative process among:
  - Steady State Assessment
  - Stability Screening
  - Short-Circuit Assessment

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Potential Downtown Boston Area Transmission Alternatives

- Potential transmission alternatives
  - Mystic-K St. 345 kV cable with K St. phase shifter
  - Wakefield-Ward Hill 345 kV transmission line
  - Wakefield-Woburn 345 kV cable
- Common Upgrades
  - Woburn-North Cambridge 345 kV cable
  - Mystic-Chelsea 115 kV cable
  - Needham-Baker St 115 kV cable
  - Add Mystic-Woburn 115 kV cable and bifurcate with existing 211-514 Mystic-Woburn 115 kV cable Carver St. breakers
  - Separation of the DCT's on (F-158N + Q169) and (O-167 and P-168)
- The combination of 4 short circuit options and 3 transmission alternatives resulted in 12 transmission topologies which were evaluated

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Downtown Boston Solution Evaluation Process

- Each of the 12 Downtown Boston transmission topologies were evaluated to assess overall system performance
- Additional upgrades, such as line reconductorings and equipment replacement, were added as needed to address any remaining issues
- The system performance, cost and feasibility were then compared for each Downtown Boston alternative to determine the Preferred Upgrade for the Downtown Boston sub-Area
- The evaluation process resulted in two cost competitive transmission alternatives that addressed the area needs

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NSTAR Projects

- Three projects in the NSTAR Local System Plan were also incorporated into the Downtown Boston sub-Area
  - Northern Ave. 115 kV Substation
    - Located along the K St.-Mystic 115 kV lines between K St. and Chatham St.
  - Electric Ave. Substation
    - Located along the Waltham-Brighton 115 kV lines between Brighton and Watertown
  - East Boston Substation
    - Tap off the new Mystic-Chelsea 115 kV
- These projects will be further discussed in an upcoming Transmission Owner Planning Advisory Committee (TOPAC)

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Downtown Boston Cost Comparison

- Alternative 1
  - Short-Circuit Plan 1 which opens Mystic 115 kV downtown ties and closes K St. 115 kV bus tie
  - Add Wakefield-Ward Hill 345 kV line
  - Add Woburn-North Cambridge 345 kV cable
  - Add a 2nd Mystic 345/115 kV auto
  - Terminal Upgrades at Seabrook 345 kV station to increase ratings of the 394 Seabrook-Ward Hill Line
  - Reconductor the 337 Sandy Pond-Tewksbury 345 kV Line
  - Add two additional K St. 115 kV breakers
  - Add Mystic-Chelsea 115 kV cable
  - Add a 2nd Mystic-Woburn 115 kV cable to create a bifurcated 211-514 Mystic-Woburn 115 kV circuit
    - The combination of Mystic-Chelsea 115 kV line and the Mystic-Woburn upgrade eliminates the need for the Wakefield-Everett 115 kV Line from the North sub-area solution set.
  - Add Needham-Baker St 115 kV cable
  - Separation of the DCT's on (F-158N + Q169) and (O-167 and P-168)
  - Approximate Cost $288M

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Downtown Boston Cost Comparison, cont.

- Alternative 2
  - Short-Circuit Plan 2 which opens North Cambridge 115 kV downtown ties and splits the Kingston 115 kV bus
  - Add Mystic-K St. 345 kV cable with a K St. phase shifter
  - Add a Mystic 345 kV breaker and re-terminate line positions
  - Add Woburn-North Cambridge 345 kV cable
  - Add an additional K St. 115kV breaker
  - Add Mystic-Chelsea 115 kV cable
  - Add Needham-Baker St 115 kV cable
  - Add a 3rd K. St. to Northern Ave. 115 kV cable
  - Add a 2nd Mystic-Woburn 115 kV cable to create a bifurcated 211-514 Mystic-Woburn 115 kV circuit
  - Upgrade the existing 211-514 Mystic-Woburn 115 kV cable
  - Replace the West Medway 345 kV breakers with higher rated breakers
  - Separation of the DCT's on (F-158N + Q169) and (O-167 and P-168)
  - Approximate Cost $335M

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Technical Comparison of the Two Downtown Area Alternatives

- Short Circuit
  - Alternative 1 provided generally provided lower short-circuit levels at several key buses

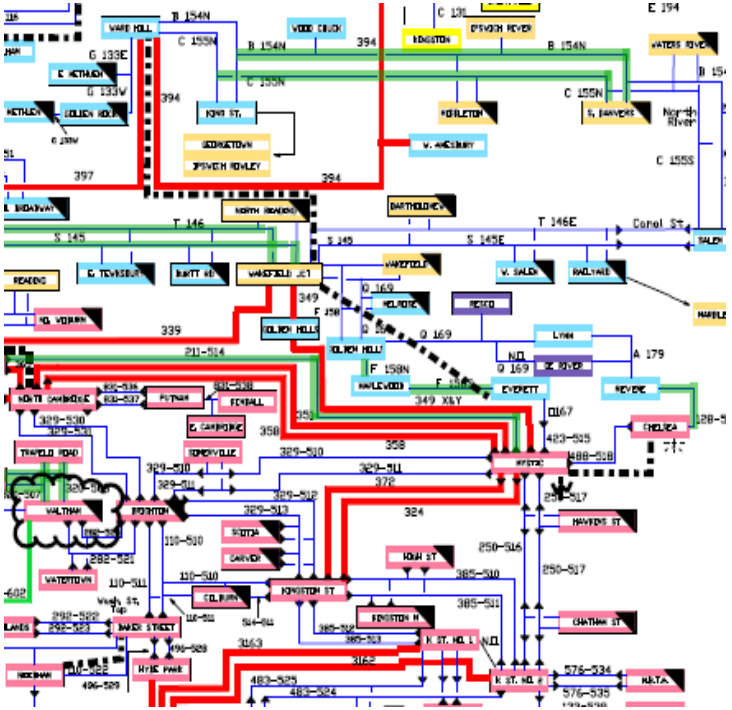
	Alternative 1	Alternative 2
Mystic 115 kV	56%	95%
Brighton 115 kV	84%	92%
Ward Hill 115kV	95%	88%

- Longevity
  - Alternative 1 provided additional thermal capability
- Operational Complexity
  - Alternative 1 proved less operationally complex

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Preferred Solution for the Downtown Boston Area

- Short-Circuit Plan 1 which opens Mystic 115 kV downtown ties and closes K St. 115 kV bus tie
- Add Wakefield-Ward Hill 345 kV line
- Add Woburn-North Cambridge 345 kV cable
- Add a 2nd Mystic 345/115 kV auto
- Terminal Upgrades at Seabrook 345 kV station to increase ratings of the 394 Seabrook-Ward Hill Line
- Reconductor the 337 Sandy Pond-Tewksbury 345 kV Line
- Add two additional K St. 115kV breakers
- Add Mystic-Chelsea 115 kV cable
- Add Needham-Baker St 115 kV cable
- Add a 2nd Mystic-Woburn 115 kV cable to create a bifurcated 211-514 Mystic-Woburn 115 kV circuit



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Complete Greater Boston Preferred Solution*

* Planning grade estimates of +50% / -25% used

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Review of the North Area Upgrades

New Facility	Length, mi	Cost, $M
Scobie – Tewksbury 345 kV	24	97
Tewksbury – Woburn 345 kV	13	66
Ward Hill – Wakefield 345 kV	38	74

Other	Length, mi	Cost, $M
Open the Y-151	NA	0

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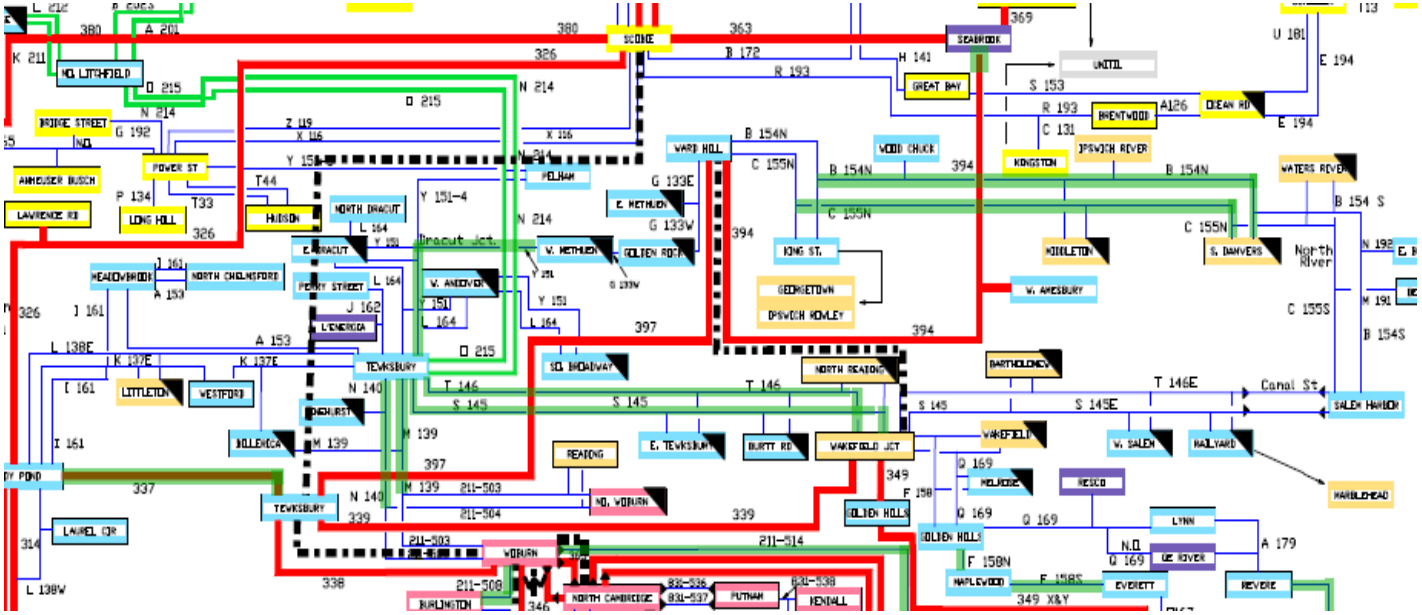
Review of the North Area Upgrades, cont.

Upgraded Facility	Length, mi	Cost, $M
Terminal upgrades at Seabrook 345 kV station to increase ratings of the 394 Line	NA	21
Reconductor 337 Sandy Pond-Tewksbury 345 kV	16	19
Reconductor Y-151 Tewksbury-Tewksbury Jct.115 kV	2	1
Reconductor Y-151 Tewksbury Jct.-West Methuen 115 kV*	8	15
Reconductor B-154N King St.-South Danvers 115 kV*	14	9
Reconductor C-155N King St.-South Danvers 115 kV*	14	9
Reconductor S-145 Tewksbury- North Reading 115 kV*	9	15
Reconductor S-145 North Reading-Wakefield 115 kV	5	5
Reconductor T-146 Tewksbury- North Reading 115 kV*	9	15
Reconductor T-146 North Reading-Wakefield 115 kV	5	5
Reconductor F-158N Golden Hills-Maplewood 115 kV	4	2
Reconductor F-158S Everett-Maplewood115 kV	3	2
Reconductor M-139 Tewksbury-Pinehurst 115 kV	7	6
Reconductor N-140 Tewksbury-Pinehurst 115 kV	7	6

* These projects have been advanced to allow the retirement of Salem Harbor

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North Area Upgrades One-Line



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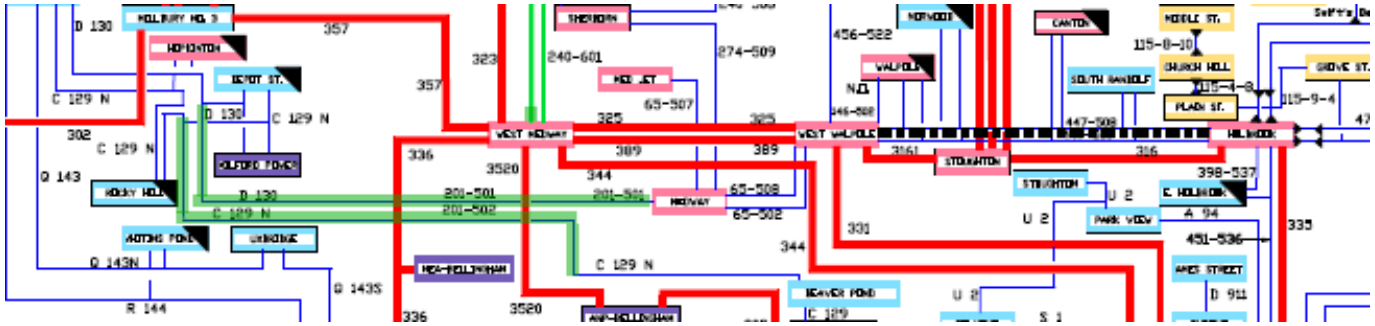
Review of the South Area Upgrades

New Facility	Length, mi	Cost, $M
West Walpole-Holbrook 115 kV	14	19

Upgraded Facility	Length, mi	Cost, $M
Reconductor C-129N/201-502 Depot St. Tap-Medway 115 kV	2	2
Reconductor D-130/201-501 Depot St. Tap-Medway 115 kV	2	4

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South Area Upgrades One-Line



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Review of Western Suburbs Upgrades

New Facility	Length, mi	Cost, $M
Sudbury – Hudson 115 kV	9	41
Woburn – Hartwell 115 kV	6	19
2nd Woburn 345/115 kV Auto	NA	23
Sudbury Substation with a 230/115 kV Auto	NA	24
Hartwell Ave 115 kV 36.7 MVAr Capacitor	NA	2

Other	Length, mi	Cost, $M
Separate the X-24 / E-157W Double Circuit Tower	4 structures	2
Reconfigure the Waltham 115 kV Substation	NA	21

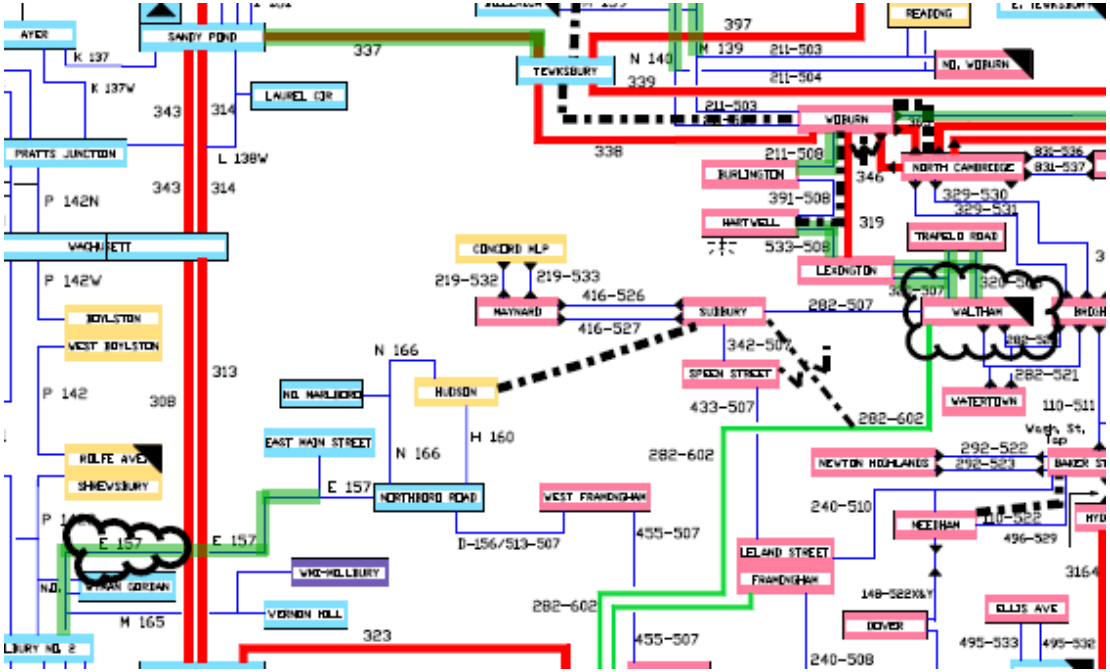
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Review of Western Suburbs Upgrades, cont.

Upgraded Facility	Length, mi	Cost, $M
Terminal Upgrades at West Medway 230 kV station to increase ratings of the 282-602 Line	NA	1
Reconductor 320-507/508 Lexington-Waltham 115 kV	5	9
Reconductor 211-508 Woburn-Burlington 115 kV	4	5
Refurbish X-24 69 kV Line	15	7
Replace the existing Woburn 345/115 kV Auto	NA	6
Reconductor 533-508 Lexington-Hartwell 115 kV	2	.5
Reconductor E-157W Millbury-East Main St. 115 kV	11	5
Reconductor W23 Fitch Rd.-Woodside 69 kV	8	6
Reconductor W23W Northboro-Woodside 69 kV	6	5

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Western Suburbs Upgrades One-Line



The Woburn Auto replacement and 69 kV upgrades are not shown

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Review of Downtown Boston Upgrades

New Facility	Length, mi	Cost, $M
Woburn – North Cambridge 345 kV	6	52
Needham – Baker St. 115 kV	5	46
2nd Mystic 345/115 kV Auto	NA	16
Mystic-Chelsea 115 kV cable	1	25

Upgraded Facility	Length, mi	Cost, $M
Add a 2nd Mystic-Woburn 115 kV cable to create a bifurcated 211-514 Mystic-Woburn 115 kV circuit	8	48
Reconductor 128-518 Chelsea-Revere 115 kV	1	1

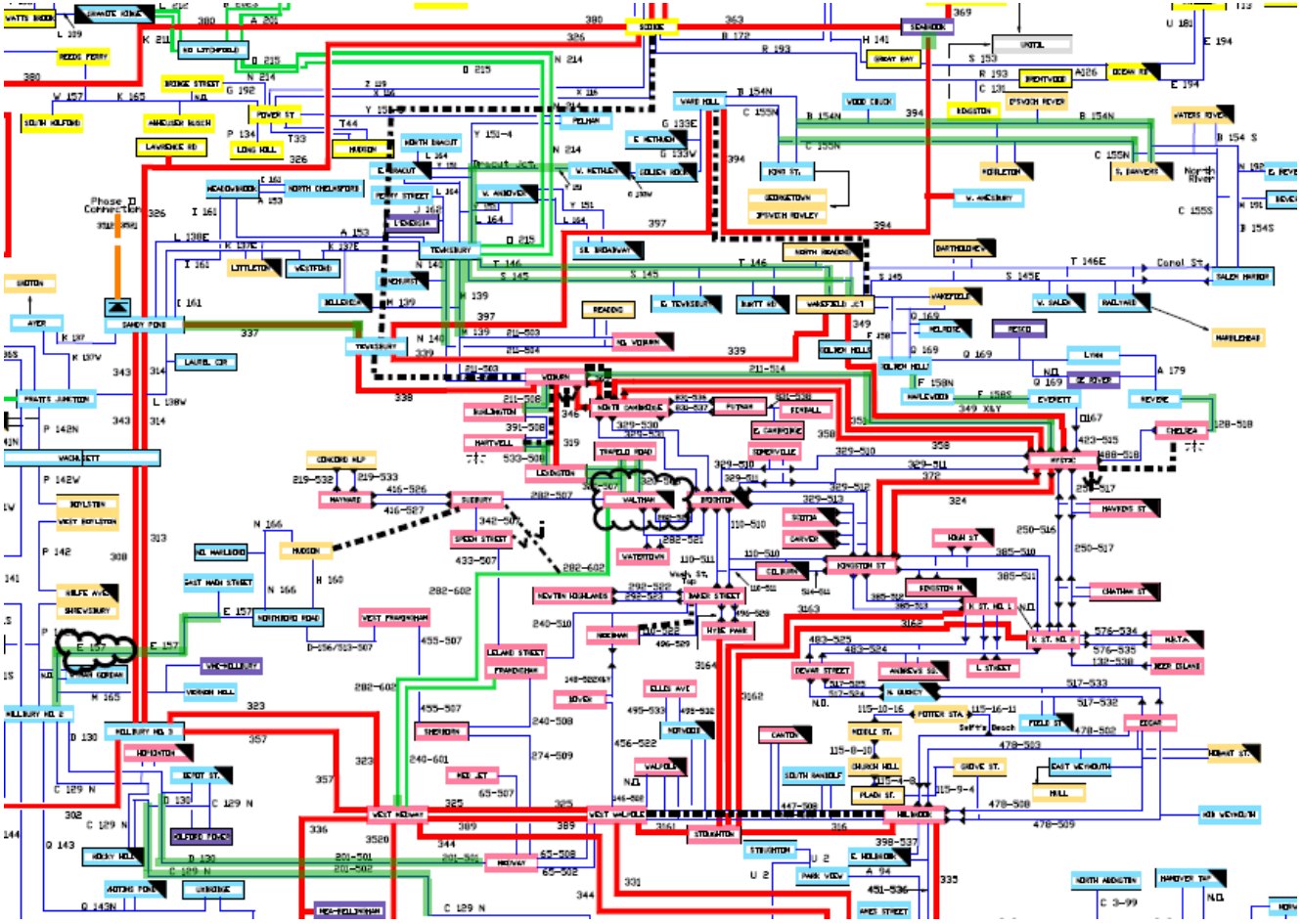
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Review of Downtown Boston Upgrades, cont.

Other	Length, mi	Cost, $M
K St. 115 kV breaker additions	NA	6
Chelsea 115 kV 36.7 MVAr Capacitor	NA	1
Separation of the F-158N and Q169 DCT	1 Structure	.5
Separation of the O-167 and P-168 DCT	1 Structure	.5
Open the Mystic 115 kV downtown ties and closes K St. 115 kV bus tie	NA	0

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Final Greater Boston One-Line

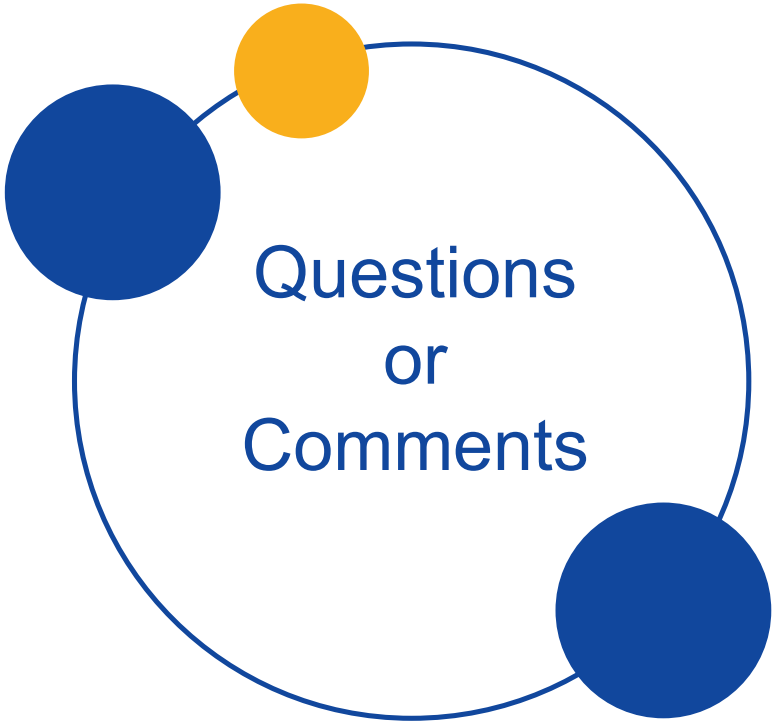


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Next Steps

- Issue Solutions Study Report
  - Draft Solution Study Report 2nd Quarter of 2012
    - One month for comments
    - One month to finalize report
  - Final Solution Study Report two months after the draft report issued
- Examine the impact of future system conditions
  - Future energy efficiency (EE) forecast updates
  - CELT 2012 load forecast updates
  - FCA #6 updates
- Complete Section I.3.9 System Impact Study and seek Proposed Plan Application approval in Q4 2012

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Greater Boston Area Transmission Solutions Study

This document has been redacted for Critical Energy Infrastructure Information (CEII). 8/19/2015

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August 12, 2015

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Section 1
Executive Summary

1.1 Needs Assessment Results and Problem Statement

1.1.1 Steady State Test Results

The scope of the Needs Assessment performed for the Greater Boston area included evaluation of the reliability performance of the transmission system serving this area of New England for the year 2018 and 2023 projected system conditions. The system was tested with all lines in and under N-1 and N-1-1 contingency conditions for a number of possible operating scenarios employing different transfer levels and generating unit availability. The study area defined as "Greater Boston" included the areas known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston, parts of the areas south of Boston, and a small area that is a part of the New Hampshire load zone. In broad terms the Greater Boston study area can be described as the communities north and east of Interstate 495 up to the border communities of southern New Hampshire, the city of Boston and some of the suburbs south of Boston. The study area encompasses the Boston Regional System Plan (RSP) subarea with the addition of some load in the west and south outside of the Boston RSP subarea. To account for the load and to describe the study area, the term Boston RSP subarea is used in general throughout the report even though a small portion of the study area is outside of the Boston RSP subarea.

The Greater Boston Area Needs Assessment results were initially reported in July of 2010. A number of system topology changing events have taken place since the initial report was produced, and the assessment has been re-performed since the initial analysis was completed. The re-assessment was conducted in May of 2013 to reflect current changes in system topology and Forward Capacity Market (FCM) obligations. The Needs Assessment results reported here are based on this reassessment of system needs. The results of the analysis for all of the study work completed indicated that there were a number of design case thermal overloads and unacceptable voltages for N-1 and N-1-1 conditions. In addition there were a limited number of cases where breaker short circuit ratings were exceeded based on short circuit evaluations.

Steady state test results varied as a function of the system conditions modeled. A number of post-contingency overloads and unacceptable voltages were observed in all of the various base cases modeled, and in many cases, only the severity of the unacceptable conditions changed. There were also a number of post contingency overloads and unacceptable voltages that were only associated with specific system conditions. The specific overloads and unacceptable voltages for each dispatch can be found the Greater Boston Area Updated Transmission Needs Assessment January 2015.

The Solutions Study was performed in accordance with NERC TPL-001-4 Transmission System Standards, NPCC "Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System", dated December 1, 2009 (Errata changes 04/20/12), the ISO-NE Planning Procedure 3, "Reliability Standards for the New England Area Bulk Power Supply System," the ISO New England Planning Procedure 5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses", as well as criteria found in Section 13.

1.1.2 Review of N-0 Testing

N-0 (also known as "all-lines-in") conditions were reviewed for the cases modeled. There were no thermal or voltage violations found for design case or sensitivity retirement case conditions.

1.1.3 Review of N-1 Testing

N-1 testing was performed for all of the system conditions described above. A number of post contingency overloads seen in simulations were determined to be correctable through operational adjustments. The Boston area phase shifters, bus tie breakers, HVDC runback and generation runback options are under the supervision of system operators, and operators have the ability to mitigate a number of the problems initially identified through use of these adjustments, all of which are acceptable under planning criteria.

By 2023, N-1 contingency overloads were observed for elements within the Boston RSP subarea across the transmission system, including elements at 69 kV, 115 kV, 230 kV and 345 kV. Some overloads were correctable through system adjustments but many are problems that will need to be addressed through a proposed solution. Sensitivity cases that modeled the retirement of Mystic 7 had contingency overloads similar to the design case problems in terms of the elements that were found to have overloads but were, in general, more severe than the design case results. In addition to increased loading of elements there were also several new contingency overloads that were observed. The higher magnitude overloads along with additional element overloads will consequently require incremental upgrades, should it become necessary to address the retirement case needs.

Additionally, there were a limited number of buses within the Greater Boston system where low voltages were observed under N-1 contingency conditions.

1.1.4 Review of N-1-1 Testing

Element-out-of-service-testing included tests for 115 kV, 230 kV and 345 kV transmission lines as well as 345 kV autotransformers that were Bulk Electric System (BES) elements serving the Greater Boston load area. These element-out-of-service conditions were tested against the full set of contingencies used in the N-1 tests. These were tested for design cases and for sensitivity retirement cases that modeled retirement of Mystic 7. N-1-1 testing was performed using an analytical tool that backed down generation inside the Boston area, backed down HVDC terminal outputs at Sandy Pond, and adjusted phase shifter settings within the Boston area to avoid overloads. The back downs were offset by generation adjustments outside the area of up to 1200 MW.

Overall, by 2023, N-1-1 contingency overloads were observed for elements within the Boston RSP subarea across the transmission system, including elements at 69 kV, 115 kV, 230 kV and 345 kV.

Additionally, there were a set of N-1 and N-1-1 events that isolated an amount of customer load that approached or exceeded 300 MW. Generally these are load pockets within the system that are served by two transmission lines and the loss of both lines disconnects the load from the system. The threshold for corrective action is 300 MW based on ISO-NE load interruption guidelines.[1] Load

[1] Transmission System Planning Load Interruption Guideline November 17, 2010 http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2011/load_interruption.pdf

isolation events that were close to, but did not exceed the 300 MW threshold, were also included. The following load interruptions for such load pockets under 2023 peak load conditions were identified in the Greater Boston area:

- Sudbury Load Pocket (within Sub-area D) - 298 MW [redacted]
- Revere/Chelsea Load Pocket (within Sub-area F) - 357 MW [redacted]
- Norwood/Canton/South Randolph Load Pocket (within Sub-area E) - 324 MW [redacted]

Low voltage violations were observed at a number of buses within sub-areas B through F of the Boston RSP subarea (see Figure 2-1 for sub-area locations) under peak load element out of service contingency conditions.

1.1.5 Limited Short Circuit Margins

The Greater Boston study area is known to have limited short circuit margin at multiple substations based on past studies, where these limited margins have proved to be a significant challenge for the integration of new resources into the area. A short circuit analysis was performed as part of the Needs Assessment, and has confirmed the limited margins in the Greater Boston study area. The results indicate that in addition to limited short circuit margins, a limited number of circuit breakers would exceed their breaker short circuit ratings and these will need to be addressed.

1.1.6 Statement of Need

The results of the Needs Assessment conducted of the Boston RSP subarea transmission performance against transmission reliability standards for the projected 2018 and 2023 system conditions in this study indicate that there are a significant number of thermal overloads and unacceptable voltages across a number of sub-areas within the Greater Boston system. The Boston RSP subarea fails to meet the reliability criteria standards in several geographical sub-areas under the design case testing performed and measures should be developed to mitigate the problems identified[2]. A determination of the year of need, published in the Greater Boston Updated Needs Assessment report, has been established for each measure that was developed as a response to the problems they address.

Please refer to the Greater Boston Updated Needs Assessment Report dated January, 2015.

1.2 Recommended Solution

The Greater Boston Solution was developed in two stages. The first stage culminated in March 2012 with the selection and presentation of a preferred solution to the Planning Advisory Committee (PAC). The second stage of the Greater Boston Solution began after the March 2012 PAC presentation using updated assumptions as documented in Section 3 of this report and evaluated an

[2] In many instances this report refers to results as being "violations". These instances are violations of the thermal, voltage and short-circuit criteria being used in the study.

AC Plan based on the March 2012 preferred solution and HVDC Plan based on a HVDC Plan from the Seabrook 345 kV substation to the downtown Boston area.

The AC Plan was ultimately selected following the second stage because it is significantly less expensive, and also because it is superior when other criteria are considered. The AC Plan consists of the upgrades shown in Table 1-1 and Table 1-2 below. The common upgrades listed in Table 1-1 would be required whether the AC Plan or the HVDC Plan were chosen.

Table 1-1 Preferred Solution Common Upgrades

New Facility	Length (Miles)
West Walpole – Holbrook 115 kV line	14
Sharon Switching Station	NA
Sudbury – Hudson 115 kV line	9
Sudbury 230/115 kV autotransformer	NA
Install K St. tie breaker	NA
Install Stoughton 345 kV series breaker	NA
Newton 115 kV capacitor	NA
Sudbury 115 kV capacitor	NA
Hartwell 115 kV capacitor	NA
345 kV shunt reactor at K St.	NA
Upgraded Facilities	**Length (Miles)**
Rebuild X-24W & X-24E 69 kV	15
Re-conductor M-139 Tewksbury – Billerica Tap 115 kV	3
Re-conductor F-158N Golden Hills – Maplewood 115 kV	4
Re-conductor W-23W 69 kV Northboro Road - Woodside	4
Re-conductor Y-151 Power St – Eversource / National Grid border	4
Other	**Length (Miles)**
Separate Needham – Baker St. 240-510 / 110-522 DCT	4
Separate F-158N / Q-169 DCT	1 structure
Separate X-24W / E-157W DCT	4 structures
Waltham Reconfiguration	NA

North Cambridge Reconfiguration	NA
Kingston 115 kV Reconfiguration	NA
Move Chelsea capacitor	NA
Add a 115 kV breaker at Framingham	NA

Table 1-2 Preferred Solution System Upgrades

AC Plan	Length (Miles)
Scobie – Tewksbury 345 kV line[3]	25
Re-conductor Y-151 115 kV Eversource border to Dracut Jct.	9
Wakefield Jct. – Woburn 345 kV underground cable plus 2 reactors	8
Bifurcate a new Woburn – Mystic 115 kV cable with existing cable	8
Upgrade 5 substations to BPS standards	NA
Add a 200 MVAR STATCOM at Coopers Mills 345 kV in ME	NA
2nd Mystic 345/115 kV autotransformer	NA
Mystic – Chelsea 115 kV underground cable	3
New Woburn 345/115 kV autotransformer and Woburn Reconfiguration	NA
K St. 115 kV breaker addition	NA
Re-conductor M-139 115kV Billerica Tap to Pinehurst Tap	3
Re-conductor N-140 115kV Tewksbury to Pinehurst Tap	7
Re-conductor F-158S 115kV Maplewood to Everett	3
Upgrade terminal equipment to increase 533-508 115 kV Lexington to Hartwell rating	NA
Open Mystic 115 kV downtown ties (mitigates short-circuit concerns)	NA
Operating one of the four Wakefield Jct. autotransformers normally open	NA
Re-conductor M-139 and N-140 lines Pinehurst Tap to North Woburn Tap	5

The criteria used to differentiate the AC Plan and the HVDC Plan and each plan's rating under those criteria are captured in Table 1-3 below.

Table 1-3 Comparison of Alternative Selection Criteria

	AC Plan	HVDC Plan
Cost	✓	✗
Constructability	✓	✓
Construction outage / cost impacts	✓	✗
Expected in-service dates	✓	✓
Interface impacts	✓	✗

[3] The Scobie – Tewksbury 345 kV line and the Y-151 115 kV re-conductoring have been named the Merrimack Valley Reliability Project by the Transmission Owners.

Losses	✓	✗
Extreme contingency analysis results	✗	✓
Expansion capabilities	✓	✗
Lifetime maintenance requirements	✓	✗
Incremental costs for potential retirements	✓	✗
Siting Issues	✓	✓
Storm Hardening	✓	✓

✓ Is applied to the plan which better achieves the objective

✗ Is applied to the plan which does not achieve the objective as well as the other plan

1.3 NERC Compliance Statement

In accordance with North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Standard, this assessment provides:

- A written summary of plans to address the system performance issues described in the *Greater Boston Area Updated Transmission Needs Assessment*, dated January 30, 2015.
- A schedule for implementation as shown in Section 8.3
- A discussion of expected required in-service dates of facilities and associated load level when required as shown in Section 8.3
- A discussion of lead times necessary to implement plans in Section 8.3

Section 2
Needs Assessment Results Summary

2.1 Introduction

The Greater Boston Area Transmission Needs Assessment ("GB Needs Assessment") was conducted for the Boston RSP subarea to evaluate transmission system performance against transmission reliability standards for the projected 2018 and 2023 system conditions. This assessment, detailed in the report "*Greater Boston Area Transmission Updated Needs Assessment*", dated January, 2015[4], indicated that there are a significant number of thermal overloads and unacceptable voltages across a number of sub-areas within the Greater Boston system.

The study area included all or part of several load zones that are collectively called the "Greater Boston" area for the purposes of this analysis. They included the load zone areas known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston, some of the load area south of Boston included in the Southeast Massachusetts load zone or SEMA load zone, and parts of the load area north of Boston included in the New Hampshire load zone (See Figure 2-1). In broad terms the Greater Boston study area can be described as the communities north and east of Interstate 495 north to the New Hampshire border, the city of Boston and some of the suburbs south of Boston. Quantifying the needs for Greater Boston area beyond the Boston RSP subarea allows for a comprehensive assessment of the Boston RSP subarea needs, and for the potential that solutions developed to solve surrounding area needs are coordinated and designed to remedy multiple Boston RSP subarea needs, if possible. This study also coordinated with other surrounding area Needs Assessment and Solutions Studies, such as those conducted for New Hampshire and SEMA/RI. However, accounting for the load, and to describe the study area in general, the term Boston RSP subarea is used throughout the report, even though a small portion of the study area is outside of the Boston RSP subarea.

The Boston RSP subarea transmission performance was tested for steady state performance with all lines in-service, as well as under N-1 and N-1-1 contingency conditions, under a number of possible operating conditions. Thermal overloads were observed for a number of N-1 and N-1-1 contingency conditions. Additionally, unacceptable voltages were observed for a lesser number of N-1 and N-1-1 contingency conditions. Furthermore, short-circuit testing revealed two 115 kV stations with short-circuit currents exceeding breaker ratings, and four 115 kV stations with short-circuit currents between 90% - 100% of their breaker ratings.

2.2 Needs Assessment Review

An overview of the results of the testing was organized by sub-areas within the study area. The set of the defined sub-areas were developed based on a review of the thermal and voltage reliability performance that was specific to particular areas within the Greater Boston study area. The Boston RSP subarea results were grouped into seven sub-areas as follows:

[4] Greater Boston Area Updated Transmission Needs Assessment, January 30, 2015: https://smd.iso-ne.com/planning/ceii/reports/2010s/greater_boston_updated_needs_assessment_report_final.pdf

A. 345 kV And 115 kV Northern Ties to Greater Boston
B. Woburn And Lexington Area
C. Downtown Boston 115 kV Cables
D. Sudbury, Marlboro and Northborough Area
E. Holbrook and W. Walpole Area
F. Boston, Golden Hills and Wakefield Junction Area
H. 115 kV Lines Near Tewksbury

Sub-Area G (115 kV Lines North of Boston in the Salem Area and Near Tewksbury) was recognized but, due to recent upgrades associated with the retirement of the Salem Harbor station (Salem Harbor 1-4) which resulted in the reconductoring of 115 kV lines in the area and with the addition of new resources at Salem Harbor (Salem Harbor 5-6), this sub-area no longer had any reliability issues.

The geographic location of the defined sub-areas in which these concerns were observed is shown in Figure 2-1 below:

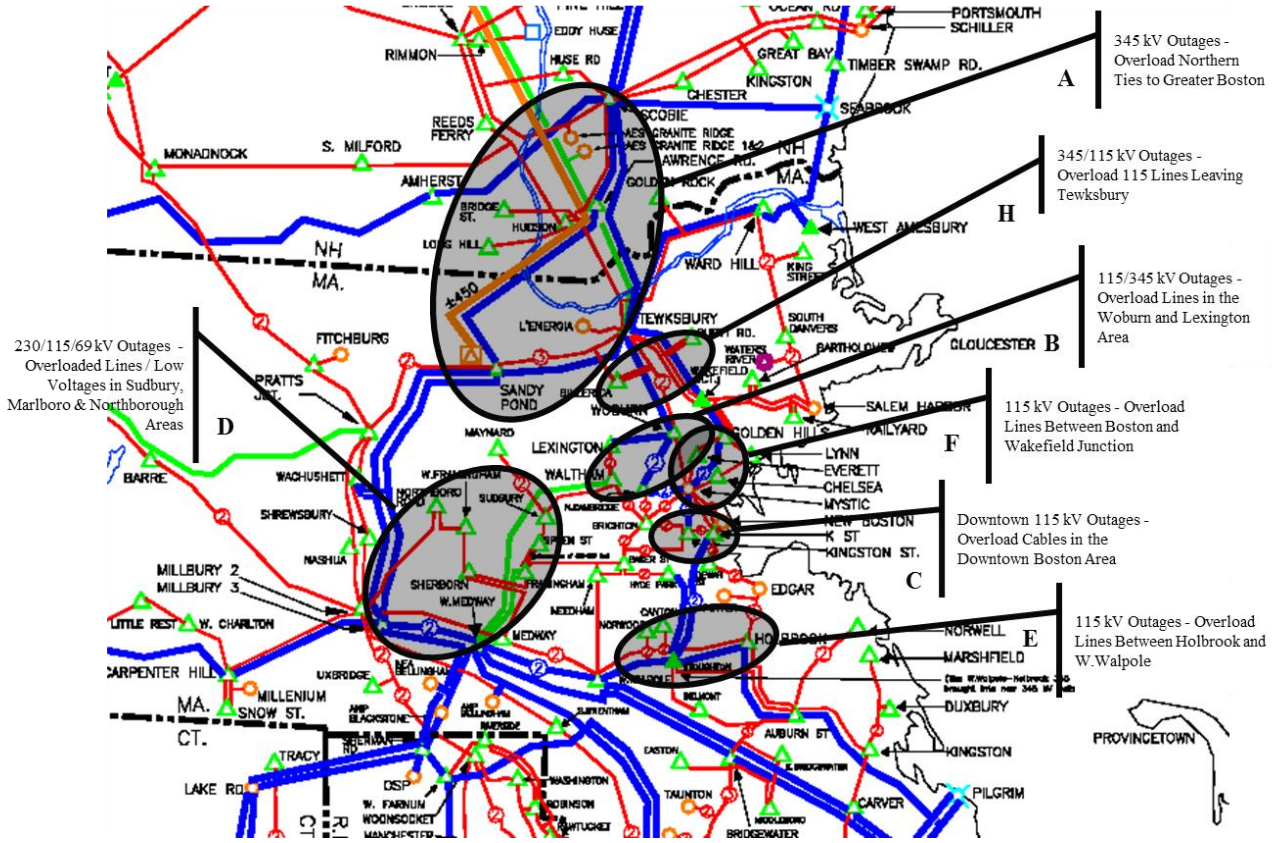


Figure 2-1 Greater Boston Sub-Areas of Concern

2.2.1 Thermal and Voltage Summary

A total of 37 cases for each of the test years (2018 and 2023) were used for the Needs Assessment testing which represented various generation dispatch and transfer level conditions. Combinations of study area resources (Mystic, Kendall, Salem Harbor (5 & 6)[5], Fore River and HQ Phase II HVDC) and/or variations of SEMA/RI, western New England, and northern New England generation were included in the system models tested. These dispatch conditions were also combined with transfer level variations to create a comprehensive set of possible system conditions.

The dispatches used in the needs assessment were categorized as "Design Cases" and "Generation Retirement Sensitivity Cases". Design cases included reasonably expected generation unavailability of two major units in the study area under various New England system transfer stresses. In addition to the design cases with two critical units out of service, the study included design cases with one critical unit out of service, recognizing that one generator out of service in the Boston area may potentially highlight different issues than when there is more than one generator out of service, partly due to generator status-dependent system switching. Additional generation retirement sensitivity cases representing generation retirement/extended shutdown cases have been tested as well. The Solutions Study detailed in this report was conducted to: (1) address the concerns identified in the Greater Boston Needs Assessment report; (2) evaluate performance of solutions for the same design and; and (3) to identify the incremental upgrades associated with the retirement sensitivity cases to determine the robustness of the proposed solutions.

Design Cases

- **One Critical Unit Out of Service Cases**
  These cases assumed Mystic 8, Mystic 9, Kendall CT, Salem Harbor 5(also known as Footprint 1), or Salem Harbor 6 (also known as Footprint 2) out of service, while simultaneously stressing New England system interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface.

- **Two Critical Units Out of Service Cases**
  These cases assumed conditions where two critical units are out of service. These cases included various combinations where two of Mystic7, Mystic 8, Mystic 9, Kendall CT, Salem Harbor 5, or Salem Harbor 6 were out of service. In addition to assuming two critical units in the Boston RSP subarea out of service the New England system interfaces adjacent to the Boston RSP subarea were modeled with a range of stressed conditions on the interfaces which included the North-South interface, SEMA/RI interface and the East-West interface.

[5] Following a non-price retirement request submitted by the owners of Salem Harbor units 1-4, a new resource was proposed by Footprint Power and has cleared in the seventh Forward Capacity Auction. These units were modeled in the base cases and are currently designated as Salem Harbor unit 5 and 6. In certain tables, they are referred to as FP1 or FP2.

Generation Retirement Sensitivity Cases

Generation retirement sensitivity case testing was performed based on stakeholder concerns that the older generating units or stations in the Boston area could retire from service in the near future or be subject to extended shutdown.

- **Mystic 7 Retirement Sensitivity**
  These cases assumed the retirement of the Mystic 7 generation (constructed in 1975). Study cases included two critical units (Mystic 8 and Mystic 9) out of service with related interface transfer levels within their respective defined limits. The Boston Import transfer level was above the existing limit for these cases.

2.2.2 Review of N-0 Testing

N-0 (also known as "all-lines-in") conditions were reviewed for the cases modeled. The results indicate that there were no thermal or voltage reliability concerns under design cases and under the generation retirement sensitivity case conditions.

2.2.3 Review of N-1 Testing

N-1 testing was performed for all of the system conditions described above. A number of post contingency overloads seen in simulations were determined to be correctable through operational adjustments. The Boston area phase shifters, bus tie breakers, HVDC runback and generation runback options are under the supervision of system operators, and operators have the ability to mitigate a number of the problems initially identified through use of these adjustments, all of which are acceptable under planning criteria.

By 2023, N-1 contingency overloads were observed for elements within the Boston RSP subarea across the transmission system, including elements at 69 kV, 115 kV, 230 kV and 345 kV. Some overloads were correctable through system adjustments but many are problems that will need to be addressed through a proposed solution. Sensitivity cases that modeled the retirement of Mystic 7 had contingency overloads similar to the design case problems in terms of the elements that were found to have overloads but were, in general, more severe than the design case results. In addition to increased loading of elements there were also several new contingency overloads that were observed. The higher magnitude overloads along with additional element overloads will consequently require incremental upgrades, should it become necessary to address the retirement case needs.

Additionally, there were a limited number of buses within the Greater Boston system where low voltages were observed under N-1 contingency conditions.

2.2.4 Review of N-1-1 Testing

Element-out-of-service-testing included tests for 115 kV, 230 kV and 345 kV transmission lines as well as 345 kV autotransformers that were Bulk Electric System (BES) elements serving the Greater Boston load area. These element-out-of-service conditions were tested against the full set of contingencies used in the N-1 tests. These were tested for design cases and for sensitivity cases that modeled retirement of Mystic 7. N-1-1 testing was performed using an analytical tool that backed down generation inside the Boston area, backed down HVDC terminal outputs at Sandy Pond, and

adjusted phase shifter settings within the Boston area to avoid overloads. The back downs were offset by generation adjustments outside the area of up to 1200 MW.

Overall, by 2023, N-1-1 contingency overloads were observed for elements within the Boston RSP subarea across the transmission system, including elements at 69 kV, 115 kV, 230 kV and 345 kV.

Additionally, there were a set of N-1 and N-1-1 events that isolated an amount of customer load that approached or exceeded 300 MW. Generally these are load pockets within the system that are served by two transmission lines and the loss of both lines disconnects the load from the system. The threshold for corrective action is 300 MW based on ISO-NE load interruption guidelines. Load isolation events that were close to, but did not exceed the 300 MW threshold, were also included. The following load interruptions for such load pockets under 2023 peak load conditions were identified in the Greater Boston area:

- Sudbury Load Pocket (within Sub-area D) – 298 MW [redacted]
- Revere/Chelsea Load Pocket (within Sub-area F) – 357 MW [redacted]
- Norwood/Canton/South Randolph Load Pocket (within Sub-area E) - 324 MW [redacted]

Low voltage violations were observed at a number of buses within sub-areas B through F of the Boston RSP subarea (see Figure 2-1 for sub-area locations) under peak load element out of service contingency conditions.

2.2.5 Review of Light Load Testing

Testing for element-out-of-service contingency conditions was conducted for two levels of light load conditions. The first level was based on system-wide annual minimum load conditions. This is the lowest load level expected to be seen across the system and typically occurs during the Spring or Fall load periods. The second level tested was based on the lowest load levels seen during summer load periods. Based on the current practice of changing the no-load tap position each season of certain transformers in the Boston RSP subarea, light or off-peak loads during summer months could also introduce an unacceptable voltage condition concern. Off-peak loads were tested at the minimum load level historically seen during summer month periods.

The results of these tests indicated that there were a number of buses within the Boston RSP subarea that exceeded high voltage limit criteria under both minimum load and off-peak load conditions.

2.2.6 Short-Circuit Summary

A short-circuit assessment was conducted to determine the fault current levels and breaker duty for the "as-planned" 2017 Boston RSP subarea transmission system.

The results indicated that there were 26 breakers at Mystic 115 kV and Kingston 115 kV Substations which were found to have a short circuit current above its short circuit rating (overdutied) under 2018 system model condition. In addition breakers at the Brighton 115 kV, K St. 115 kV, Wakefield Junction 115 kV, West Medway 345 kV, and Salem Harbor 115 kV substations were between 90% and 100% of their short circuit breaker rating (highly dutied).

[redacted]

The short-circuit constraints observed in the Greater Boston Needs Assessment were particularly challenging to address in the solution development. This is mainly due to the fact that the transmission solutions needed to address thermal overloads increased the short-circuit current at many of the over-dutied or highly dutied buses. In addition, to allow for future system changes, the solutions were developed with margin in mind. The available margin was used as a factor to determine the final selection of a preferred solution.

2.3 Year of Need/Critical Load Level Analysis

An assessment of the initial year and load level that the system fails to meet the established criteria was performed based on evaluation of thermal overload conditions. This evaluation was performed for N-1 overloads and N-1-1 overloads under design case conditions. The process used was based on a linear projection of the load level at which overloaded elements first fail to meet criteria. The projection for each element with a thermal violation was derived by comparing the 2018 loading to the 2023 loading for specific contingency and dispatch conditions that resulted in the worst case thermal violation to establish a rate of change in loading. This rate of change was then used to calculate the load level at which an overload would first be seen. This process provides an approximation of when contingency based loading on specific elements will reach a threshold level and actual overloads may occur earlier or later than the results indicate. The Boston Critical Load Levels for each element found to be overloaded are listed in Table 2-1 for N-1 and Table 2-2 for N-1-1 below. The Boston load levels identified correspond to the lowest load level for which each element overloads regardless of whether the loading was N-1 (STE or LTE) or N-1-1 condition.

Table 2-1 Year of Need N-1 Assessment

Greater Boston Area N-1 Testing Year of Need Calculation Results							
				LTE Loading for Year		Year of	Critical
Ref	Element ID	Monitored Element	LTE Rating Contingency	2018	2023	Need	Load Level
A-3	394-1-FPL-NED	104127 SEABROOK 345 104128 NU_394_SBK 345 1	[redacted]	111	113	Pre-2013	4680
B-2	WOBURN 345A	110799 WOBURN 115 110756 WOBURN 345 1		105	109	2013	6463
B-3	533-508	110805 HARTWELL 115 110806 LEXINGTON 115 1		100	104	2018	6868
B-5	211-514	110799 WOBURN 115 110820 MYSTIC GIS 115 1		195	204	Pre-2013	2740
B-6	282-520-1	110811 WATERTWN 520 115 903019 282-520_BRTN 115 1A		128	131	Pre-2013	4075
C-1	329-510-1	110816 SOMERVIL 510 115 903025 329-510_MYST 115 1B		108	113	Pre-2013	6182
C-3	385-511-2	110832 KINGSTN ST A 115 903039 385-511_HIGH 115 1A		137	143	Pre-2013	4528
C-4	250-516-3	110818 MYSTIC MA 115 903013 250-516_HAWK 115 1B		141	141	Pre-2013	NA
C-5	110-510-4	110854 WASH_TAP 510 115 903006 110-510_BAKR 115 1A		120	113	2023	7856
C-7	372	110766 KINGSTON ST 345 903005 372_MYST 345 2B		115	116	Pre-2013	2912
C-9	496-529	110892 HYDE PARK B 115 903052 496-529_BAKR 115 1B		134	136	Pre-2013	1165
D-1	W-23	113332 FITCH ROAD 69.0 114785 WOODSIDE 69.0 1		100	105	2018	6858
D-3	W-23W-2	114779 MWRA_W23W 69.0 114780 NBORO_W23W 69.0 1		113	119	Pre-2013	6003
E-1	447-508-1	110900 HOLBROOK 115 114765 S RANDLPH508 115 1		108	111	Pre-2013	5776
E-8	146-502	110895 WEST WALPOLE 115 110913 WALPOLE 502 115 1		114	127	Pre-2013	6403
H-2	M139-2	113969 BILERCA 39_T 115 113987 TEWKSBURY 115 1		99	101	2020	6986

Table 2-2 Year of Need N-1-1 Assessment

Greater Boston Area N-1-1 Testing Year of Need Calcuation Results										
							LTE Loading for Year		Year of	Critical Load
Sub-Area	Element ID	Monitored Element	LTE Rating	Units Out	Line Out	Contingency	2018	2023	Need	Level (MW)
A-10	I135	104990 FITZWILLIAM 115 105001 NU_I135_NGR 115 1	[redacted]	1-2 Units	[redacted]		101	107	2017	6789
A-13	N214	106013 N.LITCHFLD2 230 113955 TEWKSBURY 230 1		1-2 Units			107	111	2021	7021
A-2	337	113950 SANDY POND 345 113951 TEWKSBURY 345 1		1-2 Units			103	109	2021	7082
A-3	394	104127 SEABROOK 345 104128 NU_394_SBK 345 1		1-2 Units			105	107	Pre-2013	5880
A-5	SANDY POND XFMR#1	113950 SANDY POND 345 114027 SANDY PD T1 99.0 1		1-2 Units			133	136	Pre-2013	3347
A-8	A253	104111 MERRIMACK 230 104113 NU_A253_NGR 230 1		1-2 Units			118	124	Pre-2013	5689
A-9	B202S	106011 DUNBARTAN TP 230 106013 N.LITCHFLD2 230 1		1-2 Units			108	113	Pre-2013	6305
B-1	391-508	110804 BURLINGTN MA 115 110805 HARTWELL 115 1		1-2 Units			112	124	Pre-2013	6424
B-2	WOBURN 345A XFMR	110799 WOBURN 115 110756 WOBURN 345 1		1-2 Units			150	158	Pre-2013	4462
B-3	533-508	110805 HARTWELL 115 110806 LEXINGTON 115 1		1-2 Units			152	167	Pre-2013	5563
B-5	211-514	110799 WOBURN 115 110820 MYSTIC GIS 115 1		1-2 Units			266	277	Pre-2013	879
B-6	282-520 / 282-521	110811 WATERTWN 520 115 903019 282-520_BRTN 115 1B		1-2 Units			204	216	Pre-2013	3586
B-7	351 / 358	110759 MYSTIC MA 345 903003 358_NCAMB 345 1B		1-2 Units			141	146	Pre-2013	3500
B-8	346 / 365	110758 N. CAMBRIDGE 345 903000 346_WOBURN 345 1B		1-2 Units			151	151	Pre-2013	N/A
C-1	329-510 / 329-511	110813 BRIGHTON A 115 903026 329-510_SOMR 115 1B		1-2 Units			126	145	Pre-2013	6318
C-2	329-512 / 329-513	110830 KINGSTN ST W 115 903031 329-512_CARV 115 1B		1-2 Units			121	126	Pre-2013	5212
C-3	385-510 / 385-511	110832 KINGSTN ST A 115 903039 385-511_HIGH 115 1A		1-2 Units			162	168	Pre-2013	2903
C-3	385-513	110830 KINGSTN ST W 115 903042 385-513_KST 115 2B		1-2 Units			143	146	Pre-2013	1945
C-4	250-516 / 250-517	110842 CHATHAM 516 115 903015 250-516_KST 115 1B		1-2 Units			135	141	Pre-2013	4181
C-5	110-510 / 110-511	110854 WASH_TAP 510 115 903006 110-510_BAKR 115 1A		1-2 Units			141	148	Pre-2013	4683
C-7	324 / 372	110766 KINGSTON ST 345 903004 324_MYST 345 1B		1-2 Units			117	119	Pre-2013	3182
C-8	329-530 / 329-531	110815 N. CAMBRIDGE 115 903036 329-531_BRTN 115 1B		1-2 Units			129	135	Pre-2013	4998
D-1	W-23	113332 FITCH ROAD 69.0 114785 WOODSIDE 69.0 1		1-2 Units			213	213	Pre-2013	N/A
D-2	E157	113271 WYMNGRDN57_T 115 113275 E157_M165_J 115 1		1-2 Units			131	136	Pre-2013	4227
D-3	W-23W	114779 MWRA_W23W 69.0 114780 NBORO_W23W 69.0 1		1-2 Units			265	265	Pre-2013	N/A
D-4	X-24W	113339 N GRAFTON 69.0 114784 WESTBORO 69.0 1		1-2 Units			184	185	Pre-2013	N/A
D-5	433-507	110870 FRAMINGHAM 115 110871 SPEEN STREET 115 1		1-2 Units			136	137	Pre-2013	N/A
D-6	282-507	110810 WALTHAM PS 115 110872 SUDBURY 115 1		1-2 Units			105	110	Pre-2013	6429
D-7	240-508	110868 SHERBORN 115 110870 FRAMINGHAM 115 1		1-2 Units			108	108	Pre-2013	2102
D-7	274-509	110866 MEDWAY 115 110868 SHERBORN 115 1		1-2 Units			101	106	2017	6758
D-7	455-507	110868 SHERBORN 115 110869 W FRAMINGHAM 115 1		1-2 Units			132	137	Pre-2013	4406
D-7	513-507	110869 W FRAMINGHAM 115 115027 NG513-507NST 115 1		1-2 Units			106	111	Pre-2013	6348
D-9	N-40 A&B	113332 FITCH ROAD 69.0 113346 PRATTS JCT 69.0 1		1-2 Units			126	127	Pre-2013	N/A
E-1	447-508 / 447-509	110895 WEST WALPOLE 115 110897 WALPOLE 509 115 1		1-2 Units			118	125	Pre-2013	5885
E-4	3162	110862 K STREET 2 345 903062 3162_STGTN 345 1A		1-2 Units			98	101	2021	7090
E-4	3163	110790 K STREET 1 345 903063 3163_STGTN 345 1A		1-2 Units			99	102	2020	6946
E-5	HYDE PARK 345A XFMR	110791 HYDE PARK 115 110788 HYDE PARK 345 1		1-2 Units			107	108	Pre-2013	5150
E-6	282-602	110789 WALTHAM 230 110794 W MEDWAY A 230 1		1-2 Units			99	104	2019	6910
F-1	F158N	114410 GOLDNHL45-58 115 114412 MAPLEWOOD 115 1		1-2 Units			150	154	Pre-2013	1895
F-2	F158S	114409 EVERETT 115 114412 MAPLEWOOD 115 1		1-2 Units			132	135	Pre-2013	2736
F-4	349 XY	110759 MYSTIC MA 345 115017 NGR_349X_NST 345 1		1-2 Units			99	105	2019	6898
F-6	Q169	114430 GE RIVER69_T 115 114448 LYNN Q169 115 1		1-2 Units			110	116	Pre-2013	6082
H-1	T146-1	113974 E TWKSBRY_46 115 113987 TEWKSBURY 115 1		1-2 Units			104	110	2015	6577
H-1	S145E	114405 RAILYARD_45 115 114417 SALEM HARBOR 115 1		1-2 Units			129	129	Pre-2013	N/A
H-1	T146W	113999 N READING_46 115 114485 WAKEFLD146 115 1		1-2 Units			117	129	Pre-2013	6242
H-2	M139	113969 BILERCA 39_T 115 113987 TEWKSBURY 115 1		1-2 Units			121	127	Pre-2013	5405
H-3	N140	113962 PINEHURST 115 113987 TEWKSBURY 115 1		1-2 Units			110	114	Pre-2013	5991

[redacted]

Section 3
Solutions Study Assumptions

3.1 Analysis Description

This Solutions Study evaluated the transmission solutions to the long term area reliability needs, as identified in the Greater Boston Area Transmission Updated Needs Assessment study issued January, 2015 for the Greater Boston and surrounding areas. The study included steady state, dynamic, and short-circuit assessments.

The course of the Solutions Study was essentially segmented into two distinct study efforts or stages. The initial study stage developed a comparison of potential transmission upgrades culminating in a preferred solution presented to PAC in March of 2012. This study used the original assumptions for load, resources, system topology, and circuit ratings as documented in the Greater Boston Area Transmission Needs Assessment July 2010.

The second stage began in 2012 after the March 2012 preferred solution selection and developed a comparison of an updated AC Plan to a newly developed HVDC Plan that featured an HVDC line from Seabrook to downtown Boston and other AC solution components. The second stage of the study included a revision to the base case assumptions as noted in Section 3.6 of this report. The assumption changes between Stage 1 and Stage 2 resulted in a similar, but not exactly the same, set of reliability concerns than in the initial stage that are documented in the Greater Boston Area Transmission Assessment dated January 2015. As a result of the changes in study assumptions the final AC Plan identified as the preferred solution in this report differs from the March 2012 preferred solution.

The transmission needs in the Boston RSP subarea required the evaluation of numerous transmission alternative solutions. In many cases there were two or more competing alternatives that could potentially meet the needs of each Greater Boston sub-area. The multiple competing alternatives for each of the subareas resulted in a large number of combinations of competing solutions, and testing each combination was not practical. To manage the evaluation of the competing solutions, the Greater Boston Working Group (GBWG) evaluated the competing solutions in sequential phases in the following geographical and electrical areas: North, South, Western Suburbs, and Downtown Boston.

Several software modeling tools were used for the evaluations. These include:

- Transmission Analysis and Reliability Assessment (TARA) version 7.10[6] was used to conduct all steady state contingency analysis presented in this report. This application allowed for interactive adjustment of phase shifter settings to capture operational responses, re-dispatch of generation to minimize overloads, processing of multiple base cases against a large number of contingencies and reporting of results in an effective manner.

[6] TARA (Transmission Adequacy and Reliability Assessment) is load flow software tool for identifying and analyzing transmission bottlenecks, DC (linear) & AC (non-linear) contingency analysis, Security Constrained Economic Dispatch (SCED), and Security Constrained Reliability Dispatch (SCRD).

- PSS/E version 32 was used to set-up the system topologies for steady-state contingency analysis and was used for dynamic analysis.
- ASPEN version 11 was used to conduct the short-circuit analysis.

3.2 Steady State Model Assumptions

3.2.1 Study Assumptions

The Greater Boston steady-state models were developed to be representative of system states which model reasonably stressed conditions that may be seen during summer peak load seasons. The assumptions included a wide range of generation unit unavailability as well as variations in surrounding area transfer levels at 90/10 summer peak, light load and minimum load conditions. The case summaries for the conditions studied are found in Section 11.

3.2.2 Source of Power Flow Models

The power flow cases used for the peak load assessment were developed from the Greater Boston Transmission Needs Assessment study and represent a 2023 load level. The transmission topology is identical for the Greater Boston area for 2018 and 2023 and hence only the 2023 case was used for the solutions development. The power flow study cases used in this study were obtained from the ISO-NE Model on Demand (MOD) system.

The power flow cases used for the minimum load assessment were also developed from the 2023 ISO-NE MOD database.

3.2.3 Transmission Topology Changes

The original Greater Boston Needs Assessment and Solutions Study base cases were created in 2008 and included all transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff. The Greater Boston Needs Assessment and Solutions Study base cases were updated in 2012 and included all transmission projects with Proposed Plan Application (PPA) approval in accordance with Section I.3.9 of the Tariff, as of the March 2012 RSP Project Listing. However, in April 2013 the cases were modified to reflect the changes post Forward Capacity Auction 7 (FCA-7). As a part of this process several additional transmission upgrades were added based on the March 2013 project listing and were included in the base cases. A list of transmission system facility changes included in the study cases can be found in Section 10.

3.2.4 Generation Assumptions (Additions & Retirements)

Generation projects with an FCM Capacity Supply Obligation as of FCA-7 were included in the study base case. A listing of the major new future projects cleared in FCA-1 through FCA-7 that were not yet in-service at the time of the study is included below.

New Hampshire

- QP 251 – Laidlaw Berlin (Burgess) Biomass Energy Plant (FCA-4)

Massachusetts

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

Rhode Island

- QP 233 – Rhode Island Landfill (FCA-2)

Connecticut

- QP 150 – Plainfield Renewable Energy Project (FCA-3)

A significant sized new unit was cleared in FCA-7 for the Boston RSP subarea and this new generation was modeled in the study cases. The unit is identified as Footprint (Queue Position 387.2), also known as Salem 5 & 6 Generation. This new generation was included in the Greater Boston area study. The plant consists of two combined cycle units configured as four generators. Each pair is to be made up of a 203 MW and 134 MW generators. The total combined output of both pairs is 674 MW. These units are expected to be in service by June 1, 2017.

The existing Salem Harbor units 1 through 4 have retired and these units have been removed from all base cases used in the study.

Generation was modeled at its qualified capacity from FCA-7, as per ISO-NE Planning Technical Guide.

As mentioned above, retirement sensitivity cases capturing potential generation retirements were created to represent the potential retirement of a unit at Mystic Station. This retirement case was based on past submitted requests for reliability determinations (Mystic 7). This possible retirement condition was evaluated under various transfer level conditions to determine additional incremental upgrades needed for the retirement scenarios.

3.2.5 Explanation of Future Changes Not Included

All known system changes for the area under study were included in the study cases. Transmission upgrades that have not been fully developed and generation additions that have not cleared in the 2013 FCA-7 were not modeled due to the uncertainty concerning these proposed system additions.

Additionally, as a part of the case refresh in April 2013, certain transmission projects that are electrically located a significant distance away from the study area and were not expected to have a significant impact on the study area were excluded. The following list highlights a few prominent projects that were excluded:

- The Pittsfield-Greenfield Solution (RSP ID: 1208-1210, 1221-1226)
- Advanced SWCT – Line 8300 Reconfiguration (RSP ID: 1246)
- Advanced SWCT – Glenbrook to South End 115 kV Cable (RSP ID: 1228)

There are also Non Price Retirement (NPR) requests from FCA-8 that were not removed from the load flow or short circuit base cases as their determination was made following completion of the assessment. Vermont Yankee and Brayton Point units requested NPRs in FCA-8 but were not removed from the thermal base case models.

Finally, the New England East West Solution (NEEWS) – Central Connecticut Reliability Project components (RSP ID: 576, 1114, 1372, 1373) had PPA approval at the time of the study initiation

were excluded. The PPAs for these projects have since been withdrawn and the project has been replaced with the Greater Hartford Central Connecticut projects. Since these changes are remote to the study area, they are not expected to have a significant impact on the Solutions Study.

3.2.6 Forecasted Load (including assumptions concerning energy efficiency, interruptible loads, etc.)

The 2013 ISO-NE system load forecast was used as a basis for the demand levels modeled in the study. As of 2012, load modeling for the New England network model is based on forecasted loads as well as forecasts in energy efficiency (EE), passive and active demand resources (DR). The values reported in the 2013 CELT report were used to develop the 2023 network load model that was included in the study. Table 3-1 and Table 3-2 below show the aggregate amount of passive and active DR modeled in the 2023 cases. A more detailed breakdown of DR assumptions can be found later in section 3.2.13 showing all forms of demand resources including availabilities for the different years. Demand resources were not explicitly modeled in either minimum load level or summer off-peak load level testing as they are already incorporated into the load levels being examined.

Table 3-1:
2023 Passive DR Values: DR through FCA-7 and EE Forecast

Load Zone	Passive DR (FCA-1-7) DRV[7] (MW)	EE Forecast (2017-2023) DRV[5] (MW)	Total 2023 Passive DR DRV[5] (MW)
Maine	159	71	230
New Hampshire	80	64	144
Vermont	125	108	233
Northeast Massachusetts & Boston	341	341	682
Southeast Massachusetts	194	168	362
West Central Massachusetts	245	205	450
Rhode Island	142	139	281
Connecticut	417	173	590
New England Total	1,703	1,269	2,972

[7] DRV = Demand Reduction Value = the actual amount of load reduced measured at the customer meter. These values exclude transmission and distribution losses.

Table 3-2 Active DR Values through FCA-7

Dispatch Zone	Active DR (FCA-1-7) DRV (MW)
Bangor Hydro	56
Maine	207
Portland, ME	32
New Hampshire	49
New Hampshire Seacoast	12
Northwest Vermont	38
Vermont	25
Boston, MA	62
North Shore Massachusetts	20
Central Massachusetts	51
Springfield, MA	31
Western Massachusetts	78
Lower Southeast Massachusetts	18
Southeast Massachusetts	69
Rhode Island	74
Eastern Connecticut	53
Northern Connecticut	100
Norwalk-Stamford, Connecticut	45
Western Connecticut	126
New England Total	1,146

3.2.7 Load Levels Studied

The 2023 90/10 summer peak load level was tested. These cases were based on the 2013 CELT report (See Section 9) forecast 90/10 summer peak load level of 34,460 MW for all of New England and the Boston Import area loads were modeled based on a forecasted peak demand level of 7,210 MW[8] or 20.9% of the New England demand which is consistent with area load peak demand assumptions of 20% to 21%. The CELT forecast shown in Section 9 only has loads until 2022 and the load growth rate from 2021 to 2022 was used to derive the 2023 loads.

Additionally, light load analysis was conducted and this analysis included modeling of system loads at their minimum observed levels as well as under summer off-peak load levels. Minimum load levels have been trending in the downward direction and a system load level of 8,500 MW has been established as the most appropriate load level to study when conducting minimum load level analysis. This load level was used for the assessment of minimum load level voltage performance of the

[8] The Boston Import area load was derived based on the definition of busses that are included in the Boston Import area as established by ISO-NE.

Greater Boston area. Based on the current practice of changing the no-load tap position each season of certain transformers in the Greater Boston area, light or off-peak loads during summer months could also introduce a voltage violation concern. Off-peak loads were tested at the minimum load level historically seen during summer month periods (New England load at 10,500 MW). Testing was performed for both the minimum load level and the summer off-peak load level conditions.

3.2.8 Load Power Factor Assumptions

Load power factors consistent with each of the Transmission Owner's planning practices for establishing power factors for loads in the Greater Boston area were assumed for the load model data. The appropriate load power factor was used for each of the load levels modeled.

Peak load power factor was modeled based on the data submitted by the Transmission Owners. Light load high voltage testing was performed at a 0.998 p.u. leading power factor across New England with the exception of 0.978 p.u. lagging power factor for NSTAR load in downtown Boston and unity power factor for the NSTAR suburban load.

3.2.9 Transfer Levels

The purpose of the Solutions Study was to test the potential solutions under a variety of system stresses. The system stresses that most impact the Boston RSP subarea are the North/South transfer, the SEMA/RI export level, and the Phase II HVDC level. Cases were developed that captured each of these system stresses in combination with the Boston unit outage assumptions. This resulted in stressed cases under 2023 peak load conditions with Boston Import levels, depending on the unit outage assumptions, varying between 3,259 MW and 5,075 MW. Additionally cases were run to test a range of interface transfer levels for both the North-South interface and the SEMA/RI interface. The North-South interface levels for 2023 ranged from a high of 2,785 MW to a low of 1,620 MW and the SEMA/RI export values ranged from 2,496 MW to a low of 1,242 MW.

Other relevant interfaces that play a role in the area under study are listed below along with their current maximum transfer level ranges based on the 2013 Federal Energy Regulatory Commission (FERC) 715[9] report for the 2018 system:

- Phase II Import: [redacted]
- East-West: [redacted]
- West-East: [redacted]
- New Brunswick – NE: [redacted]
- Highgate – NE: [redacted]
- Northern New England (NNE) – Scobie +394 Line: [redacted]

New York-New England and other external interfaces were allowed to float within acceptable limits.

[9] http://www.iso-ne.com/system-planning/transmission-planning/ferc-form-no-715-reports

[redacted]

Table 3-3 below provides a summary of the transfer levels modeled in all base cases for the significant interfaces associated with the Boston RSP subarea.

Table 3-3 Significant Interface Modeled Transfer Levels

Case Title and Year	NE-BOSTON	NORTH-SOUTH	SEMA/RI - NE	SANDY POND IMPORT	EAST-WEST	NB-NE	ME-NH
[redacted]	3438	2779	2496	2000	2317	700	1841
	3259	2721	2495	2000	2479	700	1841
	3788	2726	2496	2000	2001	700	1841
	3787	2729	2493	0	36	700	1841
	3802	2725	2495	2000	1987	700	1841
	3799	2729	2492	0	23	700	1841
	3778	2781	2496	2000	2020	700	1841
	3838	2724	2496	2000	1947	700	1841
	4370	2727	2496	2000	1428	700	1841
	4124	2784	2496	2000	1686	700	1841
	4488	2727	2495	2000	1311	700	1841
	4137	2783	2495	2000	1672	700	1841
	5072	2728	2494	2000	735	700	1841
	3438	2759	1816	0	-429	700	1823
	3258	2720	1792	0	-288	700	1823
	3790	2717	1243	2000	606	700	1823
	3787	2718	1790	0	-813	700	1823
	3804	2716	1242	2000	589	700	1823
	3800	2718	1789	0	-827	700	1823
	3780	2753	1795	2000	1168	700	1823
	3840	2752	1794	2000	1109	700	1823
	4372	2757	1793	2000	591	700	1823
	4125	2756	1819	2000	859	700	1823
	4489	2757	1791	2000	473	700	1823
	4138	2756	1817	2000	844	700	1823
	5073	2758	1787	2000	-108	700	1823
	3434	1649	1812	1400	-184	700	1184
	3253	1650	1813	1400	-3	700	1184
	3776	1646	2488	0	-1230	700	1184
	3793	1647	2487	0	-1246	700	1184
	3772	1622	2494	1400	159	700	1184

[redacted]

[redacted]	3831	1623	2493	1400	101	700	1184
	4363	1619	2492	1400	-424	700	1184
	4118	1622	2492	1400	-185	700	1184
	4480	1619	2490	1400	-541	700	1184
	4129	1622	2491	1400	-197	700	1184
	5064	1647	2485	1400	-1125	700	1184

Additionally, light load (minimum load and summer off-peak) level testing included modeling of transfer level conditions appropriate to this load level. The assessment included modeling the North-South transfers at a reduced level, high and low West-East transfers and modeling of Hydro Quebec Phase II at 0 MW and 500 MW.

3.2.10 Generation Dispatch Scenarios

A total of 37 cases were modeled for each of the two study years and used in all the N-1 and N-1-1 contingency testing for the peak load testing which represented a number of possible generation dispatch and availability conditions. The cases all have a major Boston RSP subarea unit out of service as a base condition. The cases are organized by surrounding interface transfer levels. One set (labeled "A" cases) is based on high North-South transfers along with high SEMA/RI export levels, the second set (labeled "B" cases) is based on high North-South transfers with low SEMA/RI export levels and the final set (labeled "C" cases) is based on low North-South transfers with high SEMA/RI export levels.

Based on operational experience, it was assumed that approximately 80% of the fast start units in the Boston RSP subarea were modeled as being in-service.

In addition, combinations of study area resources (Mystic, Kendall, and Footprint) as well as resources in close proximity to the Boston RSP subarea (Fore River and HQ Phase II HVDC) were adjusted versus variations of SEMA/RI, western New England, and northern New England resources in the system models tested. These dispatch conditions were also combined with the North-South and SEMA/RI interface transfer level variations to create a comprehensive set of possible reliability assessment system conditions.

The cases tested are also categorized throughout the report as design cases and retirement sensitivity cases. Design cases include reasonably expected generation unavailability with various New England system transfer stresses. Included in the set of design cases with two critical units out of service were cases with one critical unit out of service, recognizing that one generator out of service in the Boston RSP subarea may potentially highlight different issues than when there is more than one generator out of service, partly due to unit status-dependent system switching [redacted] Reliability concerns identified in design cases constitute a need that must be addressed by a proposed solution to meet reliability criteria at the load level studied. Additional retirement sensitivity cases representing generation retirement/extended shutdown cases have been tested as well to be consistent with NERC planning criteria. The Solutions Study objective was to address the problems and concerns identified in the Greater Boston Area Transmission Updated Needs Assessment for the design cases. The results of this study were based on analysis for both design and

[redacted]

retirement sensitivity case conditions to determine both the robustness of the proposed solutions and to identify the incremental upgrades associated with the sensitivities.

PEAK LOAD DISPATCH CONDITIONS

Design Cases

- **One Critical Unit Out of Service Cases**

  These cases assumed Mystic 8, Mystic 9, Kendall CT, Salem Harbor 5, or Salem Harbor 6 out of service, while simultaneously stressing New England system interfaces adjacent to the Boston RSP subarea which included the North-South interface, SEMA/RI interface and the East-West interface.

- **Two Critical Units Out of Service Cases**

  These cases assumed conditions where two critical units are out of service. These cases included various combinations where two of Mystic7, Mystic 8, Mystic 9, Kendall CT, Salem Harbor 5, and Salem Harbor 6 were out of service. In addition to assuming two critical units in the Boston RSP subarea out of service the New England system interfaces adjacent to the Boston RSP subarea were modeled with a range of stressed conditions on the interfaces which included the North-South interface, SEMA/RI interface and the East-West interface.

Generation Retirement Sensitivity Cases

Generation retirement sensitivity case testing was performed based on stakeholder concerns that the older generating units or stations in the Boston area could retire from service in the near future. The unit that was chosen for the "Generation Retirement Sensitivity" testing was Mystic 7 due to the age of the unit – 40 years old, which is based on the unit's commercial operation year of 1975. The sensitivity cases assumed the retirement of the Mystic 7 generation. Study cases included two critical units (Mystic 8 and Mystic 9) out of service with related transfer levels within their respective defined limits. The Boston Import transfer level was above the existing limit for these cases.

Summary of Generation Dispatch Conditions Modeled

Table 3-4 shows the major generation dispatch for units associated with the Boston RSP subarea. The values shown in Table 3-4 are the total output of the generators which consists of the qualified capacity of each unit.

Table 3-4 2023 Modeled Generation Dispatch Conditions

[redacted]	697	158	601	698	706	337	0
	697	0	601	698	706	337	337
	697	158	601	0	706	337	337
	697	158	601	0	706	337	337
	697	158	601	698	0	337	337
	697	158	601	698	0	337	337
	697	158	601	698	706	0	0
	697	0	0	698	706	337	337
	697	158	0	0	706	337	337
	697	158	601	0	706	337	0
	697	158	601	0	0	337	337
	697	158	601	698	0	337	0
	697	158	0	0	0	337	337
	697	158	601	698	706	337	0
	697	0	601	698	706	337	337
	697	158	601	0	706	337	337
	697	158	601	0	706	337	337
	697	158	601	698	0	337	337
	697	158	601	698	0	337	337
	697	158	601	698	706	0	0
	697	0	0	698	706	337	337
	697	158	0	0	706	337	337
	697	158	601	0	706	337	0
	697	158	601	0	0	337	337
	697	158	601	698	0	337	0
	697	158	0	0	0	337	337
	0	158	601	698	706	337	0
	0	0	601	698	706	337	337
	697	158	601	0	706	337	337
	697	158	601	698	0	337	337
	697	158	601	698	706	0	0
	697	0	0	698	706	337	337
	697	158	0	0	706	337	337
	697	158	601	0	706	337	0
	697	158	601	0	0	337	337
	697	158	601	698	0	337	0
	697	158	0	0	0	337	337

Light Load Dispatch Conditions

Light load dispatch conditions were similar for both the minimum load level modeling and the summer off-peak load level modeling. Light load level analysis used the generation dispatch conditions listed below:

[redacted]

- All major Boston generation out of service
- Pilgrim and Seabrook generators out of service
- Reduced eastern New England generation
- All pumped storage hydro units off-line

Minimum load testing was based on the following dispatches:

1. Phase II on at 500 MW with low SEMA/RI export and low North-South transfers
2. Phase II on at 500 MW with medium SEMA/RI export and low North-South transfers
3. Phase II off with low SEMA/RI export and low North-South transfers

In addition two sensitivity cases were tested with the following modifications to Phase II Dispatch 1 above:

1. Seabrook on
2. Pilgrim on

3.2.11 Reactive Resource and Dispatch Assumptions

All area reactive resources were assumed available and dispatched if conditions called for their dispatch. Reactive output of units was constrained to defined limits and shunt reactive resources were dispatched as conditions called for. Summaries of reactive output for units and for shunt devices connected to the transmission system that play a significant role in the Boston RSP study area can be found in Section 12 in the generation summary Table 12-1 and the shunt reactive device summary Table 12-2.

Light Load Assumptions

The following system adjustments were used for both the minimum load level and summer off-peak load level testing.

Northern New England Reactors
The northern New England reactors were dispatched to keep the 345 kV voltages within acceptable limits, which resulted in some reactors being off. Turning on all the reactors was avoided since the study was utilizing a reduced contingency set and there could be the possibility that other contingencies could potentially cause low voltages.

Sandy Pond Filter Banks
The filter capacitors at Sandy Pond were adjusted to match the dispatch instructions for Phase II. The filter bank requirement is based on the MW dispatch at Sandy Pond. For a 500 MW dispatch the total filter banks were set to 345 MVAR. For one of the Phase II lines out, the filters were reduced to 175 MVAR.

Sandy Pond Reactors
At 500 MW import on Phase II the reactors at Sandy Pond were adjusted to keep the Sandy Pond voltage between 353 kV and 358 kV. In general a maximum of two reactors at Sandy Pond were on

line for the base cases with a potential third reactor switched on if voltage at Sandy Pond rises above 358 kV for the element out cases.
At 0 MW import on Phase II the voltage at Sandy Pond was typically maintained above 350 kV.

NSTAR Autotransformer Taps
The no load taps on the following NSTAR autotransformers were adjusted to match the light load setting. Once a preferred solution was developed the tap settings at the different stations were reviewed and modified to work with the final system:

1. North Cambridge 345 A and 345 B
2. Mystic 345 A
3. West Medway 345 A and 345 B
4. Kingston St. 345 A and 345 B
5. Framingham 230 A
6. Waltham 230 A

Woburn Load Tap Changer
The LTC on the Woburn 345/115 kV transformer was used to absorb up to 240 MVAR off the 345 kV system through voltage schedule adjustments that take advantage of the shunt reactive resources located on the 115 kV system.

3.2.12 Market Solutions Consideration

All market solution alternatives were assumed to have been identified through the ISO-NE FCM process and have been captured in the base case models used in the analysis.

3.2.13 Demand Resource Assumptions

Demand Resources were modeled in the base cases consistent with current practices for inclusion of DR. Demand Resources were modeled in peak load base cases as detailed in Table 3-5 and Table 3-6 below. The passive and active demand reductions are constant for the 2018 and 2023 system conditions. The differences for the two study years is based on EE forecasts. In Table 3-5 below the variable forecasted EE for 2018 and 2023 is lumped together with the fixed passive demand reductions through FCA-7 to provide the total passive DR that was modeled for the years 2018 and 2023.

Table 3-5:
2023 Passive and Active DR Values

Load Zone	2023 Passive[10] DR (DRV[11] MW)	2023 Active DR (DRV MW)	Total 2023 Available DR (Modeled[12] MW)
Maine	230	295	476
New Hampshire	144	61	200
Vermont	233	63	296
Northeast Massachusetts & Boston	682	82	784
Southeast Massachusetts	362	87	451
West Central Massachusetts	450	160	601
Rhode Island	281	74	355
Connecticut	590	324	879
New England	**2,972**	**1,146**	**4,042**

Table 3-6 New England Demand Resource Performance Assumptions

Region	Passive DR	Energy Efficiency	Active DR	RTEGs
New England	100%	100%	75%	0%

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

There are a number of Special Protection Systems (SPS) that are designed to operate in and around the Greater Boston study area. These SPSs have, in some cases, been in service for a significant period of time.[13] Each of these SPSs was either modeled directly or taken into consideration when

[10] Passive DR includes passive DR cleared through FCA-7 as well as forecasted EE for the study year.

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

[12] Modeled DR in cases includes 100% of Passive DR and 75% of Active DR. The DRV values are scaled up by 5.5% to account for avoided distribution losses. Modeled MW = 1.055 x (100% Passive DRV + 75% Active DRV).

[13] [redacted] have been in service since prior to 1990.

[redacted]

reviewing results. Table 3-7 below lists the SPSs that potentially affect the Greater Boston transmission system.

Table 3-7
Greater Boston Area Special Protection Systems

SPS Name	SPS Action Description
[redacted]	

3.2.15 Explanation of Operating Procedures and Other Modeling Assumptions

The Boston area transmission power flows are managed on a daily basis through the use of generation dispatch and phase shifting transformers located at [redacted] The phase shifters are located on the 115 kV systems inside the Boston Import area and are set to balance power flows under normal conditions and are adjusted to mitigate power flows post contingency, as necessary.

For the purposes of the contingency testing conducted as part of this study, phase shifters were adjusted to angles that appeared to work best for post contingency conditions based on phase shifter optimization analysis included in the power flow testing application. This was not intended to reflect how the phase shifters would be operated under normal system conditions or to reflect the exact response to particular contingencies. Rather they were set to post contingency angles, within an appropriate operating range of the phase shifters to minimize potential overloads due to contingencies. This avoided reporting of overloads for which phase shifter action would serve as the

[redacted]

mitigating measure. Further adjustment of the phase shifters was also found to be effective at relieving other overloads post-contingency for overloads that did not exceed STE ratings for elements on the Greater Boston transmission system. It should be noted that phase shifter tap settings were adjusted to unit specific values to accurately model the actual tap settings available on each phase shifting transformer as part of the final solution assessment.

Generation adjustments were also modeled in the analysis to reflect system adjustments that could occur between outages under N-1-1 contingency conditions. These adjustments were primarily limited to [redacted] The adjustments were limited to a total of 1,200 MW across the New England system to reflect consistency with operating reserve constraints. The units listed in Table 3-8 were included in the set of units used for system adjustments between contingencies. Units in western New England and New York were allowed to vary their dispatch up or down if on-line in the case whereas all other (including Boston area) units could only reduce output in response to potential overloads.

Additionally, for the purposes of conducting voltage assessments it is important to note that a number of autotransformers in the Greater Boston area have their no-load tap positions adjusted each season to better optimize the voltage performance of the system between peak load conditions and shoulder period (Spring and Fall) load conditions.

Table 3-8 Units That Were Allowed to Adjust Between Contingencies

Unit Name	Unit Name
Boston Units	**Western NE Units**
Framingham Jets	New Haven Harbor
Kendall Jet	Lake Road 1
L Street Jet	Montville 6
Mystic Jet	Westbrook C1, C2 & ST
W Medway Jet 1, 2 & 3	C. Cove
MATEP 3	**Northern NE Units**
MATEP Diesels	Granite GT
MBTA Jet	Newington G
Waters River J1	Merrimack ST & CT
Mystic 7	MIS C1, C2 & ST
Mystic 8	SEMA/RI Units
Mystic 9	Cherry Street Diesels
Salem Harbor 5	Fitchburg
Salem Harbor 6	Canal 2
Kendal ST & CT	Brayton Point 3
HVDC Terminals	**Greater Boston Units**
Phase 2 HVDC Pole 1	Fore River
Phase 2 HVDC Pole 2	ANP Bellingham
CSC Terminal	Ipswich Diesels
	Marblehead

Additionally, operator initiated system adjustments were assumed to be available as mitigating measures for certain conditions. In some cases closing of bus tie breakers that are normally operated open or that can be opened under certain dispatch conditions were assumed to be viable operator responses to certain overloads under appropriate conditions. [redacted]

3.3 Stability Modeling Assumptions

3.3.1 Study Assumptions

The introduction of new transmission elements into the Boston RSP subarea may cause some stability criteria concerns. Once the preferred alternatives were identified a screening test of Bulk Power System (BPS) classification of stations in the Greater Boston and surrounding areas was conducted. BPS testing requirements call for the assessment of dynamic performance under contingency conditions with local protection systems out of service. The performance of the power system under these contingency events is intended to determine the need for independent protection systems based on the power system's ability to withstand such events without grid collapse or propagation outside of the local area of the station under test. The BPS contingency testing includes modeling a permanent 3-phase fault on a bus without local protection systems in operation.

Additionally, a stability analysis was performed for each alternative for a limited number of 115 kV extreme contingencies that simulated 3 phase faults with a stuck breaker. A number of stressed system conditions were selected to test stability performance which included a heavy Maine and Boston dispatch case, a heavy SEMA/RI and Boston dispatch case and a heavy central Boston dispatch case.

The stability models used as part of this analysis were developed to be representative of the near term projection of a light load system demand level to assess the dynamic performance of the power system under stressed system conditions. The model assumptions included consideration of surrounding area regional transfer levels. These study assumptions are consistent with Planning Procedure 3 (PP-3).

The starting base case for the analysis was the 2016 light load case from the 2011 Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Base Case library.

A more detailed stability analysis will be performed as part of the PPA analysis for the final selected preferred solution. This analysis will include a detailed assessment of normal contingencies, extreme contingencies and BPS performance.

[redacted]

3.3.2 Load Levels Studied

The transient stability study was performed at light load levels. The testing was performed at a 2016 light load (45% of 50/50 peak load) New England load and, with losses included, represents a New England system load level of approximately 14,200 MW.

3.3.3 Load Models

The load models used when performing dynamic simulations for New England included a constant impedance load model, consistent with New England practices for stability modeling.

3.3.4 Dynamic Models

The dynamic models are captured in the snapshot file from the ERAG/MMWG Base Case libraries. The normal testing corresponds with the 2016 light load cases from the 2011 series MMWG Base Case library.

3.3.5 Transfer Levels

Transfer levels for interfaces associated with the Greater Boston study area were modeled to represent stressed conditions that would have the most significant effect on general stability and BPS performance for the Boston RSP subarea. Table 3-9 below identifies the interface transfer levels modeled in the three stability base cases used in the stability screening tests and the BPS testing analysis.

Table 3-9 Interface Transfer Levels Modeled For Stability and BPS Testing

Interface	D1 Heavy Maine & Boston Dispatch MW	D3 Heavy SEMA % Boston Dispatch MW	D6 N-S and W-E Dispatch MW
[redacted]	1001	1014	1014
	1376	1090	1324
	196	11	213
	1306	1011	1347
	40	24	72
	1605	692	1604
	2004	413	2007
	3111	1184	3025
	2893	619	3283
	3527	3533	-3482
	766	122	665
	-64	-683	1509
	1184	2759	2206
	-1203	-1222	-1206

[redacted]

3.3.6 Generation Dispatch Scenarios

The generation dispatch scenarios incorporate the common practice of turning on a significant amount of local area generation to stress the specific interface transfer levels. The dispatch conditions for major New England units modeled for stability testing is shown in Table 3-10 below.

Table 3-10 Generator Disptach Conditions Modeled for Stability Screening and BPS Testing

Generator	D1	D3	D6
MAINE			
[redacted]	0	184.4	0
	25	0	25
	28.5	0	28 5
	28.5	0	28 5
	26	0	26
	27	0	27
	33	0	33
	147.6	0	147.6
	19.1	0	19.1
	27.4	0	27.4
	14.1	0	14.1
	8.7	0	8.7
	6.6	0	6.6
	9.5	0	9.5
	30	0	30
	10.8	0	10 8
	10.8	0	10 8
	39	0	0
	27	0	0
	39	0	0
	27	0	0
	0	27.4	27.4
	0	29.9	29.9
	0	0	25.7
	15.5	0	15 5
	7.2	0	7.2
	10.4	0	10.4
	6.6	0	6.6
	54.5	0	54 5
	54.3	0	54 3
	54.5	0	54 5
	0	0	50.9
	185.8	0	185.8
	95.3	0	95 3
	8.6	0	8.6
	17.3	0	17 3
	28	0	28
	9.2	0	9.2
	13.2	0	13 2
	19.4	0	19.4
	13.6	0	13 6
	20.2	0	20 2
	22.7	0	0
	9.9	0	9.9
	8.9	0	8.9
	7.5	0	7.5
	7.6	0	7.6
	6.2	0	6.2
	9.1	0	9.1
	9.1	0	9.1
	56	0	56
	0	0	56.2
	188.2	0	188.2
	188.2	0	188.2
	188.9	0	188.9
	1.4	1.4	12.4
	17.5	0	17 5
	11.6	0	11 6
NEW HAMPSHIRE / VERMONT			
[redacted]	16.7	0	0
	19.3	0	0
	15.7	0	0
	23.2	0	0
	15.7	0	15.7
	9.1	0	9.1
	14.5	0	0
	13.9	0	0
	51.5	0	0
	21	21	0
	180.5	0	180.5
	180.5	0	180.5
	211.3	0	0
	0	0	271.4
	0	0	271.4
	0	0	275.5
	6.5	6.5	0
	6.8	6.8	0
	47.3	47.3	0

Generator	D1	D3	D6
MASSACHUSETTS / RHODE ISLAND			
[redacted]	0	0	10
	67.2	67.2	0
	615.5	615.5	0
	289.6	289.6	0
	294.9	294.9	0
	283.7	283.7	0
	289.6	289.6	0
	294.9	294.9	0
	0	0	63
	117.9	117.9	0
	117.9	117.9	0
	113.4	113.4	0
	46.5	46.5	0
	25.4	25.4	0
	0	0	69.9
	0	0	24
	0	54.3	0
	0	150	0
	0	609	609
	0	0	57.4
	42	57.4	0
	0	314.5	0
	0	314.5	0
	0	119.9	119.9
	0	119.2	119.2
	0	114.2	114.2
	0	0	48
	0	47.7	47.7
	0	0	52.5
	0	45.5	0
	37.8	0	37.8
	0	96.6	96.6
	0	96.6	96.6
	0	131.4	131.4
	0	98.6	98.6
	0	0	98.6
	0	0	133.7
	-300	-300	0
	0	0	287.4
	0	0	125.5
	0	0	56.8
	0	0	22.4
	0	0	92.4
	119.1	119.1	0
	0	0	187.6
	102	102	0
	0	0	70.7
	0	0	48
	291	291	0
	0	0	192.5
	0	0	96.3
	0	0	196.9
	0	0	193.3
	0	0	196.9
	0	0	37.9
NNETICUT			
	305.8	305.8	0
	306.1	306.1	0
	304.7	304.7	0
	43	43	0
	13	13	0
	0	0	36.1
	0	0	257.4
	415.1	415.1	0
	0	0	19.2
	43.2	43.2	0
	172	170.1	305.1
	0	0	100
	192.9	192.9	0
	190.5	190.5	0

[redacted]

3.3.7 Reactive Resource and Dispatch Assumptions

Load power factors consistent with the local Transmission Owners' planning practices were applied uniformly at each substation and consistent with the MW load level assumed at each power flow model substation bus. The base cases assume all reactive resources are available.

3.3.8 Explanation of Operating Procedures and Other Modeling Assumptions

Not applicable for stability testing performed in this study.

3.4 Short Circuit Model Assumptions

3.4.1 Study Assumptions

The short circuit analysis assumptions used for this study are consistent with those used for all other studies for this region of the New England system. The case was developed to be representative of the transmission and generation system configuration that would be in place by 2018.

3.4.2 Short Circuit Model

The study model was based on the ISO-NE's 2013 Master Short Circuit case updated with the addition of generators and transmission lines expected to be in service by 2018. The case used was developed from Round 8 of the New England Short-Circuit database release. A listing of the system topology changes included in the short circuit model is shown in Table 10-1 included in Section 10.

3.4.3 Contributing Generation Assumptions (Additions & Retirements)

The generation model included new generation that cleared FCA-7 as well as PPA approved generators in the vicinity of the study area. In particular this included the new Footprint plant at the existing Salem Harbor plant location. Additionally, units requesting non-price retirements in FCA-8 were not removed from the case because the request had not been finalized at the time of the study. This included the Vermont Yankee, Norwalk Harbor 1 & 2, and Brayton Point 1, 2, 3, & 4 units. These units were modeled as in service and running for the short-circuit analysis. However, their presence is considered of minimal impact to the results given their location on the transmission system.

3.4.4 Generation and Transmission System Configurations

A significant system configuration factor was that the testing assumed [redacted]

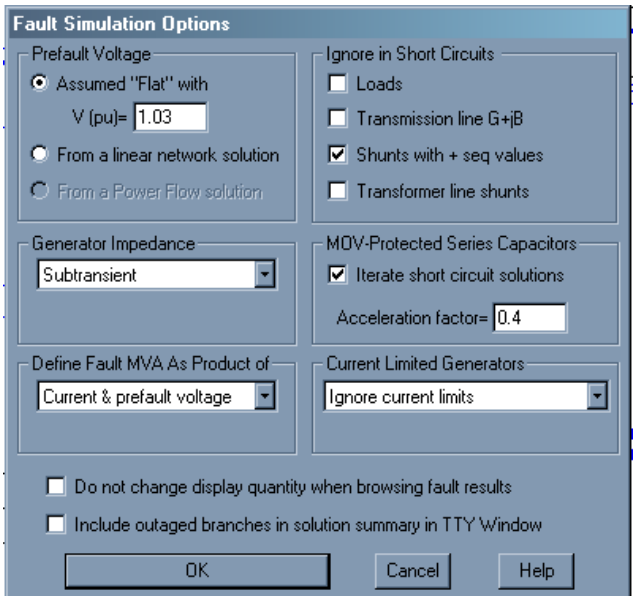
3.4.5 Boundaries

Case boundaries were consistent with the New England short-circuit database model assumptions and no additional equivalent source models were added to the case.

[redacted]

3.4.6 Other Relevant Modeling Assumptions

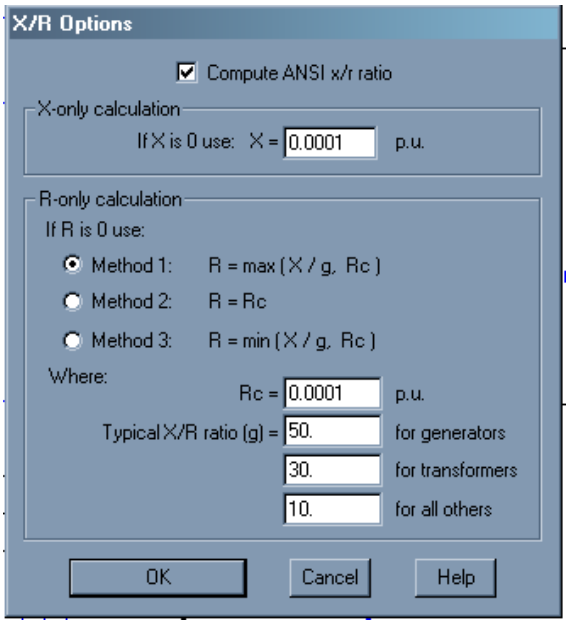
The following options were set with respect to the Fault simulation options:



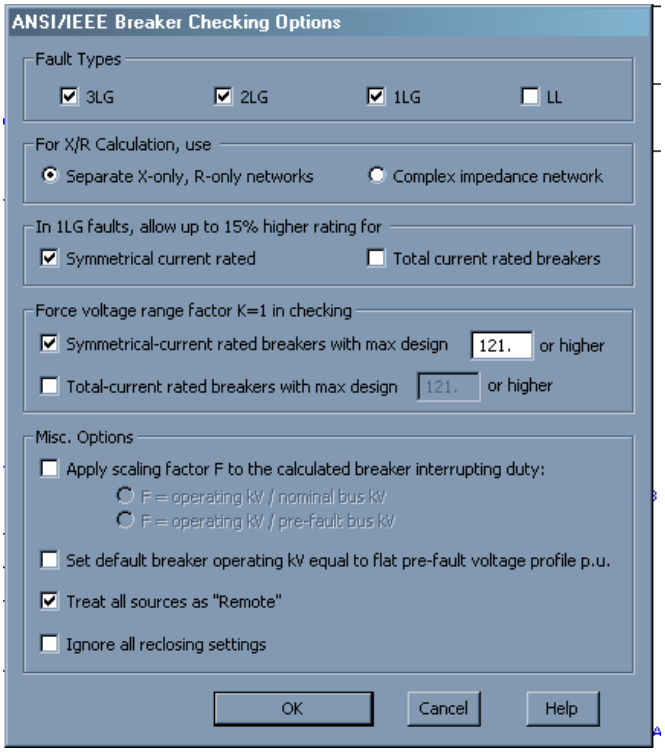
The pre-fault voltage was set to 1.03 for National Grid and NSTAR buses and 1.05[14] for Public Service of New Hampshire (PSNH) buses as per respective company-specific practices.

[14] The Planning Technical Guide states that the pre-fault voltage for the PSNH system should be 1.04. Since no overdutied breakers were seen in the PSNH system the analysis was not redone with the lower pre-fault voltage

The following options were set with respect to the X/R options:



The following provides assumptions used for the Breaker Rating Module:



3.5 Other System Studies (such as transient network analysis, harmonic analysis, equipment assessments, etc.)

Not Applicable.

3.6 Changes in Study Assumptions

There have been a significant number of changes in study assumptions and system topologies since the Needs Assessment was first initiated in 2008. The following is a summary of the most significant changes that have occurred followed by a chronology of reports provided to the PAC.

3.6.1 Changes in Load Forecast

Since 2008 load forecast data has changed in a slightly downward direction. However the New England system peak demand load level forecast over this time period has decreased by less than 4%. The table below provides a summary of the 90/10 summer peak demand forecast for 2018 for each of the CELT forecasts published from 2008 through 2013.

Table 3-11 CELT Report Load Forecast History

CELT Forecast Year	2018 90/10 New England Summer Peak (MW)
2008 Report	33,830 (extrapolated)
2009 Report	33,235
2010 Report	32,895
2011 Report	32,955
2012 Report	32,675
2013 Report	32,615

The most significant change in study scope since 2008 is the study horizon. In 2008 the study horizon ended in 2018. The current assessment has a study horizon that ends in 2023. A summary of the changes in load modeling assumptions from the initial study to the current study is provided in Table 3-12 below:

Table 3-12 Comparison of Greater Boston Study Load Forecast Assumptions

Assumption Metric	Initial Needs Assessment (July 2010) and Solutions Study (March 2012)	Updated Needs Assessment (July 2013)
Study Horizon Year	2018	2023
Study Years	2013 & 2018	2018 & 2023
Load Forecast Basis	2008 CELT 90/10 Summer	2013 CELT 90/10 Summer
New England Peak Load	2013 - 32,410 MW 2018 - 33,830 MW	2018 - 32,615 MW 2023 - 34,460 MW
Boston RSP subarea Peak Load	2013 - 6,460 MW 2018 - 6,900 MW	2018 - 6,830 MW 2023 - 7,210 MW
NEMA/BOSTON Load Zone DR	300 MW through FCA-2	457 MW[15] through FCA-7
Additional Energy Efficiency	None	2018 – 124 MW 2023 – 369 MW[16]

3.6.2 Changes in System Resources and Topology

Other significant changes in study conditions are the changes in system topology that have occurred since the study was first initiated. The availability of generation resources for the study area was among the most significant changes. In 2010 Dominion announced its intention to retire Salem Harbor units 1 through 4 from the system reducing generation resources for the area by 750 MW, a significant reduction of over 20% in area resources. The resources ceased operations as of 2014. As a result of this retirement, additional upgrades have been placed in service to address potential reliability concerns for the area. These unit retirements triggered the need for a full reassessment of area needs.

Subsequent to the Salem Harbor retirement announcement, a new resource (Footprint) was proposed and ultimately cleared in FCA-7 which will effectively replace the generation retired at Salem Harbor with new generation. The Footprint generating facility has a qualified capacity of 674 MW. This new generation addition once again changed the resources of the Greater Boston area requiring a full reassessment of area needs.
Other system topology changes also occurred with additions of new step down facilities as well as implementation of system upgrades that were more urgent such as the need to upgrade the Lexington-Trapelo Rd.-Waltham 115 kV lines (320-507/508).

[15] The DR number is calculated by adding 8% transmission and distribution losses to the NEMA/BOSTON Passive DR and Boston and North shore Dispatch zone active DR from Table 3-6 and Table 3-7 respectively.

[16] The Forecasted EE number obtained by adding 8% transmission and distribution losses to the NEMA/BOSTON EE forecast number from Table 3-6.

3.6.3 Changes in System Modeling

An additional significant study adjustment was the change in system modeling of underground cable systems in the Boston RSP subarea[17]. The design typically used by NSTAR for its underground transmission system includes the construction of companion circuits in a common duct bank where two circuits share cooling fluids in order to maximize thermal cooling capabilities. This construction technique relies on pumping facilities and in some cases heat exchanger facilities to improve the thermal performance of both circuits by circulating cooling fluid from one circuit to the other and back in a looped manner.

One significant consequence of this design is the change in thermal capabilities of a circuit when its companion circuit is out of service. In many cases loss of a companion circuit results in loss of coolant circulation and, consequently, a reduction in thermal cooling. This means that, for modeling purposes, the rating of an underground circuit changes when its companion circuit is out of service requiring the use of alternative rating tables. A modeling change was developed by ISO-NE to capture this change in rating. The process called for a revision to the circuit model to include alternate versions of each underground cable as well as revision to all associated contingency files to use the appropriate cable model depending on the contingency that was being simulated. This change in modeling more accurately captures the thermal capability of underground cables during outage events.

An additional change also occurred related to the ratings used for underground transmission facilities in the NSTAR system. As a follow-up to ISO-NE's request for single line in-service ratings, NSTAR also re-rated underground cables based on new rating practices and to ensure consistency with ISO-NE rating procedure requirements. The new ratings used in the base case models were all based on a 12-hour LTE rating methodology consistent with ISO-NE rating procedures.[18]

There was also a change in assumptions concerning N-1-1 testing in the updated Needs Assessment. Prior assessments were based on a general practice that included all lines that interconnect two or more BPS stations as the initial element to be taken out of service in N-1-1 testing. This approach changed to be more expansive and the study was modified to include all BES elements in the study area.

3.6.4 Chronology of Needs Assessment Study Effort

The Greater Boston Needs Assessment and Solutions Study progress has been routinely reported at PAC meetings. A chronology of the reports provided to the PAC is shown in Table 3-13 below:

[17] See April 2013 PAC presentation available at http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

[18] NSTAR Underground Cable Ratings Update, April 2013: https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/apr242013/a10_nstar_greater_boston_cable_ratings.pdf

Table 3-13 Chronology of Greater Boston Study PAC Reviews

PAC Meeting Date	Discussion Topic	Presentation or Report Title[19]
May 20, 2008	Initial announcement of starting Needs Assessment and study scope	Northeast Massachusetts / Greater Boston Transmission Needs Assessment – Study Scope
Jan 21, 2009	Needs Assessment Study status update including initial N-1 results	Greater Boston Transmission System Needs Assessment – Study Results
Jul 16, 2009	Needs Assessment Study Results; Announced of commencement of Solutions Study	Greater Boston Transmission System Needs Assessment Review and Solutions Study Initiation
Dec 16, 2009	Revisit Needs Assessment for generator retirement/delist scenarios	Greater Boston Needs Assessment (Status Update)
Mar 18, 2010	Update on Needs Assessment and review of options for potential solutions	Greater Boston Needs Assessment Solutions Status Update (ISO presentation) Greater Boston Transmission Reliability Assessment and Preliminary Discussion of Alternatives (NSTAR presentation)
July 8, 2010	Needs Assessment Report posted to ISO-NE web site	Greater Boston Area Transmission Needs Assessment
Dec 16, 2010	Needs Assessment and Solutions Study update	Greater Boston Study Needs Assessment/Solutions Study Status Update
Jun 30, 2011	Needs Assessment and Solutions Study update	Greater Boston Study Needs Assessment/Solutions Study Status Update
Jan 18, 2012	Solutions Study update on preliminary preferred solution	Greater Boston Study Needs Assessment/Solutions Study Status Update
Mar 14, 2012	Solutions Study update on preliminary preferred solution; NHT proposes HVDC as alternative which ISO-NE agrees to study	Greater Boston Study Needs Assessment/Solutions Study Status Update
Feb 12, 2013	Solutions Study update	Greater Boston Solutions Study Status Update
April 2013	NSTAR led discussion on changes to the underground cable ratings	NSTAR Underground Cable Ratings Update
July 9, 2013	Needs Assessment updated with the latest load forecasts and FCA results and Solutions Study update	Greater Boston 2023 Needs Assessment and Solutions Study Status Update
Nov 20, 2013	Solutions Study Update	Greater Boston 2023 Solutions Study Status Update
June 19, 2014	Disclosure of Cost Estimate for the "AC Plan" and "HVDC Plan"	Greater Boston Solutions Study Update
November 18, 2014	Greater Boston Solutions Study Update	Greater Boston 2023 Solutions Study Status Update

[19] The PAC presentations are available at http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

December 18, 2014	Comparison of "AC Plan" and "HVDC Plan"	Greater Boston Solutions – NHT Comparison of the AC and HVDC Solutions Greater Boston – National Grid and Northeast Utilities
February 18, 2015	Selection of a Preferred Plan	Greater Boston Preferred Solution

Section 4
Analysis Methodology

4.1 Planning Standards and Criteria

The applicable NERC, Northeast Power Coordinating Council (NPCC) and ISO-NE criteria were tested as part of this evaluation. A description of each of the NERC, NPCC and ISO-NE standard tests that were included in all studies used to assess steady state system performance are shown in section 4.3.1 below.

4.2 Performance Criteria

4.2.1 Steady State Criteria

The Solutions Study was performed in accordance with NERC TPL-001-4 Transmission System Standards, NPCC "Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System", dated December 1, 2009 (Errata changes 04/20/12), the ISO-NE Planning Procedure 3, "Reliability Standards for the New England Area Bulk Power Supply System," the ISO New England Planning Procedure 5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses", as well as criteria found in Section 13.

NERC Reliability Standards require that the system thermal and voltage levels remain within applicable limits after the events as described in "Table I. Transmission System Standards – Normal and Emergency Conditions" of the NERC Reliability Standard TPL-001-4.

Steady State Thermal and Voltage Limits
A summary of the limits that were used in assessing system performance for thermal and/or voltage violations used in the study are included in Section 13.

Steady State Solution Parameters
The pre-contingency and post-contingency solution parameters that were used for adjustment of area interchange, adjustment of load tap-changing transformers (LTCs), static var devices (SVDs, including automatically-switched capacitors) and phase angle regulators (PARs) were modeled as described in Table 4-1 below:

Table 4-1
Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Pre-contingency	Tie Lines Regulating	Stepping	Locked[20]	Regulating
Post-contingency	Disabled	Stepping	Locked	Regulating

4.2.2 Stability Performance Criteria

The criteria used for assessment of acceptable dynamic performance were based on the criteria established in section 3.1 of the ISO-NE PP-3. This criteria states that "The New England bulk power supply system shall remain stable and damped in accordance with the criterion specified in Appendix C during and following the most severe of the contingencies stated below with due regard to reclosing, and before making any manual system adjustments." Assessments were performed for both normal criteria and extreme criteria faults in and around the study area. Additionally, an assessment was performed based on the NPCC criteria Document A-10 Classification of BPS Elements to determine the potential impact of the proposed plans on classification of substations within the Greater Boston area as BPS elements.

4.2.3 Short Circuit Performance Criteria

The criteria used to determine short circuit duty adequacy was consistent with recognized industry standards. Each Greater Boston study area breaker's fault current (I_{SC}) and breaker duty was determined based on IEEE Standard C37.010. The maximum fault current duty that an individual breaker would be exposed to at the expected breaker operating time was determined based on the physical arrangement of the breakers clearing the fault. Pre-fault voltages were assumed to be a flat profile with 1.05 per unit for Northeast Utilities and New Hampshire Transmission (NHT) buses while 1.03 per unit was used for National Grid and NSTAR buses.

Short circuit criteria for New England is based on fault interrupting duty ratings that are provided by Transmission Owner's in New England and require that no circuit breaker shall be operated in excess of 100% of the provided ratings.

[20] Boston Area PARs set to optimized settings

4.2.4 Other Performance Criteria (as appropriate)

Not Applicable.

4.3 System Testing

4.3.1 Steady State Contingencies/Faults Tested

Contingencies in each of the following NERC, NPCC and ISO-NE reliability criteria categories were tested as part of this evaluation.

Table 4-2 Summary of NERC, NPCC and ISO-NE Category Contingencies to be Tested

Contingency Type	NERC Type	NPCC D-1 Section	ISO-NE PP-3 Section	Tested in This Study
All Facilities in-service	P0	5.4.2.b	3.2.b	Yes
Generator (Single Unit[21])	P1.1	5.4.1.a	3.1.a	Yes
Transmission Circuit	P1.2	5.4.1.a	3.1.a	Yes
Transformers	P1.3	5.4.1.a	3.1.a	Yes
Shunt Devices	P.1.4	5.4.1.a	3.1.a	Yes
Single Pole DC line	P.1.5	5.4.1.a	3.1.a	Yes
Element w/o Fault	P2.1	5.4.1.d	3.1.d	Yes
Bus Section	P2.2	5.4.1.a	3.1.a	Yes
Breaker Failure	P.2.3, P.2.4, P4	5.4.1.e	3.1.e	Yes
Double Circuit Tower	P.7.1	5.4.1.b	3.1.b	Yes
Bipolar DC line	P.7.2	5.4.1.f	3.1.f	Yes

Additionally, to cover NERC TPL-001-4 P3 and P6, and NPCC and ISO-NE criteria, N-1-1 testing was performed as follows:

- An initial contingency of a transmission circuit, autotransformer, or generator in the study area was taken
- System adjustments were performed between contingencies
- All the contingencies in Section 14 were applied as second contingencies

[redacted]

[redacted]

4.3.2 Stability Contingencies/Faults Tested

Stability testing was conducted as both a screening assessment and to evaluate any potential impact that the selected preferred solution alternatives may have had on the status of stations for compliance with NPCC designations as a BPS station as well as for a general assessment of system stability performance. The faults shown in Table 14-3 which can be found in Section 14 were tested for all of the preferred alternatives to assess both basic stability performance and determination of BPS compliance.

4.3.3 Short Circuit Faults Tested

Three-phase-to-ground, two-phase-to-ground, and single-line-to-ground bus faults were analyzed for each 345kV and 115kV substation in the Greater Boston study area. Faults were simulated with an assumed pre-fault voltage "Flat" option of 1.05pu for Northeast Utilities (including PSNH) and NHT (Seabrook 345kV) buses; and 1.03pu for NSTAR and National Grid buses. Fault duties were evaluated for each of the major Boston RSP subarea stations shown in Table 4-3 shown below:

Table 4-3 Boston Area Stations Considered for Short Circuit

Station	Station	Station
Andrew Square 115 kV	Kingston 345 kV	Seabrook 345 kV
Baker Street 115 kV	K-Jet2 13.8kV	Seabrook 24.5 kV
Brighton 115 kV	K Street 115 kV	Sherborn 115.kV
Burlington 115 kV	K Street 345 kV	Shrewsbury 69 kV
Canton 115 kV	Lexington 115 kV	Slayton Hill 115 kV
Chelsea 115 kV	Lexington 345 kV	Speen Street 115 kV
Colburn Street 115 kV	Lynn115 kV	Stoughton 345 kV
Deer Island 115.kV	Maplewood 115 kV	Sudbury 115 kV
Dewar Street115 kV	Maynard 115.kV	Tewksbury 115 kV
Dover 115 kV	Medway 115 kV	Tewksbury 230 kV
E Holbrook 115 kV	Merrimack 115 kV	Tewksbury 345 kV
E Methuen 115 kV	Mystic 345.kV	
E Cambridge 115.kV	Mystic115 kV	W Methuen 115 kV
Edgar 115 kV	N Cambridge 115 kV	Wachusett 115 kV
Everett 115 kV	N Cambridge 345 kV	Wakefield Jct. 115kV
Fitch Road 69 kV	Needham 115.kV	Wakefield Jct. 345kV
Framingham 115 kV	Northboro Road 115 kV	Walpole 115 kV
Golden Hills 115 kV	North Quincy 115 kV	Waltham 115 kV
Greendale 115 kV	Pratts Junction 115 kV	Ward Hill 115 kV
Hartwell 115 kV	Read Street 115 kV	Ward Hill 345 kV
Holbrook 115 kV	Revere 115 kV	W Framingham 115 kV
Holbrook 345 kV	Rolfe Avenue 115 kV	W Medway 345 kV
Hyde Park 115 kV	S Danvers 115 kV	Woburn 115 kV

Hyde Park 345 kV	Salem Harbor 115 kV	Woburn 345 kV
Kendall 115 kV	Sandy Pond 115 kV	W Walpole 115 kV
Kingston 115 kV	Sandy Pond 345 kV	W Walpole 345 kV

Section 5
Development of Alternative Solutions

The transmission needs in the Boston RSP subarea required the evaluation of a large number of transmission solution alternatives. In many cases there were two or more alternatives that could potentially meet the needs of a Greater Boston subarea transmission system reliability concern. The multiple alternatives for each of the subareas resulted in a large number of combinations of the competing solutions, and testing each combination was not practical. To manage the process of assessing all the various alternatives, the GBWG evaluated the competing solutions in sequential phases that followed a geographical progression for specific regions within the study area. The geographic areas and related study subareas were:

1) **North** – Areas north of the central Boston area including facilities located in Tewksbury, Dracut and surrounding areas up through southern New Hampshire, (Subareas A and H);
2) **South** – Areas south of the central Boston area including facilities located in Medway, Walpole, Canton, Norwood, Holbrook and surrounding areas, (Subarea E);
3) **Western Suburbs** – Areas west of the central Boston area including facilities located in Marlboro, Millbury, Northboro and other surrounding locales, (Subarea D) and;
4) **Downtown Boston** – Areas in and around central Boston including facilities located in Cambridge, Waltham, Woburn, Belmont, Chelsea, Everett, Wakefield and surrounding locales (Subareas B, C and F).

The course of the Solutions Study was essentially segmented into two distinct study efforts or stages. The initial study stage developed a comparison of potential transmission upgrades culminating in a preferred solution presented to PAC in March of 2012. This study used the original assumptions for load, resources, system topology, and circuit ratings as documented in the Greater Boston Area Transmission Needs Assessment July 2010.

The second stage began in 2012 after the March 2012 preferred solution selection and developed a comparison of an updated AC Plan to a newly developed HVDC Plan that featured an HVDC line from Seabrook to downtown Boston and other AC solution components. The second stage of the assessment included a revision to the base case assumptions as noted in Section 3.6 of this report. The assumption changes between Stage 1 and Stage 2 resulted in a similar, but not exactly the same, set of reliability concerns than in the initial stage that are documented in the Greater Boston Area Transmission Assessment dated January 2015. As a result of the changes in study assumptions the final AC Plan identified as the preferred solution in this report differs from the March 2012 preferred solution.

A listing of the upgrades for the preferred solution plan presented at the March 2012 PAC meeting can be found in Table 5-3 and a listing of the upgrades for the updated AC plan and HVDC plan presented at the November 2014 PAC meeting can be found in Table 5-6, Table 5-7, Table 5-8.

As mentioned above, the second stage also considered an HVDC submarine cable to the downtown Boston area originating from Seabrook generating station. This required re-evaluation of both the North area solutions and the Boston area solutions as the HVDC upgrade could potentially address

system performance concerns in both areas. A large number of alternative HVDC design and interconnection options were evaluated including interconnection at various 345 kV and 115 kV buses within the downtown Boston area. HVDC injections at K St., Kingston St., N. Cambridge, Wakefield Jct., Salem Harbor and Mystic were all evaluated as potential sites. The Mystic 115 kV bus was found to be the most cost effective option and was selected to be included in the final comparison to the AC Plan. Since the HVDC alternative included a termination point in New Hampshire additional testing was performed to include consideration of additional Maine and New Hampshire stressed transfer level conditions.

Each phase of the assessment monitored the complete Boston RSP subarea and used the complete Greater Boston Study contingency list for all of the thermal performance testing. This manner of analysis served to double check each of the preceding phases for missed needs and unintended impacts. The final phase thus modeled the complete Greater Boston solution and validated the work completed in the previous phases.

5.1 Stage 1

5.1.1 Preliminary Screen of Alternative Solutions

An initial screening of the transmission alternatives was conducted by the participating transmission owners in the GBWG to ensure the feasibility of each alternative and as a basis for developing the cost of the alternative. This step considered the availability of right-of-way, expansion potential of substations, and other potential physical limitations. In addition, when considering re-conductoring or rebuilding of existing lines, the loading levels observed in the Needs Assessment were used as targets for conductor sizing and estimating costs.

The following set of transmission alternative upgrades was considered as part of the initial evaluation of alternatives. One of the alternatives was an overland HVDC line from an undetermined substation in New Hampshire to either a downtown Boston substation (western route) or to the Salem Harbor 115 kV substation (eastern route). The introduction of the HVDC alternative proposed by NHT was not considered until Stage 2.

The following six alternatives shown in Table 5-1 below were considered feasible alternatives for the North and were presented to the PAC in March 2010.

Table 5-1 North Area Solutions Alternatives

Alternative	ROW Consideration	Electrical Performance	Construction Outage Exposure	Cost Indicators / Relative Cost
Scobie – Tewksbury 345 kV	Uses existing ROW	Provides alternative path into the Boston Area	Relocate 10 mi. of 115 kV and rebuild 5 mi. of 230 kV	26 mi. of new line plus 115 kV relocation / low relative cost
2nd Seabrook – Ward Hill 345 kV and re-conductor Scobie – Sandy Pond 345 kV	Requires ROW expansion in NH and possibly MA	Provides alternative path into the Boston Area	Relocate 7 mi. of 115 kV and re-conductor 31 mi. of 345 kV	24 mi. of new line, 115 kV relocation and 31 mi. of 345 kV re-conductor / medium relative cost
Scobie – Woburn 345 kV	Uses existing ROW	Provides alternative path into the Boston Area	Relocate 10 mi. of 115 kV and rebuild 5 mi. of 230 kV and 12 mi. of 115 kV	38 mi. of new 345 kV plus 115 relocation / medium relative cost
Overland HVDC to downtown Boston	Western route requires 17 mi. of ROW expansion; eastern route requires 20 mi. of ROW expansion. Requires two 5+ acre terminal sites	Provides alternative path into the Boston Area	West: relocate 10 mi. of 115 kV, rebuild 5 mi. of 230 kV and 12 mi. of 115 kV, plus underground 10 mi. East: relocate and rebuild 20+ mi. 115 kV plus underground 10+ mi.	HVDC terminal $220M - $400M plus terminal sites and relocations / high relative cost
Seabrook – Salem 345 kV	Requires ROW expansion in NH 7 mi. and MA 20 mi.	Provides alternative path into the Boston Area	Relocate up to 27 mi. of 115 kV	42 mi. of new line plus 27 mi. of 115 kV relocation / medium – high relative cost
Convert 230 kV to 345 kV	Uses existing ROW	No new path and lowest incremental capacity added to Boston	Outages to rebuild 20 mi. of 230 kV to 345 kV	20 mi. of new line plus new 230 / 345 kV station / low – medium relative cost

The following three alternatives shown in Table 5-2 below were considered feasible alternatives for the South and were presented to the PAC in March 2010. Alternatives for the Western Suburbs, and

Downtown Boston were similarly developed while the detailed assessment of the alternatives for the North and South progressed.

Table 5-2 South Area Solutions Alternatives

Alternative	Consideration
Holbrook – Walpole 115 kV line Re-conductor part of C-129N/201-502 and D-130/201-501 Medway to Millbury lines	Uses 16 mi. of vacant side of existing 345 kV DCT
Re-conductor both Holbrook – Walpole 115 kV lines Re-conductor part of C-129N/201-502 and D-130/201-501 Medway to Millbury lines	Existing towers may not be strong enough to support re-conductored lines
Install switching station at Sharon to split the two existing 115 kV lines Re-conductor part of C-129N/201-502 and D-130/201-501 Medway to Millbury lines	Requires a new station site and structure changes to DCT approaches

5.1.2 Step 1: North Area

As mentioned above, to manage the process of assessing the competing solutions, the GBWG evaluated competing solutions in sequential phases that followed a geographical progression for specific regions within the study area. The first area of study was the North subarea.

The assessment of the North subarea consisted of N-1, N-1-1 contingency analysis, and transfer assessment. Two competing options were developed from the solutions alternatives in Table 5-1 above for the North subarea using the N-1 and N-1-1 assessments, however neither of the options fully met the reliability concerns of the North Shore section of the North subarea. Therefore two competing alternatives were developed to meet the North Shore section reliability concerns as well.

The two competing options for the North subarea were:

- Scobie – Tewksbury and Tewksbury – Woburn 345 kV lines for $155M
- Seabrook – Ward Hill, Ward Hill – Wakefield Jct. and Wakefield Jct. – Woburn 345 kV lines for $410M

The two competing options for the North Shore section were:

- Re-conductor six 115 kV lines for $51M
  - Y-151 Tewksbury – Tewksbury Jct.
  - B-154N King St. Tap – S. Danvers
  - C-155N King St. Tap – S. Danvers
  - S-145 Tewksbury – Wakefield Jct.
  - T-146 Tewksbury – Wakefield Jct.

  - G-133E Ward Hill – East Methuen[22]
- Ward Hill – Wakefield Jct. 345 kV line for $74M

In addition to the competing options, seven common upgrades were needed for a total of $93M:

- Woburn – North Cambridge 345 kV line
- 2nd Woburn 345/115 kV autotransformer
- Wakefield – Everett 115 kV line[23]
- Re-conductor Tewksbury to Pinehurst Tap sections of the M-139 and N-140 lines
- Re-conductor Wakefield Jct. to Everett sections of the F-158N and F-158S lines
- Re-conductor Chelsea to Revere 128-518 line
- Add Chelsea 115 kV 63 MVAR capacitor

A transfer assessment screening was conducted to investigate the impact of the two North subarea options on the Boston Import capability; the assessment revealed both options had a similar impact on transfer capability. A second transfer assessment screening was conducted to investigate the two North Shore options' impact on the ability of the Salem Harbor units to retire. This assessment revealed that both options provide sufficient capacity for the Salem Harbor units to retire.

Based on the analysis performed and the cost of the projects, the Scobie – Tewksbury and Tewksbury – Woburn 345 kV lines and the six 115 kV line re-conductorings were selected as preliminary preferred alternatives. This selection was announced at the December 2010 PAC meeting[24].

Salem Harbor Non Price Retirement Impact

The ISO received a permanent de-list request from Dominion Energy for the four Salem Harbor units on October 6, 2010 during the period of evaluation of the competing options for the North subarea. The permanent de-list request was followed by a NPR request on February 11, 2011. The ISO performed a transmission assessment for the Salem Harbor NPR was presented to the NEPOOL Reliability Committee (RC) on May 9, 2011. The assessment determined the NPR of Salem Harbor 1 & 2 was accepted and the interconnection rights of these units would be terminated on May 31, 2014. The assessment further rejected the NPR for Salem Harbor 3 & 4 due to reliability concerns in the North Shore section. Consistent with the Tariff right to retire a resource even when needed for system reliability, Dominion Energy, on May 11, 2011, provided notice of their intent to retire Salem Harbor 3 & 4 on June 1, 2014.

The reliability concerns without Salem Harbor 3 & 4 in the North Shore section corresponded to the reliability concerns in subarea G (115 kV lines North of Boston in the Salem Area) in the Greater Boston Area Transmission Needs Assessment, July 2010. The solution to these needs was the re-conductoring of portions of five of the six 115 kV lines in the North Shore section. The five 115 kV re-conductorings were then separated out of the Greater Boston North solution and advanced to the

[22] This upgrade was only needed in the dispatches with Salem Harbor 1-4 at Pmax. It was later removed after the Salem Harbor NPR.

[23] This upgrade was eliminated with the solutions studied during the Downtown Boston Area phase.

[24] Greater Boston Study Needs Assessment / Solution Study Status Update December 2010 https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2010/dec162010/greater_boston.pdf

status of proposed. A PPA for the five re-conductorings was presented to the RC and approved by ISO-NE in July 2011.

The five 115 kV re-conductorings were added to the cases used in the Greater Boston study. The five re-conductorings included:

- Y-151 Tewksbury Jct. – West Methuen
- B-154N King St. Tap – S. Danvers
- C-155N King St. Tap – S. Danvers
- S-145 Tewksbury – North Reading
- T-146 Tewksbury – North Reading

Other

Two critical needs documented in the July 2010 report Greater Boston Area Transmission Needs Assessment were the overloads of the Chelsea – Revere 128-518 115 kV line and low voltages in the Downtown Boston subarea.

The solution for the overloaded line was to re-conductor the Chelsea – Revere 128-518 115 kV line and the solution for the low voltages was to add a capacitor at the Chelsea 115 kV substation. There were no feasible alternatives to these solutions and the re-conductoring and capacitors were separated out of the Greater Boston solution and advanced to the status of proposed. A PPA for the projects was presented to the RC and approved by ISO-NE in May 2011 for the re-conductoring and April 2011 for the Chelsea capacitor. The re-conductoring and the capacitors were added to the cases used in the Greater Boston study.

5.1.3 Step 2: South

The assessment of the South subarea was performed simultaneously with the North subarea and consisted of N-1 and N-1-1 contingency analysis. Performing the assessments for the North and South subareas simultaneously was considered prudent since the solutions considered for the two areas were both complementary and independent of each other. They were complementary in that many of the transmission reliability concerns in the South were caused by the N-1-1 contingency scenario [redacted] in the North. In this case either of the North competing options eliminated the reliability concerns. The remainder of the transmission reliability concerns in the South was independent of the North in that they were local overloads resulting from local contingencies and could be solved by reconductoring of 115 kV transmission lines or adding new lines.

The two competing options for the South subarea were:

- Re-conductor C-129N/201-502 and D-130/201-501 lines for $4M
- Tying C-129N/201-502 into Medway 115 kV substation for $14M

In addition to the competing options, the West Walpole – Holbrook 115 kV line was a common upgrade for a total of $19M.

Based on the analysis performed and the cost of the projects, the re-conductoring of the C-129N/201-502 and D-130/201-501 lines along with the common upgrade of a new West Walpole – Holbrook

[redacted]

115 kV line was selected as preliminary preferred alternatives. This selection was announced at the December 2010 PAC meeting.

The re-conductoring of the C-129N/201-502 and D-130/201-501 lines were then separated out of the Greater Boston solution and advanced to the status of proposed. A PPA for the project was presented to the RC and approved by ISO-NE in October 2011. The re-conductoring was added to the cases used in the Greater Boston study.

5.1.4 Step 3: Central Subarea

The assessment of the Central subarea was performed subsequent to the North and South subareas and included the preliminary preferred solutions from the North and South subareas. The assessment for the Central subarea began as an assessment for the remainder of the Greater Boston area but after reviewing the remaining area needs and potential solutions, it was determined the best course of action was to limit the combinations of upgrades by examining the Western Subareas subarea and determining the preliminary preferred solution before proceeding to the Downtown Boston subarea.

Short-Circuit Examined

During this phase of Stage 1 a short-circuit assessment was performed for the Greater Boston area planned system[25] to quantify known limited short-circuit margins in the Boston area. This was done to establish a pre-upgrade baseline to compare to the post project results since the projects being proposed in the central area would add additional sources of short-circuit current to the known substations with limited short-circuit ratings. A short-circuit assessment was not done for the initial Greater Boston Area Transmission Needs Assessment July 2010. The effort began with the short-circuit assessment being introduced at the December 2010 PAC meeting. The results of that assessment were presented at the June 2011 PAC meeting.

[redacted]

Solution alternatives were developed for the breakers that had short-circuit current between 90% and 100% or over 100% of their short circuit rating. The solution alternatives included splitting substations, opening breakers and moving the Mystic 9 generators from the 115 kV to the 345 kV system. Replacing the breakers with larger size breakers was not considered a feasible alternative since the footprint of the higher short circuit rated breakers was considerably larger than the existing breakers and expanding the stations, located in the downtown Boston area, was not a practical option.

Western Suburbs Subarea

[25] The planned system examined at this point in time did not include the North or South preliminary preferred alternatives but did include the PPA approved projects that were advanced.

[redacted]

The assessment of the Western Suburbs subarea was performed subsequent to the North and South subareas and consisted of N-1 and N-1-1 contingency analysis. The Western Suburb's needs were subdivided into three sections; Marlboro, Woburn – Waltham, and Sudbury.

The two competing options for the Marlboro section were:

- Convert Millbury – Westboro X-24W and Westboro-Northboro Rd. X-24E 69 kV lines to 115 kV, re-conductor Northboro Rd. – West Framingham (D-156/513-507) 115kV and West Framingham-Sherborn 455-507 115 kV and Northboro Rd. – East Main St. E-157E 115 kV for $60M
- Sudbury – Hudson 115 kV and refurbish Millbury – Westboro X-24W and Westboro-Northboro Rd. X-24E 69 kV for $41M plus the cost of the refurbishment. The refurbishment cost was not available at the time of the decision but was not expected to approach the $19M difference between the two options.

The two competing options for the Woburn – Waltham section were:

- Re-configure the Waltham 115 kV Substation, 2nd Woburn autotransformer[26], Woburn – Hartwell 115 kV line, re-conductor Woburn – Burlington 211-508 115 kV and terminal upgrades on Lexington Waltham 320-507/508 115 kV for $68M
- Two new Waltham – Brighton 115 kV cables and re-conductor Framingham – Speen St. 115 kV for $115M

The two competing options for the Sudbury section were:

- Sudbury 230/115 kV autotransformer, terminal upgrades on the West Medway – Sudbury 282-602 230 kV line for $25M
- Sudbury – Framingham 115 kV line and Sudbury capacitor bank for $28M

In addition to the competing options, seven common upgrades were needed for a total for $22M:

- Re-conductor Lexington – Hartwell 533-508 115 kV line
- Re-conductor Millbury – East Main St. E-157W 115 kV line
- Re-conductor Fitch Rd. – Woodside W-23 69 kV line
- Re-conductor Woodside – Northboro Rd. W-23W 69 kV line
- Replace Woburn 345/115 kV autotransformer
- Hartwell 54 MVAR 115 kV capacitor
- Separate X-24W / E-157W DCT

Based on the analysis performed and the cost of the projects, the following projects were selected as preliminary preferred alternatives. This selection was announced at the January 2012 PAC meeting.

- Sudbury – Hudson 115 kV and refurbish Millbury – Westboro X-24W and Westboro-Northboro Rd. X-24E 69 kV

[26] The 2nd Woburn autotransformer which was considered a common upgrade in the North Subarea was re-examined as part of the Western Suburbs Subarea.

- Re-configure the Waltham 115 kV Substation, 2nd Woburn autotransformer, Woburn – Hartwell 115 kV line, re-conductor Woburn – Burlington 211-508 115 kV and terminal upgrades on Lexington Waltham 320-507/508 115 kV
- Sudbury 230/115 kV autotransformer, terminal upgrades on the West Medway – Sudbury 282-602 230 kV line

Critical Central Subarea Need Addressed

Two critical needs documented in the July 2010 Greater Boston Area Transmission Needs Assessment were addressed at this time. The first was the overloads of the Lexington – Waltham 320-507/508 115 kV lines. [redacted]

Two competing options were presented for the 320-507/508 lines at the June 2011 PAC meeting:

- Re-conductor the existing lines for $8.4M
- Install a third overhead circuit for $27.8M

Based on the analysis performed and the cost of the projects, the re-conductor of the existing lines was selected as the preliminary preferred alternative. This selection was announced at the June 2011 PAC meeting.

The re-conductorings were then separated out of the Greater Boston solution and advanced to a status of proposed. A PPA for the project was presented to the RC and approved by ISO-NE in February 2011. The re-conductorings were added to the cases used in the Greater Boston study.

The second critical need was the low voltages in the Hartwell and Burlington area. This need was addressed by advancing the Hartwell 115 kV capacitor. During this assessment the size of the capacitor was revised from 54 MVAR to 36.7 MVAR.

The Hartwell capacitor was then separated out of the Greater Boston solution and advanced to a status of proposed. A PPA for the project was presented to the RC and approved by ISO-NE in August 2012. The Hartwell capacitor was then added to the cases used in the Greater Boston study.

Additional Northern Subarea Need

During the Central Subarea solution development, the GBWG found an unresolved North subarea reliability concern. The Sandy Pond – Tewksbury 337 345 kV line is overloaded for N-1-1 contingency pairs [redacted]

The two competing options for the Sandy Pond – Tewksbury 337 line are:

- Re-conductoring the Sandy Pond – Tewksbury 337 345 kV line for $19M
- A parallel 345 kV line for $73M

Based on the analysis performed and the cost of the projects, the re-conductoring was selected as the preliminary preferred alternative. This selection was announced at the January 2012 PAC meeting.

[redacted]

Downtown Boston Subarea

The assessment of the Downtown Boston subarea was performed subsequent to the North, South and Western Subareas and consisted of N-1 and N-1-1 contingency analysis and short-circuit analysis. The assessment began by evaluating the short-circuit options to address pre-existing overdutied breakers. The options included potential changes to the transmission topology by splitting substations, opening breakers and moving generation from the 115 kV side of a substation to the 345 kV side of the substation. This was followed by adding transmission upgrades to address the remaining steady-state transmission reliability concerns and to address any new concerns introduced by the short-circuit transmission topology changes. The assessment iterated back and forth between short-circuit and steady-state assessments until two solutions that mitigated all the transmission reliability concerns were achieved.

The re-conductoring of the Sandy Pond – Tewksbury 337 345 kV line was further investigated as part of the Downtown Boston subarea. The second competing option for the Downtown Boston subarea includes adding a 345 kV line between Mystic and K St. With this new line, the overload seen on the Sandy Pond – Tewksbury 337 345 kV line was eliminated and thus the need to re-conductor the Sandy Pond – Tewksbury 337 345 kV line was eliminated. The re-conductoring is shown in the first competing option.

The two competing options for the Downtown Boston subarea were:

- Alternative 1 for $116.5M:
  - Open Mystic 115 kV downtown ties and close K St. 115 kV bus tie
  - Wakefield – Ward Hill 345 kV line
  - 2nd Mystic autotransformer
  - Terminal upgrades at Seabrook for the Seabrook – Ward Hill 345 kV line
  - Re-conductor the Sandy Pond – Tewksbury 337 345 kV line
  - Two additional 115 kV breakers at K St.
- Alternative 2 for $163.5M:
  - Open North Cambridge 115 kV downtown ties and split the Kingston 115 kV bus
  - Mystic – K St. 345 kV and a 345 kV phase shifter
  - Add Mystic 345 kV breaker and re-terminate lines
  - K St. 115 kV breaker
  - 3rd K St. to Northern Ave. 115 kV cable
  - Upgrade the existing Mystic – Woburn 211-514 cable
  - Replace West Medway 345 kV breakers with higher rated breakers

The following upgrades totaling $171.5M are common to both competing alternatives:

- Woburn – North Cambridge 345 kV cable - $52M
- Mystic – Chelsea 115 kV cable - $25M
- Needham – Baker St. 115 kV cable - $46M
- Bifurcate the Mystic – Woburn 211-514 cable - $48M
- Separate F-158N/Q169 and O-167/P-168 DCTs - $0.5M

Based on the analysis performed and the cost of the projects, Alternative 1 was selected as the preferred alternative. This selection was announced at the March 2012 PAC meeting.

5.1.5 Stage 1 Solution

A complete Greater Boston solution that met all the transmission reliability needs documented in the Greater Boston Area Transmission Needs Assessment, July 2010 was presented at the March 2012 PAC meeting. The complete solution is shown below in Table 5-3.

Table 5-3 Stage 1 Greater Boston Preferred Solution

Upgrade	Length (Miles)	Cost ($ M)
Scobie – Tewksbury 345 kV	25	97
Tewksbury – Woburn 345 kV	13	66
Wakefield – Ward Hill 345 kV	38	74
Open the Y-151 Power St – Wakefield Jct. 115 kV line at Power St.	NA	NA
Terminal upgrades at Seabrook 345 kV station to increase ratings of the 394 Line	NA	21
Re-conductor 337 Sandy Pond-Tewksbury 345 kV	16	19
Re-conductor Y-151 Tewksbury-Tewksbury Jct.115 kV	2	1
Re-conductor Y-151 Tewksbury Jct.-West Methuen 115 kV	8	15
Re-conductor B-154N King St. Tap-South Danvers 115 kV	14	9
Re-conductor C-155N King St. Tap-South Danvers 115 kV	14	9
Re-conductor S-145 Tewksbury- North Reading 115 kV	9	15
Re-conductor S-145 North Reading-Wakefield 115 kV	5	5
Re-conductor T-146 Tewksbury- North Reading 115 kV	9	15
Re-conductor T-146 North Reading-Wakefield 115 kV	5	5
Re-conductor F-158N Golden Hills-Maplewood 115 kV	4	2
Re-conductor F-158S Everett-Maplewood115 kV	3	2
Re-conductor M-139 Tewksbury-Pinehurst Tap 115 kV	7	6
Re-conductor N-140 Tewksbury-Pinehurst Tap 115 kV	7	6
West Walpole-Holbrook 115 kV	14	19
Re-conductor C-129N/201-502 Depot St. Tap-Medway 115 kV	2	2
Re-conductor D-130/201-501 Depot St. Tap-Medway 115 kV	2	4
Sudbury – Hudson 115 kV	9	41
Woburn – Hartwell 115 kV	6	19
2nd Woburn 345/115 kV autotransformer	NA	23
Sudbury Substation with a 230/115 kV autotransformer	NA	24

Upgrade	Length (Miles)	Cost ($ M)
Hartwell Ave 115 kV 36.7 MVAR capacitor	NA	2
Separate the X-24W / E-157W DCT	4 structures	2
Reconfigure the Waltham 115 kV Substation	NA	21
Terminal Upgrades at West Medway 230 kV station to increase ratings of the 282-602 Line	NA	1
Re-conductor 320-507/508 Lexington-Waltham 115 kV	5	9
Re-conductor 211-508 Woburn-Burlington 115 kV	4	5
Refurbish X-24W and X-24E 69 kV Lines	15	7
Replace the existing Woburn 345/115 kV autotransformer	NA	6
Re-conductor 533-508 Lexington-Hartwell 115 kV	2	0.5
Re-conductor E-157W Millbury-East Main St. 115 kV	11	5
Re-conductor W-23 Fitch Rd.-Woodside 69 kV	8	6
Re-conductor W-23W Northboro-Woodside 69 kV	6	5
Woburn – North Cambridge 345 kV	6	52
Needham – Baker St. 115 kV	5	46
2nd Mystic 345/115 kV autotransformer	NA	16
Mystic-Chelsea 115 kV cable	1	25
Add a 2nd Mystic-Woburn 115 kV cable to create a bifurcated 211-514 Mystic-Woburn 115 kV circuit	8	48
Re-conductor 128-518 Chelsea-Revere 115 kV	1	1
K St. 115 kV breaker additions	NA	6
Chelsea 115 kV 36.7 MVAR capacitor	NA	1
Separation of the F-158N and Q169 DCT	1 Structure	0.5
Separation of the O-167 and P-168 DCT	1 Structure	0.5
Open the Mystic 115 kV downtown ties and closes K St. 115 kV bus tie	NA	0

The comments received from the stakeholders at the PAC presentation in March of 2012 included a recommendation that an additional proposal, which was based on an HVDC submarine cable be included in the assessment. This led to a re-assessment of alternatives and development of an HVDC based plan alternative.

It should be noted that the upgrades in bold above were not reassessed as these upgrades were separated from the Greater Boston solution and advanced independently. These advanced Greater

Boston solutions were considered in the basecase for the stage 2, i.e. post March 2012, assessment. The rest of the upgrades were reassessed in stage 2.

5.2 Stage 2

The second stage began after the March 2012 PAC presentation of the Stage 1 preferred solution selection. In this stage the GBWG developed an updated AC Plan and developed the HVDC Plan that featured an HVDC line from the substation at Seabrook to downtown Boston. The solution alternatives for the AC Plan and the competing HVDC Plan which would include some AC components considered all of the same factors as described in the prior evaluations and the development of complementary upgrades relied heavily upon the prior assessment results. Extensive testing was performed to determine the optimal location and interconnection of an HVDC terminal in the Boston area. Additional alternative AC transmission based solution alternatives were also extensively tested which resulted in improved optimization of system upgrades for each problem area. The second stage of the assessment included a revision to the base case assumptions as noted in Section 3.6 of this report that were finalized and presented to the PAC in February 2013[27]. The assumption changes between Stage 1 and Stage 2 resulted in a similar, but not exactly the same, set of reliability needs that were found in the Greater Boston Area Transmission Needs Assessment dated January 2015[28]. In addition to these peak load transmission reliability needs, a short-circuit assessment and minimum load assessment were added to the Needs Assessment study and BPS testing was added to the Solutions Study. As a result of the changes in study assumptions and the addition of minimum load cases, the final AC Plan identified as the preferred solution in this report, differs from the March 2012 preferred solution.

5.2.1 AC Plan Development

The AC Plan development began with the Greater Boston Needs Assessment 2023 cases. A complete steady-state assessment was performed beginning with the final Stage 1 plan. This testing confirmed that all the components of the Stage 1 plan were still needed and incorporated any modifications to reduce the cost of the overall plan.

As a result of the changes in assumptions there were differences between Stage 1 and Stage 2. Several examples of the changes include:

- Re-conductoring of the Sandy Pond – Tewksbury 337 345 kV line and the terminal upgrades to the Seabrook – Ward Hill 394 345 kV line upgrades were removed due to reductions in Boston Imports with the addition of Footprint generation and the updated EE forecast
- Tewksbury-Woburn, Wakefield-Ward Hill and Woburn-North Cambridge were replaced by Wakefield – Woburn based on the following: using XLPE technology, the updated cable ratings requiring a parallel cable in the downtown Boston system, and the reduced Boston Import requirements based on a reduction in the load forecast, inclusion of the EE forecast and Footprint Power generation

[27] Greater Boston Solutions Study Status Update February 2012 https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/feb122013/a5_greater_boston_solution_study_update.pdf

[28] The revised peak load Needs Assessment transmission reliability concerns using the updated assumptions were presented at the July 2013 PAC meeting.

- Sharon switching station was added based on N-1-1 load loss
- Kingston 345 kV reconfiguration was added based on the updated cable ratings
- North Cambridge upgrades were added based on updated cable rating changes in conjunction with an additional dispatch with Kendall OOS
- Opening of the Y-151 was replaced by the reconductoring of the Y-151 due to load serving concerns in the Pelham area
- Addition of the 2nd Woburn 345/115 kV autotransformer and the Woburn to Hartwell 115 kV line were no longer required due to reduced loads in the Woburn-Lexington area based on the EE forecast
- Three 345 kV shunt reactors were added to the plan based on light load high voltage testing that was not performed in the stage 1 assessment
- A 200 MVAR STATCOM was added to the plan based on the BPS testing that was not performed in the stage 1 assessment

5.2.2 HVDC Plan Development

The comments received by stakeholders at the PAC presentation in March 2012 included a request that an additional alternative based on an HVDC submarine cable be included in the assessment.

The HVDC alternative attempted to address transmission reliability needs identified in both the Downtown Boston sub-area as well as the Northern sub-area as it provided both a source of supply for the Downtown area and provided a transmission path for improving the Boston Area Import capability. The HVDC alternative, tested with the short circuit mitigation plans, required additional AC system reinforcements to adequately address all identified concerns.

The HVDC alternative began by testing the terminal connection options shown in Table 5-4. The terminal sizes tested included 400 MW, 520 MW, 600 MW, 800 MW and 1,000 MW.

The HVDC alternative also had the effect of eliminating the need for some of the North subarea AC transmission upgrades. The list of upgrades provided in Table 5-5 includes related AC transmission upgrades which were considered to complete the HVDC Plan.

Table 5-4 HVDC Alternatives

HVDC Alternatives Tested
Terminal Connections Options
Seabrook 345 kV - K Street 115 kV
Seabrook 345 kV - Kingston 345 kV
Seabrook 345 kV - Wakefield 345 kV
Seabrook 345 kV - Mystic 345 kV
Seabrook 345 kV - Mystic 115 kV
Seabrook 345 kV - Salem 115 kV

Table 5-5 HVDC Alternative Related AC Upgrades Needed for Some Options

Related AC Upgrades Needed for Some Options

Addition of 2nd 345 kV/ 115 kV autotransformer at Mystic
Bifurcate 351 and 358 N. Cambridge - Mystic 345 kV cables
Upgrade Y151 (Pelham to NU Border) to 451 MVA and Upgrade Y151 (Pelham to Dracut Jct.) to 451 MVA
Re-conductor 337 Line - Sandy Pond - Tewksbury 345 kV
Re-conductor Everett - Maplewood (F-158S) 115 kV (Plus Sub work at Everett)
Eliminate Stuck Breaker Faults for #337 at Sandy Pond 345 kV Bus
Eliminate Stuck Breaker Faults for #106 at Woburn 345 kV Bus

Based on the preliminary cost estimates for the HVDC transmission alternative it was concluded that the Seabrook – Mystic 115 kV, 520 MW HVDC line in combination with a subset of AC upgrades described below was the most cost effective HVDC transmission solution for the Downtown Boston area.

5.3 Coordination of Alternative Solutions with Other Entities

The GBWG coordinated activities with the NH/VT Working Group and the SEMA/RI Working Group in an effort to ensure the solutions proposed by each group met each area's needs, were not redundant of one another, and that the efforts of each group would result in the identification of the most cost effective solution for the region as a whole.

One significant overload condition associated with contingency events located in southeastern Massachusetts called for coordination of modeling assumptions and study efforts with the SEMA/RI Working Group. The GBWG found that certain elements in the Greater Boston area were overloaded exclusively due to SEMA/RI contingency events and, through coordination of efforts between the two study groups, it was concluded that the SEMA/RI Working Group would be best suited to develop solutions in the context of development of all solutions for the SEMA/RI study area which was underway at the time.

The SEMA/RI contingency events are [redacted] The impact of this contingency event was seen in both the AC and HVDC plans.

5.4 Description of Alternative Solutions

A final set of solution alternatives was developed based on preliminary information concerning cost and constructability associated with each of the upgrade options described above. There were two final solution alternatives identified: one based on AC only transmission solutions and a second that was based on a HVDC transmission addition between Seabrook and Boston as well as AC components common to both alternatives and other AC transmission components unique to the HVDC project. These alternatives are described in the following paragraphs and are compared on a cost and performance basis in Section 6 and Section 7.

[redacted]

Both the AC transmission based solution and the HVDC based transmission solution alternatives included a set of common upgrades needed independent of the final alternative selected. These upgrades include addition of new facilities as well as upgrades or modifications to existing facilities.

Table 5-6 Common Upgrades Needed for AC Transmission or HVDC Transmission Alternatives

New Facility	Length (Miles)
West Walpole – Holbrook 115 kV line	14
Sharon Switching Station	NA
Sudbury – Hudson 115 kV line	9
Sudbury 230/115 kV autotransformer	NA
Install K St. tie breaker	NA
Install Stoughton 345 kV series breaker	NA
Newton 115 kV capacitor	NA
Sudbury 115 kV capacitor	NA
Hartwell 115 kV capacitor	NA
345 kV shunt reactor at K St.	NA
Upgraded Facilities	**Length (Miles)**
Rebuild X-24W and X-24E 69 kV	15
Re-conductor M-139 Tewksbury – Billerica Tap 115 kV	3
Re-conductor F-158N Golden Hills – Maplewood 115 kV	4
Re-conductor W-23W 69 kV Northboro Rd. - Woodside	4
Re-conductor Y-151 Power St – Eversource / National Grid border	4
Other	**Length (Miles)**
Separate Needham – Baker St. 240-510 / 110-522 DCT	4
Separate F-158N / Q-169 DCT	1 structure
Separate X-24W / E-157W DCT	4 structures
Waltham Reconfiguration	NA
North Cambridge Reconfiguration	NA
Kingston Reconfiguration	NA
Move Chelsea capacitor	NA
Add a 115 kV breaker at Framingham	NA

The final AC transmission solution includes upgrades that address all of the issues identified in the Greater Boston Transmission System Needs Assessment January 2015 Report (including the areas known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston, parts of the areas south of Boston, and a small area that is a part of the New Hampshire load zone) transmission violations, short circuit issues and dynamic performance concerns. The one-line diagram shown in Figure 5-1 below is a high level overview of the AC transmission solution upgrades.

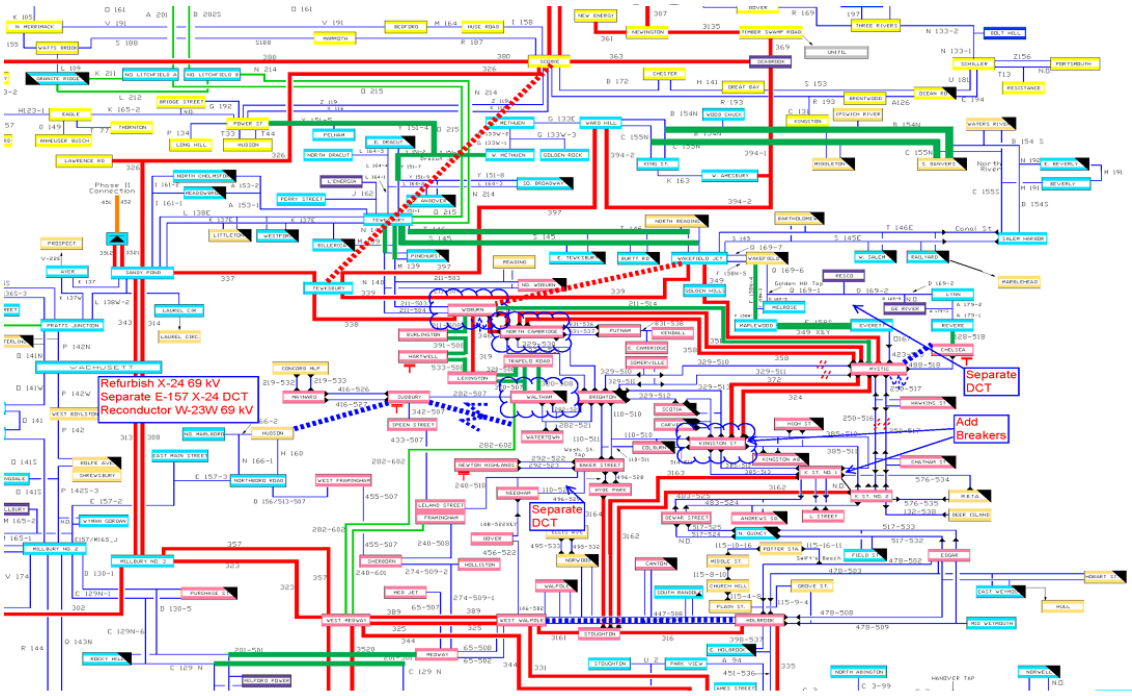


Figure 5-1 One-Line Diagram of the AC Transmission Solution Alternative

The final AC transmission solution upgrades and system modifications are listed in Table 5-7 below. This table includes a list of system upgrades that are unique to the selected AC transmission based alternative and when combined with the common upgrades shown in Table 5-6 above form a comprehensive plan to address all identified needs for the Greater Boston RSP area.

Table 5-7 Preferred AC Transmission Solution Plan Unique System Upgrades

AC Plan	Length (Miles)
Scobie – Tewksbury 345 kV line	25
Re-conductor Y-151 115 kV Eversource border to Dracut Jct.	9
Wakefield Jct. – Woburn 345 kV underground cable plus 2 reactors	8
Bifurcate a new Woburn – Mystic 115 kV cable with existing cable	8
Upgrade 5 substations to BPS standards	NA
Add a 200 MVAR STATCOM at Coopers Mills 345 kV in ME	NA
2nd Mystic 345/115 kV autotransformer	NA
Mystic – Chelsea 115 kV underground cable	3
New Woburn 345/115 kV autotransformer and Woburn Reconfiguration	NA
K St. 115 kV breaker addition	NA
Re-conductor M-139 115kV Billerica Tap to Pinehurst Tap	3
Re-conductor N-140 115kV Tewksbury to Pinehurst Tap	7
Re-conductor F-158S 115kV Maplewood to Everett	3
Upgrade terminal equipment to increase 533-508 115 kV Lexington to Hartwell rating	NA
Open Mystic 115 kV downtown ties (mitigates short-circuit concerns)	NA

Re-conductor M-139/211-503 and N-140-211-504 lines Pinehurst Tap to North Woburn Tap	5

The final HVDC transmission solution also addresses all issues identified in the Greater Boston Transmission System Needs Assessment January 2015 (including the areas known as Northeast Massachusetts – Boston load zone or NEMA/Boston load zone, as well as some parts of the surrounding areas west of Boston, parts of the areas south of Boston, and a small area that is a part of the New Hampshire load zone) transmission violations, short circuit issues and dynamic performance concerns.. The HVDC plan is a hybrid plan including both HVDC and AC transmission system element additions and upgrades. The one-line diagram shown in Figure 5-2 below is a high level overview of the upgrades included in the HVDC alternative.

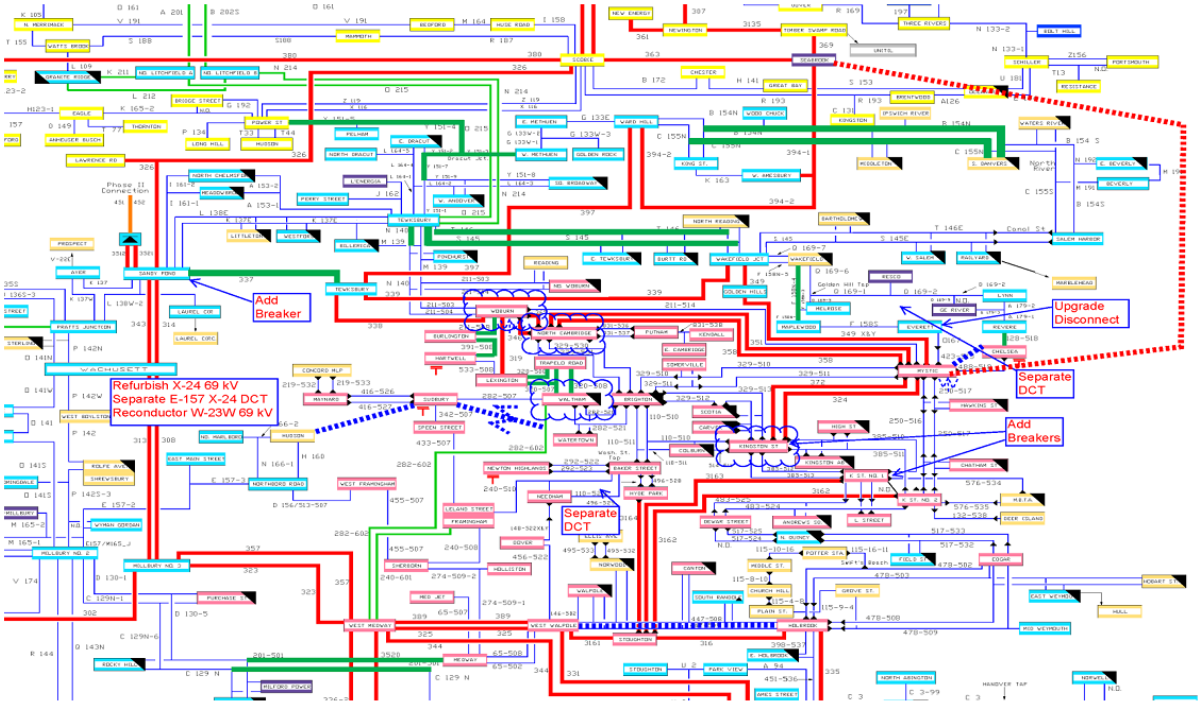


Figure 5-2 One-Line Diagram of the HVDC Transmission Solution Alternative

The final HVDC transmission based solution upgrades and system modifications are listed in Table 5-8 below. This table includes a list of the upgrades that are unique to the HVDC based transmission alternative and when combined with the common upgrades shown in Table 5-6 above constitutes a comprehensive plan that will meet the identified needs of the Greater Boston RSP area.

Table 5-8 Preferred HVDC Transmission Solution Plan Unique System Upgrades

HVDC Plan	Length (Miles)
HVDC submarine cable and two terminals	68
Seabrook 345 kV interconnection for the HVDC	NA
Mystic 115 kV interconnection for the HVDC	NA

Re-conductor Y-151 kV Eversource border to Dracut Jct.	9
Re-conductor 337 Sandy Pond – Tewksbury 345 kV line	16
Bifurcate Mystic – North Cambridge 345 kV	NA
2nd Mystic 345/115 kV autotransformer	NA
Mystic – Chelsea 115 kV underground cable	3
New Woburn 345/115 kV autotransformer and Woburn Reconfiguration	NA
Sandy Pond breaker addition	NA
Upgrades to address 250-516/517 overloads[29]	NA

[29] A final solution alternative for this issue was not developed since even without the additional cost of this alternative the AC plan was superior in terms of cost and other factors.

Section 6
Alternative Solutions Performance Testing and Results

6.1 Steady State Performance Results

Each transmission solution alternative for each sub-area was tested against the identified needs, and was augmented until a complete solution package was developed to address the needs identified in the Needs Assessment. As such, the N-0, N-1, and N-1-1 thermal and voltage criteria are fully satisfied with the full combination of each subarea solution set.

6.1.1 N-0 Thermal and Voltage Performance Summary

There were no N-0 thermal or voltage violations identified in the Greater Boston Needs Assessment testing. As such, the N-0 thermal and voltage criteria are fully satisfied with the full combination of each subarea solution set.

6.1.2 N-1 Thermal and Voltage Performance Summary

Each transmission solution alternative for each subarea was tested against the identified needs, and was augmented until a complete solution package was developed to address the needs identified in the Needs Assessment. As such, the N-1 thermal and voltage criteria are fully satisfied with the full combination of each subarea solution set.

6.1.3 N-1-1 Thermal and Voltage Performance Summary

Each transmission solution alternative for each sub-area was tested against the identified needs, and was augmented until a complete solution package was developed to address the needs identified in the Needs Assessment. As such, the N-1-1 thermal and voltage criteria are fully satisfied with the full combination of each subarea solution set.

One significant overload condition associated with contingency events located in Southeastern Massachusetts called for coordination of modeling assumptions and study efforts with the SEMA/-RI Working Group. The GBWG found that certain elements in the Greater Boston area were overloaded exclusively due to SEMA/RI contingency events and, through coordination of efforts between the two study groups, it was concluded that the SEMA/RI Working Group would be best suited to develop solutions in the context of development of all solutions for the SEMA/RI study area which was underway at the time.

The SEMA/RI contingency events are [redacted] The impact of this contingency event was seen in both the AC and HVDC plans.

6.1.4 Results of Delta P Testing

Not Applicable.

[redacted]

6.1.5 Results of Light Load Testing

Light load testing was performed at both minimum load levels (lowest design load level typically occurring during Spring and Fall load periods) and at off-peak load levels (lowest design load level typically occurring during summer load periods). Each of the selected AC and HVDC transmission plans for each sub-area was augmented until all identified needs as well as any additional issues arising from system improvements were fully addressed under light load conditions.

The addition of shunt reactors was necessary to address the identified high voltage concerns following addition of the proposed upgrades under light load conditions. Table 6-1 shows the existing and additional Boston RSP subarea shunt reactors needed to address light load high voltages for each of the two final selected plans.

Table 6-1 New and Existing Boston Area Shunt Reactors

Greater Boston Solutions Study Shunt Compensation Table		
Existing Boston Area Shunt Compensation		
Bus Name	**Voltage (kV)**	**Min Reactive (MVAR)**
EDGAR_R1	115	[redacted]
EDGAR_R2	115	
K STREET 1_R	115	
K STREET 1_R	345	
K STREET 2_R	115	
K STREET 2_R	345	
LEXINGTON_R	345	
MYSTIC_R	115	
MYSTIC_R	345	
N CAMBRDG_R1	115	
N CAMBRDG_R2	115	
N.CAMBRIDG_R	345	
SANDY POND	345	
STOUGHTON_R1	345	
STOUGHTON_R2	345	
STOUGHTON_R3	345	
STOUGHTON_R4	345	
SUDBURY_R	115	
SUDBURY_R	115	
WEST WALPOLE_R	345	
WOBURN_R1	115	

Greater Boston Solutions Study Shunt Compensation Table		
Existing Boston Area Shunt Compensation		
Bus Name	**Voltage (kV)**	**Min Reactive (MVAR)**
WOBURN_R2	115	-76
WOBURN_R3	115	-76
Additional Boston Area Shunt Compensation		
Wakefield Reactor (Not Needed in HVDC Plan)	345	-159
Woburn Reactor (Not Needed in HVDC Plan)	345	-159
K St. Reactor	345	-159

6.2 Stability Performance Results

6.2.1 Stability Performance Results

Stability testing was performed to assess both the general stability performance of the system following introduction of the proposed transmission system upgrades as well as the potential impact on BPS protection system requirements after the upgrades are in place.

6.2.2 All-Lines-In Stability Performance Results

Stability testing was conducted as a means to compare performance results between the alternative solution plans. The testing was limited to extreme contingencies as this provided the most meaningful results for differentiating the alternatives. Testing was performed considering base case conditions as well as a number of possible dynamic reactive devices such as synchronous condensers, STATCOMs or SVCs as a means to improve performance. The testing was not comprehensive and was limited to the most significant faults that would potentially be most concerning.

The results shown in Table 6-2 include performance results for three dispatch cases (D1, D3 and D6 – see Table 3-10 above for a description of each dispatch). In each case the HVDC Transmission plan (Labeled "SeaLink w/M6 Converter") and the AC Plan (Labeled "T0a w/AC Upgrades") alternatives were tested. In addition, since the D1 dispatch resulted in an unacceptable response for the AC Plan, testing with dynamic reactive devices was performed. The results of these tests found that addition of a 200 MVAR STATCOM at Coopers Mills provided an improved performance for this plan. The results of the improved plan analysis is included in Table 6-2 and indicates that, with the addition of this STATCOM, the performance of both the HVDC and AC plans is comparable. Full stability testing will be conducted as part of the PPA process and the appropriate dynamic performance reactive design, if necessary, will be developed as part of those procedures.

Table 6-2 Extreme Contingency Stability Testing Results

Fault ID	Station Name	Fault Type	Fault Description	Element(s) Removed	Sealink w/M6 Converter + Q387 + VT Yankee & Braytn PT retired	T0a w/AC upgrades + Q387 + VT Yankee & Braytn PT retired	T0a w/AC upgrades + Q387 + VT Yankee & Braytn PT retired + 200Mvar Statcom @ Coppers Mills	Sealink w/M6 Converter + Q387 + VT Yankee & Braytn PT retired	T0a w/AC upgrades + Q387 + VT Yankee & Braytn PT retired	Sealink w/M6 Converter + Q387 + VT Yankee & Braytn PT retired	T0a w/AC upgrades + Q387 + VT Yankee & Braytn PT retired
					LT16_D1_T11_Q387_r16	LT16_D1_T2_Q387_r15	LT16_D1_T2_Q387CST_r15	LT16_D3_T11_Q387_r16	LT16_D3_T2_Q387_r15	LT16_D6_T11_Q387_r15	LT16_D6_T2_Q387_r14
SLM3PSB101	Salem Harbor	3 phase	[redacted]	[redacted]	Vsag = 0.8688 pu	Vsag = 0.7536 pu	N/A	Acceptable	Acceptable	Vsag = 0.8587 pu	Vsag = 0.7082 pu
SLM1PSB101	Salem Harbor	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
SLM3PSB102	Salem Harbor	3 phase			Vsag = 0.8743 pu	Vsag = 0.7316 pu	N/A	Acceptable	Acceptable	Vsag = 0.8617 pu	Vsag < 0.7000 pu
SLM1PSB102	Salem Harbor	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
KST3PSB101	K Street	3 phase			Unacceptable / ME-NH Separation + Mystic 7	Unacceptable / Instability	Unacceptable / Orr-So Separation + Wyman Area + Mystic 7	Vsag = 0.7440 pu	Vsag < 0.7000 pu	ME-NH Separation	ME-NH Separation
KST1PSB101	K Street	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
KST3PSB102	K Street	3 phase			Unacceptable / Suro-So Separation + Portland Gen + Mystic 7	Unacceptable / Suro-So Separation + Mystic 7	Unacceptable / Suro-So Separation + Portland Gen + Mystic 7	Vsag = 0.8995 pu	Vsag < 0.7000 pu	Vsag < 0.7000 pu	ME-NH Separation
KST1PSB102	K Street	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
MLB_1402_BF	Millbury	3 phase			Vsag = 0.7800 pu	Vsag < 0.7000 pu / Mystic 7	N/A	Vsag = 0.9053 pu	Vsag = 0.8453 pu	Vsag < 0.7000 pu	ME-NH Separation
MLB1P_1402_BF	Millbury	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
NCM3PSB301	N. Cambridge	3 phase			Vsag = 0.73 pu	Unacceptable / Suro-So Separation + Mystic 7	Vsag < 0.7000 pu	Vsag = 0.9400pu	Vsag = 0.8446 pu	Vsag = 0.8400 pu	Vsag < 0.7000 pu
NCM1PSB301	N. Cambridge	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
MYS3PSB102	Mystic 115 kV	3 phase			Vsag = 0.7419 pu	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
MYS1PSB102	Mystic 115 kV	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
MYS3PSB301	Mystic 345 kV	3 phase			Vsag = 0.7623 pu	Unacceptable / Suro-So Separation + Mystic 7	Vsag @ 0.7000 pu	Acceptable	Vsag = 0.8604 pu	Vsag = 0.8309 pu	Vsag = 0.7098 pu
MYS1PSB301	Mystic 345 kV	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
WCH3PSB101	Wachusett	3 phase			Unacceptable / Suro-So Separation + Portland Gen + Mystic 7	Unacceptable / ME-NH Separation + Mystic 7	Unacceptable / Suro-So Separation + Mystic 7	Vsag = 0.8292 pu	Vsag = 0.7158 pu	Suro-So Separation	ME-NH Separation
WCH1PSB101	Wachusett	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable
WMed105BF	W. Medway	3 phase			Vsag < 0.7000 pu	Vsag < 0.7000 pu / Mystic 7	N/A	Vsag = 0.8395 pu	Vsag = 0.7522 pu	Suro-So Separation	Suro-So Separation
WMed1P105BF	W. Medway	1 phase			Acceptable	Acceptable	N/A	Acceptable	Acceptable	Acceptable	Acceptable

[redacted]

6.2.3 Line-Out-of-Service Stability Performance Results

Line out of service testing was not performed with the understanding that such testing would be conducted as part of the PPA process.

6.2.4 Bulk Power System (BPS) Stability Performance Results

BPS testing was performed using light load cases from the latest ISO base case database and included cases representing five different Boston generation dispatch levels. These cases also included stressed interface conditions for the Maine interfaces, the North-South interface, the East-West interface and the SEMA-RI interface. All BPS testing was based on 3 phase bus faults with remote clearing tested at 63 substations throughout New England with the majority of substations located in and around the Boston area. Testing for BPS classification was conducted as a basis for comparison between the plans. The results of this testing showed that there were some differences in the impact of the alternative upgrade plans on the number of stations that would be classified as BPS after implementation. The results in Table 6-3 show that there were 14 stations that would be classified as BPS under the AC Plan with the STATCOM and that there were only 10 stations that would be classified as BPS under the HVDC Plan. The results in Table 6-3 only include stations that tested BPS positive for one of the four topologies tested. There were seven stations that tested positive in the pre project topology and did not change with the addition of either plan. These were excluded from all subsequent comparisons. The performance concern that drove BPS performance issues was associated with a dynamic response that resulted in separation of the Maine transmission system from the rest of New England. These results were used as a base line for comparison of BPS performance for each of the transmission solution alternatives.

Table 6-3 Stations Requiring BPS Upgrades

Stations	Pre GB Upgrades	HVDC Plan	AC Plan w/o STATCOM	AC Plan with STATCOM
[redacted]	Yes	No	Yes	No
	Yes	Yes	Yes	Yes
	Yes	Yes	Yes	Yes
	Yes	No	Yes	Yes
	Yes	No	Yes	Yes
	Yes	Yes	Yes	Yes
	No	No	Yes	Yes
	Yes	Yes	Yes	Yes
	Yes	Yes	Yes	Yes
	Yes	No	Yes	No
	Yes	Yes	Yes	Yes
	Yes	No	Yes	No
	Yes	No	Yes	Yes
	Yes	No	Yes	No
	No	No	Yes	No
	Yes	No	Yes	No
	No	Yes	Yes	Yes

[redacted]	No	Yes	Yes	Yes
	Yes	Yes	Yes	Yes
	Yes	No	Yes	No
	Yes	No	Yes	Yes
	Yes	Yes	Yes	No
Total Stations Requiring BPS Upgrades	18	10	22	14

The following stations need to be upgraded to BPS standards for both plans:

[redacted]

To have the same number of residual BPS stations as the HVDC plan, the AC Plan with the STATCOM will need the following stations upgraded to BPS standards:

[redacted]

The following stations needed to be upgraded to BPS standards with the HVDC plan to have the same number of residual BPS stations as the AC plan with the STATCOM:

[redacted]

Finally, as a part of the PPA study for the preferred solution, the BPS testing will be re-performed to confirm the need to upgrade the additional stations to BPS.

6.2.5 Voltage Sag Stability Performance Results

For both the AC Plan and the HVDC Plan, the GBWG assessed the voltage sag at a key Maine substation for critical faults in the Greater Boston area. This assessment used the same methodology as previously developed for testing with the Maine Power Reliability Program. First, a pre –upgrade base case with acceptable performance is used to benchmark the voltage sag in Maine. This becomes the reference case for measuring performance between the two plans. Each alternative is added and the voltage sag is again measured. Based on the testing performed, the following is observed:

1. The benchmark was established with base and common upgrades [redacted] V_{sag} is lowest in Maine at [redacted] at 0.687 pu.
2. Post project results showed V_{sag} improvement for the HVDC Plan and degradation for the AC Plan:
    a. HVDC upgrades were added and V_{sag} improved to 0.772 pu
    b. AC upgrades (without the 200 MVAR STATCOM needed [redacted]) were added and V_{sag} degraded to 0.677pu
3. The test was then repeated for the AC upgrades including the addition of a 200 MVAR STATCOM at Coopers Mills [redacted]

[redacted]

a. V_{sag} improved to 0.779pu

Based on the voltage sag stability degradation with the AC upgrades without the STATCOM this configuration was not considered viable for the final AC plan even if the 8 additional stations identified in the previous section were upgraded to meet BPS standards. Hence, the 200 MVAR STATCOM became a part of the AC plan.

6.3 Short Circuit Performance Results

The short circuit breaker duty evaluation was performed for the base 2017 model year system expanded to include all upgrades for each of the solution alternatives. This assessment considered the short circuit fault duty seen by individual breakers for the worst case faults under the modeled conditions. The modeled conditions include assumptions concerning breaker interrupting characteristics as well as assumptions concerning dispatch of generation that is running and on-line. The assessment performed assumed that breakers shall not exceed 100% of the fault interruption duty ratings as provided by equipment owners.

6.3.1 Short Circuit Performance Results

The results for short circuit testing shown in Table 6-4 includes the worst case breaker duty percentages for the original Needs Assessment case as well as the preferred AC Plan and the preferred HVDC Plan connecting to the 115 kV bus at Mystic. The AC plan is based on opening the Mystic 115 kV downtown ties and operating with one of the four Wakefield Jct. autotransformers normally open. The HVDC plan is based on the re- configuration at Mystic Station needed to interconnect HVDC line. All of the results, with the exception of the Needs Assessment cases included removal of units requesting NPR that have been submitted to the Forward Capacity Market up through FCA-8.

Table 6-4 Boston RSP subarea Selected Alternatives Short Circuit Performance (Breaker Duty %)

Station	Breaker Duty (%)		
	Pre-Upgrade Case	AC Plan	HVDC Plan
Mystic 115 kV	[redacted]	86%	85%
Kingston 115 kV		88%	95%
Brighton 115 kV		87%	86%
K St. 115 kV		88%	90%
West Medway 345 kV		93%	93%
Salem Harbor 115 kV		98%	97%
Wakefield Jct. 115 kV		96%	92%

6.4 SPS Performance Results

An evaluation of the need and operational set points of the SPS's listed in Table 3-7 will be evaluated in the PPA study.

Section 7
Comparison of Alternative Solutions

Typically, ISO-NE selects the solution alternative which has the lowest cost estimate and fully addresses the identified reliability needs documented in a Needs Assessment unless the cost estimate of competing alternatives are similar. In these situations, ISO-NE considers other categories of benefits to evaluate.

This section captures these categories of benefits by comparing the two alternatives in the second stage of the Greater Boston Solutions Study, namely the AC Plan and the HVDC Plan.

7.1 Factors Used to Compare Alternative Solutions

The key factors used for the comparison of the AC Plan and the HVDC Plan are:

- Cost
- Constructability
- Construction Outage Requirements/Cost Impacts
- Expected In-Service Dates
- Interface Impacts
- Losses
- Extreme Contingency Analysis
- Expansion Capabilities
- Lifetime Maintenance Requirements
- Incremental Costs for Potential Retirements
- Siting Issues
- Storm Hardening

7.2 Cost

The costs of the individual upgrades that make up the AC Plan and HVDC Plan were developed by the participating Transmission Owners (TO). The individual estimates were developed in accordance with ISO-NE Planning Procedure 4, *Procedure for Pool-Supported PTF Cost Review*.[30] The level of detail in the estimate corresponds to the Proposed Project stage which specifies a conceptual estimate with a level of accuracy of -25% to +50%. All cost estimates were submitted in 2017 dollars except when specified otherwise.

The cost estimates for both plans were categorized into the following three categories; common upgrades, similar but not identical upgrades, and major unique upgrades. The reason for the three categories was to allow ISO-NE to concentrate on the comparison of the major unique upgrades that, in essence, defined the differences between the two plans.

[30] http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp04_0/pp4_0.pdf

7.2.1 Common Upgrades

The common upgrades are shown in Table 7-1 through Table 7-4 below for the North, South, Western Suburbs and Downtown Boston subareas.

Table 7-1 North Subarea Common Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Re-conductor Y-151 115 kV line from Power St to Eversource / National Grid border	4	8.5
Re-conductor M-139 115 kV line from Tewksbury to Billerica Tap	3	5.3
Re-conductor F-158N 115 kV line from Golden Hills to Maplewood	4	5.4
North Subarea Total		19.2

Table 7-2 South Subarea Common Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Construct West Walpole to Holbrook 115 kV line	14	17.3
Construct Sharon Switching Station	NA	12.8
South Subarea Total		30.1

Table 7-3 Western Suburbs Subarea Common Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Install Sudbury 230/115 kV autotransformer	NA	28.1
Construct Sudbury to Hudson 115 kV line	9	51.0
Refurbish the X-24W and X-24E 69 kV lines	15	8.5
Re-conductor the W-23W 69 kV line from Northboro Road to Woodside	6	5.9
Re-configure the Waltham 115 kV substation	NA	17.5
Separate the E-157W / X-24W 115 69 kV DCT	4 structures	3.4
Add a 36.7 MVAR 115 kV capacitor at Sudbury	NA	1.3
Add a 115 kV breaker at Framingham	NA	1.0
Western Suburbs Subarea Total		116.7

Table 7-4 Downtown Boston Subarea Common Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Reconfigure Kingston 115 kV substation adding four new 115 kV breakers	NA	14.5
Add K St. 115 kV tie breaker	NA	2.6
Add a 36.7 MVAR 115 kV capacitor at Hartwell	NA	1.4
Re-configure North Cambridge 115 kV	NA	8.2
Separate the 240-510 / 110-522 115 kV DCT	4	31.3
Separate the F-158N / Q-169 115 kV DCT	1 structure	0.7
Add a 160 MVAR 345 kV reactor at K St.	NA	12.0
Add a 345 kV breaker at Stoughton	NA	1.6
Add a 54 MVAR 115 kV capacitor at Newton	NA	1.4
Move the existing Chelsea capacitor	NA	0.9
Downtown Boston Subarea Total		74.6

For both the AC Plan and the HVDC Plan, the common upgrades total **$240.6 M**.

7.2.2 Similar Upgrades

For a select few upgrades, the AC Plan and the HVDC Plan require similar but not identical upgrades. These upgrades are shown in Table 7-5 below. The differences for each upgrade between the AC Plan and the HVDC plan are minor and can be described as needing slightly different substation configurations or required ratings. Therefore, the cost estimates are slightly different for each plan. All the similar upgrades are located in the Downtown Boston Subarea.

Table 7-5 Similar Upgrades Downtown Area Subarea

	AC Plan		HVDC Plan	
	Length (Miles)	**Cost (in 2017 $ M)**	**Length (Miles)**	**Cost (in 2017 $ M)**
Install a 2nd Mystic 345/115 kV autotransformer	NA	32.2	NA	28.1
Construct Mystic – Chelsea 115 kV underground cable	3	53.4	3	55.6
Replace (AC Plan) / Install (HVDC Plan) Woburn 345/115 kV autotransformer and substation reconfiguration	NA	38.8	NA	37.4
Totals		124.4		121.1

7.2.3 Major Unique Upgrades

7.2.3.1 AC Plan Major Unique Upgrades

The major unique upgrades for the AC Plan are shown in Table 7-6 through Table 7-9 below. The AC Plan features two new 345 kV elements, a new 345 kV overhead line in existing ROW from Scobie Substation in New Hampshire to the Tewksbury Substation in Massachusetts and a new 345 kV underground cable from Wakefield Jct. Substation to the Woburn Substation in Massachusetts. Also featured as part of the AC Plan is the addition of a new 115 kV underground cable bifurcated with the existing cable from Mystic Substation to Woburn Substation and the addition of a 345 kV STATCOM at Coopers Mills 345 kV Substation in Maine. The remainder of the upgrades listed in Table 7-9 that complete the Major Unique Upgrades for the AC Plan are much less costly relative to the ones mentioned here.

The total cost estimate for the AC Plan Major Unique Upgrades is **$394.3M.**

Table 7-6 AC Plan North Subarea Major Unique Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Construct Scobie – Tewksbury 345 kV line[33]	25	122.9
Re-conductor Y-151 115 kV line from Eversource / National Grid border to Dracut Jct.[33]	9	
Construct Wakefield Jct. – Woburn 345 kV underground XLPE cable plus two 160 MVAR 345 kV reactors (one at Wakefield and one at Woburn)	8	107.3
Re-conductor F-158S 115 kV line from Maplewood to Everett	3	3.7
Re-conductor M-139 115 kV line from Billerica Tap to Pinehurst Tap	3	4.4
Re-conductor N-140 115 kV line from Tewksbury to Pinehurst	7	8.8
Re-conductor M-139/211-503 and N-140/211-504 115 kV line from Pinehurst Tap to N. Woburn Tap	5	6.3
Total		253.4

[33] Also known as the Merrimack Valley Reliability Project.

Table 7-7 AC Plan Downtown Boston Subarea Major Unique Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Bifurcate by adding a parallel underground cable to the existing 211-514 115 kV line from Woburn – Mystic	8	75.0
Open the Mystic 115 kV downtown ties	NA	0.3
Add series 115 kV breaker and close the existing 115 kV tie breaker at K St.	NA	2.6
Total		77.9

Table 7-8 AC Plan Western Suburbs Subarea Major Unique Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Upgrade terminal equipment on the 533-508 115 kV line from Lexington – Hartwell	NA	0.4
Total		0.4

Table 7-9 AC Plan Unique Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Add a 200 MVAR STATCOM at Coopers Mills 345 kV	NA	26.0[34]
Upgrade 5 substations to BPS standards	NA	36.6
Total		62.6

7.2.3.2 HVDC Plan Major Unique Upgrades

The major unique upgrades for the HVDC Plan are shown in Table 7-10 and Table 7-11 below. The HVDC Plan features an HVDC line with two terminals from Seabrook 345 kV Substation to the Mystic 115 kV Substation. Also featured as part of the HVDC Plan is the re-conductoring of the existing Sandy Pond – Tewksbury 337 345 kV line. The remainder of the upgrades listed in Table 7-11 that complete the Major Unique Upgrades for the HVDC Plan are much less costly relative to the ones mentioned here.

The total cost estimate for the HVDC Plan Major Unique Upgrades is **$683.4 M.**

[34] The cost estimates for the 200 MVAR STATCOM was provided in 2014 dollars. Since the time of the evaluation, CMP has provided a revised estimate of $58M.

Table 7-10 HVDC Plan North Subarea Major Unique Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Construct Seabrook to Mystic 520 MW HVDC line and two HVDC terminals	68	543.0 [35]
Seabrook 345 kV interconnection for the HVDC line	NA	31.7 [3]
Mystic 115 kV interconnection for the HVDC line	NA	30.0
Re-conductor Y-151 115 kV line from Eversource / National Grid border to Dracut Junction	9	16.6
Re-conductor 337 345 kV line from Sandy Pond to Tewksbury	16	46.4
Add Sandy Pond 345 kV breaker	NA	3.2
Total		670.9

Table 7-11 HVDC Plan Downtown Boston Subarea Major Unique Upgrades

Facility	Length (Miles)	Cost (in 2017 $ M)
Bifurcate the existing 351 / 358 345 kV Mystic to North Cambridge lines	NA	12.5
Upgrades to address the 250-516/517 overloads	NA	Not yet provided[36]
Total		12.5

7.2.4 Cost Estimate Comparison

The total cost estimate for the AC Plan and the HVDC is shown in Table 7-12 below. Included in the table is the cost difference between the two plans. The AC Plan is $285.8 M less expensive than the HVDC Plan.

Table 7-12 Total Cost Comparison

	AC Plan Cost ($ M)	HVDC Plan Cost ($ M)	Delta ($ M)
Common Upgrades	240.6	240.6	0
Similar Upgrades	124.4	121.1	-3.3
Major Unique Upgrades	394.3	683.3	289.0
Totals	759.3	1045	285.7

[35] The cost estimates for the HVDC line and the Seabrook interconnection were provided in 2018 dollars.

[36] These upgrades are not expected to be substantial compared to the HVDC Plan total cost.

ISO-NE took the additional step of verifying the cost estimates with an independent consultant. Electrical Consultants, Inc. (ECI) was hired to develop conceptual cost estimates for the design, engineering, constructions and commissioning of the Major Unique Upgrades from each plan. The projects selected for verification are listed in Table 7-13.

Table 7-13 Major Unique Upgrades for ECI Verification

AC Plan	HVDC Plan
Construct Scobie – Tewksbury 345 kV line	Construct Seabrook to Mystic 520 MW HVDC line and two HVDC terminals
Re-conductor Y-151 Power St – Eversource / National Grid border	Seabrook 345 kV interconnection for the HVDC line
Construct Wakefield Jct. – Woburn 345 kV line	Mystic 115 kV interconnection for the HVDC line
Bifurcate 211-514 115 kV line from Mystic to Woburn	Re-conductor Y-151 115 kV line from Eversource / National Grid border to Dracut Junction
Install 200 MVAR STATCOM at Coopers Mills 345 kV	Re-conductor 337 345 kV line from Sandy Pond to Tewksbury
	Bifurcate the existing 351 / 358 345 kV Mystic to North Cambridge lines

ECI's independent cost estimates were presented to PAC on November 18, 2014[37]. ECI's cost estimates were not directly comparable to the Transmission Owners' cost estimates for two reasons. The first reason was the ECI cost estimates were provided in 2014 dollars while the Transmission Owners' cost estimates were provided in 2017 and 2018 dollars. The second reason was the Transmission Owners' included contingency in their estimate while ECI did not include contingency[38].

To make the estimates more comparable, ISO-NE removed the contingency costs from the Transmission Owners' estimates and escalated / de-escalated all of the cost estimates to 2017 dollars. This step allows for a direct comparison Transmission Owners' estimate to ECI's estimate. This comparison is shown in Table 7-14 below for the AC Plan and Table 7-15 below for the HVDC Plan.

[37] The details of the ECI's review from the November 18, 2014 PAC meeting can be found at http://www.iso-ne.com/static-assets/documents/2014/11/a4_eci_greater_boston_solutions_presentation.pdf.

[38] Contingency as defined in PP4 Attachment D Section 2.1.

Table 7-14 AC Plan ECI to Transmission Owner Cost Estimate Comparison

	ECI Cost (in 2017 $ M)	TO Cost (in 2017 $ M)	Delta
Construct Scobie – Tewksbury 345 kV line and Re-conductor of Y-151	132.3	101.6	$30.7 M /30.2%
Construct Wakefield Jct. – Woburn 345 kV line	108.3	96.6	$11.7 M / 12.1%
Bifurcate 211-514 115 kV line from Mystic to Woburn	73.9	69.1	$4.8 M / 6.9%
Install 200 MVAR STATCOM at Coopers Mills 345 kV	40.6	27.9	$12.5 M / 44.8%
Total AC Plan	354.9	295.2	$59.7 M / 20.2%

Table 7-15 HVDC Plan ECI to Transmission Owner Cost Estimate Comparison

	ECI Cost (in 2017 $)	TO Cost (in 2017 $)	Delta
Construct Seabrook to Mystic 520 MW HVDC line and two HVDC terminals	$534.6 M	$519.0 M	$15.6 M / 3.0%
Seabrook 345 kV interconnection for the HVDC line	$30.4 M	$28.9 M	$1.5 M / 5.2%
Mystic 115 kV interconnection for the HVDC line	$27.0 M	$27.6 M	$-0.6 M / -2.2%
Re-conductor Y-151 115 kV line from Eversource / National Grid border to Dracut Junction	$11.3 M	$13.2 M	$-1.9 M / -14.4%
Re-conductor 337 345 kV line from Sandy Pond to Tewksbury	$36.9 M	$36.7 M	$0.2 M / 0.5%
Bifurcate the existing 351 / 358 345 kV Mystic to North Cambridge lines	$15.8 M	$11.5 M	$4.3 M / 37.4%
Total DC Plan	$656.0 M	$637.0 M	$19.0 M / 3.0%

A summary comparison of the estimates in provided in Table 7-16 below.

Table 7-16 Summary Comparison of Cost Estimates

	ECI Cost (in 2017 $)	TO Cost (in 2017 $)	Delta

AC Plan	$354.9 M	$295.2 M	$59.7 M / 20.2%
HVDC Plan	$656.0 M	$637.0 M	$19.0 M / 3.0%
HVDC Plan – AC Plan	$301.1 M	$341.8 M	

ISO-NE made the following conclusions based on ECI's verification:

- The result shows the Transmission Owners' cost estimates are viable based on ECI's review and fall well within the +50% / -25% level of accuracy required by Planning Procedure 4 for proposed projects.
- The cost difference between the AC Plan and the HVDC plan is $301.1 M based on the ECI cost estimate and $341.8 M based on the TO cost estimate.

7.2.5 Summary of Cost

The result of the cost analysis is that the AC Plan is significantly less expensive while meeting the reliability needs identified in the Greater Boston Area Updated Transmission Needs Assessment.

7.2.6 Cost Containment Proposal

NHT proposed a cost containment scenario for a portion of the HVDC project alternative. The proposal proposed to cap the cost of the HVDC line and the two HVDC terminals. The cost containment would exclude capital costs that are more than 25% above the current estimate of the $543M for the HVDC upgrades. The proposal would cap the cost for the upgrade at $679M or $136M over the NHT estimate for the HVDC upgrade. The proposal also committed NHT to only earn the New England base return on equity (ROE) on any HVDC upgrade costs that exceed the $543M up to the capped amount of $679M.

Furthermore, NHT proposed to exclude $20M of HVDC upgrade capital costs from its rate base if the project was not in-service by December 31, 2018 as an incentive to ensure the project was operational by the estimated in-service date. This proposal was only valid if ISO-NE selected the HVDC Plan by February 2015.

Since neither the cost containment proposal for the HVDC components, or the in-service date incentive is part of the existing Tariff, the proposals would only be in effect if filed and approved by the FERC. Regardless of the applicability of the proposals, ISO-NE did evaluate the impact of the cost cap proposal on the two plans. To simplify the assessment, ISO-NE assumed that the cost of all the other project components for each alternative not subject to the cost containment proposal would increase uniformly (i.e. cost of all the common upgrades, etc. would also increase by a uniform amount).

Table 7-17 below shows the result of four cost scenarios developed by ISO-NE. The four scenarios are actual costs equal the estimates, all actual costs 50% greater than the estimates, all actual costs 50% greater than the estimates with cost cap applied to the HVDC upgrade, and all actual costs 50% greater than the estimates except the HVDC upgrades whose actual cost equals the estimate

Table 7-17 NHT Cost Cap Proposal Comparison

	HVDC Plan ($ M)	AC Plan ($ M)	Delta (HVDC – AC $ M)
Scenario 1 – Actual cost equal TO estimates	1025.4	739.7	285.7
Scenario 2 – Actual cost 50% greater than TO estimates no cost cap	1538.2	1109.6	428.6
Scenario 3 – Actual cost 50% greater than TO estimate with cost cap	1402.7	1109.6	293.1
Scenario 4 – Actual costs 50% greater except HVDC Upgrade equals estimate	1266.7	1109.6	157.1

As can be concluded from Table 7-17 above, none of the evaluated scenarios show an instance where the HVDC Plan is cost competitive with the AC Plan even with the cost containment proposal in place. Even if NHT were to cap the actual cost of the HVDC upgrade to the estimate, as shown in scenario 4, the AC Plan with significant cost overruns would still be $157.1 M less expensive than the HVDC plan.

As a result of this analysis, ISO-NE concluded that the cost containment proposal does not cause the HVDC Plan to be cost competitive with the AC Plan.

7.3 Constructability

A review of the constructability for a limited number of the Major Unique Upgrades for the AC Plan and the HVDC Plan was conducted by ISO-NE. The review was limited to the Scobie – Tewksbury 345 kV project, named the MVRP, for the AC Plan and the HVDC line, terminals and interconnections for the HVDC Plan. This effort consisted of reviewing the materials provided by NHT for the HVDC Plan and Eversource and National Grid for the AC Plan. NHT conducted both marine and land surveys of the HVDC route. Eversource and National Grid provided surveys of the existing ROW on which the Scobie – Tewksbury 345 kV line is to be built.

Eversource and National Grid demonstrated both to the PAC in December 2014 and to ISO-NE in detail that the Scobie – Tewksbury 345 kV line could be constructed without expansion of the ROW, without removal of any houses, and does not require a DCT along any portion of the ROW for any new or existing lines.

ISO-NE's position is that both plans are constructible.

7.4 Construction Outage Requirements / Cost Impacts

A review of the outage requirements for a limited number of the Major Unique Upgrades from the AC Plan and the HVDC Plan was conducted by ISO-NE. The review was limited to the Scobie – Tewksbury 345 kV for the AC Plan, the interconnection at Mystic 115 kV for the HVDC Plan, and the Sandy Pond – Tewksbury 337 345 kV line reconductoring. This effort consisted of reviewing the materials provided by Eversource and National Grid for both the HVDC Plan and the AC Plan.

For the AC Plan, Eversource and National Grid demonstrated at the December 2014 PAC meeting and internally to ISO-NE that outages associated with the construction of the Scobie – Tewksbury 345 kV line are not expected to be significant. The outage requirements for the Scobie – Tewksbury 345 kV line is shown in Table 7-18 with the outages shown in green. Most of the outages required are in the 3 – 5 day timeframe and occur outside the summer peak time period. [redacted]

Eversource and National Grid are able to achieve this schedule by scheduling much of the preliminary construction of foundations and towers without taking outages, requiring only short duration outages for wire pulling and/or wire cutovers, and using live-line techniques to minimize system impacts.

Extensive ROW configuration is only needed for a small portion, approximately 0.5 miles, of the ROW. The outage durations are short, the outage schedule is flexible, and can be scheduled during shoulder months based on the information supplied by Eversource and National Grid.

Table 7-18 Outage Requirements for the Scobie – Tewksbury 345 kV Line

[redacted]

Bus 2 Outa
L1
L2
L3

[redacted]

For the HVDC Plan, interconnecting the Boston terminal of the HVDC line into the Mystic 115 kV substation would be challenging and require significant outages. Furthermore, National Grid would need to take the Sandy Pond – Tewksbury 337 345 kV line out of service for re-conductoring.

Both the AC Plan and the HVDC Plan require a reconfiguration of the Mystic Substation. Both plans include the addition of a new 345/115 kV autotransformer. The AC Plan also includes relocating the 345 kV line and swapping terminations of two 115 kV lines. The reconfiguration of the Mystic Substation to accommodate the HVDC Plan is much more extensive and includes:

- Relocating a 345 kV line
- Relocating a 115 kV line
- Interconnecting the HVDC line
- Relocating two 115 kV breakers
- Adding two 115 kV bus sections
- Adding a 115 kV line that connects the GIS portion of the Mystic 115 kV substation to the AIS section
- Relocating two load distribution transformers

Figure 7-1 below shows the existing Mystic Substation configuration, Figure 7-2 show the outages required to interconnect the AC Plan and Figure 7-3 show the areas of work required interconnect the HVDC line. Much of the work for the relocations in the HVDC Plan would require outages of 345 kV, 115 kV lines in the downtown Boston area and bus outages within the Mystic Substation. The specific outages and the outage durations were presented by Eversource to ISO-NE. Several of the outages are for a significant timeframe (some lasting several months) and affect exit paths for existing generation at the Mystic Substation. This may require restriction of generation in the NEMA/Boston subarea which could cause congestion costs in the Boston area. A full study to quantify the congestion cost was deemed not necessary at this time.

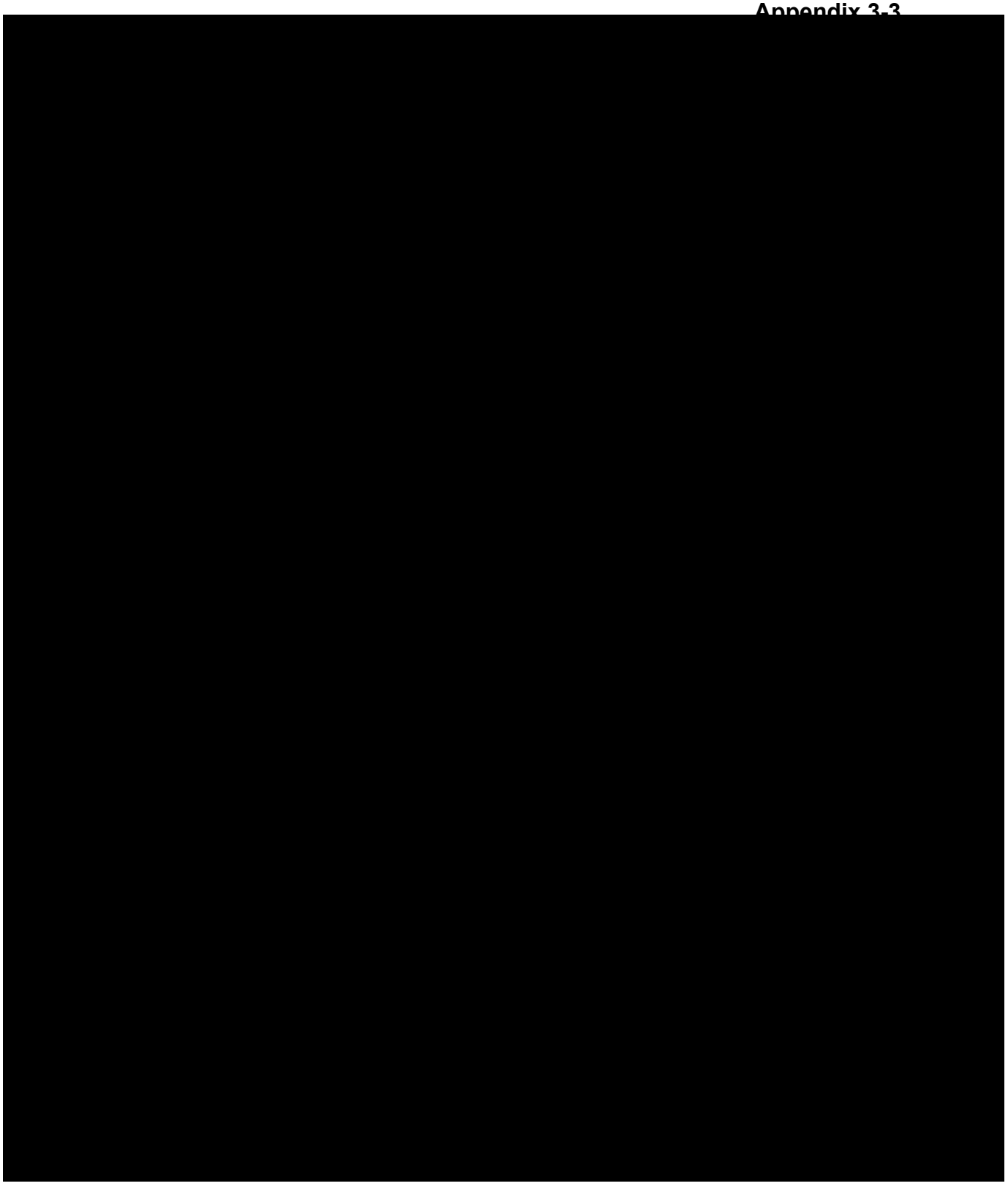


Figure 7-2 AC Plan Mystic Configuration



Figure 7-3 HVDC Plan Mystic Configuration

Based on the outage requirements for the Scobie – Tewksbury 345 kV line for the AC Plan and the reconfiguration at Mystic Substation for the HVDC plan, ISO-NE's conclusion is that the AC Plan will not significantly contribute to congestion cost and that more analysis would be needed to determine the congestion cost impact of the HVDC Plan's more significant substation reconfiguration.

7.5 Expected In-Service Dates

The expected in-service dates of the AC Plan and the HVDC Plan range from December 2016 to December 2018 depending on the upgrade. Eversource, National Grid, and NHT, have expressed confidence in meeting the proposed in-service dates.

ISO-NE does not believe that one plan would have a substantially earlier in-service date over the other plan.

7.6 Interface Impacts

A transfer capability assessment was performed as a means to compare the AC Plan to the HVDC Plan. The assessment was performed by turning generation on in an area remote (Connecticut) to Boston and turning generation down in the Boston area. This test was conducted for varying levels of North-South transfers. In this manner an operating region could be developed that showed the Boston Import capability as a function of North-South transfer levels.

This testing was aimed at gauging the relative performance of the alternative solutions for improvement in the Boston Import capability and was not intended to establish any formal transfer capability values or to serve as a measure of the North-South transfer capability. It should be noted that the transfer capability testing assumed Vermont Yankee out of service and Brayton Point in service.

The set of initial contingencies used for N-1-1 testing was limited to major transmission elements that most directly affect transfer limits for the Boston Import area. The results generally indicate that the N-1 Boston Import capability would increase by 800 MW to 900 MW for either plan and that the N-1-1 Boston Import capability increases by approximately 1250 MW for the AC Plan. The N-1-1 HVDC Plan increased approximately 1400 MW for lower levels of North-South transfers but diminishes to less than 500 MW at higher levels of North-South transfers.

Testing was performed for both N-1 contingency conditions shown in Figure 7-4 below as well as N-1-1 contingency conditions shown in Figure 7-5 below.

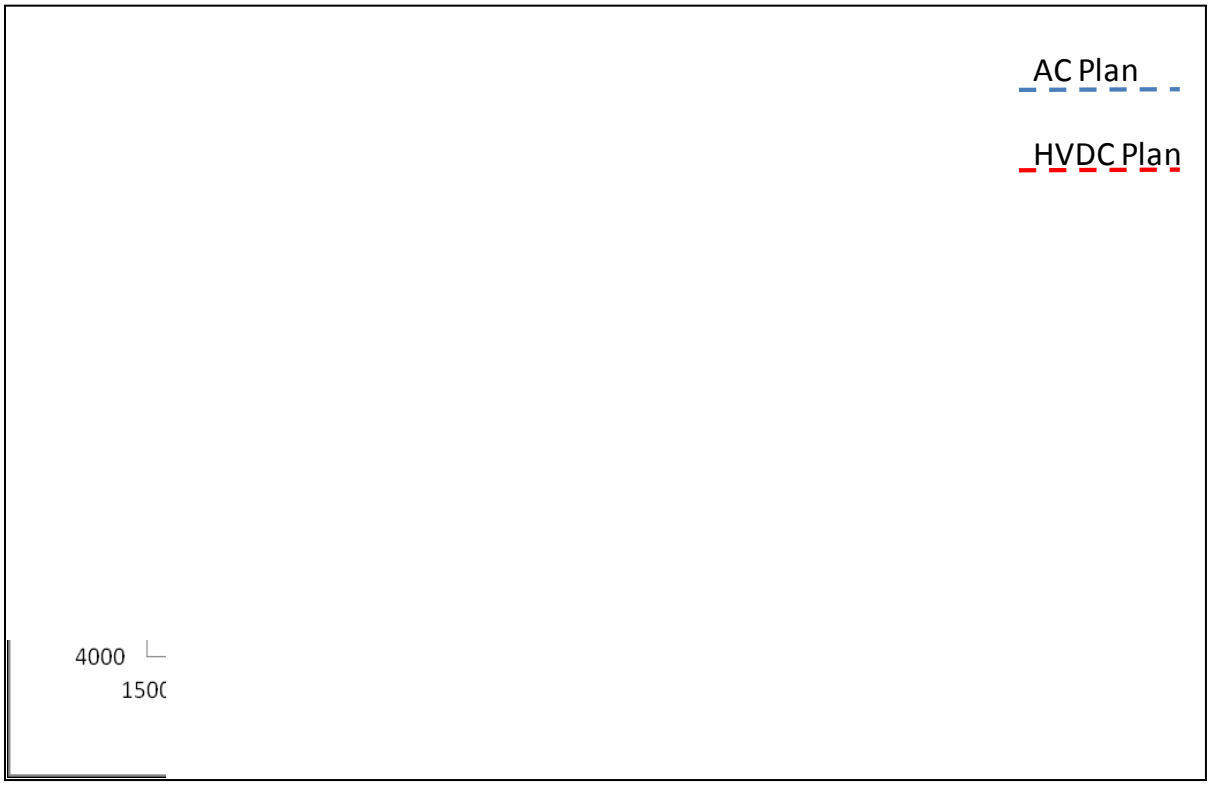


Figure 7-4 N-1 Import Capability



Figure 7-5 N-1-1 Import Capability

The results indicate that both plans result in comparable increases in N-1 Boston Import capability. The HVDC Plan has slightly higher import capability at lower levels of North / South transfer levels while the AC Plan has slightly higher import capability at the higher levels of North / South transfer levels.

The N-1-1 results show a higher level of import capability for the AC Plan at North / South levels of approximately 2000 MW and higher. However, under certain N-1-1 conditions, the Northern New England – Scobie + 394 interface limits could constrain the North / South interface making the increase in Boston Import capability at those levels unachievable.

The results generally indicate that the N-1 Boston Import capability would increase by 800 MW to 900 MW for either plan and that the N-1-1 Boston Import capability increases by approximately 1250 MW for the AC Plan. . The N-1-1 HVDC Plan increased approximately 1400 MW for lower levels of North-South transfers but diminishes to less than 500 MW at higher levels of North-South transfers. A full assessment using multiple generation dispatch and system bias conditions is required to fully quantify the increase in import capability over the existing system.

ISO-NE's position is that both plans improve the Boston Import transfer capability, but the AC Plan could potentially provide improved N-1-1 performance if the Northern New England – Scobie + 394 interface was increased.

7.7 Losses

An evaluation of the impact of the two plan's upgrades on system losses was conducted as an additional means to compare the performance of each plan. ISO-NE estimated the impact of the losses using the 34 peak load design case dispatches used in this Solutions Study. New England system losses were calculated for the 34 cases with the AC Plan and the HVDC Plan modeled. In addition to the system losses, 18 MW was added to the system losses for the HVDC plan to represent HVDC terminal losses. Similarly 1 MW was added to the system losses for the AC Plan to represent losses due to the STATCOM at Coopers Mills.

The result of the assessment is shown in Figure 7-6 below. The HVDC Plan results in higher system losses for all 34 dispatches ranging from 3 to 15 MW.

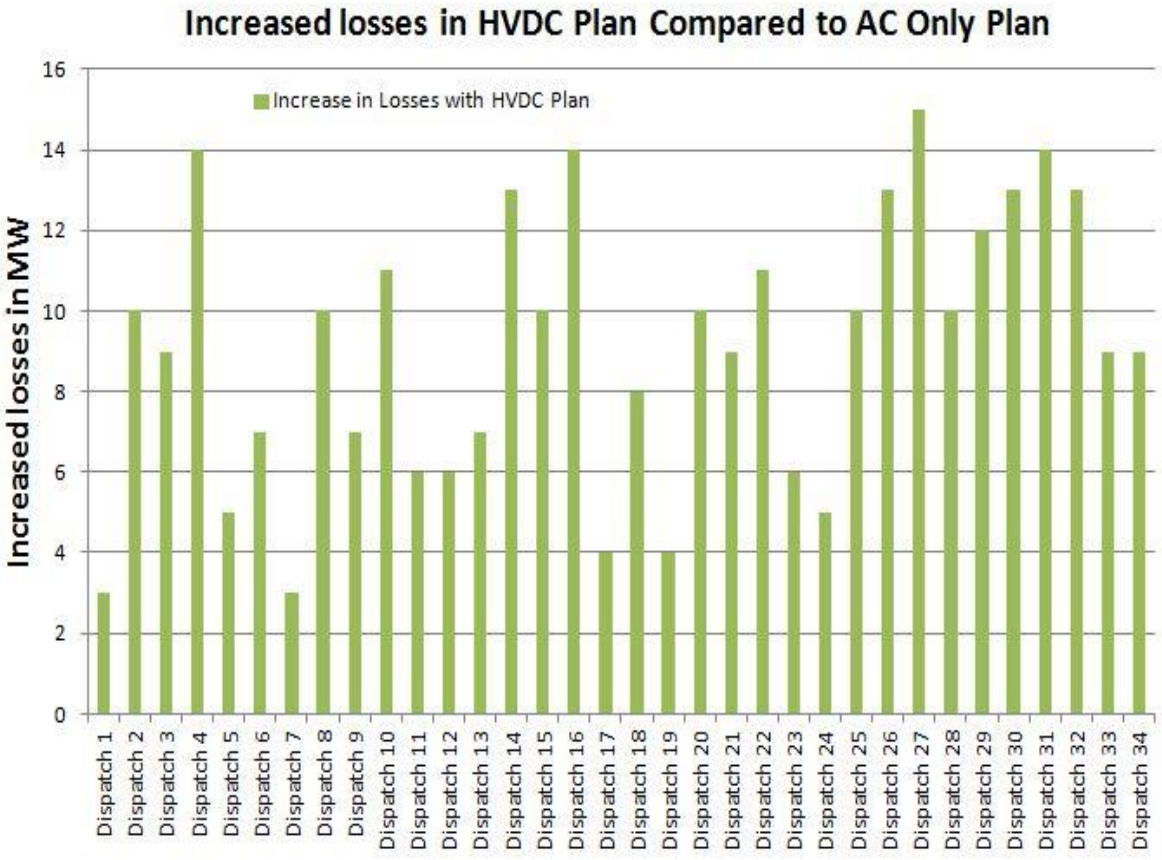


Figure 7-6 Increased Losses in HVDC Plan Compared to AC Only Plan

Based on the assessment, ISO-NE concludes that the AC Plan results in slightly lower system losses compared to the HVDC Plan.

7.8 Extreme Contingency Analysis

An extreme contingency assessment was performed for a limited set of extreme contingencies on the 34 design case dispatches used in this Solutions Study. [redacted] These contingencies were applied to the 34 cases with the AC Plan and the HVDC Plan.

The worst ROW outage case results in terms of STE overloads from the 34 cases tested with each plan are shown in Table 7-19 below. The overall conclusion drawn from these results suggest that the HVDC Plan generally resulted in fewer violations than the AC Plan.

Table 7-19 Extreme Contingency Testing STE Overloaded Element Results

Max of Final AC %Loading (STE)		Plan		Notes
Cont Name	Monitored Facility	HVDC_115	AC_Only	
ROW_10_Y151_L164_3124_N214_O215_397	[redacted]		111	Would trigger the SPS and make things worse.
ROW_2_380_326_3124			118	
ROW_3_380_326_N214_O215_PH2		113		
ROW_4_380_326_3124_N214_O215_PH2			138	
			114	
ROW_5_326_N214_O215_PH2		104		
ROW_6_326_3124_N214_O215_PH2			126	
			119	
			110	
ROW_7_Y151_N214_O215		108		
		108		
SS_SCOB_345		109	118	Overloads higher for the AC plan
		109	137	

[redacted]

	[redacted]	122	132	
			120	
SS_SCOB_ALL		109	110	Overloads higher for the AC plan
		113	145	Overloads higher for the AC plan
			120	
SS_WOBURN_345		178		

The results of the assessment show no overloads or voltage violations for the line crossing contingencies in both plans. [redacted]

ISO-NE's position is the HVDC Plan resulted in better extreme contingency performance.

7.9 Expansion Capabilities

Expanding the Downtown Boston subarea has been challenging in the recent past due to the limited short circuit margins in the subarea. As documented in the Greater Boston Area Updated Transmission Needs Assessment Report January 2015, two stations in downtown Boston [redacted] have overdutied breakers while five stations [redacted] have breakers between 95% and 100% duty.

Both the AC Plan and the HVDC Plan reduce the breaker duty seen in the downtown Boston subarea. Table 7-20 below shows the results for the substations. The AC Plan provides additional room in terms of available short-circuit margin for future transmission and generation specifically in the downtown Boston subarea while the North Shore subarea duties and the West Medway 345 kV duties are approximately the same.

Table 7-20 Downtown Boston Subarea Breaker Duty %

Substation	AC Plan	HVDC Plan
Mystic 115 kV	86%	85%
Kingston 115 kV	88%	95%
Brighton 115 kV	87%	86%
K St. 115 kV	88%	90%
West Medway 345 kV	93%	93%
Salem Harbor 115 kV	98%	97%
Wakefield Jct. 115 kV	96%	92%

[redacted]

Furthermore, the cost of expanding the system was also considered with respect to the expansion capabilities of the HVDC Plan. For the HVDC Plan, interconnecting a new resource into an HVDC facility requires a new converter station/terminal to be installed. ECI, the company hired by ISO-NE to review the costs estimates, estimates that converter stations range between $100 M to $200 M. Beyond the initial costs, ISO-NE's past experience shows that as time progresses the ability to procure additional terminals whose technology can work in concert with the existing terminals often becomes more difficult. Many times the additional terminals are required from the same manufacturer to ensure compatibility.

ISO-NE's position is the AC Plan provides better expansion capability than the HVDC Plan because it affords more short circuit margin in the Downtown Boston subarea, and the expansion would be significantly less costly than the HVDC Plan.

7.10 Lifetime Maintenance Requirements

ISO-NE's prior experience with HVDC and FACTS technology suggests that with technological advances in state-of-the-art equipment expected in the future, there will be a need for costly upgrades. Two recent examples of this are the Highgate HVDC facility needing a $38 M refurbishment in 2010 and the Chester SVC needing a $6 M control system upgrade in 2013.

The HVDC Plan has both larger sized equipment and two locations where such upgrades might be necessary, namely the two 520 MW HVDC converter stations. The AC Plan requires a single 200 MVAR STATCOM in ME that may require upgrades.

ISO-NE's position is that AC Plan provides better lifetime maintenance requirements than the HVDC Plan.

7.11 Incremental Costs for Potential Retirements

Three retirement scenario dispatches were examined as part of the Needs Assessment and Solutions Study. All three dispatches were Mystic 8 and Mystic 9 two-unit out of service cases with the addition of the Mystic 7 as the retired unit. Mystic 7 was selected since it is the oldest unit in the NEMA / Boston Subarea and the incremental upgrades were determined for both the AC Plan and HVDC Plan.

To determine the incremental upgrades for the AC Plan and the HVDC Plan, each plan was modeled separately in the three retirement scenarios. The N-1 and N-1-1 contingency assessment was then repeated for each plan to determine the reliability needs not addressed under the retirement scenarios. Additional upgrades were then added to the cases to address the reliability needs. Table 7-21 below lists the incremental upgrades and the cost estimate needed in the AC Plan and Table 7-22 lists the incremental upgrades and the cost estimate needed in the HVDC Plan.

Table 7-21 AC Plan Incremental Upgrades for the Mystic 7 Retirement Scenario

Facility	Length (Miles)	Cost (in 2017 $ M)
Construct Mystic to K St. 345 kV underground cable with a 345 kV phase angle regulator at K. St. and 160 MVAR shunt reactor at K. St. 345 kV	6.8	94.5

Install a series reactor on the Stoughton – K St. 3162 cable	NA	4.7
Total		99.2

Table 7-22 HVDC Plan Incremental Upgrades for the Mystic 7 Retirement Scenario

Facility	Length (Miles)	Cost (in 2017 $ M)
Construct the Golden Hills – Woburn 345 kV cable and 160 MVAR shunt reactor at Woburn 345 kV	6.5	88.4
Re-conductor the F-158N 115 kV line from Golden Hills to Maplewood (incremental cost of larger conductor)	4	4.5
Re-conductor the F-158S 115 kV line from Maplewood to Everett	3	3.8
Re-conductor the S-145 115 kV line from Wakefield Jct. to N. Reading tap	5.6	3.6
Re-conductor the T-146 115 kV line from Wakefield Jct. to N. Reading tap	5.6	3.6
Upgrade the West Medway 345/115 kV autotransformer	NA	7.9
Re-conductor the E-157 115 kV line from Millbury to Centech	5.7	6.4
Total		118.2

ISO-NE's position is that while the costs of both the expansion plans are similar, the AC Plan is less expensive.

7.12 Siting Issues

ISO-NE does not take the potential complexity of siting a particular alternative into account unless the costs for the alternatives under consideration are similar. In this case the cost of the AC Plan is considerably less expensive than the HVDC plan.

Applicable guidance from ISO-NE Planning Procedure-4, Section 1.6.1(C)3(i) states:

> "The proposed Project, and any feasible and practical transmission alternatives that were considered, including those offered in the most recent RSP report and, if applicable, discussed at the PAC. Note - A feasible and practical transmission alternative means a transmission alternative that is feasible and practical from an engineering design and construction perspective. An alternative that is not or may not be approved by a siting or local review board may still be considered a feasible and practical transmission alternative."

ISO-NE recognizes that preferred alternatives may change in the siting process. However, the possibility of such a change is not a factor in ISO-NE's selection of the preferred alternative. Where changes to a preferred project are made, incremental costs over the identified preferred solution may result in localized costs that are excluded from regional cost recovery. For example, ISO-NE did not support the regional cost allocation of underground cables in the Middletown-Norwalk and Bethel-Norwalk Project. The ISO Tariff and Planning Procedures provide:

- Attachment K, Section 4.2(b) states:

"Through this process, the ISO may identify the most cost-effective and reliable solutions for the region that meets a need identified in a Needs Assessment. These solutions may differ from a transmission solution proposed by a transmission owner."

- PP-4, Attachment A states:

"The following…is provided for illustration of the types of projects that would be considered to contain Localized Costs: The Project includes underground transmission cable, which is selected (a) at the direction of a local or state siting board, or (b) to address other local concerns, and the cost of overhead transmission lines is less expensive, taking into account all relevant costs.

ISO-NE's position is that both AC and HVDC plans are feasible from an engineering perspective and siting is not a determining factor.

7.13 Storm Hardening

The majority of the HVDC Plan consists of buried cable which is shielded from most storms while the AC Plan consisting of overhead transmission lines is more exposed to the environment. However, failures in buried cables may require months to repair while repairs to overhead lines are generally made within a day or two. History has shown that buried cables are not impervious to storm interruption because their terminals are still exposed to the environment.

ISO-NE's position is that the HVDC plan has less exposed facilities yet the time required to repair such facilities causes ISO-NE to view the AC Plan and the HVDC Plan as equal.

7.14 Comparison Matrix of Alternative Solutions

Table 7-23 below shows a summary of the comparisons made between the AC Plan and the HVDC Plan. In addition to the cost difference between the two plans with the AC Plan being significantly less expensive, the AC Plan performs as well or better than the HVDC Plan in all but one category.

ISO-NE's position is that the AC Plan is the most cost effective solution for the region. ISO-NE therefore selected the AC Plan as the preferred solution for the Greater Boston study.

Table 7-23 Comparison Matrix of the AC and HVDC Plans

	AC Plan	HVDC Plan
Cost	✓	✗
Constructability	✓	✓
Construction outage / cost impacts	✓	✗
Expected in-service dates	✓	✓
Interface impacts	✓	✗
Losses	✓	✗
Extreme contingency analysis results	✗	✓
Expansion capabilities	✓	✗
Lifetime maintenance requirements	✓	✗
Incremental costs for potential retirements	✓	✗
Siting Issues	✓	✓
Storm Hardening	✓	✓

Is applied to the plan which better achieves the objective
Is applied to the plan which does not achieve the objective as well as the other plan

Section 8
Conclusion

8.1 Recommended Solution Description

The Greater Boston Solution was developed in two stages. The first stage culminated in March 2012 with the selection and presentation of a preferred solution to the PAC. The second stage of the Greater Boston Solution began after the March 2012 PAC presentation using updated assumptions as documented in Section 3 of this report and evaluated an AC Plan based on the March 2012 preferred solution and HVDC Plan based on a HVDC Plan from the Seabrook 345 kV substation to the downtown Boston area.

The AC Plan was ultimately selected following stage two because it is significantly less expensive, approximately $286M, and also because it fares better when other performance criteria are considered. The AC Plan consists of the upgrades shown in Table 8-1 and Table 8-2 below.

Table 8-1 Preferred Solution Common Upgrades

New Facility	Length (Miles)
West Walpole – Holbrook 115 kV line	14
Sharon Switching Station	NA
Sudbury – Hudson 115 kV line	9
Sudbury 230/115 kV autotransformer	NA
Install K St. tie breaker	NA
Install Stoughton 345 kV series breaker	NA
Newton 115 kV capacitor	NA
Sudbury 115 kV capacitor	NA
Hartwell 115 kV capacitor	NA
345 kV shunt reactor at K St.	NA
Upgraded Facilities	**Length (Miles)**
Rebuild X-24W and X-24E 69 kV	15
Re-conductor M-139 Tewksbury – Billerica Tap 115 kV	3
Re-conductor F-158N Golden Hills – Maplewood 115 kV	4
Re-conductor W-23W 69 kV	4
Re-conductor Y-151 Power St – Eversource / National Grid border	4
Other	**Length (Miles)**
Separate Needham – Baker St. 240-510 / 110-522 DCT	4
Separate F-158N / Q-169 DCT	1 structure
Separate X-24W / E-157W DCT	4 structures
Waltham Reconfiguration	NA
North Cambridge Reconfiguration	NA
Kingston 115 kV Reconfiguration	NA
Move Chelsea capacitor	NA
Add a 115 kV breaker at Framingham	NA

Table 8-2 Preferred Solution System Upgrades

AC Plan	Length (Miles)
Scobie – Tewksbury 345 kV line	25
Re-conductor Y-151 115 kV Eversource border to Dracut Jct.	9
Wakefield Jct. – Woburn 345 kV underground cable plus 2 reactors	8
Bifurcate a new Woburn – Mystic 115 kV cable with existing cable	8
Upgrade 5 substations to BPS standards	NA
Add a 200 MVAR STATCOM at Coopers Mills 345 kV in ME	NA
2nd Mystic 345/115 kV autotransformer	NA
Mystic – Chelsea 115 kV underground cable	3
New Woburn 345/115 kV autotransformer and Woburn Reconfiguration	NA
K St. 115 kV breaker addition	NA
Re-conductor M-139 115kV Billerica Tap to Pinehurst Tap	3
Re-conductor N-140 115kV Tewksbury to Pinehurst Tap	7
Re-conductor F-158S 115kV Maplewood to Everett	3
Upgrade terminal equipment to increase 533-508 115 kV Lexington to Hartwell rating	NA
Open Mystic 115 kV downtown ties (mitigates short-circuit concerns)	NA
Operating one of the four Wakefield Jct. autotransformers normally open	NA
Re-conductor M-139/211-503 and N-140/211-504 lines Pinehurst Tap to North Woburn Tap	5

The performance criteria used to differentiate the AC Plan and the HVDC Plan and each plan's performance are captured in Table 1-3 below.

Table 8-3 Comparison of Alternative Selection Criteria

	AC Plan	HVDC Plan
Cost	✓	✗
Constructability	✓	✓
Construction outage / cost impacts	✓	✗
Expected in-service dates	✓	✓
Interface impacts	✓	✗
Losses	✓	✗
Extreme contingency analysis results	✗	✓
Expansion capabilities	✓	✗
Lifetime maintenance requirements	✓	✗
Incremental costs for potential retirements	✓	✗
Siting Issues	✓	✓
Storm Hardening	✓	✓
✓ Is applied to the plan which better achieves the objective		
✗ Is applied to the plan which does not achieve the objective as well as the other plan		

The GBWG coordinated activities with the NH/VT Working Group and the SEMA/RI Working Group in an effort to ensure the solutions proposed by each group met each area's needs, was not redundant, and was the most cost effective solution for the region as a whole.

One significant overload condition associated with contingency events located in Southeastern Massachusetts called for coordination of modeling assumptions and study efforts with the SEMA/RI Working Group. The GBWG found that certain elements in the Greater Boston area were overloaded exclusively due to SEMA/RI contingency events and, through coordination of efforts between the two study groups, it was concluded that the SEMA/RI Working Group would be best suited to develop solutions in the context of development of all solutions for the SEMA/RI study area which was underway at the time.

The SEMA/RI contingency events are [redacted] The impact of this contingency event was seen in both the AC and HVDC plans.

8.2 Solution Component Year of Need

The Boston Area critical load level was determined through load flow analysis (1) using several dispatches and system biases, (2) varying the load levels between 2018 and 2023 load levels and (3) applying both N-1 and N-1-1 contingencies to determine the Boston area load level that first produced an overload for each element.

The year of need for the majority of the elements is pre-2013 for both N-1 and N-1-1. This indicates that the year of need for the AC Plan upgrades occurs for peak load levels seen at today's levels. A complete list of the N-1 and N-1-1 year of need assessment can be found in Table 2-1 and Table 2-2 respectively.

8.3 Schedule for Implementation, Lead Times and Documentation of continuing Need

In accordance with NERC TPL Standard, this assessment provides:

- A written summary of plans to address the system performance issues described in the *Greater Boston Area Updated Transmission Needs Assessment*, dated January 30, 2015.
- A schedule for implementation as described below
- A discussion of expected required in-service dates of facilities and associated load level when required as described below
- A discussion of lead times necessary to implement plans

The planned completion date of the preferred solution as described in Section 8.1 above is 2018. With this schedule the preferred solution will be in service after the potential violations of the NERC Standards occur. Currently, system operators posture the system by generation re-dispatch and other system adjustments to prevent these violations. While these steps prevent violations of NERC operating criteria, they are not sufficient to address the requirements of NERC planning criteria. The longest lead time items required to complete the project are large power transformers and the STATCOM with projected lead times of one year.

[redacted]

Section 9
Appendix A: Load Forecast

Table 9-1 2013 CELT Load Forecast

1.6 - Seasonal Peak Load Forecast Distributions

		Peak Load Forecast at Milder Than Expected Weather				Reference Forecast at Expected Weather	Peak Load Forecast at More Extreme Than Expected Weather				
Summer (MW)	2013	26470	26715	27045	27420	27840	28285	28735	29385	30135	30790
	2014	26900	27150	27485	27865	28290	28740	29200	29860	30620	31280
	2015	27410	27665	28005	28390	28825	29285	29750	30425	31185	31860
	2016	27910	28165	28515	28910	29350	29815	30295	30980	31740	32420
	2017	28325	28590	28940	29340	29790	30265	30750	31445	32210	32900
	2018	28675	28940	29295	29700	30155	30635	31125	31830	32615	33315
	2019	29025	29295	29655	30065	30525	31010	31505	32220	33010	33720
	2020	29345	29615	29980	30395	30860	31350	31855	32575	33380	34095
	2021	29670	29950	30315	30735	31205	31700	32210	32935	33755	34480
	2022	29970	30250	30625	31045	31520	32020	32535	33270	34105	34840
	WTHI (1)	**78.49**	**78.73**	**79.00**	**79.39**	**79.88**	**80.30**	**80.72**	**81.14**	**81.96**	**82.33**
	Dry-Bulb Temperature (2)	**88.50**	**88.90**	**89.20**	**89.90**	**90.20**	**91.20**	**92.20**	**92.90**	**94.20**	**95.40**
	Probability of Forecast Being Exceeded	**90%**	**80%**	**70%**	**60%**	**50%**	**40%**	**30%**	**20%**	**10%**	**5%**
Winter (MW)	2013/14	22025	22140	22235	22295	22445	22595	22765	22865	23080	23505
	2014/15	22205	22320	22420	22480	22630	22780	22955	23055	23255	23685
	2015/16	22385	22500	22595	22660	22810	22960	23135	23235	23440	23870
	2016/17	22540	22660	22755	22815	22970	23125	23295	23400	23620	24050
	2017/18	22680	22795	22895	22955	23110	23265	23440	23540	23780	24205
	2018/19	22800	22920	23020	23080	23235	23390	23565	23670	23920	24345
	2019/20	22915	23035	23130	23195	23350	23505	23685	23785	24045	24470
	2020/21	23030	23150	23250	23315	23470	23625	23805	23910	24160	24590
	2021/22	23145	23265	23365	23425	23585	23745	23920	24025	24280	24705
	2022/23	23255	23380	23480	23540	23700	23860	24040	24145	24395	24820
	Dry-Bulb Temperature (3)	**10.72**	**9.66**	**8.84**	**8.30**	**7.03**	**5.77**	**4.40**	**3.58**	**1.61**	**(1.15)**

Appendix 3-3

Section 10
Appendix B: Upgrades Included in Base Case and Short Circuit Model

System Upgrades Included in the Base Case Models

Maine
- Maine Power Reliability Program (MPRP) (RSP ID: 1401-1472)
- Down East Reliability Improvement (RSP ID: 143)

New Hampshire
- Second Deerfield 345/115 kV autotransformer Project (RSP ID: 277, 1137-1141)
- Rebuild Bellows Falls substation (RSP ID: 680)
- Western New Hampshire Solution (RSP ID: 1269-1275, 1346)
- Northern New Hampshire Solution (RSP ID: 1263, 1276)
- Central New Hampshire Solution (RSP ID: 1277-1278, 1300)
- Southern New Hampshire Solution (RSP ID: 1301-1304, 1306-1314, 1376, 1379)
- Seacoast New Hampshire Solution (RSP ID: 1316-1325)

Massachusetts
- Auburn Area Transmission System Upgrades (RSP ID: 59, 887, 921, 919)
- Merrimack Valley / North Shore Reliability Project (RSP ID: 775-776, 782-783, 840)
- Long Term Lower SEMA Upgrades (RSP ID: 592, 1068, 1118. 1349-1351)
- Central/Western Massachusetts Upgrades (RSP ID: 924- 929, 931-932, 934-935, 937- 950, 952- 955)
- NEEWS – Greater Springfield Reliability Project (RSP ID: 196, 259, 687-688, 818-820, 823, 826, 828-829, 1010, 1070-1075, 1078-1080, 1100-1105)
- Advanced NEEWS Interstate Projects (RSP ID: 1202, 1342)
- NEEWS – Interstate Reliability Project (RSP ID: 190, 1094, 1293)
- Salem Harbor Retirement Upgrades (RSP ID: 1257-1259)

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

Connecticut
- NEEWS – Greater Springfield Reliability Project (RSP ID: 816, 1054, 1369-1371, 1378)
- NEEWS – Interstate Reliability Project (RSP ID: 191, 802, 810, 1085, 1090-1091, 1235)
- Advanced NEEWS Interstate Projects (RSP ID: 1235, 1245)
- Northeast Simsbury Substation 115 kV Circuit Breaker Project (RSP ID: 1230)
- Millstone 345 kV Circuit Separation & SLOD SPS System Retirement (RSP ID: 1218)
- Line 1990 Asset Condition Replacement Project (RSP ID: 1229)

Table 10-1 Model Changes Included in the 2017 Short Circuit Base Case

File Name	Change
2017 MASTER CASE 20130624-Starting Case for Update(No Brkrs).OLR	Original 2013 base case sent out for review on 6/20/2013
2017 MASTER CASE 20130624-Add RIRP, CCRP, IRP&GSRP-01(No Brkrs).OLR	Added all NEEWS projects including: • IRP (Card-Lake Road 3271 line, Lake Road-West Farnum 341 line) • RIRP (West Farnum-Kent County 359 line, 3rd Kent County autotransformer, Re-conductor G185, S171S, T172S) • CCRP (North Bloomfield-Frost Bridge 3208 line, 2nd Frost Bridge autotransformer, Re-conductor 3533, add 2nd Beseck shunt reactor • GSRP (Ludlow-Agawam 3196 line, Agawam-North Bloomfield 3216 line, Manchester-North Bloomfield 3642 line, reconfigure 395 line, add 2 Agawam autotransformers, 2nd North Bloomfield autotransformer, build/re-conductor 1230, 1314,1426, 1481, 1552, 1723, 1904, 1254, 1702, 1803, 1601, 1768/1821, 1781, 1782, 1845, 1556, 1645, 1784 lines). Note that these changes were already in the case, but were not in service. Added West Walpole-Carver line
2017 MASTER CASE 20130624-Add MPRP-02(Mystic, Kingston& WMedway Breakers).OLR	• Added entire MPRP project • Updated ANP Bellingham and Blackstone GSU impedances and 336/3361 line impedances
2017 MASTER CASE 20130624-ADD OTHER SEMA & RI UPDATES-03(Boston Area Breakers).OLR	• Added Medway peakers • Added Everett peakers • Added Plainfield CT gen • Placed Cape Wind in service with Kingston-Auburn and Kingston-Brook Street 115kV line upgrades • Added replacement Holbrook autotransformer
2017 MASTER CASE 20130630-Additional Gen Projects-04(BOSTON AREA BREAKERS).OLR	• Added Towantic QP384 • Added Brockton CC QP178 • Added Northfield uprates • Added Palmer Renewable QP273 • Added NH Laidlow Berlin Biomass QR251
2017 MASTER CASE 20130701-Additional Transmission Projects-05(BOSTON AREA BREAKERS).OLR	• Added Salem Harbor RSP projects • Added Pittsfield-Greenfield Solution projects • Added NGrid Central Western MA projects
2017 MASTER CASE 20130702-06(NGRID & NSTAR BRKRS).OLR	Removed Peabody generator
2017 MASTER CASE 20130806-07(NGRID & NSTAR BRKRS).OLR	Corrected all Mystic GSU transformer zero-sequence impedances
2017 MASTER CASE 20130829-08(NGRID & NSTAR BRKRS).OLR	• Removed AES Thames generator and GSU • Updated New Brunswick Equivalent (Note: The two equivalent sources were inadvertently omitted from this equivalent.) • Updated New York Equivalent • Corrected the Torrington terminal 115/69-kV autotransformer impedance (replacement) • Reconnected the A. L. Pierce generator at Wallingford that was inadvertently disconnected • Revised the Devon-Trumbull 1730 line impedances to match NX-9 data.
2017 MASTER CASE 20131117-09(NGRID & NSTAR)	Corrected New Brunswick equivalent to add the two equivalent sources that were inadvertently omitted from Rev-08.

BRKRS).OLR	

Section 11
Appendix C: Case Summaries

Select the following link to open the case summary file:



Section 12
Appendix D: Generator Dispatch Conditions

Table 12-1
2023 Boston RSP subarea Generation Dispatch Summary

BusName	[redacted]
BOOTT HYDRO	
CANAL G1	
CANAL G2	
CPC LOWELL	
EDGAR GT1	
EDGAR GT2	
EDGAR ST	
FRAMINGHAM	
GE RIVER R&T	
GE RIVER S&U	
IPSWICH DSL	
KENDALL CT	
KENDALL JET	
L STREET JET	
LAWRENCE HYD	
LENERGIA CT	
LENERGIA ST	
MALDEN MLS_T	
MARBLEHEAD A	
MARBLEHEAD B	
MATEP 3	
MATEP_CC	
MATEP_DIESEL	
MBTA	
MYSTIC 7GT	

BusName
MYSTIC 8ST
MYSTIC 9ST
MYSTIC GT 8A
MYSTIC GT 8B
MYSTIC GT 9A
MYSTIC GT 9B
MYSTIC JET
NEWINGTON_G1
NEWINGTON_S1
OGDEN-MARTIN
PERRY ST 3
PILGRIM
PUTNAM 2
QP 387-2 5CT
QP 387-2 5ST
QP 387-2 6CT
QP 387-2 6ST
RESCO-SAUGUS
SEABROOK_G1
W MEDWAY J3
W MEDWAY JET
WATERS RVRJ1
WATERS RVRJ2
YARMOUTH #4

BusName
BOOTT HYDRO
CANAL G1
CANAL G2
CPC LOWELL
EDGAR GT1
EDGAR GT2
EDGAR ST
FRAMINGHAM
GE RIVER R&T
GE RIVER S&U
IPSWICH DSL
KENDALL CT
KENDALL JET
L STREET JET
LAWRENCE HYD
LENERGIA CT
LENERGIA ST
MALDEN MLS_T
MARBLEHEAD A
MARBLEHEAD B
MATEP 3
MATEP_CC
MATEP_DIESEL
MBTA
MYSTIC 7GT

BusName	[redacted]
MYSTIC 8ST	
MYSTIC 9ST	
MYSTIC GT 8A	
MYSTIC GT 8B	
MYSTIC GT 9A	
MYSTIC GT 9B	
MYSTIC JET	
NEWINGTON_G1	
NEWINGTON_S1	
OGDEN-MARTIN	
PERRY ST 3	
PILGRIM	
PUTNAM 2	
QP 387-2 5CT	
QP 387-2 5ST	
QP 387-2 6CT	
QP 387-2 6ST	
RESCO-SAUGUS	
SEABROOK_G1	
W MEDWAY J3	
W MEDWAY JET	
WATERS RVRJ1	
WATERS RVRJ2	
YARMOUTH #4	

[redacted]

BusName	[redacted]
BOOTT HYDRO	
CANAL G1	
CANAL G2	
CPC LOWELL	
EDGAR GT1	
EDGAR GT2	
EDGAR ST	
FRAMINGHAM	
GE RIVER R&T	
GE RIVER S&U	
IPSWICH DSL	
KENDALL CT	
KENDALL JET	
L STREET JET	
LAWRENCE HYD	
LENERGIA CT	
LENERGIA ST	
MALDEN MLS_T	
MARBLEHEAD A	
MARBLEHEAD B	
MATEP 3	
MATEP_CC	
MATEP_DIESEL	
MBTA	
MYSTIC 7GT	

[redacted]

BusName	[redacted]
MYSTIC 8ST	
MYSTIC 9ST	
MYSTIC GT 8A	
MYSTIC GT 8B	
MYSTIC GT 9A	
MYSTIC GT 9B	
MYSTIC JET	
NEWINGTON_G1	
NEWINGTON_S1	
OGDEN-MARTIN	
PERRY ST 3	
PILGRIM	
PUTNAM 2	
QP 387-2 5CT	
QP 387-2 5ST	
QP 387-2 6CT	
QP 387-2 6ST	
RESCO-SAUGUS	
SEABROOK_G1	
W MEDWAY J3	
W MEDWAY JET	
WATERS RVRJ1	
WATERS RVRJ2	
YARMOUTH #4	

[redacted]

Table 12-2 Shunt Reactive Resources at 69 kV and Above for the Boston RSP subarea

Bus#	Bus Name	Volt	Area	Zone	Shunt Reactor	Shunt Capacitor
110923	BAKER ST_C1	115	101	1000		
110924	BAKER ST_C2	115	101	1000		
110824	CHELSEA_C	115	101	1000		
110959	DOVER MA_C	115	101	1000		
110957	FRAMINGHAM_C	115	101	1000		
902002	HARTWELL_CAP	115	101	1000		
110954	K STREET 1_C	115	101	1000		
111807	K STREET 1_R	345	101	1000		
110955	K STREET 2_C	115	101	1000		
110860	K STREET 2_R	115	101	1000		
111808	K STREET 2_R	345	101	1000		
110939	LEXINGTON_C	115	101	1000		
111800	LEXINGTON_R	345	101	1000		
110823	MYSTIC_C	115	101	1000		
110821	MYSTIC_R	115	101	1000		
111802	MYSTIC_R	345	101	1000		
110940	N CAMBRDG_R1	115	101	1000		
110941	N CAMBRDG_R2	115	101	1000		
111801	N.CAMBRIDG_R	345	101	1000		
110958	SUDBURY_C	115	101	1000		
110956	W FRMNGHAM_C	115	101	1000		
110936	WOBURN_R1	115	101	1000		
110937	WOBURN_R2	115	101	1000		
110938	WOBURN_R3	115	101	1000		
110902	EDGAR_R1	115	101	1020		
110960	EDGAR_R2	115	101	1020		
111803	STOUGHTON_R1	345	101	1020		
111804	STOUGHTON_R2	345	101	1020		
111805	STOUGHTON_R3	345	101	1020		
111806	STOUGHTON_R4	345	101	1020		
110784	W.WALPOLE_R	345	101	1020		
113293	MILLBURY_C1	115	101	1110		
113420	MILLBURY_C3	115	101	1110		
113418	PRATTS JCT_C	115	101	1110		
114071	SNDYPD HVDC1	345	101	1120		
114072	SNDYPD HVDC2	345	101	1120		
114073	TEWKSBURY_C1	115	101	1120		
114074	TEWKSBURY_C2	115	101	1120		
114480	REVERE_C	115	101	1130		
114481	SALEM HBR_C1	115	101	1130		
114482	SALEM HBR_C2	115	101	1130		
114870	NTHBORO RD_C	115	101	1140		
114871	NTHBORO RD_C	69	101	1140		

Section 13
Appendix E: Assessment Criteria (i.e., Steady State Thermal and Voltage Criteria)

Table 13-1
Example Steady State Thermal Criteria

SYSTEM CONDITION	TIME INTERVAL	MAXIMUM ALLOWABLE FACILITY LOADING
Pre-contingency (all lines in)	Continuous	Normal rating
Post-contingency	Less than 15 minutes after contingency occurs	Short Time Emergency (STE) Rating[1]
	More than 15 minutes after contingency occurs	Long Time Emergency (LTE) Rating

[1] Post-contingency loading above LTE but below STE is considered acceptable as long as prompt system action (local phase shifter adjustment, generation runback, or special protection system-SPS operation) could reduce loading below LTE within 15 minutes.

Table 13-2 Steady State Voltage Criteria

Transmission Owner	Voltage Level	Bus Voltage Limits (Per-Unit)	
		Normal Conditions	Emergency (Contingency) Conditions
Northeast Utilities	230 kV and above	0.95 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
National Grid	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below[1]	0.95 to 1.05	0.90 to 1.05
Millstone/Seabrook	345 kV	1.00 to 1.05	1.00 to 1.05
VT Yankee/Pilgrim	345 kV	0.99 to 1.05	0.99 to 1.05
Sandy Pond	345 kV	1.00 to 1.05	1.00 to 1.05
Other Transmission Owners	230 kV and above	0.95 to 1.05	0.95 to 1.05

[1] Buses that are part of the Bulk Power System, and other buses deemed critical by National Grid Network Operations shall meet requirements for buses that are 230 kV and above.

Section 14
Appendix F: Contingency List

Table 14-1 Contingencies Tested for All Cases and Sensitivities

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

[redacted]

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

[redacted]

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

[redacted]

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

[redacted]

BREAKER FAULTS	BREAKER FAULTS	LINE FAULTS	TRANSFORMER FAULTS	GENERATOR FAULTS	BUS FAULTS	NO FAULTS	DCT FAULTS	SPS FAULTS
[redacted]								

[redacted]

Table 14-2 Initial Contingencies Applied for N-1-1 Testing in All Cases and Sensitivities

Line Faults	Line Faults	Transformer Faults	Generator
[redacted]			

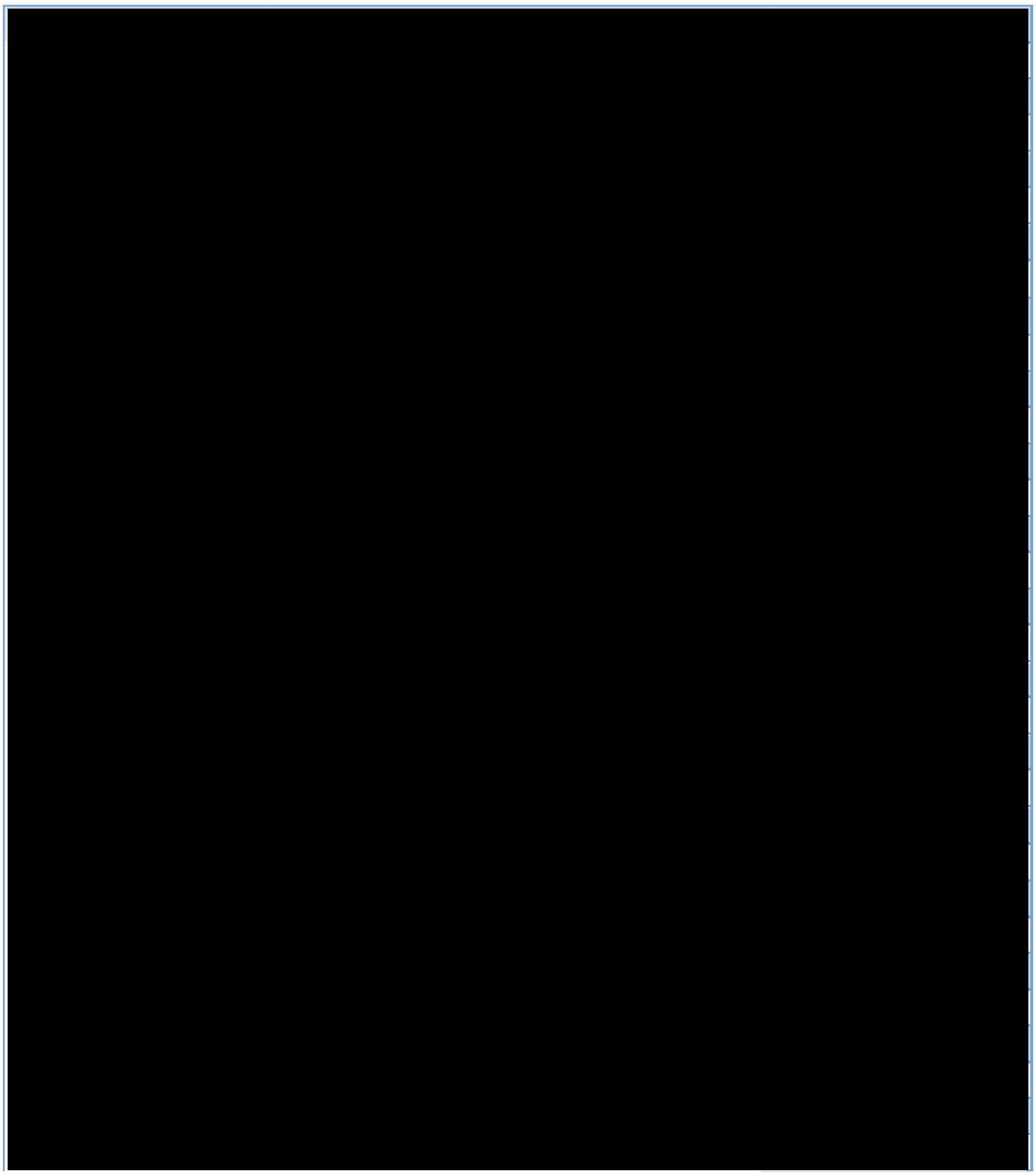


Table 14-3 Summary of BPS Contingencies Tested

Fault ID	Station Name	Fault Type	Fault Description	Remote Clearing (cycles)	Elements Removed	IPT Status	Gen Tripped Due to Fault (MW)	Note
Flat	N/A	N/A	[redacted]			N/A		
Maine & New Hampshire BPS Testing								
CHEBPS	Chester	3 phase	[redacted]			No	0	
GVNBPS	Garvins	3 phase				No	0	
MBYBPS	Madbury	3 phase				No	0	
MRMBPS	Merrimack	3 phase				No	0	
PHLBPS	Pine Hill	3 phase				No	0	
RCHBPS	Rochester	3 phase				No	0	
TRVBPS	Three Rivers	3 phase				No	0	
WBKBPS	Westbrook	3 phase				No	555	
Southern New England BPS Testing								
ANDBPS1	Andrew Sq.	3 phase	[redacted]			No	0	
AYRBPS	Ayer	3 phase				No	0	Assumed 69-kV clears
BRKBPS	Brook St	3 phase				No	0	
BURBPS	Burlington	3 phase				No	0	
CANBPS1	Canton	3 phase				No	0	
CHELBPS	Chelsea	3 phase				No	0	
DEPSBPS	Depot St	3 phase				No		
DEWBPS1	Dewar St.	3 phase				No	0	
DOVBPS	Dover	3 phase				No	0	
ECAMBPS	E. Cambridge	3 phase				No	287.6	
EDRCBPS	E. Dracut	3 phase				No		
EDGRBPS	Edgar	3 phase				No	860	
EVRTBPS	Everett	3 phase				No	0	
FMT3BPS101	Fairmont	3 phase				No	15	

[redacted]

5CRNBPS	5 Corners	3 phase			
FRAMBPS	Framingham	3 phase			
FSQ3BPS102	Franklin Sq	3 phase	No	501	
GLDRBPS	Golden Rock	3 phase			
HARTBPS	Hartwell	3 phase	No	0	
HPTNBPS	Hopkinton	3 phase			
HUDNBPS	Hudson	3 phase			
KENBPS	Kendall	3 phase			
KINGBPS1	King St.	3 phase	No	0	
LEXBPS1	Lexington	3 phase	No	0	
LYNNBPS1	Lynn	3 phase	No	0	
MAPLBPS	Maplewood	3 phase	No	0	
MAYBPS1	Maynard	3 phase	No	0	
MEDBPS1	Medway	3 phase	No	72 9	
MLFPBPS	Milford Power	3 phase			
MTMBPS	Mt Tom	3 phase			
NWBNBPSA	N. Woburn	3 phase	No	0	
NORBPS	Norwood	3 phase			
NWBNBPSB	N. Woburn	3 phase	No	0	
PLHBPS	Pelham	3 phase			
P NBPS	Pineshed	3 phase			
P P3BPS101	Piper	3 phase	No	0	
RESCBPS	Resco-Saugus	3 phase	No	31	
REVRBPS	Revere	3 phase	No	0	
ROLFBPS	Rolfe Ave	3 phase	No	0	
SEMSBPS	Semass	3 phase			
SHN3BPS101	Shawinigan	3 phase	No	281.1	
SHERBPS	Sherborn	3 phase	No	0	
SDANBPS1	S. Danvers	3 phase	No	0	
SBDWBPS	S. Broadway	3 phase			
SHOLBPS	S. Holyoke	3 phase			
SPNBPS	Speen St.	3 phase	No	0	
SUDBPS	Sudbury	3 phase	No	0	

SUDBPS2	Sudbury	3 phase	[redacted]	No	0	
TRPOBPS	Trapelo	3 phase				
WALBPS1	Walpole	3 phase		No	0	
WAM3BPS101	Wampanoag	3 phase		No	0	
WANDBPS	W. Andover	3 phase				
WFRABPS	W. Framingham	3 phase		No	0	
WMETHBPS	W. Methuen	3 phase		No	0	
WRUTBPS	W. Rutland	3 phase		No	28.1	

A description of the EC faults tested in this study are found in Table 6-2 in the body of the report.

[redacted]

Section 15
Appendix G: Short Circuit Results

15.1 Short Circuit Results

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			83.7	81.9
			83.7	82.1
			83.7	82.1
			83.1	78.2
			82.8	78
			83.1	78
			86.9	81.9
			86.9	85.6
			86.9	85.6
			86.9	76.6
			86.9	85.8
			86.9	85.8
			88.3	90.4
			87.9	89.8
			88.3	90.4
			81.8	86.1
			81.8	85.9
			81.8	86.1
			81.8	86.1
			81.8	82.6
			81.8	86.1
			81.8	86.1
			81.8	86.1
			81.3	85.4

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			88.3	90.4
			81.8	86.1
			81.8	86.1
			88.3	90.4
			88.3	90.4
			81.8	86.1
			88.3	90.4
			81.8	86.1
			88.3	90.2
			88.2	90.3
			88.3	90.4
			88.3	90.4
			88.2	90.3
			88.3	90.4
			86.8	93.1
			85.9	92.6
			87.6	94.8
			85.9	91
			86.8	93.1
			86.8	93.1
			85.9	91
			86.2	92.4
			85.8	92.4
			86.9	94.1
			86.9	94.1
			86.3	84.9
			86.3	84.9
			86.3	84.9
			86.3	84.9
			86.3	84.9
			86.3	84.9

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			75.1	81.5
			86.3	84.9
			86.3	
			86.3	
			86.3	84.4
			86.3	
			86.3	84.9
			86.3	84.9
				84.4
			86.3	84.9
			86.3	84.9
			86.3	84.9
			83.3	74.5
				74.2
			77.1	67.8
			77.1	67.8
				74.2
			56.8	56.6
			46.4	45.6
			56.8	56.7
			62.5	62.3
			62.5	62.3
			62.6	62.4
			62.6	62.4
			62.6	62.4
			62.5	62.3
			86.9	86.8
			87.2	87.1

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			87.2	87.1
			90.2	90.1
			90.2	90.1
			85.8	85.7
			86.9	86.8
			85.7	85.6
			66.9	66.5
			66.9	66.5
			66.9	66.5
			66.9	66.5
			66.9	66.5
			66.9	66.5
			66.9	66.5
			53.4	53.3
			66.9	66.5
			91.6	91.7
			76.6	76.8
			76.6	76.8
			93	93.1
			91.6	91.7
			87.4	87.7
			93	93.1
			91.8	91.9
			91.3	91.4
			93	93.1
			91.8	91.9
			93	93.1

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			91.1	87.3
			91.4	87.7
			92.3	88.4
			92.5	88.8
			92.2	88.4
			95.9	92.1
			95.9	92.1
			95.9	92.1
			91.4	87.7
			95.9	92.1
			91.1	87.3
			72.2	65.7
			72.2	65.7
			72.2	65.7
			72.2	65.7
			58.5	49.5
			71.4	64.9
			72.2	65.7
			71.4	64.9
			72.2	65.7
				51.4
			39	51.4
			39	51.4
				51.4
			42.9	42.8
				51.4
				47.5
				51.4

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]				51.4
			47.5	47.5
				51.4
				42.8
				51.4
			86.1	85.4
			85.6	85
			85.6	85
			85.6	85
			81.2	80.5
			86.1	85.4
			86.1	85.4
			86.1	85.4
			86.1	85.4
			86.1	85.4
			86.1	85.4
			47.2	46.6
			47.2	46.6
			47.2	46.6
			47	496.3
			47	46.3
			47.2	46.6
			47	46.3
			47.2	46.6
			27.7	25.6
			47	46.3
			47.2	46.6
			58.4	70

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			58.4	70
			54.3	65.1
			54.3	65.1
			54.3	65.1
			54.3	65.1
			54.3	65.1
			39.9	53.9
			54.3	65.1
			58.4	70
			54.3	65.1
			54.3	65.1
			58.4	70
			58.4	70
			54.3	65.1
			54.3	65.1
			54.3	65.1
			58.4	70
			67.7	63.8
			67.7	63.8
			67.7	63.3
			67.7	63.3
			67.4	61.7
			95.8	95.4
			97.7	97.3
			95.7	95.4
			97.7	97.3
			93.3	93

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]				
			97.7	97.3
			61.9	61.6
			97.7	97.3
			97.7	97.3
			97.7	97.3
			97.7	97.3
			97.7	97.3
			66.8	67.7
			63.4	65.4
			63.4	65.4
			41.3	41.4
			47.3	47.7
			47.3	47.7
			49.8	50.3
			51.9	52.4
			47.3	47.7
			46.7	47.1
			49.9	50.3
			52.6	53.1
			46.7	47.1
			47.3	47.7
			47.3	47.7
			43.8	44.2
			43.9	44.3
			66.4	68
			66.2	67.7

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			42.7	42.8
			44.4	44.5
			44.6	44.7
			44.7	44.9
			44.7	44.9
			44.7	44.9
			44.7	44.9
			44.7	44.9
			44.7	44.9
			80.8	80.9
			75.2	75.2
			80.9	80.9
			75.2	75.3
			75.2	75.3
			75.2	75.3
			75.2	75.2
			75.2	75.2
			74.1	74.1
			75.2	75.2
			67.9	68
			71.7	71.7
			75.2	75.2
			80.8	80.9
			77.2	77.3
			75.2	75.2
			43.2	43.3
			46.5	46.5
			48.1	48.2
			48.1	48.2
			48.1	48.2

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]				
			46.5	46.5
			45.7	45.7
			48.1	48.2
			37.1	37.1
			37.1	37.1
			47.3	47.1
			47.3	47.1
			47.3	47.1
			47.3	47.1
			47.3	47.1
			37.2	36.9
			38.4	36.9
			55.9	56.4
			55.1	55.2
			55.9	56.4
			57.7	58.2
			57.7	58.2
			57.7	58.2
			57.7	58.2
			57.7	58.2
			57.7	58.2
			57.7	58.2
			39.3	39.3
			39.3	39.3
			57.1	59.6

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			57.1	59.6
			56.7	59.1
			56.7	59.1
			36.3	37.8
			36.3	37.8
			39.1	39
			39.1	39
			31.5	31.5
			31.5	31.5
			57.2	57.4
			53.6	53.7
			57.2	57.4
			53.4	53.5
			57.2	57.4
			57.2	57.4
			57.2	57.4
			55	55.1
			57.2	57.4
			70	70.2
			67.7	68
			70	70.2
			63.1	63.4
			58.6	58.9
			24.8	24.8
			15.2	15.2
			24.8	24.8
			24.8	24.8
			24.8	24.8
			37.9	38

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			37.9	38
			21.7	21.7
			34.5	34.6
			74.9	75
			74.9	75
			74.9	75
			74.9	75
			72.7	72.8
			73.1	73.2
			73.1	73.2
			72.8	72.9
			72.8	72.9
			72.7	72.8
			74.9	75
			48.8	49.2
			58.8	59.5
			56.4	58
			54.6	49.8
			54.6	49.8
			54.6	49.8
			54.6	49.8
			54.6	49.8
			54.6	49.8
			42.3	42.6
			42.3	42.6
			43.1	43.4
			61.2	60.4
			61.2	62.5

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			71.3	72.6
			61.2	60.4
			61.2	62.2
			60.4	62.2
			71.2	68.8
			71.2	68.5
			71.2	68.5
			72.1	69.5
			71	68.8
			71	68.8
			72.1	69.5
			38.3	38.6
			38.3	38.6
			69.3	69.4
			44.9	44.9
			66.7	66.7
			69.3	69.4
			66.7	66.7
			69.3	69.4
			59.8	59.9
			66.7	66.7
			72.5	74
			72.5	74
			72.5	74
			72.5	74
			72.5	74
			72.5	74
			72.1	72.2
			71.6	71.6

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			44	43.9
			62.1	56.2
			40.6	40.6
			49.8	49.8
			49.8	49.8
			49.8	49.8
			49.8	49.8
			57.6	56.9
			45.7	45.2
			57.6	56.9
			57.6	56.9
			37.8	37.4
			67.4	67.4
			47	47.9
			48.3	46.8
			62.2	60.1
			88.9	88.7
			82.8	82.7
			68.7	68.7
			45.2	45.1
			40.8	40.8
			70.7	70.7
			40.8	40.8
			70.7	70.7
			36.9	36.9
			36.9	36.9
			78.4	78.4

[redacted]

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			78.4	78.4
			70.6	70.6
			69.7	69.7
			78.4	78.4
			78.4	78.4
			78.4	78.4
			-	-
			77.5	77.5
			78.4	78.4
			78.4	78.4
			78.4	78.4
			78.4	78.4
			58.4	58.5
			99.6	92.8
			28.2	28.2
			55.1	55
			57.8	57.7
			14.7	14.7
			13.5	13.5
			72.5	64.5
			72.5	64.5
			72.5	64.5
			65.3	57.3
			64.4	55.7

[39] Breaker was replaced with a 40,000 amp breaker as part of an asset condition replacement project.

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			72.5	64.5
			87	88.1
			85.2	86.2
			86.8	87.9
			80.2	81.3
			87	88.1
			80	81.1
			87	88.1
			86.3	87.4
			87	88.1
			86.5	87.6
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			87	88.1
			32.7	32.9
			27.4	27.6
			28.8	29.1
			32.3	32.6

Breaker Fault Duty in Percent of Rating			Recommended	Recommended
		Pre-Upgrade Case	AC Plan	HVDC Plan
BREAKER	BKR RATING	0_2017_Needs_Assessment	3_ACPlan_NPROffline_Corrected	5_115kV_HVDCPlan_NPROffline_corrected
[redacted]			32.3	32.6
			31.7	31.6
			80	79.9
			80	79.9
			80	79.9
			80	79.9
			80	79.9

[redacted]

Section 16
Appendix H: Diagrams of the Preferred (AC Plan) Solution

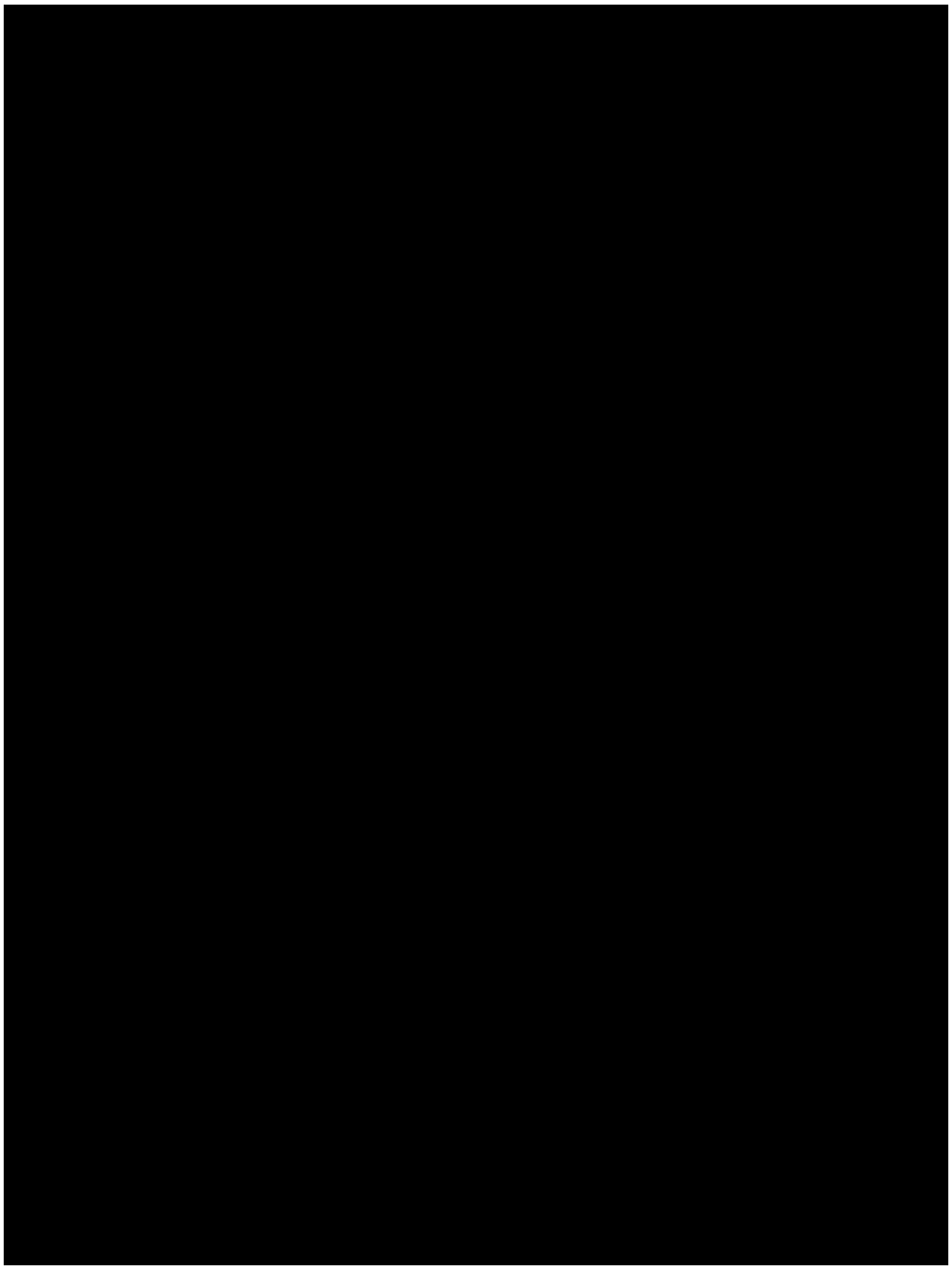


Figure 16-1 Scobie Pond Substation



Figure 16-2 Tewksbury 345 kV Substation



Figure 16-3 Wakefield Jct. Substation



Figure 16-4 Stoughton Substation



Figure 16-5 Woburn Substation



Figure 16-6 Mystic Substation



Figure 16-7 K St. Substation



Figure 16-8 Kingston Substation



Figure 16-9 North Cambridge Substation



Figure 16-10 Sudbury Substation

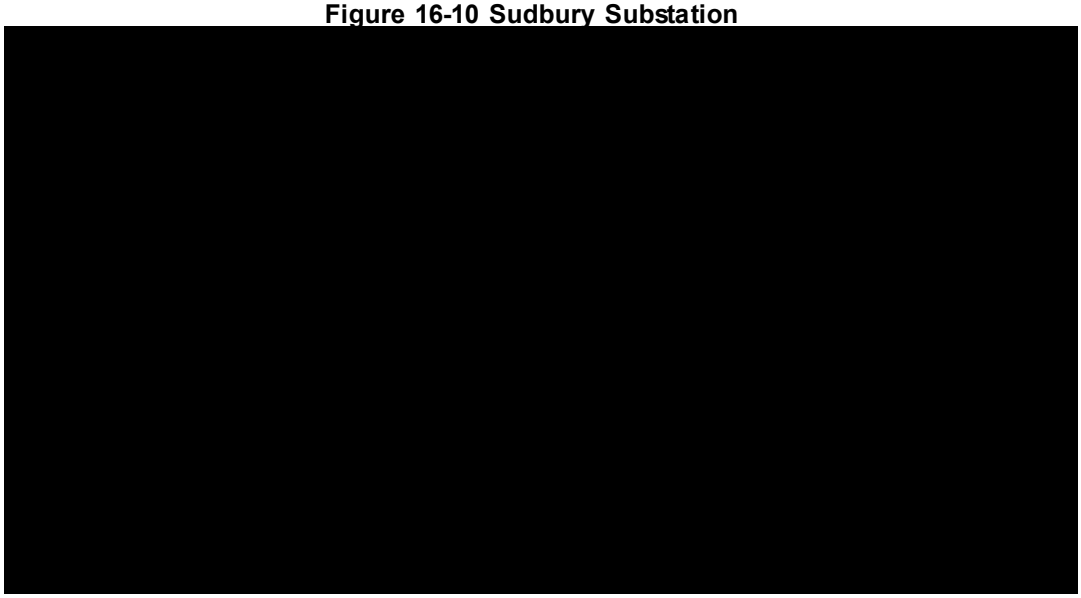


Figure 16-11 Hudson Substation



Figure 16-12 Waltham Substation



Figure 16-13 Chelsea Substation



Figure 16-14 Holbrook Substation



Figure 16-15 Sharon Switching Station



Figure 16-16 West Walpole Substation



Figure 16-17 Newton Substation



Figure 16-18 Framingham Substation



Figure 16-19 Hartwell Substation

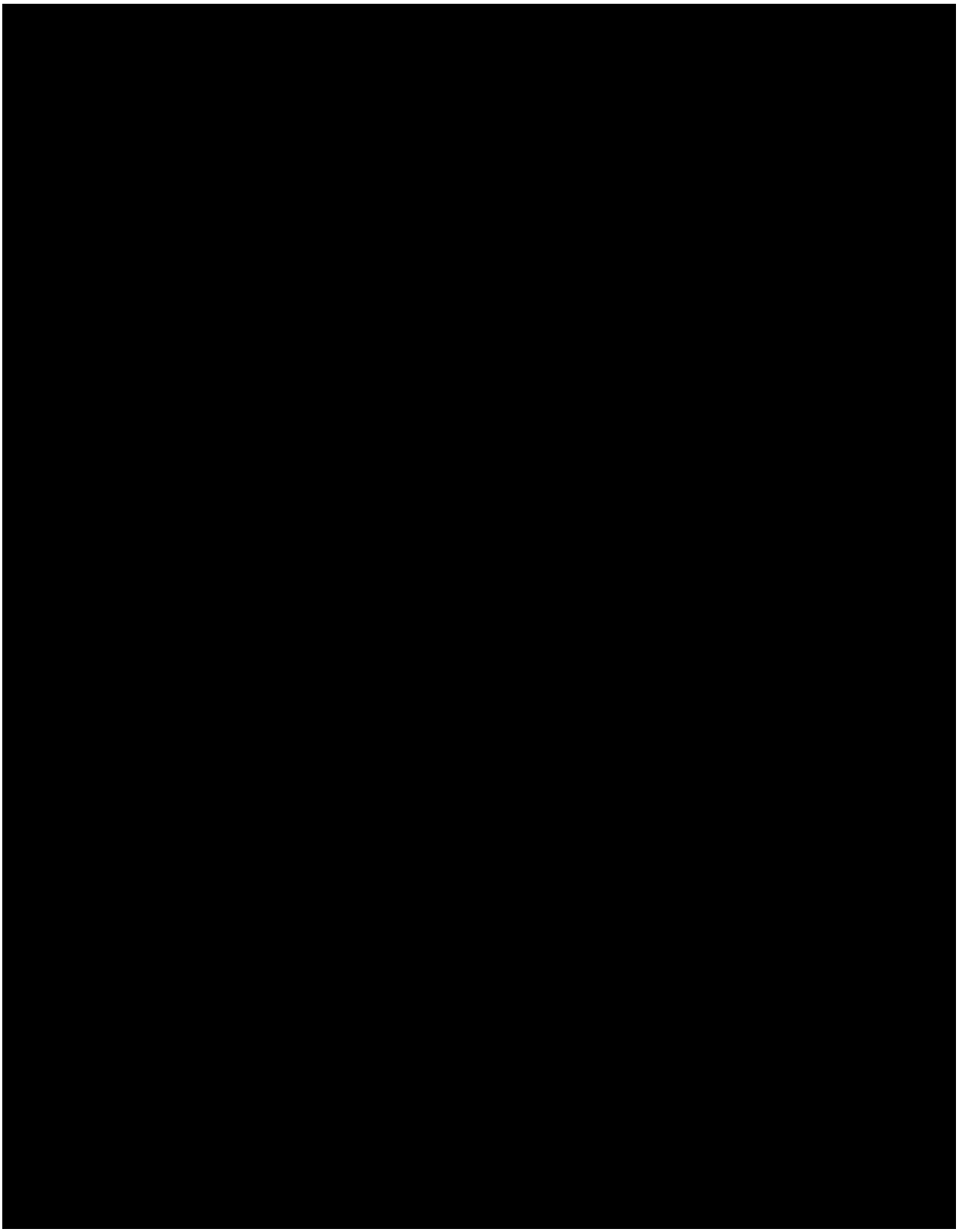


Figure 16-20 Coopers Mill Substation



Appendix 3-3

Appendix 3-4

This document has been redacted for Critical Energy Infrastructure Information (CEII). 1/19/2017

National Grid's Alternative to the Construction of Eversource's Proposed Sudbury – Hudson Line

Alternative Project Scope, Estimates and Project Durations

August 2016

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1. Problem Statement

Eversource is proposing a new overhead/underground Hudson-Sudbury 115kV transmission line to address potential thermal overloads and low voltage conditions in the Marlborough area, as documented in the Greater Boston Area Updated Transmission Needs Assessment. For siting purposes, National Grid has been asked to identify and estimate the cost of a viable alternative that addresses the same needs as the proposed Sudbury-Hudson line.

National Grid has identified an alternative to Eversource's proposed Sudbury-Hudson line consisting of the following elements:

- Upgrade of the 14.5-mile X-24 line from 69kV to 115 kV operation;
- Associated voltage conversion work at five substations; and
- Reconductoring of the 5.8-mile 115 kV E-157W Line.

This set of projects is referred to as the "NEP X-24/E-157 Alternative".

Upgrade of the 14.5-mile X-24 line from 69kV to 115 kV operation:

The existing 69 kV X-24 transmission line runs from the 69 kV Millbury #5 Substation in Millbury, MA to the Northborough Road 317 Substation in Marlborough, MA. The line consists of two sections:

- The X-24W, which extends approximately 10.3 miles from the Millbury #5 substation through the towns of Millbury, Grafton, Shrewsbury and Westborough to the Westborough substation;
- The X-24E, which extends approximately 4.2 miles from the Westborough 12 Substation through the towns of Westborough and Southborough to the Northborough Road 317 Substation.

The 69 kV North Grafton #328 substation is located between the Millbury #5 and Westborough #312 substations.

Associated voltage conversion work at five substations:

Conversion of the X-24 line to 115kV would require work at following substations:

- Millbury #2 (115 kV) – Relocate the existing V-174 line and add a position for the X-24 line, which would now terminate at Millbury 2.
- Millbury #5 – Remove the 69 kV X24W line and change the relay settings.
- North Grafton #328 – Redesign the proposed substation for 115kV[1].
- Westborough #328 – Upgrade all 69kV equipment to 115kV.
- Northborough Rd #317 – Expand the existing 115kV yard and relocate X-24 to it.

Reconductoring of the 5.8-mile 115 kV E-157W Line:

The X-24 line shares the right-of-way (ROW) with the 115 kV E-157 transmission line for much of its ROW. This line consists of three distinct sections:

- The E-157W, which extends approximately 5.8 miles from the Millbury #2 substation through the towns of Millbury, Grafton, and Shrewsbury to the Centech substation (Shrewsbury Municipal);
- The E-157, which extends approximately 5.7 miles from the Centech Substation through the towns of Shrewsbury and Westborough to the East Main Street Substation; and
- The E-157E, which extends approximately 2.5 miles from the East Main Street Substation through the towns of Westborough and Southborough to the Northborough Road Substation.

[1] A new 69/13.8 kV metal clad substation with one 24/32/40 MVA LTC transformer and six feeder positions is proposed for the new North Grafton #328 substation in Grafton, MA with a ready for load date of Sep 2019. The primary driver is projected thermal overloads of transformers and distribution feeders during summer peak load periods.

Only the E-157W would be reconductored as part of the NEP Alternative.

No substation work is required to support the E-157W reconductoring.

Please refer to Figure 1 and Figure 2 for a geographic map and a transmission one-line diagram of the area respectively.

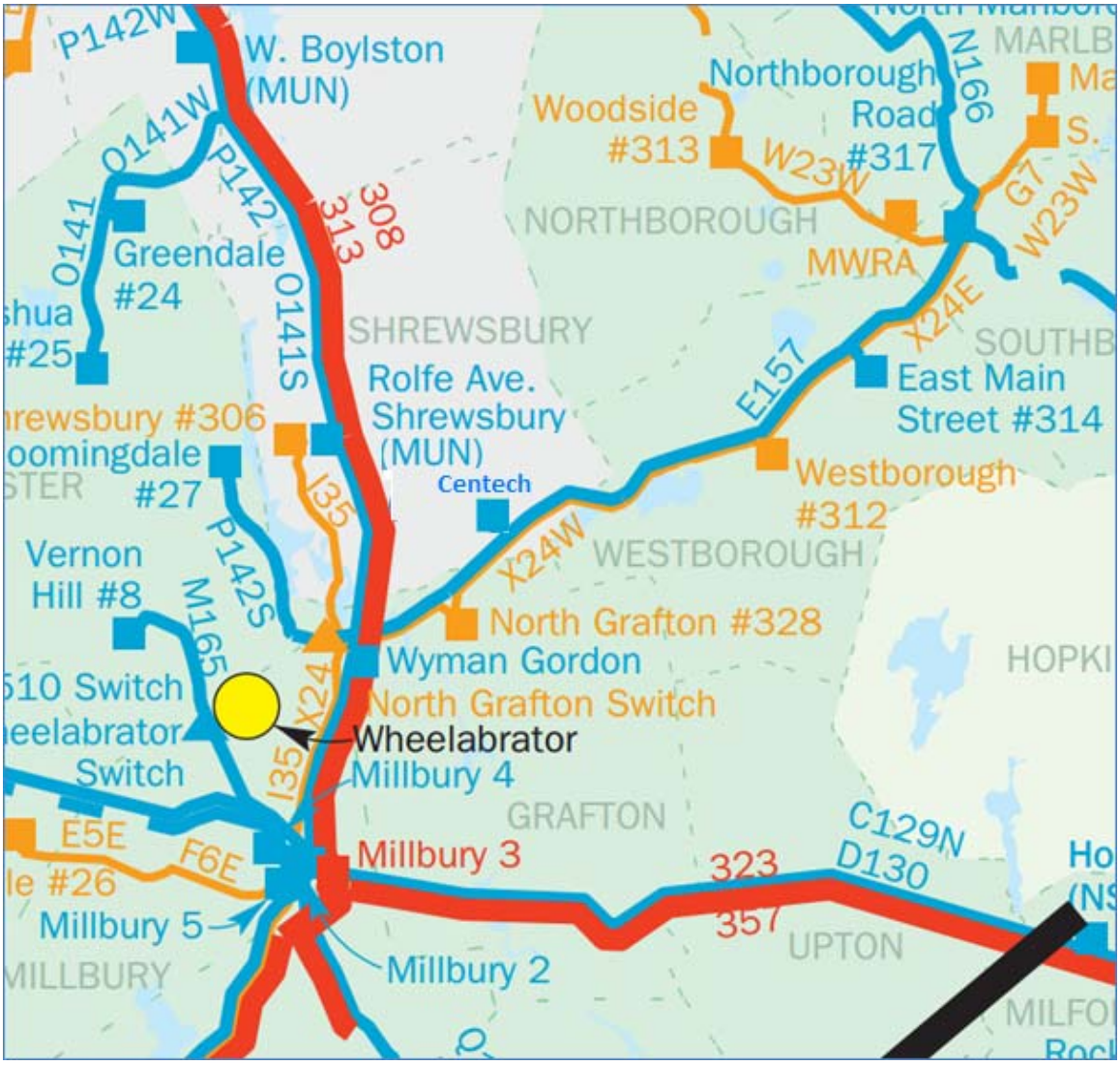


Figure 1 Geographic Map of the area

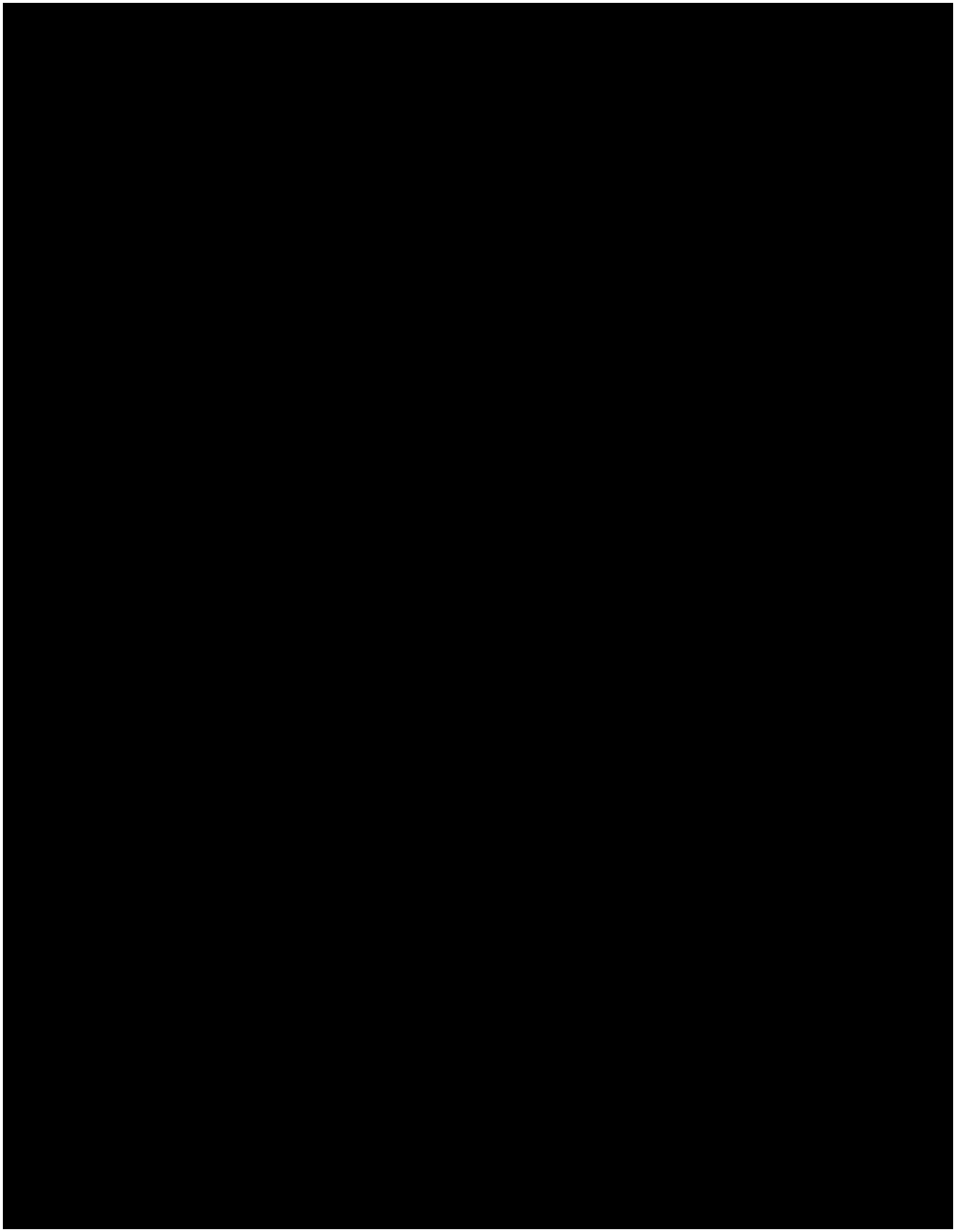


Figure 3 shows the work scope.

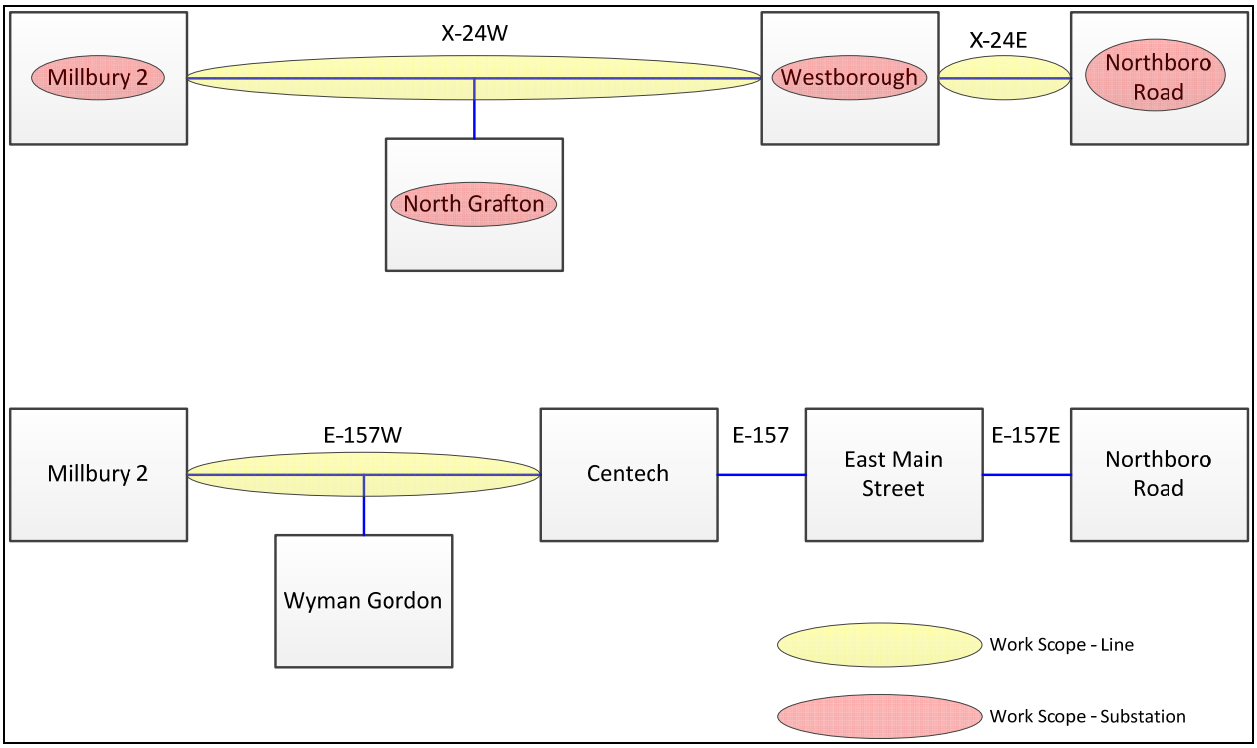


Figure 3 Work Scope (Line and Sub)

Table 1 summarizes the existing conductor lengths.

Table 1 Existing Conductor Lengths (approximate)

Participant Equipment ID	kV	From Station	To Station	Conductor Length (miles, approximate)
X-24W	69	Millbury 69kV	North Grafton Switch Tower 69kV	3.1
X-24W	69	North Grafton Switch Tower 69kV	North Grafton 69kV	1.7
X-24W	69	North Grafton 69kV	Westborough 69kV	5.5
X-24E	69	Westborough 69kV	Northboro Rd 69kV	4.2
			TOTAL	**14.5**
E-157W	115	Millbury 115kV	Wyman Gordon 115kV	2.9
E-157W	115	Wyman Gordon 115kV	Centech 115 kV	2.9
E-157	115	Centech 115 kV	East Main St 115kV	5.7
E-157E	115	East Main St 115kV	Northboro Rd 115kV	2.5
			TOTAL	**14.0**

The difference in the lengths can be attributed to couple of locations where the X-24 leaves the E-157 ROW at North Grafton and Westborough substations (see Figures 4 and below).

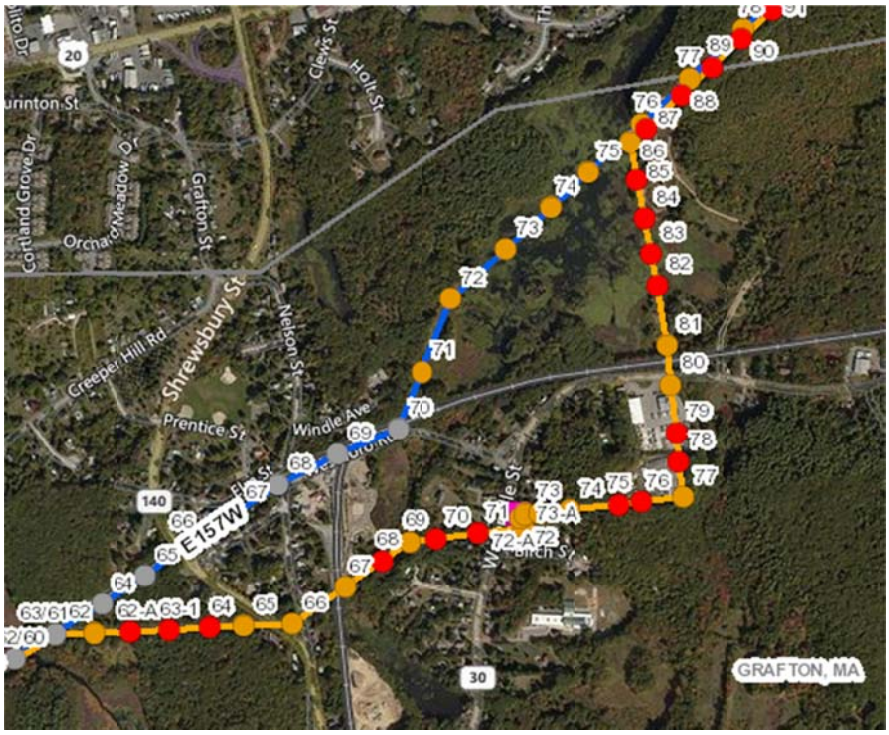


Figure 4 ROW @ North Grafton



Figure 5 ROW @ Westborough

2. Line Work

2.1. X-24 115 kV Conversion Project

2.1.1. Scope

The scope involves the conversion of the existing 69kV X-24E and X-24W lines to 115kV and the work necessary to reconfigure the existing X-24E and X-24W ROW to accommodate the upgrade. All of the existing structures supporting the X-24E and X-24W will be replaced. A total of approximately 233 steel pole structures and roughly 136 reinforced concrete caissons will be required to support the upgrade. The balance of foundations required on the project will be direct-embed. A total of 14.5 circuit miles of 1113 kcmil ACSR "Finch" conductor will replace the 795 kcmil ACSR "Condor" presently on the X-24E and X24W and 14.5 miles of OPGW will provide the shield wire on the upgraded line. Another 35 total structures on adjacent transmission lines will require replacement to accommodate the upgrade along with 29 reinforced concrete foundations. An existing, retired, 69kV line within the ROW corridor with 49 total structures and 3.2 miles of 2/0 copper is required to be removed from the ROW to support the project.

2.1.2. Project Duration

Activity	Duration (in months)
Project Initiation	1
Preliminary Engineering	18
Sanction	1
Permitting & Licensing	18-24
Detailed Design	12
Procurement	12
Construction Planning	36
Construction	18
Closeout	3
Total	66

2.1.3. Estimated Cost

$65,800,000 (Conceptual Grade Estimate, i.e. -25% to +50%, in 2016 dollars)

2.1.3.1. Cost Assumptions

- AFUDC is based on a 2 year average actual 2013/2014 debt/equity rate. It is assumed that the plant is placed in service as constructed beginning three months of construction start.
- The estimate includes budget pricing for the following:
    - Project Manager Contractor
    - Transmission Engineering Consultant
    - Outreach Consultant
    - Environmental Permitting Consultant
    - Cultural/Archaeological consultant
    - Legal outside counsel

  - Forestry ROW Clearing/Mowing
  - Surveyor
  - Outage Planning Consultant
  - Visual Mitigation Costs
  - Steel Structures
  - Caisson Foundations
  - Rock Coring
- Environmental Mitigation
  - Environmental mitigation costs include:
    - Matting
    - Sediment Barrier
    - Stone Aprons
- The estimate assumes that rock will be 20% of the foundation depth.
- Estimate includes budget pricing for non-inventory materials based on internal historic pricing.
- The estimate assumes spoils will be spread on site.

2.1.3.2. Cost Exclusions

- Charges to date are not included.
- Escalation
- Commodity Factors
- Dewatering
- Access road building or improvements
- Land Acquisition[2]
- Hazardous material removal and disposal

[2] An initial review determined that additional property rights would be needed on two parcels along the 14.5 mile ROW. Additional review of existing rights could determine that there are additional gaps in rights or that existing rights would need to be supplemented to complete the project.

2.2. E-157W Reconductoring Project

2.2.1. Scope

The scope involves the reconductoring of the 115 kV E-157W Line between the Millbury 2 Substation and the Centech Substation (Shrewsbury Electric and Cable Operations; SELCo). The scope includes the replacement in kind of a total of 26 total structures with dead-end structures being converted to self-supporting steel pole structures requiring a total of 12 reinforced concrete foundations. The existing 795 kcmil ACSR "Condor" conductor will be upgraded to 795 kcmil ACSS "Drake" conductor over a distance of 5.8 circuit miles and a 2.9 mile long stretch of 7 #9 alumoweld shield wire will be replaced with 3/8" EHS steel shield wire. The balance of the shield wire along the line between Millbury 2 and Centech will remain in-service as it is at present.

2.2.2. Project Duration

Activity	Duration (in months)
Project Initiation	1
Preliminary Engineering	6
Sanction	1
Permitting & Licensing	18-24
Detailed Design	6
Procurement	6
Construction Planning	3
Construction	6
Closeout	3
Total	42

2.2.3. Estimated Cost

$11,500,000 (Conceptual Grade Estimate, i.e. -25% to +50%, in 2016 dollars)

2.2.3.1. Cost Assumptions

- AFUDC is based on a 2 year average actual 2013/2014 debt/equity rate. It is assumed that the plant is placed in service as constructed beginning three months of construction start.
- The estimate includes budget pricing for the following:
    - Project Manager Contractor
    - Transmission Engineering Consultant
    - Outreach Consultant
    - Environmental Permitting Consultant
    - Cultural/Archaeological consultant
    - Legal outside counsel
    - Forestry ROW Clearing/Mowing
    - Surveyor
    - Outage Planning Consultant
    - Visual Mitigation Costs
    - Steel Structures
    - Caisson Foundations

  - Rock Coring
- Environmental Mitigation
  - Environmental mitigation costs include:
    - Access Matting
    - Matting for work pads
    - Sediment Barrier
    - Stone Aprons
- The estimate assumes that rock will be 20% of the foundation depth.
- Estimate includes budget pricing for non-inventory materials based on internal historic/procurement pricing.
- The estimate assumes spoils will be spread on site.

2.2.3.2. Cost Exclusions

- Charges to date are not included.
- Escalation
- Commodity Factors
- Dewatering
- Land Acquisition[3]
- Hazardous material removal and disposal

[3] NEP does not anticipate that addition property rights would be needed for the E-157W Reconductoring Project.

3. Substation Work

3.1. Millbury 2 Substation Work

3.1.1. Scope

Upgrades required to accommodate the X-24 115 kV Conversion Project include the installation of one (1) new 115 kV GCB, group operated disconnects, three (3) 115 kV CCVTS, miscellaneous 1590kcmil conductor jumpers, new relaying, settings and terminations.

3.1.2. Project Duration

Activity	Duration (in months)
Preliminary Engineering	9-10[1]
Final Engineering & Design	12-13
Material Procurement	1-2[2]
Permitting & Licensing	18-24[3]
Construction	25-28[4]
Closeout	3
Total Project Duration	50-55

Note: 1. Start after approval to begin
2. Performed in parallel with Final Eng. & Design.
3. Performed in parallel with Preliminary Eng. and Final Eng. & Design and in sync with permitting & licensing for X-24
4. Duration to include the 90 day construction bid / award window.

3.1.3. Estimated Cost

$2,120,000 (Conceptual Grade Estimate, i.e. -25% to +50%, in 2016 dollars)

3.1.3.1. Cost Assumptions

- Concrete foundation installation based on the designs provided within the project scope package.
- Soil borings were not part of this work scope package and therefore removal costs for rock and ledge are not included at this time.
- Estimate includes costs for inventory materials based on internal historic pricing.
- This estimate assumes standard installation and removal equipment usage and rentals.
- Costs for ground penetrating radar, vacuum truck and time for switching have been carried.
- This estimate assumes that the existing substation yard has the required room to accommodate this expansion, including all proper clearances to the security fencing and heights restrictions to the bussing scheduled to be extended.

3.1.3.2. Cost Exclusions

- Escalation
- Commodity Factors

- Costs for Mobile Transformer
- Permitting costs
- Rock and ledge removals

3.2. North Grafton Substation Work

3.2.1. Scope

The North Grafton 328 X24 Line 115kv Upgrades includes the replacement of one (1) 24/32/40MVA 115kv-13.8 transformer, (1) circuit switcher, associated conductor and disconnect switches.

3.2.2. Project Duration

Activity	Duration (in months)
Preliminary Engineering	9-10[1]
Final Engineering & Design	9-10
Material Procurement	2-3[2]
Permitting & Licensing	18-24[3]
Construction	10-12[4]
Closeout	3
Total Project Duration	32-35

Note: 1. Start after approval to begin
2. Performed in parallel with Final Eng. & Design.
3. Performed in parallel with Preliminary Eng. and Final Eng. & Design and in sync with permitting & licensing for X-24
4. Duration to include the 90 day construction bid / award window.

3.2.3. Estimated Cost

$3,740,000 (Conceptual Grade Estimate, i.e. -25% to +50%, in 2016 dollars)

3.2.3.1. Cost Assumptions

- Estimate includes costs for inventory materials based on internal historic pricing.
- This estimate assumes standard installation and removal equipment usage and rentals.
- It is assumed that the current project to rebuild 69kV substation will have yard expansion and will be built with 115kV clearance (see Footnote 1).

3.2.3.2. Cost Exclusions

- Escalation
- Commodity Factors
- Soil borings

3.3. Westborough Substation Work

3.3.1. Scope

Upgrades required to accommodate the X24 115 kV Conversion Project include the replacement of two (2) 24/32/40MVA 69kV-13.8 transformers, replacement of the existing 69 kV tie breaker with a new 115 kV tie breaker, installation of new structures, installation of new equipment foundations, installation of new 115 kV bus and the removal of existing 69 kV bus. The scope also includes the removal of existing foundations and installation of new foundations. Installation of associated conduit and cabling within the yard and control house is also part of this project, including associated site work to expand the yard by approximately 10,500 sq. ft. (i.e. site preparation, clearing, backfill and station stone).

3.3.2. Project Duration:

Activity	Duration (in months)
Preliminary Engineering	12-13[1]
Final Engineering & Design	12-13
Material Procurement	8-10[2]
Permitting & Licensing	18-24[3]
Construction	10-12[4]
Closeout	3
Total Project Duration	45-48

Note: 1. Start after approval to begin
2. Performed in parallel with Final Eng. & Design.
3. Performed in parallel with Preliminary Eng. and Final Eng. & Design and in sync with permitting & licensing for X-24
4. Duration to include the 90 day construction bid / award window.

3.3.3. Estimated Cost

$8,780,000 (Conceptual Grade Estimate, i.e. -25% to +50%, in 2016 dollars)

3.3.3.1. Cost Assumptions

- Concrete foundation installation based on the designs provided within the project scope package.
- Soil borings were not part of this work scope package.
- Estimate includes costs for inventory materials based on internal historic pricing included within SE.
- This estimate assumes standard installation and removal equipment usage and rentals.
- Costs for ground penetrating radar, vacuum truck, time for switching have been carried.

3.3.3.2. Cost Exclusions

- Escalation
- Commodity Factors

3.4. Northborough Road Substation Work

3.4.1. Scope

Upgrades required to accommodate the X24 115 kV Conversion Project include the replacement of two (2) 115 kV gas circuit breakers, disconnect switches, structures and foundations for new equipment, a new control house enclosure, and associated relaying, communication and protection equipment.

3.4.2. Project Duration:

Activity	Duration (in months)
Preliminary Engineering	15-16[1]
Final Engineering & Design	17-19
Material Procurement	5-6[2]
Permitting & Licensing	18-24[3]
Construction	32-35[4]
Closeout	3
Total Project Duration	72-78

Note: 1. Start after approval to begin
2. Performed in parallel with Final Eng. & Design.
3. Performed in parallel with Preliminary Eng. and Final Eng. & Design and in sync with permitting & licensing for X-24
4. Duration to include the 90 day construction bid / award window.

3.4.3. Estimated Cost

$11,200,000 (Conceptual Grade Estimate, i.e. -25% to +50%, in 2016 dollars)

3.4.3.1. Cost Assumptions

- Concrete foundation installation based on the designs provided within the project scope package.
- Soil borings were not part of this work scope package.
- Estimate includes costs for inventory materials based on internal historic pricing included within SE.
- This estimate assumes standard installation and removal equipment usage and rentals.
- Costs for ground penetrating radar, vacuum truck, time for switching have been carried.

3.4.3.2. Cost Exclusions

- Escalation
- Commodity Factors

4. Summary of Total Estimated Costs[4]

Item	Work Type	Conceptual Grade Cost Estimate[5] (-25% to +50%)
X-24E/W upgrade	Line	$ 65,800,000.00
E-157W reconductoring	Line	$ 11,500,000.00
Millbury 2	Substation	$ 2,120,000.00
North Grafton	Substation	$ 3,740,000.00
Westborough	Substation	$ 8,780,000.00
Northboro Rd.	Substation	$ 11,200,000.00
TOTAL ->		$ 103,140,000.00

[4] No estimate was developed for Millbury 5 substation, as the scope of work at that location is insignificant.
[5] In 2016 dollars

5. Summary of Project Duration

Line Work Duration (in months)		
Activity	**X-24W & E**	**E-157W**
Project Initiation	1	1
Preliminary Engineering	18	6
Sanction	1	1
Permitting & Licensing	18-24	12
Detailed Design	12	6
Procurement	12	6
Construction Planning	36	3
Construction	18	6
Closeout	3	3
Total Project Duration (in months)	66	42

Substation Work Duration (in months)				
Activity	**Millbury 2**	**North Grafton**	**Westborough**	**Northborough**
Preliminary Engineering	9-10[1]	9-10[1]	12-13[1]	15-16[1]
Final Engineering & Design	12-13	9-10	12-13	17-19
Material Procurement	1-2[2]	2-3[2]	8-10[2]	5-6[2]
Permitting & Licensing*	18-24[3]	18-24[3]	18-24[3]	18-24[3]
Construction	25-28[4]	10-12[4]	10-12[4]	32-35[4]
Closeout	3	3	3	3
Total Project Duration (in months)	50-55	32-35	45-48	72-78

Note: 1. Start after approval to begin
2. Performed in parallel with Final Eng. & Design.
3. Performed in parallel with Preliminary Eng. and Final Eng. & Design
4. Duration to include the 90 day construction bid / award window.

* The permitting and licensing of 18-24 months (from X-24 scope) should be the same for all projects as they will all be included together in the EFSB (Energy Facilities Siting Board) and ACOE (Army Corps of Engineers) permitting process which accounts for the lengthy timeframe.

ANALYSIS OF NON-TRANSMISSION ALTERNATIVES TO THE SUDBURY - HUDSON PROJECT: IDENTIFICATION OF FEASIBLE NTA TECHNOLOGIES AND LEVELIZED COSTS

January 11, 2017

prepared for Eversource Energy

by



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Synopsis

Eversource Energy ("Eversource") hired London Economics International LLC ("LEI") to conduct a Non-Transmission Alternatives ("NTA") analysis for the Sudbury to Hudson Reliability Transmission Line Project ("SHP"). The SHP has been proposed by Eversource in response to an identified reliability need in the Boston metropolitan area, surrounding suburbs, and New Hampshire. This report presents the technical feasibility and cost viability of implementing NTA technologies in lieu of the proposed transmission solution ("SHP").

We define technically "feasible" technologies as technologies that could be hypothetically implemented based on planning criteria and technology specific operating profiles. A technically feasible NTA technology could therefore hypothetically meet the reliability issues being addressed by SHP. However, a technically feasible NTA may not necessarily be cost-effective and could face practical hurdles like available land area, time required to complete construction, or availability of fuel supply. This report also addresses both the expected cost of technically feasible NTA technologies as well as the practicality of a potential NTA solution.

LEI's analysis is based on simulations of the transmission system reliability needs performed by Eversource. LEI took the resulting hypothetical NTA requirements provided by Eversource for each location and formed a list of feasible technologies by location. LEI's technology specification used a selection process that considered the size and operating characteristics of various generic NTA technologies relative to the hypothetical NTA requirement amounts and system needs under the modeled N-1-1 contingency events.[1]

LEI concluded that the most common technically feasible NTA technologies include combined cycle gas turbine ("CCGT") plants, peaker aeroderivatives, utility scale solar photovoltaic ("PV") units (with storage), dual fuel jet engines and slow discharge batteries. Distributed generation solar PV ("solar DG") and utility-scale solar PV are not technically feasible NTAs on their own, because they cannot operate during night-time hours. However, LEI has accommodated such technologies in the analysis by including the additional cost of on-site energy storage.

Using gross costs per megawatt ("MW") of installed capacity for each technology, LEI estimated that the total costs of a technically feasible NTA solution for SHP was in the range of $88 million to $131.4 million per year. However, LEI also recognized that total costs of NTA technologies can be defrayed by revenues from markets as well as other sources. Consequently, LEI computed net direct cost to ratepayers associated with NTA technologies by deducting expected average annual market-related revenues from total gross costs. Total net direct cost to ratepayers of the least cost technically feasible NTA solution for SHP was estimated to range from approximately $23 million to $35 million a year. Based on practical considerations, including likelihood assessment of the revenues that could offset gross costs in the net direct cost calculus, the technically feasible NTA solution for SHP with the highest probability of occurrence would involve installing a 249 MW CCGT at Northboro Road Substation and a 32 MW peaker aeroderivative unit at Woodside Substation with a net direct cost to ratepayers estimated at $23 million

[1] No thermal overloads or unacceptable voltage conditions were observed under N-1 contingencies in the Needs Assessment for SHP.

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a year, which is significantly higher than the range of annual revenue requirement ("ARR") for SHP, which is estimated between $5.4 and $11.8 million a year.[2]

It bears noting that the addition of such a volume of gas-fired generation would be difficult to develop and permit under current market conditions, mainly due to general market conditions that point to an absence of need, as evidenced by ISO-NE's most recent forward capacity auction results where no such resources cleared the auction for the Greater Boston area. A number of other potential hurdles, including constraints on construction time (an NTA solution should be commercialization by 2019 if it were to meet the reliability needs of SHP), sufficiency of related infrastructure (such as gas pipelines), and permitting and siting challenges must also be considered.

[2] Cost estimate for SHP provided by Eversource on November 18, 2016. The ARR range refers to project variations provided by Eversource.

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Acronyms

AC	Alternating Current
ACP	Alternative Compliance Payment
CCGT	Combined Cycle Gas Turbine
CLL	Critical Load Level
DALRP	Day Ahead Load Response Program
DG	Distributed Generation
DPU	Massachusetts Department of Public Utilities
DR	Demand Response
EFSB	Energy Facilities Siting Board
EPRI	Electric Power Research Institute
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FO&M	Fixed Operating & Maintenance
GBWG	Greater Boston Working Group
HVDC	High Voltage Direct Current
IEA	International Energy Agency
ISO	Independent System Operator
ISO-NE	Independent System Operator- New England
kW	Kilowatt
LCOE	Levelized Cost of Entry
LEI	London Economics International
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NTA	Non-Transmission Alternative
O&M	Operating & Maintenance
PNNL	Pacific Northwest National Laboratory
PV	Photovoltaic
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
SHP	Sudbury – Hudson Project
SREC	Solar Renewable Energy Credit
VOLL	Value of Lost Load
VOM	Variable Operating and Maintenance

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1 Executive Summary

A Non-Transmission Alternative ("NTA") is a solution (or group of solutions) to an identified electric system need that does not involve the construction of traditional transmission infrastructure. NTA technologies may include supply-side resources (e.g. conventional generation, distributed generation or advanced generation technologies such as energy storage technologies), demand-side resources (e.g. demand response or energy efficiency), or a combination of both.

How to choose between a transmission solution and an NTA?

In theory, if an NTA can satisfactorily meet the technical requirements of the system that are driving the need for the transmission solution, it can then delay the timing of needed transmission investment. Consumers would pay for the transmission solution and may need to pay for the costs of deploying the NTA. Therefore, it is important to then compare the costs of the transmission solution against the NTA. However, it is also important to recognize that NTAs and transmission may also have different characteristics that affect other aspects of electricity service. Even if an NTA is lower cost and can fulfill the technical requirements of the system (e.g., the reliability need), there may also be other services and benefits that transmission can provide versus NTAs. Only if an NTA can fulfill all the same technical requirements and generate benefits at comparable or lower costs than those associated with transmission projects, should an NTA be pursued.

LEI was tasked with analyzing whether there exists a technically feasible combination of NTA technologies that could be more cost-effective than the proposed SHP in addressing reliability issues in the Greater Boston area. Eversource prepared a set of NTA requirements that would meet the reliability needs of the system. Based on these NTA requirements, LEI identified technically feasible NTA technologies, and estimated their costs, to evaluate the direct cost to ratepayers associated with the implementation of the least-cost, technically feasible NTA solution. A technically feasible NTA technology is defined as a technology that can meet the requirements set out by system planning criteria. System planning criteria refer to requirements such as the maximum allowable time for an NTA technology to respond to contingency events (response time) and minimum duration of time for which an NTA technology must remain online after being called into service. In contrast, physical considerations, which are not a part of this methodology, refer to the amount of land and associated infrastructure required for a given NTA technology to be located at a substation. These physical considerations are assessed qualitatively in Section 5.3. It is important to bear in mind that a technically feasible NTA technology may still be impractical from a variety of other physical and financial considerations.

LEI has extensive experience working with both renewable and conventional generation technologies, as well as transmission infrastructure in the New England and Massachusetts region. LEI has also undertaken economic cost-benefit analysis, market price forecasting and asset valuation as well as presented expert witness testimony in front of various regulators in North America, including the Massachusetts Energy Facility Siting Board ("EFSB"). A detailed description of LEI's experience is presented in Appendix A.

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1.1 What NTA technologies were considered?

The analysis presented in this report was designed around a mix of supply-side and demand-side technologies initially identified by both LEI and Eversource:

1. conventional fossil fuel-fired generation (natural gas-fired peaking and combined cycle technologies);
2. large scale renewable generation (solar and wind);
3. distributed solar generation (5 MW or less in size);
4. active demand response (real-time demand response and real-time emergency generation);
5. passive demand response (energy efficiency programs); and
6. energy storage technologies (utility-scale battery technology and flywheels).

When identifying various technologies, and performing the cost analysis, LEI relied primarily on real world operating experience with such technologies in New England, as well as research documents and market information made publicly available by ISO-NE and the state of Massachusetts related to technologies' operational data and statistics. Where necessary, information from actual operational experience was supplemented with engineering–related data and generic technology information, including data on capital and operating costs, as well as operating parameters. Such generic information was collected from reputable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers, and engineering procurement companies that work with such technologies. A detailed bibliography list is provided in Appendix E.

1.2 Overview of methodological approach

Before LEI started its analysis, Eversource transmission planners performed an assessment of hypothetical NTA solutions that would be needed to mitigate identified reliability issues absent construction of the SHP (the "Reliability Assessment"). Figure 1 summarizes the total number of locations and total amount of NTA resources needed to address N-1-1 overloads.[3] The analysis was designed to identify the size of resources and their specific locations within the transmission system, which would be needed to alleviate thermal overloads and eliminate low voltage situations in the Marlborough subarea. Eversource determined that 264 MW of energy injection would be required at two different locations: 237 MW at the Northboro Road substation and another 27 MW at the Woodside substations.

[3] No thermal overloads or unacceptable voltage conditions were observed under N-1 contingencies in the Needs Assessment for SHP.

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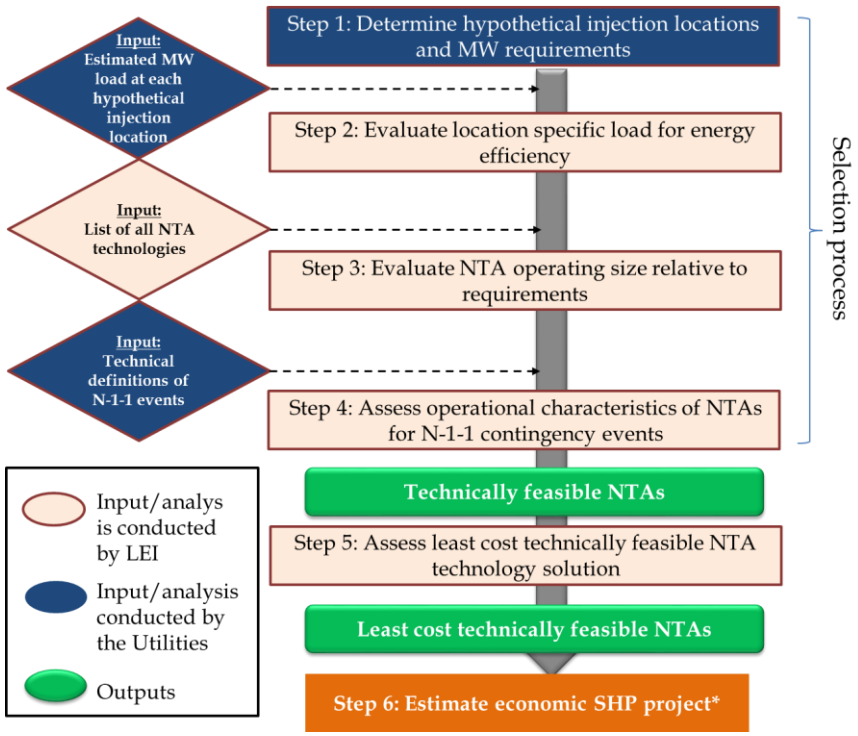
Figure 1. Summary of findings from Reliability Assessment: NTA injection amounts by location

NTA Injection Location	Total NTA Resources Needed (MW)
Northboro Road	237
Woodside	27
Total	264

Source: Eversource transmission planners

LEI then applied a multi-step analytical process to determine technically feasible NTA technologies that could satisfy the reliability issues being addressed by SHP, as illustrated in Step 2 through Step 4 in Figure 2 (Step 1 is the determination of the NTA injection amounts by Eversource transmission planners, pursuant to the Reliability Assessment described above). A technically feasible NTA technology is defined as one that can independently cater to all the requirements for an NTA (capacity, availability, response time) at a particular location. Finally, LEI considered the cost of the least costly NTA solution in Step 5 (see Figure 2). The details of LEI's methodology are presented in Section 4.3 of this report.

Figure 2. Illustration of LEI's selection process and overall methodology



* Beyond the scope of this report

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First, under Step 2, LEI considered whether *sufficient peak load* exists at each location to make active and/or passive demand response a technically feasible NTA technology at that location.

Next, under Step 3, LEI considered whether a specific technology could provide the *size of injection* required at a specific location, based on established minimum and maximum sizes for each technology. For example, a jet engine, with a maximum size of approximately 50 MW, is not a technically feasible NTA technology at a location where a larger injection is required. Therefore, Step 3 results in a preliminary list of technically feasible NTA technologies for the two locations.

Next, under Step 4, LEI considered whether a specific technology has the *operating characteristics* needed to respond to contingency conditions at a specific location. A resource responding to an N-1-1 contingency must be able to provide energy within 30 minutes of the occurrence of the first contingency. The resource must then continue to operate until the failed transmission system element is repaired or as long as deemed necessary by the ISO-NE. Typically, ISO-NE can resolve contingency events within a 12 to 24 hour cycle, and LEI has conservatively assumed a 12 hour duration to resolve the contingency in its analysis.

Step 5 in LEI's analysis employs a levelized cost methodology in order to evaluate the direct costs to ratepayers of implementing NTA technologies. The direct costs were calculated by aggregating the total cost of implementing least cost technically feasible NTA technologies for each location. LEI first assessed the costs of technically feasible NTA solutions by evaluating the total costs of investment and operations (based on gross Levelized Cost of Entry ("LCOE") per kW-year). Then, LEI considered the net costs of investment and operations that ratepayers would bear after accounting for possible market revenues and other income streams (for example, from other ratepayer-funded programs, like Renewable Energy Certificates ("RECs")).

1.3 Key Findings on technically feasible NTA technologies

The NTA injection requirement is significantly large and limited to just two substations (see Figure 1) such that a solution composed of entirely demand-side NTAs is infeasible. The required load reduction (264 MW) to achieve a demand-side NTA solution exceeds the aggregated peak load at the two substations.

The qualitative review conducted by LEI also indicates that the feasibility of commercializing supply-side resources at the identified substations may not be technically feasible for certain technologies. Based on the peak load forecasts and critical load level ("CLL") values provided by Eversource, technically feasible NTA solutions will need to be operational during both day and night hours. As a result, some NTA technologies like solar DG and utility scale solar PV without storage are unable to qualify as technically feasible NTA technologies. Similarly, technologies like demand response also don't qualify as technically feasible NTA technologies because the available load at the two substations is inadequate to allow interventions like demand response to reduce injection amounts to levels sufficient for avoiding the reliability problems. In light of these considerations, LEI identified CCGTs, peaker aeroderivatives, utility scale solar PV units (with storage), dual fuel jet engines and slow discharge batteries as feasible NTA technologies at the two substations.

Even for those technologies that have been determined to be technically-feasible, there may be challenges to bringing such projections to fruition, such as land requirements (in terms of quality and space) around the substation areas, and the need of additional infrastructure to support operations of such NTAs- for example, new pipelines to guarantee fuel supply and on-site storage of fuel (where relevant). In addition, the development time associated with bringing to service some generation technologies, combined with the process of permitting and siting (including ISO-NE interconnection requirements), can lead to a situation where the NTA is not up and running when it is needed. Such factors increase the costs of investment associated with such supply-side NTA technology and may preclude their implementation as a solution to the identified needs.

1.3.1 Demand-side NTA solution not possible given the injection requirements for the NTA

The reliability requirements of SHP could not be addressed through load reductions alone because the size of the load reduction required at the two substations (injection requirement) exceeds the aggregate peak loads (95 MW, projected for 2023 based on ISO-NE's CELT 2013). In other words, even 100% load reduction at these substations will still not be sufficient to address the low voltage issues and the thermal overloads identified in the areas of study.[4]

Moreover, to the extent that demand-side resources could be part of a hybrid NTA solution (that includes both demand-side and supply-side NTAs), it would be costly. Implementing incremental energy efficiency ("EE") programs by 2023 would be increasingly difficult and challenging. ISO NE forecast only a total of 85 MW of incremental EE resources[5] in 2023 for the **entire state** of Massachusetts beyond the amounts of EE (also known as passive demand response) that cleared forward capacity auction # 7 ("FCA#7").[6,7] Generally speaking, if low cost energy efficiency alternatives have been already implemented/targeted for implementation, LEI would expect that the average unit cost for incremental programs would be higher than existing program costs. In addition, implementing incremental EE resources tends to be a costlier NTA approach on a levelized cost basis, $ per kW, as compared to supply-side options based on our prior experience and research (see Figure 4 on page 15).

1.3.2 Supply-side resources as NTAs

Stand-alone supply-side resources could be a workable technical solution, so long as such resources could be built and operated to provide the power injections into the grid at the specific locations (Northboro Road and Woodside Substations) and in amounts equal to or greater than the NTA

[4] The performance of real-time active demand response, which is typically associated with industrial or large commercial customer sites, might vary with a number of factors including the customers mix, equipment type and duration of operation. Such variables must be analyzed in detail before considering active real-time demand response as a qualified viable alternative to SHP in the Marlborough area. This required analysis was beyond the scope of work. On a similar note, the limit on operational hours imposed to real-time emergency generation ("RTEG") by calendar year, would be a stumbling block to its consideration as a viable alternative to SHP under N-1-1 contingency events.

[5] The EE resources that cleared FCA#7 (2016-2017), combined with ISO-NE's EE forecasts for the 2018-2023 period were already captured in the Needs Assessment, and as such cannot be associated with a potential demand-side NTA solution.

[6] ISO NE, Energy-Efficiency Working group, Final 2014 Energy-Efficiency Forecast 2018-2023, May 1, 2014.

[7] For the sake of consistency, LEI has continued to rely on the same inputs and assumptions made in the Needs Assessment for SHP and/or other NTA studies that it has completed for other Greater Boston transmission projects, which have been previously presented over the course of 2015 and 2016 to the EFSB.

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requirements (264 MW). Examples of supply-side resources that could be considered hypothetically as NTA technologies include the following:

- Conventional fossil fuel fired generation (e.g. natural gas-fired or dual fuel peaking plant, natural gas or dual fuel combined cycle generation plant, or a diesel internal combustion unit);
- Large scale renewable generation (solar[8]) with battery storage if required; and
- (utility-scale) energy storage technologies (e.g. flow batteries, flywheels or NaS batteries).[9]

1.3.2.1 Solar is not a practical alternative at the two locations specified in the Reliability Assessment

Unless combined with an energy storage device, solar based technology cannot provide power around the clock and therefore will not qualify for further consideration.[10] The combination of solar PV and energy storage device is likely to be much more expensive than a new gas-fired generation under most plausible market conditions. In addition, some forms of energy storage technologies such as flywheels are excluded from further consideration, as these technologies are more suited for addressing short disturbances on the grid (through provision of regulation services) rather than recovering from a N-1-1 contingency event. Many energy storage technologies are also currently not well-suited to provide a constant amount of energy injection into the grid for an extended period of time (12 hours) cost effectively. Therefore, the levelized costs of commercially available long discharge energy storage technologies are currently higher than the levelized costs of conventional gas-fired generation (see Section 5.2 for more information). As a result, CCGTs, peaker aeroderivatives, utility scale solar PV units (with storage), dual fuel jet engines and slow discharge batteries were selected by LEI as the most plausible technically feasible alternatives to SHP.

1.3.2.2 Supply-side NTA solutions will be challenging

Given the operating requirements to properly address an N-1-1 contingency event, a supply-side NTA would need to be able to provide power within 30 minutes. The resource must then continue to operate until the failed transmission system element is repaired or as long as deemed necessary by the ISO-NE. Typically, ISO-NE can resolve contingency events within a 12 to 24-hour cycle, and LEI has conservatively assumed a 12 hour duration to resolve the contingency in its analysis. As such, certain generation technologies would not qualify, as discussed above.

In order to be comparable to SHP, an NTA would also need to come in service by 2019. To date,[11] no generation project has been proposed by any generation developer for development and interconnection with ISO-NE's grid at the Northboro Road and Woodside Substations. Furthermore, since FCA#10 has already occurred, there would be no "room" in the forward capacity market for additional gas fired generation for a few years, given the extent of oversupply system-wide relative to ISO-NE's latest

[8] Wind installations were not considered in the review due to the general low penetration of large wind resources in the Greater Boston area.
[9] On a standalone basis, or in tandem with solar based technologies.
[10] Please see Appendix B for more information on time of day operability of various NTA technologies
[11] As of September 16, 2016

demand projections.[12] Therefore, an NTA solution composed of new generation at these locations and with in-service dates that are comparable to SHP would not be viable without financial support from consumers and expedient siting treatment by state authorities and regional system operators.

In addition to market considerations and development lead times, other practical siting and permitting challenges can also increase the total cost to ratepayers. For instance, the availability of a large amount of unencumbered land could be a prerequisite for developing any new generation facility. Furthermore, the availability of accommodating infrastructures such as gas pipelines (for natural gas supply) will be critical for a new gas-fired generator (and if there are no existing pipeline capacity available in the vicinity, the developer will need to build a new lateral to inter-state pipelines). In addition, a CCGT would require access to water for cooling. Any new generation project may also require upgrades to the local transmission system for purposes of interconnection and qualifications for the Forward Capacity Market.

1.4 Key Findings from cost analysis

After identifying the set of technically feasible NTA technologies, LEI evaluated the costs of an NTA solution using a combination of least cost technically-feasible NTA technologies at each location, based on gross and net[13] levelized cost of entry ("LCOE") for each technology. LEI compared the net levelized cost of entry for technically feasibly NTA solutions with the estimated annual revenue requirements ("ARR") for the SHP. ARR for a transmission facility is comparable to the all in levelized costs of the NTAs from the point of view of the end consumers in the following manner: the end-user would have to pay for their share of the transmission facility or alternatively, when considering NTAs, the end-user will have to pay for the portion of NTAs that would be recoverable from the market or other sources.

For each technology deemed technically feasible at a specific location, LEI multiplied the net LCOE for that technology by the injection requirement at that location, adjusted for the minimum scale, performance and availability of that technology. The technology with the lowest resultant direct cost to ratepayers was then selected as the least-cost technology for that location.[14] LEI then aggregated the total costs associated with the identified least-cost feasible NTA technologies across Woodside and Northboro Road in order to determine a total direct cost to customers for a technically-feasible NTA solution.

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[12] A total of 35,567 MW of resources cleared the FCA#10 for a net installed capacity requirements of 34,151 MW (in 2019). In May 2016, the ISO-NE updated its load forecast, which would impact targets like the net installed capacity requirements. Source: ISO-NE, Forward Capacity Auction #10 Results Summary,

[13] The gross LCOE for each technology is a dollar per-kilowatt per-year ($/kW-year) figure that embodies all investment and operating costs, including capital costs, fuel costs (where relevant), and fixed and variable operating and maintenance costs. In other words, the gross LCOE represents a resource's all-in costs, levelized over a notional estimate of economic life.

[14] The net LCOE for each NTA technology is derived by deducting from the gross LCOE potential revenue streams (e.g., energy sales, REC payments, avoided energy costs, capacity market revenues) that could offset these costs. Use of the net LCOE reflects the fact that total direct cost to ratepayers could be reduced through revenues yielded by resources in energy markets.

Because future market revenues are inherently uncertain, LEI calculated a net LCOE for each technology under four scenarios with varying assumptions about capacity market (FCM) revenues and REC prices, as described in Figure 3.

Figure 3. Scenarios description

Scenarios	Methodology	Key assumptions for net LCOE
Scenario 1 *(Gross LCOE net of ACP rates for REC revenues and FCM revenues based on half of the latest FCA price)*	Net LCOE used to select the least cost technologies	• We assume that solar PV NTA resources will earn prevailing ACP rates for REC revenues • We assume that new resources would receive capacity payments for about half of their life cycle given the absence of need for such resources in the short to medium term
Scenario 2 *(Gross LCOE net of ACP rates for REC revenues and no FCM revenues)*		• Same assumptions on REC revenues as Scenario 1 • We assume no FCM revenues (NTA resources do not clear future FCAs)
Scenario 3 *(Gross LCOE net of REC revenues based on current REC forwards and no FCM revenues)*		• We assume that over time, on average, solar PV NTA resources will earn REC revenues at around the current forward REC prices • Same assumptions for FCM revenues as scenario 2
Scenario 4 *(Gross LCOE net of REC revenues based on current REC forwards and FCM revenues based on half of the latest FCA price)*		• Same assumption on REC revenues as scenario 3 • Same assumptions on FCM revenues as scenario 1

The least-cost mix of NTA technologies could vary, depending on the scenario chosen. For example, a CCGT technology has the lowest net LCOE if resource is guaranteed to receive full capacity revenues across its entire lifetime, while a solar project (utility scale) with energy storage (to allow for nighttime power injections and 12-hour durations of injections) will be the most costly. Figure 4 shows the mix of technologies included in the least-cost NTA and the annual net levelized cost ($/kW-year) per scenario.

Figure 4. Summary of Net LCOE ($/kW-year) by technology[15]

Net LCOE for feasible technologies ($/kW-yr)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CCGT	$ 72	$ 114	$ 114	$ 72
Peaker aeroderivative	$ 163	$ 206	$ 206	$ 163
Slow Discharge Battery	$ 136	$ 136	$ 136	$ 136
Dual fuel jet engine	$ 200	$ 243	$ 243	$ 200
Solar utility-scale (with storage)	$ 241	$ 256	$ 301	$ 286
Passive DR (energy efficiency)*	$ 264	$ 309	$ 309	$ 264

**Although EE is not considered as a technically feasible NTA solution on a stand-alone basis, we added its estimated costs for reference purposes*

On the basis of the above LCOEs, LEI estimated the direct cost to ratepayers for an NTA solution to range from $23 million annually to $35 million annually depending on the scenario chosen (50% FCM revenues or no FCM revenues) for a solution combining a 249 MW CCGT with a 32 MW peaker aeroderivative unit. While utility scale solar with storage is a technically feasible NTA, its net LCOE is higher than every other technically feasible NTA technology regardless of whether the solar PV unit earns REC revenues based on rates consistent with Alternative Compliance Payments ("ACP") or current REC forwards, as shown in Figure 5. As a result, utility scale solar PV does not qualify as a least cost NTA technology. Figure 5 summarizes the combination of least cost technically feasible NTAs, with associated net direct costs to ratepayers per scenario.

Figure 5. Annual direct cost to consumers of an NTA solution in lieu of SHP

Scenarios	Least cost technically feasible technologies	Total cost ($ million/year)
Scenarios 1 & 4 (50% FCM capacity payments)	249 MW CCGT at Northboro Road 32 MW peaker aeroderivative at Woodside	$23 million/year
Scenarios 2 & 3 (no FCM capacity payments)	249 MW CCGT at Northboro Road 32 MW peaker aeroderivative at Woodside	$35 million/year
Cost of transmission solution shouldered by end users		Between $5.4 and $11.8 million/year

[15] For the sake of consistency, LEI has continued to rely on the same inputs and assumptions made in the Needs Assessment for SHP and/or other NTA studies that it has completed for other Greater Boston transmission projects, which have been previously presented over the course of 2015 and 2016 to the EFSB.

This implies that the only difference between the scenarios results from assumptions regarding FCM capacity revenues (Scenarios 1 & 4 are the same as ACP revenues for solar are irrelevant and scenarios 2 & 4 are the same as REC revenues for solar are irrelevant).

Under scenarios 1 & 4, with 50% FCM revenues, the least cost feasible NTA solution (comprising of 249 MW of CCGTs at Northboro Road substation and 32 MW of a peaker aeroderivative unit at Woodside substation) will cost $23 million/year to ratepayers. If we assume that technical feasible NTA solution does not earn any capacity payments (Scenarios 2 & 4), the cost to ratepayers for the same technical solution increases to $35 million/year.

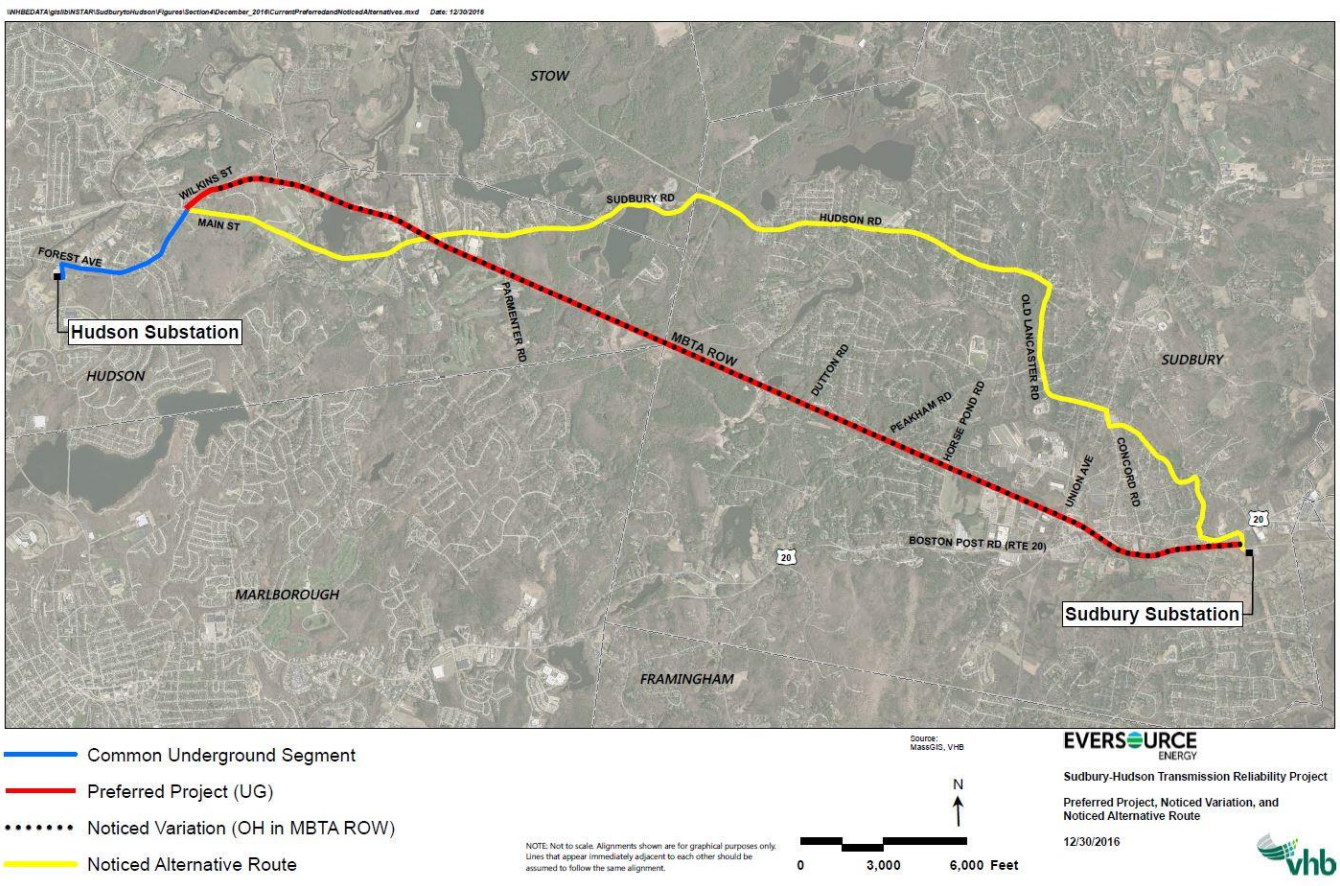
Consequently, LEI determined that the most probable of the lowest cost technically feasible solutions would have an annual net direct cost to ratepayers of $23 million (scenario 1 & 4). In comparison, the annual cost to ratepayers (revenue requirement) for the transmission project (SHP) ranges between $5.4 million and $11.8 million a year.[16]

[16] Cost estimate for SHP provided by Eversource on November 18, 2016. The ARR range refers to project variations provided by Eversource.

2 Background on the Sudbury – Hudson transmission project

The proposed transmission solution for SHP is a new 115-kV transmission line between the Sudbury Substation and the Hudson Substation, both located in Massachusetts. SHP is one of a suite of projects designed to improve the reliability of the electric system serving the Greater Boston area, and will be the subject of petitions to the ESFB, as well as other federal, state and local authorities.

Figure 6. Map of the Preferred Project and Noticed Variation for SHP



Source: Eversource Energy

The new line would be constructed between the Eversource Substation in Sudbury, and the Hudson Light and Power substation in Hudson, passing through portions of Sudbury, Marlborough, Stow, and Hudson. The project route consists of 9.01 miles of underground line. The first 7.6-miles of SHP is located along an existing Massachusetts Bay Transportation Authority ("MBTA") railroad bed, and the remaining 1.3 miles would be located under streets within the town of Hudson. Approximately 4.3 miles of the line will be in Sudbury and 4.6 miles in Hudson. The proposed route also includes small portions within Marlborough and Stow.

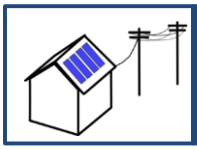
SHP is designed to eliminate low voltage violations on the system, resolve thermal overloads on the existing 115-kV and 69-kV lines, and mitigate the potential loss of load (more than 500 MW of load) to customers served by both National Grid and Eversource Energy.

3 What is an NTA?

An NTA is a solution (or a group of solutions) to an identified electric system need that does not involve the construction of traditional transmission infrastructure. NTAs may include supply-side resources (e.g. conventional generation, distributed generation and advanced generation-like technologies such as batteries and storage), demand-side resources (e.g. demand response and energy efficiency), or a combination of the two. More recently, the term "NTA" has been expanded to include smart grid distribution technologies.

Discussions of NTAs occurring in wholesale power markets and at state regulatory bodies generally focus on six categories of NTA technologies as described further in Figure 7 below: energy efficiency; demand response; utility-scale generation; distributed generation; energy storage; and smart grid technology.

Figure 7. NTA Technology Categories

 **Energy Efficiency**	improvements that result in the ability to use less energy to provide end-use customers with the same (or a better) level of service in an economically efficient way
 **Demand Response**	changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments
 **Utility-scale Generation**	relatively large generators that connect to the grid at the transmission (high voltage) level
 **Distributed Generation**	small generation systems located at a customer site
 **Energy Storage**	technologies that allow electricity generated at one time to be used at another time
 **Smart Grid**	technologies that enable a more efficient use of the electric power grid through computer-based remote control and automation

Note: LEI did not consider SmartGrid as a technology category in the analysis of SHP because it is relatively untested and there is limited data available to model it as an NTA technology with confidence.

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Consistent with the general categories of NTA technologies and adjusted for what is reasonable in New England (and specifically in eastern Massachusetts), the analysis presented in this report was designed around a list of six types of NTA technologies initially identified by both LEI and Eversource:

1. conventional fossil fuel fired generation (natural gas-fired peaking and combined cycle technologies);
2. large scale renewable generation (solar and wind);
3. distributed solar generation (5 MW or less in size);
4. active demand response (such as real-time demand response and real-time emergency generation);
5. passive demand response (such as energy efficiency programs); and
6. energy storage technologies (such as utility-scale battery technology and flywheels).

The six types of NTA technologies listed above include both supply-side and demand-side resources. Supply-side technologies include conventional fossil fuel-fired generation, large-scale renewable generation, and energy storage technologies. Demand-side technologies include distributed generation and various forms of demand response. Demand-side technologies can also include applications with energy storage technologies.

Each of these NTA technologies has inherent operating characteristics that may determine their applicability as a technically feasible NTA technology vis-à-vis the reliability-driven requirements for a solution. When evaluating the practical feasibility of NTA technologies (ability for the NTA technologies-based solution to be implemented in real life) versus a transmission line, the analysis must be done in a way that would make NTAs and transmission comparable in terms of both technical characteristics (reliability) and economic attributes (costs and benefits), as we discuss further below.

3.1 Evaluation of an NTA

As part of its ongoing work with the energy industry, LEI has proposed a set of tools and analytical techniques to comprehensively evaluate NTA technologies and transmission solutions.[17] Although the specific steps and analytical tools can differ, subject to the specific context of a given investment need and system operator's planning process, there are a number of guiding principles that must be considered. First and foremost, a rigorous analysis should acknowledge that NTA technologies and transmission will provide different services and therefore could generate different levels of benefits for consumers. Furthermore, a rigorous analysis needs to ensure that NTA technologies meet the technical needs underpinning the transmission solution. Finally, LEI recommends that a comparative analysis is conducted within the discipline of cost-benefit framework, where benefits and costs are considered as comprehensively as possible. Economic cost-benefit analysis should consider the dynamic evolution of the system, rational market response to NTAs and/or transmission, and consideration of the operational uncertainties of each over time.

[17] *Market Resource Alternatives – an examination of new technologies in the Electric Transmission Planning Progress*, WIRES Group, September 2014.

LEI applied these principles in this NTA analysis. The study begins with the simulation-based analysis performed by Eversource, where the reliability requirements of the system are presented in the form of location-specific NTA requirements under three plausible solutions. LEI then assigned technologies to the specified NTA requirements using a logical decision tree process to sequentially filter and narrow down the available list of technologies that meet the technical needs underpinning the solutions. Next, LEI employed a levelized cost methodology in order to evaluate the direct costs to ratepayers of implementing NTA technologies. LEI's cost analysis was designed to be as comprehensive as possible. For each NTA technology LEI developed an all-in cost (gross levelized cost of energy "LCOE") inclusive of development and operation costs (capital cost, fixed and variable operating and maintenance cost, and fuel cost). The net LCOE were then derived by adjusting gross LCOE from potential revenues yielded by the NTA technologies.

Finally, as part of LEI's comprehensive evaluation of NTA technologies and transmission solutions, a quantification of benefits originating from both an NTA and the preferred transmission solution would be undertaken for comparative purposes. At this time, such analysis has been determined to be outside the scope of this report for SHP.

3.2 Prospective NTA technologies

LEI developed a short list of twelve prospective NTA technologies based on their implementation potential in the Greater Boston region. Each of these technologies have unique operating characteristics which are compared against NTA injection requirements to determine their technical feasibility. Figure 8 lists the technologies under consideration for technically feasible NTA technologies. The figure also outlines typical capacity ranges, operating profiles and performance rates associated with these technologies, which are detailed in Appendix B. In addition to stand-alone NTAs, the analysis also includes various practical combinations such as solar PV with storage, which are also included in the figure below.

In undertaking the technology identification and cost analysis, and for developing the technical assumptions in Figure 8, LEI relied primarily on real world operating experience of such technologies in New England, as well as research documents and market information made publicly available by ISO-NE and the state of Massachusetts. Where necessary, actual operational information was supplemented with engineering–related data and generic information on technologies, including generic information on levelized costs. Such generic information was collected from reliable sources, such as the US Department of Energy and affiliated national laboratories, manufacturers, and engineering procurement companies that work with such technologies. A detailed bibliography list is provided in Appendix D.

As can be seen in Figure 8, the performance rate for solar technologies is assumed to be at 15% on average over the year. While this may seem low relative to the performance rates of thermal technologies, it is in line with actual performance of solar units in Massachusetts.[18]

[18] We assumed an annual average capacity factor of 15% for solar PV in Massachusetts based on modeling results as documented in NREL's System Advisor Model. An annual average capacity factor of 15% is consistent with the state of Massachusetts' estimated solar PV's capacity factor of 13% (see "SREC project calculation", Massachusetts Energy and

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Figure 8. Descriptive summary of NTA technologies

NTA Resource	Installed Capacity range	Operations profile	Performance Rate
Combined Cycle Gas Turbine (CCGT)	100 to 800 MW range in MA	Baseload	95% availability factor
Peaker Aeroderivative Unit	1 to 125 MW range in MA	Peaking load	85% availability factor
Peaker Frame Unit	20 to 250 MW range in MA	Peaking load	83% availability factor
Dual-fuel Jet Engine	<1 to 50 MW	Peaking load	85% availability factor
Solar Utility Scale (with storage)	5 to 250 MW	Potential baseload depending on storage capacity	15% efficiency ratio
Solar Utility Scale	5 to 250 MW	Daytime peaking load during sunny days	15% efficiency ratio
Solar DG (with storage)	<1 to 5 MW	Potential peaking load depending on storage	15% efficiency ratio
Solar DG	<1 to 5 MW	Daytime peaking load during sunny days	15% efficiency ratio
Fast Discharge Battery	<1 to 10 MW	Can provide instantaneous power for short periods	Variable, depending on efficiency, charging time and storage capacity
Slow Discharge Battery	10 to 20 MW	Can provide steady supply of power for short periods	Variable, depending on efficiency, charging time and storage capacity
Active DR - Emergency Generation	Variable (based on type of equipment and load)	Peaking load	Assume 15% of peak load becomes available to respond
Passive DR (Energy Efficiency)	Variable (based on type of equipment and load)	Intermittent	Assume 15% of peak load becomes available to respond

Note 1: Wind was not considered as a technically feasible NTA due to the lack of potential for sizeable wind capacity development in the Greater Boston region.

Note 2: Installed capacity range for fast and slow discharge batteries depends on the number of individual batteries connected together at a given site. The range indicated in the figure above is indicative, and LEI used variable sizes depending on requirements in order to ascertain the technical feasibility of using batteries as NTA technologies.

Note 3: Performance rates for CCGTs, Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines calculated based on the ISO New England EFORd Class Averages, sourced from: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf

Note 4: Active DR emergency profile is sourced from ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." ISO-NE, November 7, 2014 http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

More details on the methodology and sources are provided in Appendix B.

Environmental Affairs – Department of Energy Resources). It is worth noting that the annual average capacity factor that is required for assessment of performance in LEI's analysis is distinct from the 35% derating factor that ISO-NE is currently assuming for its analysis of solar DG. The 35% derating factor is used to determine a capacity contribution from such resources in ISO-NE's planning documents and therefore it represents the potential performance only during the summer super-peak hour rather than the average performance across all hours that is measured by an annual capacity factor (see 2014 Interim Forecast of Solar Photovoltaic (PV) Resources, ISO-NE). For assessing the technical feasibility of a technology to meet the NTA requirements, LEI employs the annual capacity factor as contingency events can occur anytime – not just during the summer super-peak. In the net direct costs analysis, LEI uses both the annual capacity factor and the 35% derating factor.

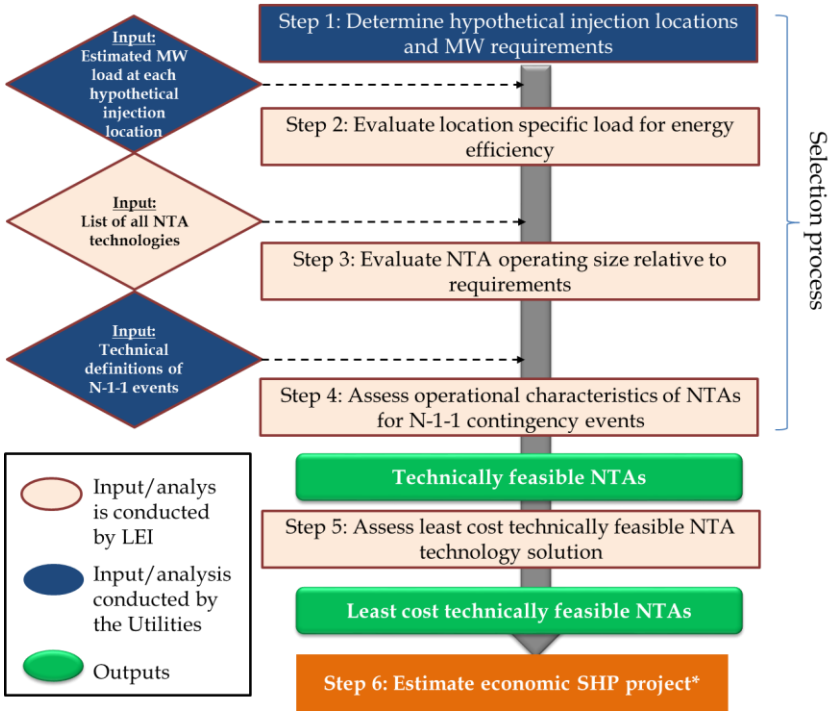
It is important to note that Real-Time Active DR ("RTDR"), which is typically associated with industrial or large commercial customer sites (such as manufacturing facilities or processing factories), were not directly taken into consideration in the analysis, although LEI still considered them as potential NTA technologies. There is a lack of publicly available information on RTDR's operational mode (such parameters will vary with equipment and size), timing and duration of operation, as well as response/ performance rates and opportunity costs, which does not allow us to model these technologies with confidence. Furthermore, under ISO-NE's rules, RTDR and real-time emergency generation ("RTEG") are not typically operable at any given time of the day, which would be a stumbling block to their technical feasibility under N-1-1 contingency events.[19] For reference purposes, LEI nevertheless estimated gross and net LCOE figures associated with both RTDR and RTEG in Appendix C.

[19] "ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." *ISO-NE,* November 7, 2014 http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

4 Overview of Methodological Approach

In order to identify technically feasible NTAs that can satisfy the reliability issues being addressed by SHP, a six-phase methodology was designed. These phases are shown in Figure 9 below.

Figure 9. Methodological Approach



* Beyond the scope of this report

The objective of LEI's methodology identifying technically feasible NTAs (Steps 2 through 4 in the figure above) is to associate a technically feasible NTA technology for each location (substation) and injection amount (NTA requirement) specified by Eversource. The process uses decision tree analysis to sequentially filter and narrow down the available list of technologies according to the requirements at each location. The three specific steps to achieve this are summarized below:

- assess the projected load available at each injection location in order to determine the feasibility of using certain NTA technologies like energy efficiency and demand response, which depend on the amount of available load (Step 2 in Figure 9).
- evaluate hypothetical injection points at substations to determine required size of NTA technologies (corresponds to Step 3 in Figure 9); and
- compare the operational characteristics of NTA technologies against the requirements imposed by the N-1-1 contingency events at each injection location (substation) (corresponds to Step 4 in Figure 9).

The sequence of steps in this methodology is important because it assigns a technically suitable NTA technology to a given injection location through a staged process of selection. As a starting point, Step 2 compares the total projected available load at the identified substations against the injection requirements estimated by the Planners at those substations. The purpose of this comparison is to determine if sufficient load exists at the identified substations for implementing demand response (energy efficiency or real time demand response) as a viable NTA solution at the given substation. Step 3 of the methodology screens NTA technologies based on their sizes, which is analytically straightforward and effectively narrows the list of technically feasible NTA technologies for the subsequent steps. Step 4 evaluates the successfully screened NTA technologies based on their technical parameters and selects the ones that conform to the contingency event requirements. Steps 3 and 4 (in increasing order of analytical complexity), further refine the list of technically feasible NTA technologies.

While LEI recognizes that there may be multiple NTA technologies that are feasible with each injection point/amount, the purpose of this analysis is to identify technically feasible NTA technologies that meet the criteria of the hypothetical NTA injections (either in terms of size, location, or operating profile).

In the next step (Step 5 in Figure 9), the levelized cost methodology evaluates the net direct cost to ratepayers of implementing NTA technologies as opposed to building and servicing the SHP. The net direct cost is calculated by aggregating across all locations net costs estimated for each identified least cost technically feasible NTA technology.

4.1 Determination of hypothetical NTA solutions

Eversource performed an analysis, referred to as the Reliability Assessment, to identify specific capacity of resources and their specific locations within the transmission system that would be needed to mitigate transmission overloads seen on the 2023 transmission system absent construction of SHP. The analysis was conducted using the PowerGEM Transmission Analysis and Reliability Assessment ("TARA") application -- the same analytical tool used in the Greater Boston Solution Study. TARA has the ability to optimize the dispatch of a multitude of generating resources across a defined area to mitigate transmission overloads that are the consequence of single contingency (N-1) or multiple contingency (N-1-1) events.

Figure 10 identifies the total number of locations and total amount of NTA resources needed to address N-1-1 overloads in the Sudbury-Hudson area.

Figure 10. Summary of NTA injection amounts by location

NTA Injection Location	Total NTA Resources Needed (MW)
Northboro Road	237
Woodside	27
Total	264

4.2 Methodology for identifying technically feasible NTA technologies

As summarized in the introduction to Section 4, LEI's methodology for identifying technically feasible NTA technologies uses a three-step process to evaluate and then select technically feasible NTA technologies for the SHP.

A technically feasible NTA technology is defined as one that can independently cater to all the requirements at the specific location. In other words, if at a location, two different technologies are required to work together (e.g. solar PV during the day and a CCGT at night) to meet the requirements, then neither of these technologies is determined to be technically feasible for this location on their own.[20] However, a given location can have multiple NTA technologies that can each independently meet the NTA requirement. In such cases, the final selection from among the technically feasible NTA technologies at a given location is based on their levelized costs, as discussed further in Section 5.2 below.

The "technically feasible" qualifier refers to a specific technology's ability to meet requirements set out by system planning criteria, and therefore in the case of this analysis, "feasibility" is not to be interpreted in the more connotative sense of the word (and the technologies may still be deemed to be impractical or commercially infeasible, as discussed in Section 5 of this report). System planning criteria refer to requirements such as the maximum allowable time for an NTA technology to respond to N-1-1 contingency events (response time)[21] and the minimum duration of time for which an NTA resource must remain operational after being called into service. In contrast, physical considerations, which are not a part of this methodology, refer to the amount of land required for a given NTA technology to be located at a substation and the time required for siting and construction, as well as the anticipated market need for the NTA technology in the future. These commercial development considerations outlined above are assessed qualitatively in Section 5.3. In addition, the cost implications of technically feasible NTA technologies are also assessed in detail in Section 5.2.

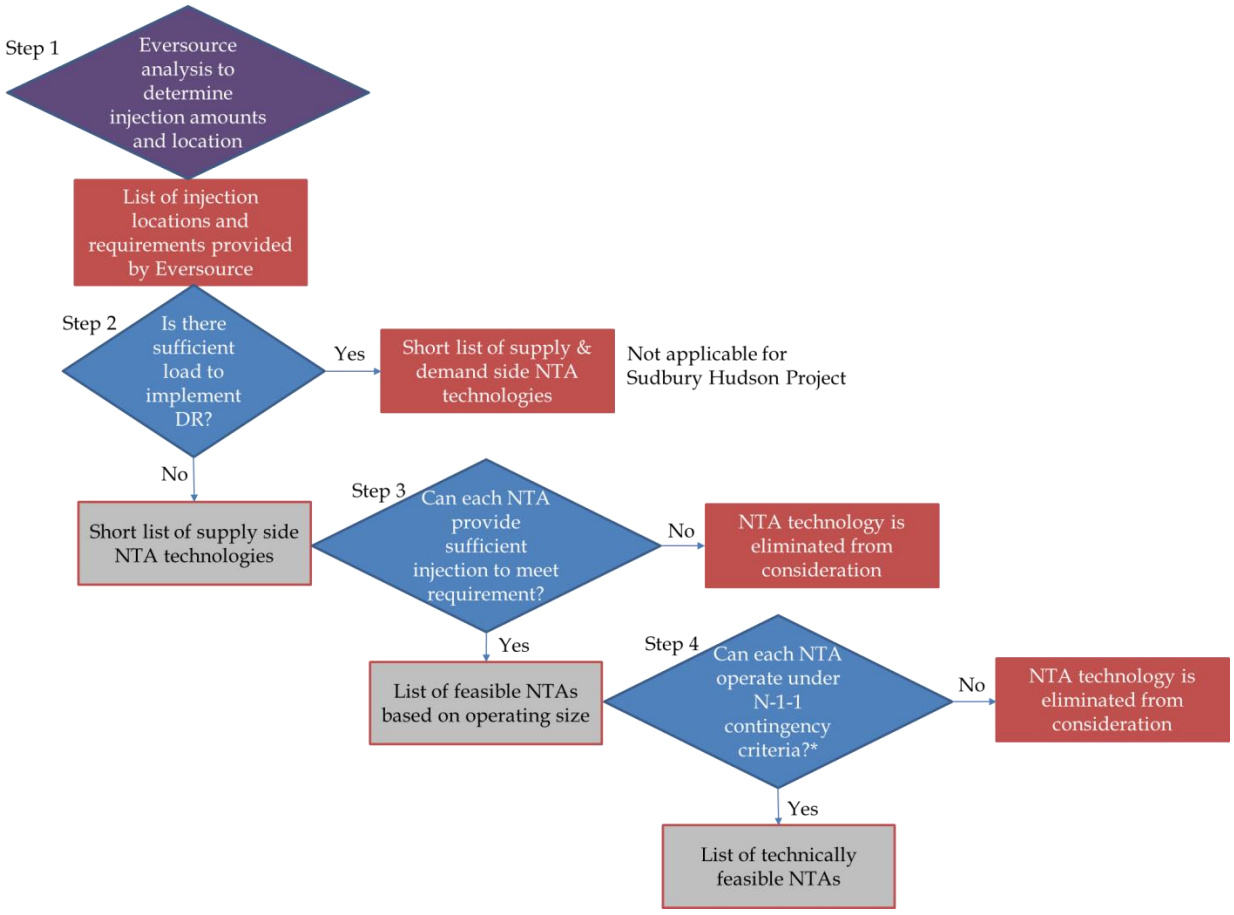
The three-step process is illustrated in Figure 11 and explained in the following sub-sections. The description starts with step 2 because step 1 in this flowchart summarizes the analytical process

[20] The exception to this philosophy relates to solar PV technologies and energy storage. We do combine these two separate NTA technologies in order to form a third unique technology; energy storage enables the solar PV unit to qualify as a technically feasible NTA technology (if some of the production from day-time hours is stored so that it can be injected into the grid at night).

[21] See Step B for details on N-1-1 contingency event requirements.

undertaken by Eversource's transmission planners to determine the injection locations and requirements which formed an input and starting point for LEI's analysis (Step 2 onwards).

Figure 11. Methodology for identifying technically feasible NTA technologies



* Step 4 illustrates the decision process for selecting technically feasible NTA technologies that can operate under N-1-1 contingency conditions. In general, LEI's methodology evaluates both N-1 and N-1-1 contingency conditions, but since the planners did not identify any requirements under N-1 contingency conditions, only N-1-1 is shown in the figure above. For more information on N-1-1 contingency conditions, please see Appendix B.

Step 2: Locational

This first step compares the total load (MW demand) at each injection location against the NTA requirement at that location. This comparison reveals whether a particular location has sufficient demand that can be curtailed either through active demand response or by implementing new energy efficiency measures so that the NTA requirement at that location can be met. LEI found that even if total demand at both substations under consideration for the Sudbury Hudson Project were to be completely eliminated, total reduction in demand would still be insufficient to solve the identified reliability

problems. As a result, active and passive demand response (energy efficiency) do not qualify as feasible NTA technologies.

Step 3: Size considerations

This step focuses on the level or size of injection required by location or node. Upon reviewing commercial information provided by manufacturers (such as General Electric ("GE") or SIEMENS) on technologies size, and comparing the typical size of NTA technologies in operation in Massachusetts/Greater Boston region against the size of injection requirements at each location, it is possible to eliminate NTA technologies that are not suitable to the size of the injection. For example, a conventional CCGT can be eliminated from consideration at a substation where the injection requirement is small. For example, at the Woodside substation, total identified injection requirement is 27 MW (Figure 10on page 25), which is much too small for a CCGT to qualify as a feasible technology. The maximum and minimum sizes considered for each NTA technology are summarized in Figure 8 on page 22.

Step 4: Operational considerations

After evaluating all of the NTA technologies based on the injection size (Step 2), the next step in the process considers the operating characteristics of the resulting subset of feasible NTA technologies relative to the requirements of the NTA injection amounts. These operating characteristics refer to the two contingency conditions defined by Eversource for N-1 and N-1-1 events.

The N-1 and N-1-1 contingency events each have specific operational considerations that must be met by a technology in order for it to be considered a technically feasible NTA technology. It is important to note that no overload situations were found under N-1 contingency events; therefore, all reliability issues were determined under N-1-1 events. However, the selection process was designed to solve situations where NTA requirements could also emerge under N-1 contingency events. An N-1 contingency event refers to a situation when a single element of the generation or transmission system fails. Under such circumstances, technically feasible NTA technologies would need to provide energy within 5 minutes and continue to operate until the single element is repaired or as long as deemed necessary by the ISO-NE. Similarly, an N-1-1 contingency event refers to a situation where an additional single element of the generation or transmission system fails within 30 minutes of the N-1 contingency event. Under these circumstances, a qualified NTA technology must be able to provide energy within 30 minutes and must continue to do so until the elements are repaired or as long as deemed necessary by the ISO-NE (typically, ISO-NE can resolve contingency events within a 12 to 24 hour cycle; LEI has assumed a 12 hour duration to resolve each of the contingency events in its analysis.

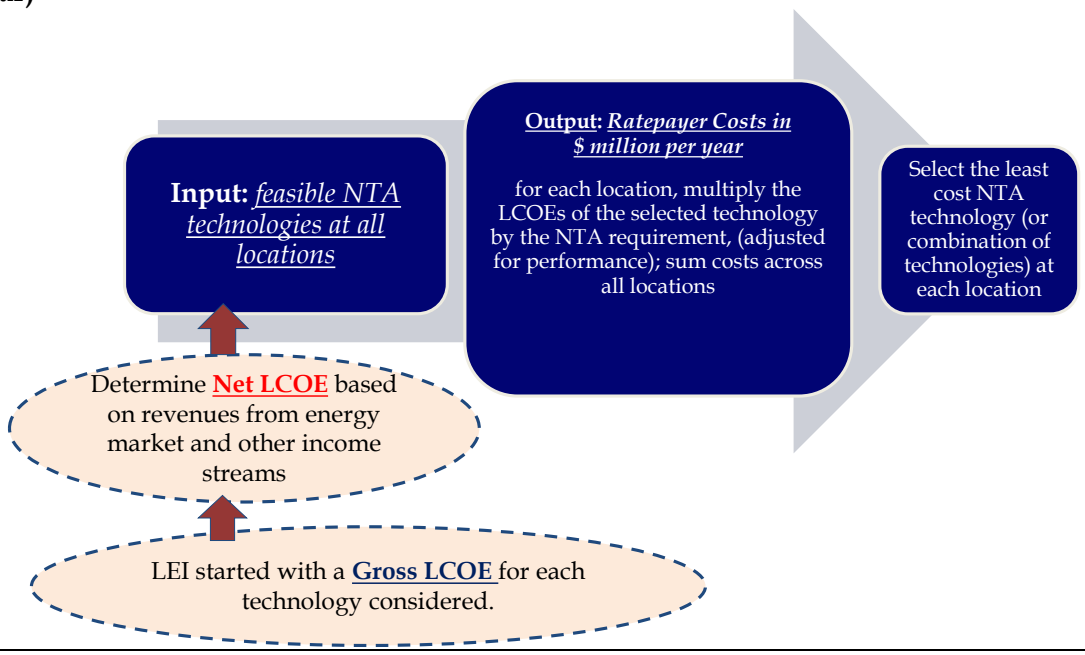
In light of the requirements defined by these contingency events, Step 4 selects NTA technologies that are able to respond within the time-frame required, and are able to continue injecting energy reliably for the duration required by these contingency events.

4.3 Methodology for estimating cost of technically feasible NTA technologies

LEI employed industry-standard levelized costing principles to the identified pool of technically feasible NTA technologies from step 4 above in order to estimate the total cost of implementing the least cost

technically feasible NTA portfolio that eliminates the identified reliability issues. For each selected technology, LEI estimated a gross LCOE, which represents a resource's all-in-costs, levelized over its life cycle. The gross LCOE is a per kilowatt per year figure ($/kW-year) that embodies all costs, including capital costs, going-forward Fixed Operation & Maintenance ("FOM") costs, and fuel and Variable Operation & Maintenance ("VOM") costs. The gross LCOE represents a long-term timeframe that is consistent with the requirements identified at each injection point. As a next step, LEI derived Net LCOE for each technology by deducting from gross LCOE a bundle of potential revenue streams associated with each NTA technology. The analysis then consisted of multiplying at each injection point the net LCOEs of all feasible technologies by the NTA capacity requirements (adjusted for performance and availability). The least cost technically feasible NTA technologies were selected at each location by comparing the products of net LCOEs and NTA capacity requirements across all feasible technologies. Finally, we aggregated the total costs associated with the identified least cost technically feasible NTA technologies across all locations in order to determine net direct cost for the ratepayers. Figure 12 provides an illustration of the methodology.

Figure 12. Methodology for estimating net direct costs of technically feasible NTA technologies ($/kW-year)



4.3.1 Determining gross LCOE for technically feasible NTA technologies

Gross LCOE represents the total fixed cost of NTA technologies levelized over the lifetime of the relevant technologies. As discussed previously, gross LCOE includes capital costs, fuel costs, as well as both FOM and VOM. Gross LCOE is denominated in $/kW per year and then multiplied by the installed capacity of the technically feasible NTA technologies to yield an annual gross cost. Figure 13 provides a summary of calculated gross LCOE for all technologies deemed technically feasible. For cost information, LEI relied primarily on data made publicly available by ISO-NE and the state of Massachusetts. We then cross-compared and supplemented this data with information collected from reputable sources, such as the

US Department of Energy and affiliated national laboratories, manufacturers and engineering procurement companies that work with such technologies, as well as actual operating data from similar installations across New England.

Appendix C provides a detailed description of assumptions and sources used for determining the ranges of gross LCOEs. In fact, in real life, development and operation costs of facilities can vary significantly and deviate from a generic assumption due to a variety of reasons including plant location, financing structure and market conditions, technology types, labor cost, environmental cost, site preparation, fuel supply, etc. The cost range was suggested in an attempt to crystallize this uncertainty. The +/- 20% cost range was used to measure the impact of this uncertainty on the net direct costs of technically feasible NTA solutions.

Figure 13. Summary of Gross LCOE per technology[22]

Feasible technologies	Gross LCOE ($/kW-yr)	Range ($/kW-yr) [-20% - +20%]	
CCGT	$ 398	$ 318	$ 477
Peaker aeroderivative	$ 323	$ 259	$ 388
Slow Discharge Battery	$ 181	$ 145	$ 218
Dual fuel jet engine	$ 363	$ 290	$ 435
Solar utility-scale (with storage)	$ 416	$ 333	$ 499
Passive DR (energy efficiency)	$ 424	$ 339	$ 509

Note: This table presents the midpoint values of the estimated ranges

Sources: ISO-NE, National Renewable Energy Laboratory ("NREL"), Pacific Northwest National Laboratory ("PNNL"), International Energy Agency, Electric Power Research Institute ("EPRI"), Department of Energy, GTM Research, and LEI

4.3.2 Determining Net LCOE for technically feasible NTA technologies

The total gross cost of NTA technologies can be reduced by market revenues and other sources of income received by these resources when they begin operations. Although these revenues are passed through to customers in the form of cost through the supply portion of their utility bill, these costs would have to be borne by customers regardless of whether a resource is qualified as a technically feasible NTA technology or not. Therefore, we deduct these revenues from the gross LCOEs, so as to isolate the net direct costs to ratepayers for a technically feasible NTA solution. In this respect, LEI adjusted the gross LCOE analysis by incorporating a number of potential market revenue streams associated with each feasible technology. The resulting calculation is the net LCOE which is relied upon to evaluate net direct cost of implementing technically feasible NTA technologies for ratepayers. The revenue streams considered in this analysis include revenues from the energy and capacity markets, Local Forward Reserve Market ("LFRM") and Regulation Market revenues, income associated with avoided retail rate

[22] For the sake of consistency, LEI has continued to rely on the same inputs and assumptions made in the Needs Assessment for SHP and/or other NTA studies that it has completed for other Greater Boston transmission projects, which have been previously presented over the course of 2015 and 2016 to the EFSB.

costs (for solar DG and energy efficiency resources), as well as Renewable Energy Credits. However, we did not integrate in the analysis any additional charges (such as Net Commitment Period Compensation ("NCPC") associated with operating the technologies out of merit.[23] Figure 14 depicts the revenue streams considered and provides a summary of calculated Net LCOE by feasible technology. Appendix C summarizes the sources relied upon to estimate the revenue offsets.

Figure 14. Components of the net LCOE calculations for each technically feasible NTA technology ($/kW-year)[24]

Feasible technologies	Gross LCOE ($/kW-yr)	Energy	FCM	LFRM	Regulation	Avoided Retail Cost	RECs	Net LCOE ($/kW-yr)
CCGT	$ 398	$ 283	$ 42	$ -	$ -	$ -	$ -	$ 72
Peaker aeroderivative	$ 323	$ 118	$ 42	$ -	$ -	$ -	$ -	$ 163
Fast response energy storage	$ 154	$ -	$ -	$ -	$ 33	$ -	$ -	$ 121
Solar utility-scale (with storage)	$ 416	$ 66	$ 15	$ -	$ -	$ -	$ 49	$ 286
Passive DR (energy efficiency)	$ 424	$ -	$ 46	$ -	$ -	$ 115	$ -	$ 264

Notes: This table illustrates net LCOEs for a scenario assuming half of FCM payments are received by the resources and SREC prices are at similar level as 2017 forwards. Rows highlighted in pink represent revenue offsets, while the bottom blue row contains the net LCOE results from the realization of all of these revenue offsets
FCM price based on FCA#10 results ($7.03/kW-month) (before adjustment for derating factor and scenario)
Energy revenues inclusive of VOM and fuel cost recovery
LFRM ($/MW-month) for summer 2013: $2,996; LFRM ($/MW-month) for winter (2013/2014): $5,501
Annual average regulation price (without performance payment in 2013):$18/MWh
Avoided retail cost: (based on average retail rate) 17.6 cents per kWhREC: 2019 forward price ($37/MWh); ACP for Class I REC ($71/MWh)
Sources: ISO-NE, NREL, PNNL, IEA, EPRI, DOE and LEI

[23] NCPC is the additional compensation received by a resource that is committed for reliability purposes but not dispatched above its economic minimum output level.

[24] For the sake of consistency, LEI has continued to rely on the same inputs and assumptions made in the Needs Assessment for SHP and/or other NTA studies that it has completed for other Greater Boston transmission projects, which have been previously presented over the course of 2015 and 2016 to the EFSB.

5 Analysis and results

Of the total twelve NTA technologies that were originally included at the start of the analysis (before Step 2), only five technologies qualify as technically feasible NTA technologies for the SHP. These include combined-cycle gas turbines, peaker aeroderivative units, dual-fuel jet engines, slow discharge batteries, and utility scale solar (with energy storage). Technologies like fast discharge batteries, solar PV (DG)[25], and solar PV (utility scale) without storage and peaker frame units are among the technologies that do not qualify as technically feasible NTA technologies owing to their various technical characteristics and the injection requirements for an NTA solution for the Sudbury-Hudson area.

There were considerations regarding the five technically feasible NTA technologies. First, the injection amounts associated with the five technologies need to be converted into an installed capacity figure using the performance rates for each individual technology (e.g., availability factor for thermal technologies, conversion efficiency for solar units and batteries). Therefore, a requirement of 1 MW may actually require installed capacity that exceeds 1 MW. Furthermore, since more than one NTA technology can be technically feasible for a given location, the installed capacity of all the technically feasible technologies can be significantly larger than the NTA requirement at that location, as there are multiple feasible technologies that are possible at many locations.

With regard to the cost comparison of the five technically feasibly technologies, the cost analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and estimated required nameplate capacity. LEI recognized that total costs of NTA technologies can be reduced by revenues from markets as well as other sources. Therefore, in estimating the cost of a feasible NTA solution, LEI deducted expected notional market revenues from the gross costs to derive a net LCOE. The net LCOE multiplied by the required nameplate capacity for the technically feasible NTA technologies completes the process of estimating the net direct cost to ratepayers.

The primary uncertainty in estimating the net LCOE is the revenue forecast for each technology. The future expected revenues were projected based on existing market information. In summary, the range of annual net direct cost was estimated at $23 million to $35 million per year over the various scenarios. However, some scenarios and NTA solutions are very unlikely from a practical and markets perspective.

[25] Small scale NTA technologies, such as solar DG, cannot effectively meet the technical requirements posed by N-1-1 contingency and the sizing required of hypothetical NTA requirements at the various locations. For example, solar DG resources have an operating profile that does not provide for the sustained performance required under N-1-1 contingency events. Even if solar DG were to be paired with energy storage technologies (battery) to overcome the intermittency of operation, solar DG units are in all instances too small to qualify as NTAs for the SHP project. Specifically, in Massachusetts, a solar DG unit is conventionally defined as less than 5 MW of nameplate capacity and exhibits an average performance rate of 15%, implying that a 5 MW unit would only produce 0.75 MW of energy on average. Of course, it is possible to add more than one stand-alone solar DG project to a given grid location (sub-station). However, there is some uncertainty as to the maximum number of feeder connections that could be allowed at any given sub-station. A detailed modeling analysis would be required to further refine these revenue estimates and factor in the resources' year on year impacts on market conditions and how that, in turn, affects market prices; such an analysis is beyond the scope of this report.

While utility scale solar with storage is a technically feasible NTA, its net LCOE is higher than every other technically feasible NTA technology regardless of whether the solar PV unit earns ACP or REC revenues, as shown in Figure 4 on page 15. As a result, utility scale solar PV does not qualify as a least cost NTA technology. This implies that the only difference between the scenarios results from assumptions regarding FCM capacity revenues (Scenarios 1 & 4 are the same as ACP revenues for solar are irrelevant and scenarios 2 & 4 are the same as REC revenues for solar are irrelevant).

Under scenarios 1 & 4, with 50% FCM revenues, the least cost feasible NTA solution (combining a 249 MW CCGT at Northboro Road substation and a 32 MW peaker aeroderivative unit at Woodside substation) will cost $23 million/year to ratepayers. If we assume that technical feasible NTA solution does not earn any capacity payments (Scenarios 2 & 4), the cost to ratepayers for the same technical solution increases to $35 million/year. Consequently, LEI determined that the most probable of the lowest cost technically feasible solutions would have an annual net direct cost to ratepayers of $23 million (scenario 1 & 4). In comparison, the annual cost to ratepayers (revenue requirement) for the transmission project (SHP) ranges between $5.4 million to $11.8 million a year.

5.1 Technically Feasible NTA technologies

Based on the technical and operational requirements at injection locations, and corresponding capabilities of the NTA technologies, Figure 15 presents a summary of the technically feasible NTA technologies for each case. These include a combined-cycle gas turbine or multiple peaker aeroderivative units at the Northboro Road substation at Southborough and a choice of peaker aeroderivative unit, dual-fuel jet engine, slow discharge batteries, or utility scale solar (with energy storage) resources at the Woodside substation at Northborough.

Figure 15. Technically feasible technologies by location

Northboro Road	Woodside
CCGT*	
Peaker (aeroderivative)**	Peaker (aeroderivative)
	Dual-fuel jet engine
	Utility scale solar with battery
	slow discharge battery

*Note: * small CCGT unit; **multiple units.*

LEI assumed that utility scale solar PV installations with storage will be a single large size facility which will be eligible to earn RECs[26], while a small scale solar DG unit (which was found to be technically infeasible) will earn SREC revenues. LEI recognizes that even from a technical point of view, it is easier

[26] Considering that utility scale solar PV resources (with energy storage) have the same performance profile as solar DG resources (with energy storage), the selection of utility scale solar PV resources is equivalent to selecting multiple solar DG installations (although such a combination of multiple solar DG installations would operate at a higher cost than the utility scale (notably, the gross LCOE is on average 40% lower for utility-scale solar PV as compared to solar DG)).

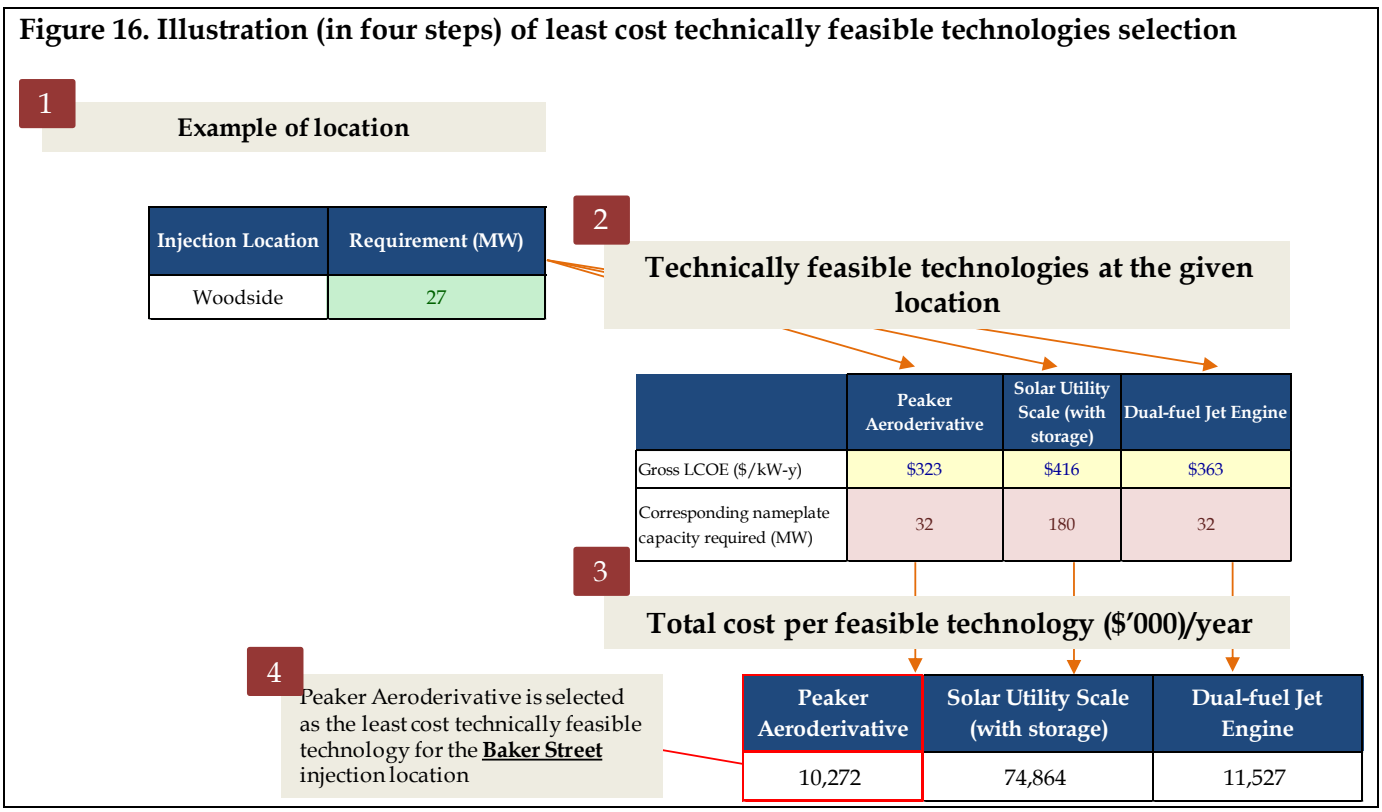
and preferable to install a single large scale solar PV facility (utility scale) than a series of smaller scale DG units to aggregate to the same capacity.

It is important to note that energy efficiency, while traditionally considered a small-scale NTA technology, does not qualify as a technically feasible NTA technology because the load available at each substation is too small to provide enough energy efficiency savings as to meet the required NTA MWs at that location. As discussed earlier, the viability of each technically feasible alternative is impacted by cost, geographic considerations, development time and enabling infrastructure, as discussed further below.

5.2 Cost estimates

The goal of the cost analysis is to evaluate the net direct cost of implementing NTA technologies for ratepayers as opposed to building the SHP. The analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and nameplate capacity, followed by a net LCOE analysis which leads to an estimate of the net direct costs to ratepayers.

Figure 16. Illustration (in four steps) of least cost technically feasible technologies selection



LEI calculated the total cost for all identified technically feasible NTA technologies based on the combination of their respective gross LCOE and total nameplate capacity requirements (at the injection

location) - adjusted for operating factors.[27] At each location, the resulting costs across all technically feasible NTA technologies was compared in order to determine the corresponding least cost NTA technology per location, given the technology's specific gross LCOEs. Finally, costs were aggregated for all identified least cost technically feasible NTA technologies across all injection locations to derive the overall total gross cost of each NTA solution per case.

5.2.1 Net direct cost estimates of NTA solutions for ratepayers

Future REC prices for Class I may range from $0/MWh to the Alternative Compliance Payment ("ACP"), which is forecasted to be $71/MWh in 2019. The reduction of cost provided to ratepayers by REC revenues could vary a great deal based on market conditions and price levels.

Similarly, LEI also considered the uncertainty of new generating resources such as CCGTs or peakers clearing the FCA. If all the resources in an NTA solution were to clear the FCA, that would reduce the clearing price in the FCA (and the capacity revenue offsets in the net LCOE), which would then raise the net direct costs of the NTA solution to ratepayers. Moreover, there may not be "room" in the near-term auctions for additional resources to clear, as we have new resources – that would not be qualified to serve as part of an NTA solution for Greater Boston – already committed to the market. Consequently LEI calculated the net direct costs to ratepayers under two scenarios: (i) feasible resources would be able to clear FCAs in the long term yielding FCA payments (revenues) for only half (50%) of their life span; and (ii) feasible resources do not clear any FCA and consequently do not earn any capacity revenues to defray NTA direct costs to ratepayers.

Figure 17 describes in details the resulting four scenarios considered by LEI.

[27] Operating factors include capacity factor, availability factor and ramping rates.

Figure 17. Summary of LEI's scenarios

Scenarios	Methodology	Key assumptions for net LCOE
Scenario 1 *(Gross LCOE net of ACP rates for REC revenues and FCM revenues based on half of the latest FCA price)*	Net LCOE used to select the least cost technologies	• We assume that solar PV NTA resources will earn prevailing ACP rates for REC revenues • We assume that new resources would receive capacity payments for about half of their life cycle given the absence of need for such resources in the short to medium term
Scenario 2 *(Gross LCOE net of ACP rates for REC revenues and no FCM revenues)*		• Same assumptions on REC revenues as Scenario 1 • We assume no FCM revenues (NTA resources do not clear future FCAs)
Scenario 3 *(Gross LCOE net of REC revenues based on current REC forwards and no FCM revenues)*		• We assume that over time, on average, solar PV NTA resources will earn REC revenues at around the current forward REC prices • Same assumptions for FCM revenues as scenario 2
Scenario 4 *(Gross LCOE net of REC revenues based on current REC forwards and FCM revenues based on half of the latest FCA price)*		• Same assumption on REC revenues as scenario 3 • Same assumptions on FCM revenues as scenario 1

As a result, the net LCOE by technology varies depending on the scenario chosen. For example, a CCGT technology utility-scale solar has the lowest net LCOE if resource is guaranteed to receive capacity revenues across its entire lifetime. Figure 18 illustrates the annual net levelized cost ($/kW-year) for each technically feasible NTA technology, per scenario.

Figure 18. Summary of Net LCOE ($/kW-year) by technology

Net LCOE for feasible technologies ($/kW-yr)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CCGT	$ 72	$ 114	$ 114	$ 72
Peaker aeroderivative	$ 163	$ 206	$ 206	$ 163
Slow Discharge Battery	$ 136	$ 136	$ 136	$ 136
Dual fuel jet engine	$ 200	$ 243	$ 243	$ 200
Solar utility-scale (with storage)	$ 241	$ 256	$ 301	$ 286
Passive DR (energy efficiency)*	$ 264	$ 309	$ 309	$ 264

Figure 19 summarizes the combination of least cost technically feasible NTAs, with associated net direct costs to ratepayers per scenario.

Figure 19. Annual direct cost to consumers of an NTA solution in lieu of SHP

Scenarios	Least cost technically feasible technologies	Total cost ($ million/year)
Scenarios 1 & 4 (50% FCM capacity payments)	249 MW CCGT at Northboro Road 32 MW peaker aeroderivative at Woodside	$23 million/year
Scenarios 2 & 3 (no FCM capacity payments)	249 MW CCGT at Northboro Road 32 MW peaker aeroderivative at Woodside	$35 million/year
Cost of transmission solution shouldered by end users		Between $5.4 and $11.8 million/year

While utility scale solar with storage is a technically feasible NTA, its net LCOE is higher than every other technically feasible NTA technology, regardless of whether the solar PV unit earns REC revenues based on the ACP rate or based on the current expectations for REC prices (which are lower than the ACP rate)). As a result, utility scale solar PV does not qualify as a least cost NTA technology at either location. This implies that the only difference between the scenarios results from assumptions regarding FCM capacity revenues (Scenarios 1 & 4 are the same and Scenarios 2 & 4 are the same (as REC revenues are irrelevant for gas fired generation)).

Under scenarios 1 & 4, with 50% FCM revenues, the least cost feasible NTA solution (combining a 249 MW CCGT at Northboro Road substation and a 32 MW peaker aeroderivative unit at Woodside substation) will cost $23 million/year to ratepayers. If we assume that technical feasible NTA solution does not earn any capacity payments (Scenarios 2 & 4), the net direct cost to ratepayers for the same technical solution increases to $35 million/year.

Consequently, LEI determined that the most probable of the lowest cost technically feasible solutions would have an annual net direct cost to ratepayers of $23 million (scenario 1 & 4). In comparison, the annual cost to ratepayers (revenue requirement) for the transmission project (SHP) ranges between $5.4 million and $11.8 million a year.

5.3 Qualitative discussion on feasibility of NTA solution in lieu of SHP

There are several geographic considerations associated with each NTA technology that will have further bearing on its practical feasibility at a given hypothetical injection point. The scope of this analysis does not extend to identifying specific geographical features at each hypothetical injection point. Instead, this section comments on the general geographic requirements associated with each NTA technology and a macro-level assessment of feasibility in the Greater Boston region.

Some of the important geographical considerations are as follows:

Land requirements

The NTA injection requirement is the key driver for determining the size of a generation project at a given location. The installation of supply-side NTA technologies, like a CCGTs, would require suitable and sufficient land (that is permitted for such commercial use, environmentally amendable for such a project), as well close physically to the transmission infrastructure at the specific substations.

The areas surrounding the substations that are the focus of an NTA study (Northboro Road and Woodside) are in majority residential area and suburban settings,[28] and it is highly unlikely that there are many parcels of land that could accommodate a CCGT plant.

Peaking technology does not require as large of a footprint as a combined cycle plant (especially an aeroderivative or diesel internal combustion turbine). Moreover, the existence of brownfield sites could provide an opportunity to contain the costs of development (and expediting of the development process). However, to LEI's knowledge, there are no existing generation sites at the two substations.

Although solar PV projects were not selected as least cost technically feasible NTA technologies at either location, it is interesting to note that for these technologies, the nameplate rating of a project will need to be much larger than the NTA requirement because of the performance of the technology. The lower the capacity factor for solar PV, the larger the nameplate capacity required to meet a given injection requirement. In addition, for solar based technology, the proposed site must be fairly leveled, without shading from large buildings or other features and preferably should be free of vegetation (or otherwise, certain additional costs may be incurred in association with leveling the site and clearing vegetation).

Enabling infrastructure

All supply-side resources will require interconnection with the grid and therefore, there may be costs involved with development at these substations if there is no "headroom" in available transmission capacity. In addition to transmission interconnection and land, fossil fuel-fired conventional generation will also need other enabling infrastructures to be practically feasible at a given location. For example, a gas-fired generator unit would require access to fuel infrastructure (gas pipelines for instance[29]). Dual fuel generators might also necessitate permitting for backup supply (such as a storage tank for fuel oil onsite), and that might raise the costs and further complicate the permitting process (including environmental permitting).

Development time

[28] The customers mix is approximately 70% residential and 30% commercial. Sourced from Eversource.

[29] The closest pipeline (Algonquin Gas pipeline) is located at 2.6 miles and 5.7 miles of Northboro Road and Woodside, respectively

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It is also important to consider the time required to construct and bring into service NTA technologies before the anticipated need in 2019. It is useful to consider the time needed for construction of new supply-side resources, as well as all pre-development activities associated with the construction stage. This includes, among others, permitting and siting processes, interconnection requests with ISO-NE, compliance with environmental regulations, and identification of and contracting with equipment suppliers and construction vendors. Each of these requirements could contribute to delaying a given project. Notwithstanding project development effort (which can range from a year to many years), the average time for just constructing and bringing to service a new conventional generation project ranges between 18 and 48 months.

One must also consider how a timely in-service date could affect the revenue profile of a generating resource, and consequently the decision to build the facility. In New England, the decision to build a conventional generation project is linked to the prospect for securing capacity market revenues. As such, a generating resource projected to be commercialized by 2019[30] and expecting to receive capacity market revenues would need to have cleared FCA#10, which occurred in February 2016.[31] Among the new projects that cleared FCA#10 in New England, none are located close to the Northboro Road or Woodside substations. It is unclear whether any additional supply-side resources will clear the FCA#11, given the extent of oversupply in the market currently. Therefore, securing supply-side NTA resources in a timely fashion in order to meet the reliability requirements in the Marlborough area would need to be done outside the Forward Capacity Market ("FCM") timetables, and therefore result in potentially higher costs for ratepayers (in the absence of capacity revenues that could partially defray the generating resources' costs).

[30] 2019 is the expected in service date for SHP

[31] By clearing the FCA#10, the plant would have the obligation to be in service by June 2019

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6 Conclusion

A number of NTAs are possible on a conceptual and hypothetical basis. However, practically it will be very difficult to bring an NTA sufficient to meet the reliability needs of this subarea to commercial reality. Demand-side NTAs cannot be a viable exclusive solution as there is simply not enough demand in the area to achieve the required amount of load reduction. Although some supply-side NTA resources are technically feasible, their cost to commercialize ($23 million a year) is significantly higher than the revenue requirements that Massachusetts ratepayers would bear for the SHP ($5.4-$11.8 million a year). In addition to their higher cost, commercializing NTAs is challenging from a practical perspective as well, given the lack of market conditions to otherwise attract such investments without ratepayer funding and regulatory intervention, and also given the need to develop various enabling infrastructures. No projects have been proposed in the vicinity of the two substations thus far by market participants; and given that FCM clears new generation three years out, the window for attracting a market-based generation project to this area by 2019 has closed.

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7 Appendix A: LEI's Qualifications

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation, transmission and distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm has its roots in advising on the initial round of privatization of electricity, gas, and water companies in the UK. Since then, LEI has advised private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulating markets worldwide.

LEI's areas of expertise straddle both the deregulated/market environments (including for example, price forecasting and asset valuation; wholesale power market analysis; market design (ISO market rules); and competitive procurement) and application of regulatory economics (such as regulated tariff design; cost of service ratemaking and performance based ratemaking; productivity analysis; policy design for incentivizing renewable energy and new technologies; and transmission and distribution network analysis). Provided below is a sample of previous LEI work showcasing its considerable experience, notably in the analysis of transmission projects and Non-Transmission Alternatives.

Sample of projects relating to Non-transmission alternatives, cost-benefit analysis of transmission projects

Non-Transmission Alternative ("NTA") testimony for Merrimack Valley Reliability Project ("MVRP") before the MA Energy Facilities Siting Board ("EFSB"): London Economics International LLC ("LEI") was engaged by Eversource and National Grid (collectively referred to as the "Utilities") to conduct a NTA analysis for the MVRP project. The MVRP project is one of the three components of the larger transmission solution known as the "AC Solution." These transmission projects were proposed by the Utilities in response to an identified reliability need in the Boston metropolitan area and surrounding suburbs. LEI conducted its analysis based on the information on injection amounts, injection locations, critical load level ("CLL") and load at each substation that was provided by the Utilities to estimate the least cost technically feasible NTA solution. LEI also worked with the Utilities to provide testimony about its analysis to the ESFB.

Non-Transmission Alternative ("NTA") testimony for Mystic - Woburn Project ("MWP") before the MA Energy Facilities Siting Board ("EFSB"): London Economics International LLC ("LEI") was engaged by Eversource and National Grid (collectively referred to as the "Utilities") to conduct a NTA analysis for the MWP project. The MWP project is one of the three components of the larger transmission solution known as the "AC Solution." These transmission projects were proposed by the Utilities in response to an identified reliability need in the Boston metropolitan area and surrounding suburbs. LEI conducted its analysis based on the information on injection amounts, injection locations, critical load level ("CLL") and load at each substation that was provided by the Utilities to estimate the least cost technically feasible NTA solution. LEI also worked with the Utilities to provide testimony about its analysis to the ESFB.

Non-Transmission Alternative ("NTA") testimony for Wakefield Woburn Reliability Project ("WWP") before the MA Energy Facilities Siting Board ("EFSB"): London Economics International LLC ("LEI") was engaged by Eversource and National Grid (collectively referred to as the "Utilities") to conduct a NTA analysis for the WWP project. The WWP project is one of the three components of the larger transmission solution known as the "AC Solution." These transmission projects were proposed by the Utilities in response to an identified reliability need in the Boston metropolitan area and surrounding suburbs. LEI conducted its analysis based on the information on injection amounts, injection locations, critical load level ("CLL") and load at each substation that was provided by the Utilities to estimate the least cost technically feasible NTA solution. LEI also worked with the Utilities to provide testimony about its analysis to the ESFB.

White paper on Non-transmission Alternatives (NTAs): London Economics International LLC ("LEI") was engaged by WIRES to prepare a White Paper on Market Resource Alternatives ("MRAs") which provides external parties with a clear understanding of MRAs and a concise description of how MRAs can work effectively alongside transmission investment in US power markets to support market development, reliability, and cost-effective supply. The structure of the White Paper specifically has the goal of "education" in mind. It started with the definition of MRAs, and then LEI presented case studies and lessons learned from several regional markets. The White Paper also recommended a conceptual analytical framework for proper and effective consideration of MRAs in transmission planning processes.

Cost-benefit analysis of a proposed transmission line: For a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible.

CHPE application for siting - Julia led LEI's team regarding the detailed cost-benefit analysis and macroeconomic impact analysis in support of the Champlain Hudson Power Express ("CHPE") application for siting approval at the New York Department of Public Service ("DPS"). LEI's analysis on economic effects was the cornerstone of the settlement agreement reached between Transmission Developers, Inc. ("TDI") and a number of New York agencies. Julia acted as independent expert on behalf of TDI and prepared updated study results on energy market impacts, capacity market impacts and also macroeconomic benefits stemming from the operation of the CHPE project. Julia's testimony was used in the DPS proceeding in the summer of 2012.

Lake Erie HVDC transmission project – cost /benefit analysis: LEI was hired by a private developer to assess the economics of the proposed Lake Erie HVDC transmission project and determining the additional revenue streams or value adders of the Lake Erie HVDC transmission project ("LEP") from the perspective of third-party shippers. The LEP is a 100-km long 1,000 MW bi-directional HVDC transmission line that will connect the Ontario energy market with the PJM market. LEI prepared a

comprehensive report that includes a review of the Ontario and PJM markets, a 20-year (2017 to 2036) market outlook and prices for electricity, capacity and renewable energy credits in Ontario and the relevant zone/s in PJM; the total gross arbitrage value for the energy congestion rents, the capacity revenue potentials for PJM, and the renewable energy credits revenue potential in PJM.

Forecast the impact of a 1,000 MW DC transmission line on New England market prices: LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices. The project proposes to build a 1,000 MW DC-based transmission line that between Quebec and Vermont and import energy into Vermont. LEI modeled the long-term price forecast for Vermont and the rest of ISO-NE over the 2019-2028 period, and examined the price differentials. Two cases were modeled: a Base Case (without the HVDC project), and the Project Case (with the HVDC project). Analysis was done under the assumption that the transmission capacity on the project will accommodate low-cost hydro imports from Quebec. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to Vermont and other New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

Assess the potential economic benefits of a New England transmission project: LEI was commissioned by Northeast Utilities to determine the potential economic benefits of the proposed NEEWS transmission project. Using detailed hourly simulation modeling of future power market conditions, LEI studied the potential market implications of NEEWS for ten years from a notional expected date of commercial operation of 2014. LEI reached the following conclusions: New England ratepayers could expect cumulative energy cost savings attributable to NEEWS over ten years under normal operating conditions; NEEWS would create regional energy market impacts; each phase of NEEWS would create energy market benefits over the ten-year modeling horizon; NEEWS would reduce LFRM costs each year; NEEWS would provide an insurance hedge against stressed system events; and NEEWS would offer market access to renewable resources in Northern New England/Canada.

Forecast the impact of a proposed transmission interconnection on Maine customers: LEI was engaged by a US power utility to perform a 15-year simulation analysis to estimate the market impacts resulting from a new transmission interconnection (covering the timeframe 2015-2029) and project the impact on Maine customers (including Northern Maine customers). LEI evaluated the market evolution with and without the interconnection and described the potential ramifications for purchasing electricity for Northern Maine customers. The analysis also estimated the potential impact on ratepayers from the re-allocation of the ISO-NE Pool Transmission Facility rate to incorporate the Northern Maine load and franchise area under a pro forma 10-year transitional agreement. LEI performed the modeling using our up-to-date ISO-NE simulation model (which covers the energy and capacity markets), extended to represent in detail the Maritimes control area.

Analysis of congestion rents and forecast impact on energy and capacity prices due to a proposed transmission line: In connection with a proposed transmission line from Hydro Quebec to New York City, LEI Managing Director Julia Frayer led a team that forecast 10-year energy and capacity prices of the New York market using POOLMod. The team also conducted analysis on congestion rents to support the client's negotiation with potential shippers. In support of the client's filing at the NYPSC, the LEI team conducted analyses on generation and production cost savings, emission reductions and sensitivities.

MA Energy Facilities Siting Board ("EFSB"): in response to NU retaining LEI, New England wholesale electricity markets were simulated in order to determine whether the Greater Springfield Reliability Project ("GSRP") would produce economic benefits to the New England region. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. Using these simulations, a distribution of results was used to calculate confidence intervals and hypothesis tests run on the results, hence increasing the robustness of our findings. The study results introduced as testimony to the EFSB, which is scheduled to be presented in October. (2009) **[MA EFSB, EFSB 08-2/DPU 08-105/DPU 08-106]**

Assess the economic value of a proposed transmission project: LEI was hired by a transmission developer to conduct an independent rigorous modeling exercise to determine the potential revenues for the proposed transmission project wheeling power from western MISO to East MISO (and eventually PJM). LEI evaluated both the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM. LEI's modeling exercise entailed evaluating intrinsic revenues (originating from power markets), extrinsic revenue (originating from price volatility), along with the green value of the Project (originating from the purchase of low cost renewable energy). LEI's overall analysis was comprehensive and included a series of sensitivity scenarios testing key value drivers.

Sample of projects in New England

Projection of retail rates for commercial customers in New England: LEI performed a market study reviewing historical electric rates (and projecting forward electric rates) for large commercial customers in the New England market. The electric rates analysis was composed of a number of components, such as the commodity costs of electricity, compliance costs for certain state programs (like RPS), delivery charge for delivering electricity, and ancillary services and administrative supply charges. LEI created projections for each of these components and considered state retail sales requirements for renewables and other factors.

New England energy price outlook and economic impacts: LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed transmission project on New England market prices. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized

the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI took into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

Review of NESCOE study: LEI conducted a comprehensive review of the NESCOE Gas Electric Phase Three study in order to ensure that the appropriate economic models and techniques were being used to accurately model the hydro and gas solutions. LEI also aided the client in identifying any assumptions and modeling approaches which may be suboptimal, and communicated how these issues can be addressed and improved in future studies.

Connecticut

NU-NSTAR merger: in support of a client's opposition of a proposed NU-NSTAR merger, LEI analyzed the potential competitive market effects on a vertical scale and considered the extent of buyer market power for the purchase of standard service (full requirements) products. The testimony was submitted to the Public Utility Regulatory Authority (PURA). In a later submission, LEI also analyzed the settlements reached or proposed in a number of recent utility mergers. (2012) [**PURA Docket No. 12-01-07**]

CSC – NU/GSRP: LEI simulated the New England wholesale electricity markets in order to compare the economic benefits between Greater Springfield Reliability Project ("GSRP") and responses to the Connecticut Energy Advisory Boards' ("CEAB") RFP for a non-transmission alternative ("NTA") to GSRP. The NTA consisted of modeling a new CCGT plant to be placed in Southwestern Connecticut. In order to ensure that economic benefits were not subject to the forced outage and availability schedule of the simulated energy markets, LEI simulated the energy market with 30 different random forced outage and availability schedules. In effect these 30 different simulations added further robustness to our results because it captured the flexibility of the New England energy market under several different normal operating conditions. Furthermore, the simulations created a distribution of results which was used to calculate confidence intervals and hypothesis tests, hence further increasing the robustness of our findings. The study results were used to produce written testimony to the CSC, oral testimony was provided in late August and early September 2009. (2008-2009) [**CSC, Docket 370**]

2006 "All Source" RFP: LEI served as the economic advisor to the Connecticut Department of Public Utility Control (DPUC), helping them design and implement an "all source" RFP for new capacity in the state in order to mitigate the exposure to ratepayers from Federally Mandated Congestion Costs. As economic advisor and RFP Coordinator, LEI was responsible for managing all aspects of the RFP, including design of innovative financial contracts for capacity, administration of RFP process, and evaluation of bids submitted by project sponsors, and recommendation to the DPUC for selection of winning projects. The selection of projects is based on a proprietary set of models that LEI staff designed to estimate the cost-benefit to ratepayers from long term contracts with new capacity, based on reduction in wholesale market costs across three different ISO New England power markets. LEI also submitted significant written testimony during the 18 months of this engagement, and LEI staff also testified orally on numerous occasions. (2006-2007) **[DPUC, Docket No. 05-07-14PH02; FERC, ER03-563-000**]

DPUC auction oversight: the DPUC retained the services of LEI to assist it in monitoring the power procurement processes for Connecticut Light & Power's (CL&P) Transitional Standard Offer auction in November 2004 for services in 2005 and 2006, and in September 2005 to monitor the November 2005 auction for services in 2006. LEI 's mandate included providing advisory services to the DPUC, including guidance on communications protocols, design of sales contract agreement (between CL&P and winning bidders), and also valuation of final bids vis-à-vis the forward market alternatives available to the utility. LEI filed affidavits after the completion of each auction process which the Commissioners used to approve the process and the contracts between CL&P and the winning bidders. (2004 and 2005) **[DPUC, Docket No. 03-07-18PH02]**

Maine

Advisory to Maine Public Utilities Commission on RPS: LEI presented a written report on the state of renewable portfolio standard (RPS) requirements in Maine and regionally across New England. LEI also testified at the Maine legislature. The report was commissioned by the Maine Public Utility Commission to fulfill a statutory requirement to provide research on the issue of RPS and its impact on generators and consumers.

Advisory to Maine Public Utilities Commission on transmission cost allocation: LEI advised Maine Public Utilities Commission on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report will provide a 'strawman' recommendation for an effective cost allocation methodology. (2010) **[Docket No. RM10-23-000]**

Advisory to the Maine Public Utilities Commission on RFP: LEI assisted the Commission on the RFP related to the procurement of electricity in response to statutory mandates and state policy preferences. LEI provided economic analyses of bid proposals by estimating the benefits and costs to the ratepayers, and is currently supporting Commission staff in negotiations with short-listed bidders. (2009)

Development of an Electric Resource Adequacy Plan in Maine: in Docket No. 2008-104, LEI assisted the Maine Public Utilities Commission in developing an electric resource adequacy plan to aid MPUC in the development of a strategy for the pursuit of the long-term contracts. LEI submitted a report that builds up a set of recommendations for a long-term investment strategy based on an analysis of the current supply-demand situation, a review of the existing wholesale market rules for energy and the Forward Capacity Market, an examination of historical price trends, and review of the investment needs assessments prepared by Eversource and ISO-NE, as well as relevant sub-regional planning studies. (2008) **[Maine PUC, Docket No. 2008-104]**

Maine renewable portfolio requirement: LEI was engaged by the Maine Public Utilities Commission to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by a legislative Act. This analysis supported a Commission study and report to the Legislature. Julia led the team in preparation of the report, which was submitted to the Commission and later testified at the state legislature on the key findings of that report.

New Hampshire

Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project: LEI prepared an 11-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices. The project proposes to build a 1,090 MW DC-based transmission line that between Québec and New Hampshire. LEI modeled the long-term price forecast for New Hampshire and the rest of ISO-NE over the 2019-2029 period, and examined the price differentials. LEI also determined the benefits of the proposed transmission project on employment and economic activity in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region.

Testimony describing wholesale market dynamics and benefits of Northern Pass in averting supply risks associated with generation "at risk" for retirement: On behalf of Public Service of New Hampshire, LEI testified in front of the new Hampshire Senate Committee on issue of eminent domain generally and more specifically, on the power market context and near term outlook for the New England power market and reasons for the development of a new proposed transmission project known as Northern Pass.

Vermont

Testimony on proposed merger between Central Vermont Public Service and Green Mountain Power: for a small independent power producer, LEI prepared a testimony on the potential harms of the proposed merger to the client and proposed certain conditions for the Vermont Public Service Board to consider. (2012) **[PSB Docket No. 7770]**

ISO-NE tariff design: LEI submitted testimony on behalf of ISO New England to the FERC to help defend ISO New England's self-funding tariff. LEI first defined the basic underlying economic principles for specifying the tariff, and then undertook to show how the tariff should be applied to various system users. The engagement involved an intensive financial modeling effort, and frequent interaction with stakeholders. (2000) **[ER01-316-000]**

Commercial litigation in New England

PPA contract dispute: LEI provided expert witness service for a private equity investor in matter related to a contractual dispute regarding a long term power purchase agreement between a municipal utility located in New England and a landfill gas generator. LEI analyzed the key contractual terms of the PPA and providing an expert's review of how those terms compared to the industry norm when the contract was signed and became effective. LEI will also be providing an independent estimate of potential contractual damages. (2010-2011) **[Commonwealth of Massachusetts Superior Court Department, Civil Action No. PLCV2006-00651-B]**

Updated market power analysis: prepared for a US utility's triennial review of market-based rate authorizations for certain subsidiaries in the northeast region. LEI analyzed the company's market power in PJM and ISO-NE. (2010) **[ER98-4159, et al.]**

Section 203 and 205 analysis in support of NRG's acquisition of certain Dynegy assets in CAISO and ISO-NE: LEI was engaged to provide testimony in support of a proposed acquisition. LEI performed a Delivered Price Test (DPT) for CAISO and ISO-NE energy markets as well as a standalone Herfindahl-Hirschman Index (HHI) analysis for the capacity markets. In addition, LEI discussed the impact of the acquisition of the ancillary services markets. (2010) **[EC10-88-000]**

Confidential FERC investigation in 2009-2010 of market manipulation in New England: Julia and her team assisted the client with certain matters pertaining FERC investigation. Specifically, the scope of this retention included economic and market analysis in support of a market participant in ISO New England's day ahead load response program ("DALRP"). Julia also provided affidavits and deposed in connection with FERC investigation of behind-the-fence industrial generator and participation in a wholesale power market in New England. Julia helped the client to respond to assertions of market manipulation and estimate market benefit provided through its participation in demand response program.

8 Appendix B: Technical and operational characteristics of various NTA technologies

Operating size and capacity factor

Each injection point has a specified amount of MW requirement that must be met by an eligible NTA. Each NTA under consideration has been selected based on whether previous examples of its successful operations have been documented in Massachusetts. In addition, the minimum and maximum operating size for the short-listed NTAs were determined by evaluating typical operating size of similar technologies in Massachusetts and where available in the Greater Boston region. In addition, each NTA also has a representative capacity factor which is based on actual data relevant to installations of that technology in Massachusetts and where available, in the Greater Boston region. Together these parameters help determine if a particular NTA can meet the injection requirements at a specific injection point.

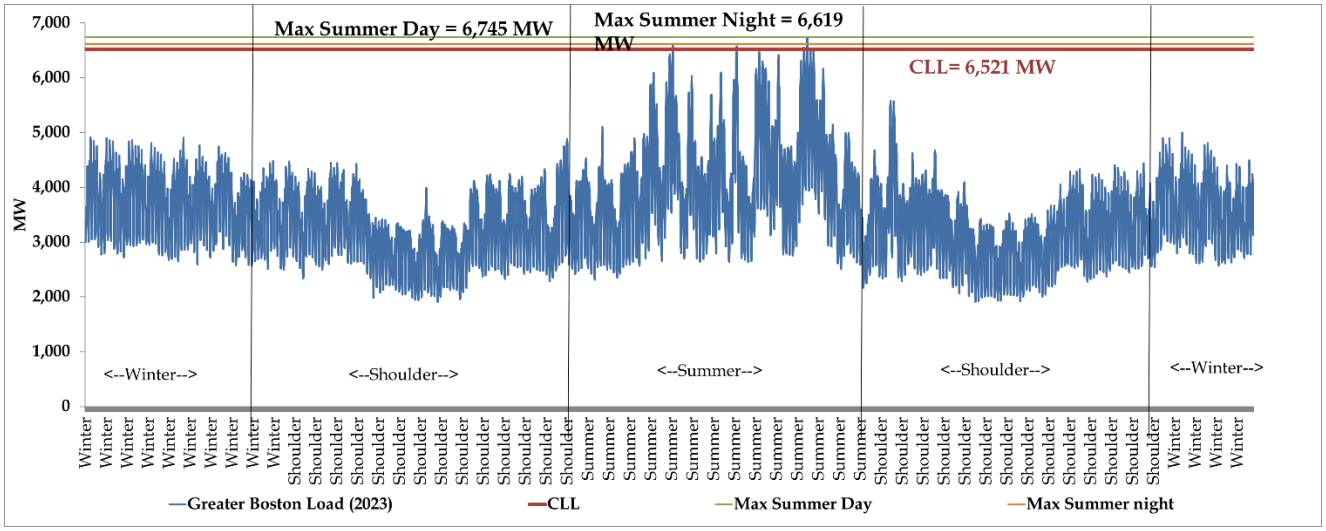
Ability to respond to CLL requirements

One of the primary criteria to qualify as an N-1-1 NTA is the ability to operate whenever load in the Greater Boston region exceeds the critical load limit ("CLL"). According to the ISO New England, the CLL is defined as the load level at which a system problem could occur, and therefore a solution would be needed.[32] For SHP, the CLL has been estimated at 6,521 MW. Figure 20 graphs this estimated CLL (red line) against the hourly load forecast for the Boston Zone in 2023 (blue band). As can be seen, the Boston Zone load does not exceed the CLL during most hours of the year (except in the summer). When looking at the maximum load during different times of the year, it is evident that in 2023, maximum summer load during the day and at night will exceed the CLL, which might result in reliability needs.

[32] Section 5.5: Information on Critical Load Level. Regional System Plan 2013. Available at: http://iso-ne.com/static-assets/documents/trans/rsp/2013/rsp13_final.docx

London Economics International LLC
717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com

Figure 20. Forecast hourly load for Boston zone versus CLL



This implies that any technology that will qualify as a technically feasible NTA must be able to operate during the period where the Boston Zone load will exceed the CLL in 2023. This is essential because system problems caused when load exceeds the CLL can be reliably addressed only if the chosen NTA can operate during those periods. Figure 21 identifies which technology can operate in any of the six defined parts of a year. These parts of the year correspond to when load in the Greater Boston region varies during a typical year.

Figure 21. Seasonal characteristics of NTA technologies

	Summer	Winter	Shoulder	Summer	Winter	Shoulder
	Daytime	Daytime	Daytime	Nighttime	Nighttime	Nighttime
Combined Cycle Gas Turbine (CCGT)	1	1	1	1	1	1
Peaker Aeroderivative Unit	1	1	1	1	1	1
Peaker Frame Unit	1	1	0	0	0	0
Dual-fuel Jet Engine	1	1	1	1	1	1
Solar Utility Scale (with storage)	1	1	1	1	1	1
Solar Utility Scale	1	1	1	0	0	0
Solar DG (with storage)	1	1	1	1	1	1
Solar DG	1	1	1	0	0	0
Fast Discharge Battery	1	1	1	1	1	1
Slow Discharge Battery	1	1	1	1	1	1
Active DR - Emergency Generation	1	1	1	0	0	0
Active DR - Real Time DR	1	1	1	0	0	0
Passive DR (Energy Efficiency)	1	1	1	1	1	1

NTA can operate = 1; NTA cannot operate = 0

Source: LEI research

When comparing Figure 20 and Figure 21, it is clear that not all technologies can qualify as technically feasible NTAs.

Notes on the table

- In the case of CCGTs, it is assumed that newer units put in service as NTA technologies would be efficient enough so as to be economically committed for most hours and therefore available for any of the 6 previously defined parts of a year (summer, winter, shoulder/daytime and nighttime). Alternatively, if a CCGT is not in merit but needs to be committed to prevent an overload should an event occur, the ISO would have the option of committing the unit out-of-merit, albeit at a cost (which cost is not taken into account in our analysis)

- Peaker aeroderivatives and dual-fuel jet engines are small fuel-burning generator technologies which have the capacity of delivering power in a very short time frame even from a cold start. Their dual-fuel capability, make them also relatively flexible and less fuel constrained. It is therefore assumed that these units can be dispatched from a cold start following a contingency so as to provide the required level of injection and prevent an overload of a transmission component.

- In order for peaker frame units to operate as NTA technologies, they would need to be effectively committed and running when requested. These units would need to be committed and dispatched on a day-ahead basis, and secure fuel at least one day in advance. This lack of flexibility prevents these units to be available at night and during shoulder period (when the load is at lower levels).

- For obvious reasons, solar technologies (DG or utility-scale) without any kind of storage capacity are not eligible as NTAs as they cannot be dispatched should an event occur during the nighttime. However, coupled with a storage capacity sufficient to provide an energy output equivalent to their average capacity factor during all hours of the year, solar technologies become feasible as NTA technologies for all periods of the year.

- Batteries of both fast- and slow-discharge types are assumed available for all periods of the year as their charge status is not dependent on any particular time or period of the year.

- The use of emergency generation as a form of active DR is limited by federal, State/or local environmental air permits (because of toxic emissions) and is consequently limited in operational time (7 AM and 7 PM on all non-holiday weekdays)[33]. As a result, if cannot be considered as a technically feasible NTA events

[33] ISO-NE Operating Procedure No. 4 ("OP-4")

- In addition to the seasonal characteristics of NTA technologies we also conducted a sensitivity analysis where energy efficiency is only available during day time hours. As can be expected, no energy efficiency qualifies as a technically feasible NTA under any of the three cases.

NTA Performance Parameters

Response time is an important criterion to determine eligible technologies under N-1 and N-1-1 contingency events. Under an N-1 contingency event, eligible NTAs must be able to inject power in less than 5 minutes. Under an N-1-1 contingency event, eligible NTAs must be able to inject power in less than 30 minutes. Some technologies, such as peakers and CCGTs can meet the N-1 response time requirements only if they are synchronized and ready to dispatch. However, if these technologies are ramping up from cold start, they cannot meet N-1 requirements, but can meet N-1-1 requirements depending on their ramp time. For example, a CCGT unit ramps up at the rate of 1.4% of its full rated capacity per minute. This would imply that in 30 minutes, a 100 MW CCGT unit will be able to inject 40.7 MW assuming at 95% capacity factor (1.4% * 100 MW * 30 minutes * 95%).

In addition to response time and ramp rate, the duration for which a given NTA can inject power after it has been called into service during a contingency event is also a vital criterion. Based on discussions with Eversource, and LEI's understanding of ISO-NE rules,[34] LEI's model uses a conservative estimate of 12 hours as the minimum duration for which an NTA must remain online for either an N-1 or an N-1-1 contingency event in order to qualify as a technically feasible NTA.

Specific values for each of these criteria defined above are summarized in Figure 22. The second and third columns indicate the minimum and maximum MW size for each NTA. The column labeled ramp rates specifies how fast the corresponding NTA can ramp up to start producing at its maximum capacity. For example, a 14.3% of total size per minute ramp rate for Dual-fuel jet engines implies that these units can start producing at their maximum capacity in about 7 minutes. Finally, the last column, duration refers to the length of time these NTAs can produce power without interruption. For fossil fuel powered NTAs, the underlying assumption is that the availability of fuel is not a constraint. For NTAs with storage technologies such as solar PV, we assume that the storage capacity is long enough to support the NTA for during nighttime hours.

[34] Subsection III of Part III – Procedure of ISO New England Operating Procedure No. 8 Operating Reserve and Regulation. May 2, 2014. Available at http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

Figure 22. Technical characteristics of NTA technologies

NTA Resource	Installed Capacity range	Operations profile	Performance Rate	Duration (Hr.)
Combined Cycle Gas Turbine (CCGT)	100 to 800 MW range in MA	Baseload	95% availability factor	24
Peaker Aeroderivative Unit	1 to 125 MW range in MA	Peaking load	85% availability factor	24
Peaker Frame Unit	20 to 250 MW range in MA	Peaking load	83% availability factor	24
Dual-fuel Jet Engine	<1 to 50 MW	Peaking load	85% availability factor	24
Solar Utility Scale (with storage)	5 to 250 MW	Potential baseload depending on storage capacity	15% efficiency ratio	24
Solar Utility Scale	5 to 250 MW	Daytime peaking load during sunny days	15% efficiency ratio	12
Solar DG (with storage)	<1 to 5 MW	Potential peaking load depending on storage	15% efficiency ratio	12
Solar DG	<1 to 5 MW	Daytime peaking load during sunny days	15% efficiency ratio	8
Fast Discharge Battery	<1 to 10 MW	Can provide instantaneous power for short periods	Variable, depending on efficiency, charging time and storage capacity	2
Slow Discharge Battery	10 to 20 MW	Can provide steady supply of power for short periods	Variable, depending on efficiency, charging time and storage capacity	12
Active DR - Emergency Generation	Variable (based on type of equipment and load)	Peaking load	Assume 15% of peak load becomes available to respond	24
Passive DR (Energy Efficiency)	Variable (based on type of equipment and load)	Intermittent	Assume 15% of peak load becomes available to respond	24

Note 1: Maximum size of demand response (DR) depends on the amount of available load. We assume that the peak load at a given substation can be reduced by 15%
Note 2: Ramp rates for Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines sourced from: http://www.wartsila.com/fi/voimalat/learning-center/combustion-engine-vs-gas-turbine-ramp-rate
Note 3: Performance rates for CCGTs, Peaker Aeroderivative units, Peaker frame units and dual-fuel jet engines calculated based on the ISO New England EFORd Class Averages, sourced from: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf
Note 4: Maximum size for batteries can be significantly higher if individual batteries are connected together. LEI's analysis takes this possibility into account, and therefore the size represented here are not the exact values used for the analysis
Note 5: Active DR emergency profile is sourced from ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources." ISO-NE, November 7, 2014 http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

Figure 23. Technology parameter determination assumptions

	Parameter	Methodology	Source
CCGT	**Minimum/Maximum Size**	Based on typical observed installed capacities, capped at the maximum value of CCGT unit in Massachusetts	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE (based on new construction over the past 20 years)
	Ramp Rate	CCGTs are assumed already committed	Not applicable
	Performance Rate	CCGTs are assumed to have 95% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	CCGTs are not energy limited resources	Not applicable
Peaker Frame Unit	**Minimum/Maximum Size**	Based on typical observed installed capacities	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance Rate	Peaker Aeroderivative units are assumed to have 85% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Frame units are not energy limited resources	Not applicable
Peaker Aeroderivative Unit	**Minimum/Maximum Size**	Based on typical observed installed capacities, with the assumption that several units can be installed together (capped at the value for which a peaker aeroderivative unit becomes a feasible technology	Review of information provided by manufacturers (SIEMENS and GE) and actual data of operation in ISO-NE (based on new construction over the past 20 years)
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance Rate	Peaker Frame units are assumed to have 83% availability factor	Based on ISO-NE EFORd Class Averages

	Parameter	Methodology	Source
	Duration	Aeroderivative units are not energy limited resources	Not applicable
Dual-Fuel Jet Engines	**Minimum/Maximum Size**	Based on typical observed installed capacities	Review of information provided by manufacturers (Wartsila) and actual data of operation in ISO-NE
	Ramp Rate	Industry-standard ramp rates	Review of information provided by manufacturers and plants' operational data in ISO-NE
	Performance factor	Dual fuel jet engines are assumed to have 85% availability factor	Based on ISO-NE EFORd Class Averages
	Duration	Jet Engines are not energy limited resources	Not applicable
Solar Utility-Scale	**Minimum/Maximum Size**	Based on typical observed installed capacities and ISO's definition	Review of utilities' new installations in MA and external sources such as "Utility-Scale Concentrating Solar Power and Photovoltaic Projects: A Technology and Market Overview." (National Renewable Energy Laboratory)
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in MA	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Massachusetts
	Duration	Limited to daytime	Not applicable
Solar Utility-Scale with storage	**Minimum/Maximum Size**	Based on typical observed installed capacities and ISO's definition	Similar assumptions as for "utility scale solar"
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in MA	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Massachusetts
	Duration	Storage capacity assumed sufficient to deliver energy equivalent to solar capacity factor at night [needed for a minimum of 12 hours to last through a contingency]	Not applicable

	Parameter	Methodology	Source
Solar DG	**Minimum/Maximum Size**	Based on typical observed installed capacities and ISO's definition	Review of utilities' new installations in MA and external sources such as "Utility-Scale Concentrating Solar Power and Photovoltaic Projects: A Technology and Market Overview." National Renewable Energy Laboratory. April 2012. http://www.nrel.gov/docs/fy12osti/51137.pdf
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Utility scale solar units have a conversion efficiency comparable to standard solar PV unit in MA	System Advisory Model ("SAM)" from National Renewable Energy Laboratory ("NREL") for Massachusetts
	Duration	Limited to daytime	Not applicable
Fast-Discharge Batteries	**Minimum/Maximum Size**	Based on typical observed installed capacities, with the assumption that batteries can be installed in banks (capped in the model to total installed capacity in the US in 2015)	Review of information provided by manufacturers (Flywheel (Beacon Power, Nas Batteries (NJK)) & Energy Storage Association
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Based on typical charging-discharging cycle efficiency	Review of information provided by manufacturers, and Electric Power Research Institute
	Duration	Typical value for available technologies	Review of information provided by manufacturers , and Electric Power Research Institute ("EPRI"),
Slow-Discharge Batteries	**Minimum/Maximum Size**	Based on typical observed installed capacities, with the assumption that batteries can be installed in banks (capped in the model to total installed capacity in the US in 2015)	Review of information provided by manufacturers (Flywheel (Beacon Power, sodium sulfur (NaS) Batteries (NJK)) & Energy Storage Association
	Ramp Rate	Not applicable	Not applicable
	Performance factor	Based on typical charging-discharging cycle efficiency	Review of information provided by manufacturers, and Electric Power Research Institute
	Duration	Typical value for available technologies	Electric Power Research Institute ("EPRI")

9 Appendix C: Derivation of cost estimates for various NTA technologies[35]

Figure 24. Assumptions and sources on gross LCOE

Technologies	Methodology	Sources
Peaker (aeroderivative and frame units) and CCGT technologies	Gross LCOE based on ISO-NE's estimates adjusted for O&M and fuel cost	ISO New England's demand curve assumptions for the Forward Capacity Auction # 10 http://www.iso-ne.com/static-assets/documents/2016/02/20160229_fca10_finalresults.pdf
Energy storage (slow discharge and fast operating response)	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs such as capital cost and VOM and FOM were sourced from NREL and PNNL. Results were then cross-checked against industry's estimates (IEA)	National Assessment of Energy Storage for Grid Balancing and Arbitrage", Pacific Northwest National Laboratory http://energyenvironment.pnnl.gov/pdf/National_Assessment_Storage_PHASE_II_vol_2_ International Energy Agency http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapEnergystorage.pdf and LEI
Utility -scale solar	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to such as capital costs and O&M sourced from NREL, EIA and DOE. Results were then cross-checked against industry's estimates	National Renewable Energy Laboratory ("NREL") http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html Sun Shot Initiative (US Department of Energy), SEIA - http://www.seia.org/research-resources/solar-market-insight-report-2014-q1; and LEI
Solar DG	Gross LCOE was estimated through LEI's proprietary LCOE model. Key inputs to LEI's proprietary LCOE model such as capital costs and O&M provided by the Utilities. Results were then cross-checked against industry's estimates - (from NREL and DOE)	Utilities (National Grid and Eversource) (proprietary experience), NREL (PV system pricing trends, 2014 - http://www.nrel.gov/docs/fy14osti/62558.pdf and LEI
Dual fuel jet engine	Key inputs to LEI's proprietary LCOE model such as capital costs and O&M sourced from NYISO's estimates (technologies reviewed to established cost of new entry) sand Wärtsilä	Wärtsilä, NYISO Demand curves filing http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-22/2013%20NYISO%20Demand%20Curve%20Recommendation_draft_8-18-13.pdf

[35] For the sake of consistency, LEI has continued to rely on the same inputs and assumptions made in the Needs Assessment for SHP and/or other NTA studies that it has completed for other Greater Boston transmission projects, which have been previously presented over the course of 2015 and 2016 to the EFSB.

Figure 25. Assumptions and sources of revenue streams

Technologies	Methodology	Source
Energy	Determined average annual revenue on the energy markets for a generic technology based on LEI's outlook of market prices	Based on LEI's ISO-NE wholesale price forecasts
FCM	Revenues calculated based on FCA#10 results	Based on FCA#10 - http://www.iso-ne.com/static-assets/documents/2016/02/20160229_fca10_finalresults.pdf
LFRM	Revenues calculated using most recent clearing price (winter and summer) adjusted for participation time	Based on 2014 summer and winter results (net of capacity payments) http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf
Regulation	Revenue calculated based on regulation price adjusted for estimated market share	Based on 2014 clearing prices (ISO NE; 2014 state of themarket report - Internal market monitor; http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf
Avoided retailed cost	Avoided cost calculated based on average annual retail costs	EIA's statistics on MA's retail costs in MA; http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a
SREC prices	SREC revenues calculated based on forward cu	based on forward curves for SRECII (carveout II) for the year 2018 (July 2016) - source: Karbone and State of Massachusetts

10 Appendix D: Summary of the Non-Transmission Alternative Reliability Planning Analysis

10.1 Analysis Description

A Non-Transmission Alternative (NTA) solution reliability assessment study was conducted to determine the resource requirements needed to address thermal overloads and prevent voltage collapse which are addressed through addition of the Sudbury-Hudson 115 kV transmission line. The assessment was based on the projected 2023 transmission system serving the Greater Boston study area and evaluated N-1 and N-1-1 contingency conditions. The analysis was designed to identify the specific size of resources and their specific locations within the transmission system that would be needed to mitigate transmission overloads and prevent voltage collapse which are addressed through the proposed transmission addition.

10.2 Modeling Assumptions

A subset of the set of base cases used in the Greater Boston Solution Study was selected for use in the NTA analysis. Selection of the base cases was based on a worst-case high level contingency overload assessment. The selected cases included one "A" transfer level case, one "B" transfer level case and one "C" transfer level case as defined within the Greater Boston Needs Assessment Study. Among these cases one case had two major area units out of service and the other two had one major unit out of service.

The assumptions concerning eligible locations for NTA resources considered the voltage level of numerous points of the transmission system serving the Marlboro area. The set of eligible nodes evaluated included both the 69 kV and 115 kV nodes in the Marlboro area. All study units had a maximum dispatch of 500 MW.

10.3 Analytical Process

The analytical tool used for the study has the capability to optimize the dispatch of a multitude of generating resources across a defined area as a means to mitigate transmission overloads that are the consequence of single contingency (N-1) or multiple contingency (N-1-1) events. The analytical tool can also optimize settings for phase shifters and HVDC terminals to aid in the optimization of resources needed to mitigate overloads. These adjustments are consistent with the adjustments system operators use in anticipation of contingencies and in response to overloads before, after or between contingency events.

The analysis only monitored the Marlboro area for overloads and found that there were no N-1 contingency overloads. Consequently, the analysis was focused on selection of the optimal nodes and output levels from the set of available "study" resources as a means to mitigate all identified overloads for N-1-1 events in the Marlboro area. This optimization process attempted to place the least amount of potential resource (up to a maximum of 500 MW) at the most effective locations needed to mitigate all overloads found to exist for each of the modeled conditions.

10.4 Results

The results shown in Table 1 below summarize the NTA resources. They include identification of the total number of locations and total amount of NTA resources needed to address N-1-1 overloads.

The optimization process attempts to identify the least amount of resource needed to address identified overloads. The analysis first finds a helpful location to place a resource and then continues to increase the dispatch level until either the maximum level is reached or additional increases are no longer helpful. The analysis then proceeds to the next most helpful location and continues with the process until either all overloads are mitigated and/or all possible helpful locations have been utilized.

Figure 26. Summary of Total NTA MW Resource and Locations

Location (Substation), kV	**Size (MW)**
Northboro Rd. 69.0	237
Woodside 69.0	27
Total Generation	**264.0**

10.5 Modeling Tool Description

The PowerGEM Transmission Analysis and Reliability Assessment (TARA) application version 7.10 was used to conduct all thermal contingency and resource optimization analysis presented in this report. TARA is a power flow software tool used for identifying and analyzing transmission bottlenecks, DC (linear) & AC (non-linear) contingency analysis, Security Constrained Economic Dispatch (SCED), and Security Constrained Reliability Dispatch (SCRD). Use of this application allowed for optimization of phase shifter settings and generator dispatch needed to mitigate overloads and provided results that are representative of operational responses to such overloads. The application has the capability of processing multiple base cases against a large number of contingencies and generates output that fully summarizes the results of the analysis.

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APPENDIX 4-1: DETAILED CANDIDATE ROUTE DESCRIPTIONS

Candidate Routes 1-3: Routes Primarily Utilizing the MBTA ROW, with Roadway Variations in Hudson

Candidate Routes 1, 2, and 3 provide various overhead and underground transmission line design variations along the MBTA ROW from Sudbury to Hudson, with different routing options along public roadways in Hudson. The MBTA ROW property is primarily forested and with an inactive railroad bed that runs through the center of the property. While designated land uses adjacent to the MBTA ROW vary, the property is primarily abutted by undeveloped forested land.

Candidate Route 1A: MBTA ROW (OH) to Chestnut (9.33 miles)

Candidate Route 1A is a combination overhead and underground transmission line design. The overhead portion of this route originates at the Sudbury Substation and travels along the MBTA ROW in a westerly direction for 7.02 miles to Chestnut Street in Hudson. This route then transitions to an underground transmission line design and travels in a southwesterly direction for 2.31 miles within public roadways and an access road owned by Intel ("Intel access road") before terminating at the Hudson Substation. This route is 9.33 miles long and includes 4.28 miles in Sudbury, 0.01 miles in Marlborough, and 5.04 miles in Hudson.

Sudbury (4.28 miles OH)
In Sudbury, Candidate Route 1A originates at the Sudbury Substation and travels overhead in a westerly direction for 4.28 miles along the MBTA ROW before entering Marlborough. From the Sudbury Substation, the route crosses Landham Road, Boston Post Road, Union Avenue, Horse Pond Road, Peakham Road, and Dutton Road, before entering Marlborough.

Marlborough (0.01 mile OH)
Candidate Route 1A travels overhead in a westerly direction for 0.02 mile along the MBTA ROW through a small corner of Marlborough, before entering Hudson.

Hudson (5.04 miles total; 2.73 miles OH and 2.31 miles UG)
In Hudson, Candidate Route 1A travels overhead in a westerly direction for 2.73 miles along the MBTA ROW and underground in a southwesterly direction for 2.31 miles within public roadways and the Intel access road before terminating at the Hudson Substation. After exiting Sudbury and Marlborough, this route continues along the MBTA ROW and crosses White Pond Road, Parmenter Street, and Main Street. At the MBTA ROW intersection with Chestnut Street, Candidate Route 1A transitions to an underground transmission line design for the last 2.31 miles. From the MBTA ROW, this route travels within public roadways for 2.20 miles in a southwesterly direction along Chestnut Street and Lewis Street before turning

west onto Main Street. The route then turns southwest onto Forest Avenue and crosses Glendale Road, Old North Road, Richardson Street, John Robinson Road, and Marlboro Street to the south; and Woodrow Street and Robert Bonazzoli Avenue to the north. This route finally turns south onto the Intel access road, adjacent to the driveway of the Hudson Light and Power Department, for 0.11 mile before terminating at the Hudson Substation.

Candidate Route 1B: MBTA ROW (UG) to Chestnut (9.33 miles)

Candidate Route 1B provides a design variation by travelling entirely underground along the same route as Candidate Route 1A.

Candidate Route 1C: MBTA ROW (Hybrid) to Chestnut (9.33 miles)

Candidate Route 1C provides a design variation by travelling underground along the MBTA ROW from the Sudbury Substation to a point near the western edge of the Charter Oak Country Club in Hudson. From this point, Candidate Route 1C would travel overhead along the MBTA ROW to Chestnut Street in Hudson. The route would then transition back underground along the remainder of the route, following the same roadways as Candidate Route 1A.

Candidate Route 2A: MBTA ROW (OH) to Wilkins (9.01 miles)

Candidate Route 2A is a combination overhead and underground transmission line design. The overhead portion of this route originates at the Sudbury Substation and travels along the MBTA ROW in a westerly direction for 7.64 miles to Wilkins Street in Hudson. This route then transitions to an underground transmission line design and travels in a southwesterly direction for 1.37 miles within public roadways and the Intel access road before terminating at the Hudson Substation. This route is 9.01 miles long and includes 4.29 miles in Sudbury, 0.01 mile in Marlborough, 0.07 mile in Stow, and 4.64 miles in Hudson. In Hudson, this route provides a variation from Candidate Route 1 by extending past Chestnut Street on the MBTA ROW for an additional 0.60 mile to Wilkins Street and alternatively traveling along Wilkins Street before entering Forest Avenue and terminating at the Hudson Substation.

Sudbury (4.29 miles OH)
In Sudbury, Candidate Route 2A follows the same Route as Candidate Route 1A, originating at the Sudbury Substation and traveling overhead in a westerly direction for 4.29 miles along the MBTA ROW before entering Marlborough.

Marlborough (0.01 mile OH)
In Marlborough, Candidate Route 2A continues to follow the same Route as Candidate Route 1A, traveling overhead in a westerly direction for 0.01 mile along the MBTA ROW before entering Hudson.

Hudson (4.64 miles total; 3.27 miles OH, 1.37 miles UG)
In Hudson, Candidate Route 2A travels overhead in a westerly direction for 3.27 miles along the MBTA ROW and underground in a southwesterly direction for 1.37 miles within public roadways and the Intel access road before terminating at the Hudson Substation.

After exiting Sudbury, Candidate Route 2A continues traveling in a westerly direction along the MBTA ROW for 3.27 miles. This route becomes its own distinct variation from Candidate Route 1A by extending past Chestnut Street on the MBTA ROW for an additional 0.60 mile to Wilkins Street. After crossing the intersection of Chestnut Street, this route crosses a small corner of Stow before reaching the intersection of Wilkins Street.

At the MBTA ROW intersection with Wilkins Street, Candidate Route 2A transitions to an underground transmission line design for the last 1.37 miles. From the MBTA ROW, this route travels within public roadways for 1.26 miles in a southwesterly direction on Wilkins Street/Route 62 and continues onto Forest Avenue at the intersection with Main Street, following the same route as Candidate Route 1, turning south onto the Intel access road for 0.11 mile before terminating at the Hudson Substation.

Stow (0.07 mile OH)
Candidate Route 2A travels overhead in a westerly direction for 0.07 mile along the MBTA ROW through a small corner of Stow, before reentering Hudson.

Candidate Route 2B: MBTA ROW (UG) to Wilkins (9.01 miles)

Candidate Route 2B provides a design variation by travelling entirely underground along the same route as Candidate Route 2A.

Candidate Route 2C: MBTA ROW (Hybrid) to Wilkins (9.01 miles)

Candidate Route 2C provides a design variation by travelling underground along the MBTA ROW from the Sudbury Substation to a point just west of the Charter Oak Country Club in Hudson. From this point, Candidate Route 2C would travel overhead along the MBTA ROW to a point near the western end of Ferjulian's Farm Stand in Hudson. The route would then transition back underground along the remainder of the route, following the MBTA ROW to Wilkins Street and following the same roadways as Candidate Route 2A.

Candidate Route 3A: MBTA ROW (OH) to Woodrow (9.19 miles)

Candidate Route 3A is a combination overhead and underground transmission line design. The overhead portion of this route originates at the Sudbury Substation and travels along the MBTA ROW in a westerly direction for 7.98 miles to Cox Street in Hudson. This route then transitions to an underground transmission line design and travels in a southwesterly direction for 1.21 miles within public roadways and the Intel access road before terminating

at the Hudson Substation. This route is 9.19 miles long and includes 4.29 miles in Sudbury, 0.01 mile in Marlborough, 0.07 mile in Stow, and 4.82 miles in Hudson. In Hudson, this route provides a variation from Candidate Route 2 by extending past Wilkins Street on the MBTA ROW for an additional 0.37 mile to Cox Street and alternatively traveling along Cox, Makin and Woodrow Streets before terminating at the Hudson Substation.

Sudbury (4.29 miles OH)
In Sudbury, Candidate Route 3A follows the same Route as Candidate Route 1A, originating at the Sudbury Substation and traveling overhead in a westerly direction for 4.27 miles along the MBTA ROW before entering Marlborough.

Marlborough (0.01 mile OH)
Candidate Route 3A travels overhead in a westerly direction for 0.02 mile along the MBTA ROW through a short corner of Marlborough before entering Hudson.

Hudson (4.82 miles; 3.61 miles OH, 1.21 miles UG)
In Hudson, Candidate Route 3A travels in a westerly direction for 3.61 miles along the MBTA ROW and underground in a southwesterly direction for 1.21 miles within public roadways and the Intel access road before terminating at the Hudson Substation.

After exiting Sudbury, Candidate Route 3A continues traveling in a westerly direction along the MBTA ROW for 3.61 miles. This route becomes its own distinct variation from Candidate Route 2A by extending past Wilkins Street on the MBTA ROW for an additional 0.37 mile to Cox Street. After crossing the intersection of Wilkins Street, this route continues traveling in a westerly direction before reaching the intersection of Cox Street.

At the MBTA ROW intersection with Cox Street, Candidate Route 3A transitions to an underground transmission line design for the last 1.21 miles. From the MBTA ROW, this route travels within public roadways for 1.10 miles in a southerly direction on Cox Street and Mackin Street and continues onto Woodrow Street at the intersection with Main Street. At the intersection with Forest Avenue this route turns west and follows the same route as Candidate Route 1A, turning south onto the Intel access road for 0.11 mile before terminating at the Hudson Substation.

Stow (0.07 mile OH)
Candidate Route 3A travels overhead in a westerly direction for 0.07 mile along the MBTA ROW through a small corner of Stow before reentering Hudson.

Candidate Route 3B: MBTA ROW (UG) to Woodrow (9.19 miles)

Candidate Route 3B provides a design variation by travelling entirely underground along the same route as Candidate Route 3A.

Candidate Route 3C: MBTA ROW (Hybrid) to Woodrow (9.19 miles)

Candidate Route 3C provides a design variation by travelling underground along the MBTA ROW from the Sudbury Substation to a point just west of the Charter Oak Country Club in Hudson. From this point, Candidate Route 2C would travel overhead along the MBTA ROW to a point near the western end of Ferjulian's Farm Stand in Hudson. The route would then transition back underground along the remainder of the route, following the MBTA ROW to Woodrow Street, then following the same roadways as Candidate Route 3A.

Candidate Routes 4-8: Routes Entirely Utilizing Public Roadways

Candidate Routes 4 through 8 are routes for an underground transmission line located entirely within public roadways from Sudbury to Hudson.

Candidate Route 4: Route 20 to Concord Road to Hudson (10.46 miles)

Candidate Route 4 originates at the Sudbury Substation and travels 10.46 miles in a westerly direction within public roadways for 5.62 miles in Sudbury, 0.75 miles in Stow, and 4.09 miles in Hudson within public roadways and the Intel access road before terminating at the Hudson Substation.

Sudbury (5.62 miles UG)
In Sudbury, Candidate Route 4 originates at the Sudbury Substation and travels underground in a northwesterly direction for 5.62 miles along public roadways before entering Stow. From the Sudbury Substation, this route travels north along the substation driveway and turns west onto Boston Post Road/Route 20, passing Landham Road. Candidate Route 4 then turns north onto Concord Road and enters the intersection at Union Avenue before turning onto the western branch of Old Lancaster Road. Candidate Route 4 follows Old Lancaster Road to the intersection of Hudson Road. This route then continues west on Hudson Road to the municipal boundary with the Town of Stow.

Stow (0.75 miles UG)
In Stow, Candidate Route 4 continues traveling underground in a westerly direction for 0.75 miles along public roadways before entering Hudson. As Candidate Route 4 enters Stow, Hudson Road becomes Sudbury Road for a short distance before entering Hudson.

Hudson (4.09 miles UG)
In Hudson, Candidate Route 4 continues traveling underground in a westerly direction for 4.09 miles along public roadways before terminating at the Hudson Substation. As Candidate Route 4 enters Hudson, Sudbury Road becomes Main Street, crossing Parmenter Street and Chestnut Street, following the same route as Candidate Route 3 before terminating at the Hudson Substation.

Candidate Route 5: Route 20 to Union to Hudson (10.93 miles)

Candidate Route 5 originates at the Sudbury Substation and travels 10.93 miles in a westerly direction within public roadways for 6.09 miles in Sudbury, 0.75 miles in Stow, and 4.09 miles within public roadways and the Intel access road in Hudson before terminating at the Hudson Substation. In Sudbury, this route varies from Candidate Route 4 by extending past Concord Road on Boston Post Road/Route 20 for an additional 0.33 mile and alternatively traveling north along Union Avenue before reaching the western branch of Old Lancaster Road where it continues west following the same route as Candidate Route 4.

Sudbury (6.09 miles UG)
In Sudbury, Candidate Route 5 originates at the Sudbury Substation and travels underground in a northwesterly direction for 6.09 miles along public roadways before entering Stow. From the Sudbury Substation, this route follows the same roadways as Candidate Route 4, traveling north along the substation driveway and turning west onto Boston Post Road/Route 20. This route becomes its own distinct variation from Candidate Route 4 by extending past Concord Road on Boston Post Road/Route 20 for an additional 0.33 mile before turning north onto Union Avenue.

Candidate Route 5 then turns north onto Union Avenue, passing Station Road and Codjer Lane. The route enters the intersection with Concord Road before turning onto the western branch of Old Lancaster Road where it continues west following the same route as Candidate Route 4 before entering Stow.

Stow (0.75 mile UG)
In Stow, Candidate Route 5 continues to follow the same route as Candidate Route 4, traveling underground in a westerly direction for 0.75 mile along public roadways before entering Hudson.

Hudson (4.09 miles UG)
In Hudson, Candidate Route 5 continues to follow the same route as Candidate Route 4, traveling underground in a westerly direction for 4.09 miles along public roadways before terminating at the Hudson Substation.

Candidate Route 5A: Route 20 to Station to Hudson (10.75 miles)

Candidate Route 5A primarily follows the same route as Candidate Route 5, with the exception of a short stretch of Boston Post Road between Station Road and Union Avenue. Instead of traversing Boston Post Road in this area, Candidate Route 5A turns onto Station Road to reach Union Avenue. The rest of the route follows the same roadways as Candidate Route 5.

Candidate Route 6: Route 20 to Horse Pond to Hudson (11.10 miles)

Candidate Route 6 originates at the Sudbury Substation and travels 11.10 miles in a westerly direction within public roadways for 6.26 miles in Sudbury, 0.75 miles in Stow, and 4.09 miles within public roadways and the Intel access road in Hudson before terminating at the Hudson Substation. In Sudbury, this route provides a variation from Candidate Route 5 by extending past Union Avenue on Boston Post Road/Route 20 for an additional 0.89 mile and alternatively traveling north along Horse Pond, Pratts Mill, and Dutton Roads before reaching the intersection of Hudson Road where it continues west following the same route as Candidate Route 5.

Sudbury (6.26 miles UG)
In Sudbury, Candidate Route 6 originates at the Sudbury Substation and travels underground in a northwesterly direction for 6.26 miles along public roadways before entering Stow. From the Sudbury Substation, this route follows the same roadways as Candidate Route 5, traveling north along the substation driveway and turning west onto Boston Post Road/Route 20. This route becomes its own distinct variation from Candidate Route 5 by extending past Union Avenue on Boston Post Road/Route 20 for an additional 0.89 mile before turning north onto Horse Pond Road. Along this segment of Boston Post Road/Route 20, this route crosses intersections with Union Avenue to the north and Nobscot Road, Highland Avenue, and Dudley Road to the south.

Candidate Route 6 then turns north onto Horse Pond Road, and turns northwest onto Pratts Mill Road. At the intersection with Dutton Road, the route turns north, then turns west onto Hudson Road, following the same route as Candidate Route 5 before entering Stow.

Stow (0.75 mile UG)
In Stow, Candidate Route 6 continues to follow the same route as Candidate Route 5, traveling underground in a westerly direction for 0.75 mile along public roadways before entering Hudson.

Hudson (4.09 miles UG)
In Hudson, Candidate Route 6 continues to follow the same route as Candidate Route 5, traveling underground in a westerly direction for 4.09 miles along public roadways before terminating at the Hudson Substation.

Candidate Route 7: Route 20 to Sudbury to Main (10.85 miles)

Candidate Route 7 originates at the Sudbury Substation and travels 10.85 miles in a westerly direction within public roadways for 4.61 miles in Sudbury, 0.04 miles in Framingham, 2.75 miles in Marlborough, and 3.45 miles within public roadways and the Intel access road in Hudson before terminating at the Hudson Substation. This route provides a variation that

extends past Horse Pond Road on Boston Post Road/Route 20 for an additional 2.37 miles and alternatively travels north along the west side of Wayside Inn Road, Sudbury Street, Concord Road, Goodale Street, and Chestnut Street before reaching the intersection of Main Street where it continues west following the same route as Candidate Route 6.

Sudbury (4.61 miles UG)
In Sudbury, Candidate Route 7 originates at the Sudbury Substation and travels underground in a westerly direction for 4.61 miles along public roadways before entering Marlborough. From the Sudbury Substation, this route follows the same roadways as Candidate Route 6, traveling north along the substation driveway and turning west onto Boston Post Road/Route 20. This route extends past Candidate Route 6 on Boston Post Road/Route 20 for an additional 2.37 miles into Framingham and then Marlborough.

Framingham (0.04 mile UG)
Candidate Route 7 passes through a small corner of Framingham along Boston Post Road, for 0.04 miles near Grist Millpond.

Marlborough (2.75 mile UG)
In Marlborough, Candidate Route 7 continues underground along Boston Post Road for 0.17 miles next to primarily undeveloped lands. At the west end of Wayside Inn Road, the route turns northeast, and then turns north onto Sudbury Street. At the intersection with Concord Road, the route briefly turns west before continuing north on Goodale Street to the Hudson town line.

Hudson (3.45 miles UG)
In Hudson, Goodale Street becomes Chestnut Street, and Candidate Route 7 follows Chestnut to the intersection with Main Street, where it joins Candidate Route 6 to travel westward along Main and Forest Avenue to the Hudson Substation.

Candidate Route 8: Route 20 to Hosmer to Causeway (11.10 miles)

Candidate Route 8 originates at the Sudbury Substation and travels 11.10 miles in a westerly direction within public roadways for 4.61 miles in Sudbury, 0.04 miles in Framingham, 4.51 miles in Marlborough, and 1.94 miles within public roadways and the Intel access road in Hudson before terminating at the Hudson Substation. This route provides a variation that extends past Wayside Inn Road on Boston Post Road/Route 20 for an additional 2.27 miles in Marlborough and alternatively traveling north along Hosmer Street, Causeway Street, and Marlboro Street before reaching the intersection with Forest Avenue where it continues west following the same route as Candidate Route 7 to reach the Hudson Substation.

Sudbury (4.61 miles UG)
In Sudbury, Candidate Route 8 originates at the Sudbury Substation and travels underground in a westerly direction for 4.61 miles along public roadways before entering Marlborough, following the same route as Candidate Route 7.

Framingham (0.04 mile UG)
Candidate Route 8 passes through a small corner of Framingham along Boston Post Road, for 0.04 miles along the same route as Candidate Route 7.

Marlborough (4.51 mile UG)
In Marlborough, Candidate Route 8 continues underground along Boston Post Road for 4.51 miles. At the intersection with Hosmer Street, the route turns north, then turns northwest at the intersection with Causeway Street to enter Hudson.

Hudson (1.94 miles UG)
In Hudson, Candidate Route 8 continues underground in a northwesterly direction on Causeway Street. The route turns north onto a short section of Marlboro Street before turning west onto Forest Avenue and continuing west along the same route as Candidate Route 7 to reach the Hudson Substation.

Candidate Routes 9 and 10: Routes Primarily Utilizing Public Roadways, with Use of the MBTA ROW in Sudbury

Candidate Route 9A: MBTA (OH) to Station to Union to Hudson (10.71 miles)

Candidate Route 9A is a combination overhead and underground transmission line design. The overhead portion of this route originates at the Sudbury Substation and travels for 1.30 miles along the MBTA ROW, and then transitions to an underground transmission line design within public roadways for 4.56 miles in Sudbury, 0.75 miles in Stow, and 4.09 miles within public roadways and the Intel access road in Hudson before terminating at the Hudson Substation. This route provides a variation to Candidate Route 5A that follows the MBTA ROW from Sudbury Substation to Station Road, then traverses public roadways for the remainder of the route.

Sudbury (1.30 miles OH in ROW, 4.56 miles UG in roads)
In Sudbury, Candidate Route 9 originates at the Sudbury Substation and travels overhead in a northwesterly direction for 1.30 miles along the MBTA ROW before transitioning to an underground transmission line design and entering public roadways at Station Road. From the Sudbury Substation, this route travels north along the substation driveway and turns west onto the MBTA ROW. At Station Road, this route joins Candidate Route 5A.

Stow (0.75 mile UG)
In Stow, Candidate Route 9 continues to follow the same route as Candidate Route 5A, traveling underground in a westerly direction for 0.75 mile along public roadways before entering Hudson.

Hudson (4.09 miles UG)
In Hudson, Candidate Route 5 continues to follow the same route as Candidate Route 4, traveling underground in a westerly direction for 4.09 miles along public roadways before terminating at the Hudson Substation.

Candidate Route 9B: MBTA (UG) to Station to Union to Hudson (10.70 miles)

Candidate Route 9B provides a design variation by travelling entirely underground along the same route as Candidate Route 9A.

Candidate Route 10A: MBTA (OH) to Horse Pond to Hudson (10.48 miles)

Candidate Route 10A is a combination overhead and underground transmission line design. The overhead portion of this route originates at the Sudbury Substation and travels 2.18 miles within the MBTA ROW, and then transitions to an underground transmission line design within public roadways for 3.46 miles in Sudbury, 0.75 miles in Stow, and 4.09 miles within public roadways and the Intel access road in Hudson before terminating at the Hudson Substation. This route provides a variation to Candidate Route 6 that follows the MBTA ROW from Sudbury Substation to Horse Pond Road, then traverses public roadways for the remainder of the route.

Sudbury (2.18 miles OH in ROW, 3.46 miles UGin roads)
In Sudbury, Candidate Route 10A originates at the Sudbury Substation and travels overhead in a northwesterly direction for 2.18 miles along the MBTA ROW before transitioning to an underground transmission line design and entering public roadways at Horse Pond Road. From the Sudbury Substation, this route follows the same corridor as Candidate Route 9, traveling north along the substation driveway and turning west onto the MBTA ROW. It continues past Station Road along the ROW to Horse Pond Road, where the route joins Candidate Route 6.

Stow (0.75 mile UG)
In Stow, Candidate Route 10A continues to follow the same route as Candidate Route 6, traveling underground in a westerly direction for 0.75 mile along public roadways before entering Hudson.

Hudson (4.09 miles UG)
In Hudson, Candidate Route 10 continues to follow the same route as Candidate Route 6, traveling underground in a westerly direction for 4.09 miles along public roadways before terminating at the Hudson Substation.

Candidate Route 10B: MBTA (UG) to Horse Pond to Hudson (10.48 miles)

Candidate Route 10B provides a design variation by travelling entirely underground along the same route as Candidate Route 10A.

Candidate Route 11: Route 20 to Green Hill to Hudson (10.30 miles)

Candidate Route 11 originates at the Sudbury Substation and travels 10.30 miles in a westerly direction within public roadways for 5.46 miles in Sudbury, 0.75 miles in Stow, and 4.09 miles in Hudson within public roadways and the Intel access road before terminating at the Hudson Substation.

Sudbury (5.46 miles UG)
In Sudbury, Candidate Route 4 originates at the Sudbury Substation and travels underground in a northwesterly direction for 5.46 miles along public roadways before entering Stow. From the Sudbury Substation, this route travels north along the substation driveway and turns west onto Boston Post Road/Route 20, passing the intersection with Landham Road. Candidate Route 11 then turns north onto Green Hill Road, then west onto Old Lancaster Road. The route enters the intersection with Concord Road then continues onto the western branch of Old Lancaster Road. At the intersection of Hudson Road, this route turns west, crossing Dutton Road before entering Stow.

Stow (0.75 miles UG)
In Stow, Candidate Route 11 continues traveling underground in a westerly direction for 0.75 miles along public roadways before entering Hudson. As Candidate Route 11 enters Stow, Hudson Road becomes Sudbury Road for a short distance before entering Hudson.

Hudson (4.09 miles UG)
In Hudson, Candidate Route 11 continues traveling underground in a westerly direction for 4.09 miles along public roadways before terminating at the Hudson Substation. As Candidate Route 11 enters Hudson, Sudbury Road becomes Main Street and crosses Parmenter Street and Chestnut Street, following the same route as Candidate Route 3 before terminating at the Hudson Substation.

Sudbury to Hudson 115 KV Line

Sound Study for Shunt Reactor at Sudbury Substation #342

PREPARED FOR

Eversource
One NSTAR Way
Westwood, MA 02909-9230

PREPARED BY

101 Walnut Street
PO Box 9151
Watertown, MA 02471
617.924.1770

November, 28, 2016

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1. Introduction

VHB has conducted a sound study for Eversource Energy to assess potential noise impact from the proposed installation of a 20 megavolt-ampere reactive (MVAR) air core shunt reactor and associated switching and protection equipment at Sudbury Substation #342 on Boston Post Road. The installation of the shunt reactor is in association with the proposed construction of the 9-mile underground[1] transmission line from the Sudbury Substation to the Hudson Light and Power Department's Hudson Substation at Forest Avenue, the Sudbury to Hudson Transmission Reliability Project.

The study included measurements of existing ambient sound conditions near the Sudbury Substation, future sound level predictions with the proposed equipment, and an assessment of potential impact according to the Massachusetts Department of Environmental Protection ("MassDEP") regulation (310 CMR 7.10(1)) and the Town of Sudbury Zoning By Laws (2003 Zoning Bylaws, Noise Performance Standard 3422).

2. Background on Sound

Noise is defined as unwanted or excessive sound. Sound becomes unwanted when it interferes with normal activities such as sleep, work, communication or recreation. How people perceive sound depends on several measurable physical characteristics including:

- Level - Sound level is based on the amplitude change in pressure and is related to the loudness or intensity.
- Frequency - Sounds are comprised of acoustic energy distributed over a range of frequencies. Acoustic frequencies, commonly referred to as tone or pitch, are typically measured in Hertz. Pure tones exist when there is a concentration of sound in a narrow frequency range.

Sound levels are most often measured on a logarithmic scale of decibels (dB). The decibel scale compresses the audible range of acoustic pressure levels, which can vary from the threshold of hearing (0 dB) to the threshold of pain (120 dB). Because sound levels are measured in dB, the addition of two sound levels is not linear. For example, adding two equal sound levels results in a 3 dB increase in the overall level.

[1] Underground and overhead alternatives are being considered for the project. The shunt reactor would only be required for the underground alternatives.

Research indicates the general relationships between sound level and human perception are as follows:

- A 3 dB increase is a doubling of acoustic energy and is approximately the smallest difference in sound level that can be perceived in most environments.
- A 10 dB increase is a tenfold increase in acoustic energy and is generally perceived as a doubling in loudness to the average person.

The human ear does not perceive sound levels from each frequency equally loud. To compensate for this phenomenon in perception, a frequency filter known as A-weighting [dBA] is commonly used to evaluate environmental noise levels. Table 1 presents a list of common outdoor and indoor sound levels in dBA.

A variety of sound level descriptors can be used for environmental analyses. These descriptors relate to the way sound varies in level over time. The following is a list of common sound level descriptors:

- Statistical sound metrics (i.e. L_{01}, L_{10}, L_{50}, L_{90}) are the levels that are exceeded for a particular percentage of time over the measurement period. For example, L_{90} is the level which is exceeded for 90 percent of the time during a given time period. Therefore, it represents the lower end of the range of sound levels. The L_{90} is typically representative of the background ambient conditions and includes contributions from vehicular traffic and natural sources of sound in the environment.
- L_{eq} is the continuous equivalent A-weighted sound level that represents the same acoustic energy that exists over a period of time, typically one hour, in a single value as the fluctuating levels. The L_{eq} takes into account how loud events are during the period, how long they last, and how many times they occur. L_{eq} is commonly used to describe environmental sound and relates well to human annoyance.
- L_{dn} is the day-night average A-weighted sound level that represents the cumulative exposure to sound over a 24-hour period. It is similar to the Leq in that it takes into account how loud events are and how long they last, but it also takes into account how many occur during the daytime period (7:00 AM to 10:00PM) and how many occur during the nighttime period (10:00 PM to 7:00 AM) with a 10-dB penalty applied to events occurring at night.
- L_{max} is the maximum instantaneous A-weighted sound level. The L_{max} represents the highest sound level generated by a source. For sources that generate relatively constant sound, the L_{max} is similar to the L_{eq}. For sources that generate variable or intermittent sound, the L_{eq} is lower than the L_{max}.

Table 1 Common Outdoor and Indoor Sound Levels

Outdoor Sound Levels	Sound Pressure μPa*		Sound Level dB(A)**	Indoor Sound Levels
	6,324,555	-	110	Rock Band at 5 m
Jet Over-Flight at 300 m		-	105	
	2,000,000	-	100	Inside New York Subway Train
Gas Lawn Mower at 1 m		-	95	
	632,456	-	90	Food Blender at 1 m
Diesel Truck at 15 m		-	85	
Noisy Urban Area—Daytime	200,000	-	80	Garbage Disposal at 1 m
		-	75	Shouting at 1 m
Gas Lawn Mower at 30 m	63,246	-	70	Vacuum Cleaner at 3 m
Suburban Commercial Area		-	65	Normal Speech at 1 m
	20,000	-	60	
Quiet Urban Area—Daytime		-	55	Quiet Conversation at 1 m
	6,325	-	50	Dishwasher Next Room
Quiet Urban Area—Nighttime		-	45	
	2,000	-	40	Empty Theater or Library
Quiet Suburb—Nighttime		-	35	
	632	-	30	Quiet Bedroom at Night
Quiet Rural Area—Nighttime		-	25	Empty Concert Hall
Rustling Leaves	200	-	20	
		-	15	Broadcast and Recording Studios
	63	-	10	
		-	5	
Reference Pressure Level	20	-	0	Threshold of Hearing

Source: *Highway Noise Fundamentals*. Federal Highway Administration, September 1980.

* μPA – MicroPascals, which describe pressure. The pressure level is what sound level monitors measure.

** dB(A) – A-weighted decibels, which describe pressure logarithmically with respect to 20 μPa (the reference pressure level).

3. Applicable Sound Regulations and Criteria

MassDEP adopted this Noise Control Regulation, 310 CMR 7.10, under the authority of M.G.L. Chapter 111, Section 142B and 142D. The Noise Control Regulation is used to limit the sound impact of new stationary sources and to respond to complaints of certain excessive sound. The MassDEP regulation limits sound from the proposed equipment according to the following conditions:

"No person owning, leasing, or controlling a source of sound shall willfully, negligently, or through failure to provide necessary equipment, service, or maintenance or to take necessary precautions cause, suffer, allow, or permit unnecessary emissions from said source of sound that may cause noise."

The MassDEP has established a Noise Level Policy for implementing this regulation. The MassDEP policy for implementing its noise regulation is contained in DAQC Policy 90-001 which states that a source of sound violates the Department's noise regulation if the source:

- Increases the broadband sound level by more than 10 dB(A) above ambient, or
- Produces a "pure tone" condition – when any octave-band center frequency sound pressure level exceeds the two adjacent center frequency sound pressure levels by 3 decibels or more.

The MassDEP criteria identified in the Policy are commonly evaluated at the property line of the nearest inhabited residences. "Ambient" is defined as the background L_{90} sound level measured during hours that equipment may operate (24 hours a day). The evaluation assesses the quietest ambient period, which is typically during the night. Source sound levels from the proposed equipment are evaluated according to the L_{max} sound metric. Future sound levels are the combination of existing ambient sound levels and additional sound from the proposed equipment.

The Town of Sudbury Zoning By Laws has Performance Standards which prohibit excessive noise that would cause nuisance or hazard to persons or property. The Town By Laws adopt the MassDEP regulation for this Performance Standard.

4. Existing Conditions

Ambient Sound Levels at Nearest Receptors

VHB conducted a long-term (24-hour) sound measurement at the existing substation site, as shown in Figure 1, to characterize the ambient sound level conditions in the study area. The measurement was representative of the existing sound levels at the backyard property lines of the closest residences at #260, #266 and #272 Landham Road. The sound level monitor was set up in the MBTA right-of-way in a location that is representative of the closest residential property line of the homes on Landham Road. The monitor met Type 1 American National Standards Institute standards and was calibrated by a laboratory traceable to the National Institute of Standards and Technology and calibrated in the field prior to and after the measurements.

The sound level monitor collected the following overall A-weighted metrics; L_{max}, L_{min}, L_1, L_{10}, L_{50}, L_{90} and L_{eq} and one-third octave band sound levels. A complete record of the measurements was documented including specific measurement locations, time of measurements, meteorological conditions, equipment used and significant noise sources. Measurements were conducted for 24 hours between October 12, 2016 (beginning at 12:00 PM) and October 13, 2016. The temperature ranged from 43 to 70 degrees Fahrenheit with wind speeds generally less than 5 mph, clear skies and no precipitation.

The ambient measurements show that the typical background sound levels (L_{90}) range between 33 and 46 dBA with a sound level of 32.7 dBA during the quietest period between 2:00 and 3:00 AM. Figure 3 shows the sound level spectra during the quietest period between 2:00 and 3:00 AM which has the greatest frequency content in the 1,000 Hz frequency range.



Figure 1 Long-term Ambient Sound Monitoring and Receptor Locations

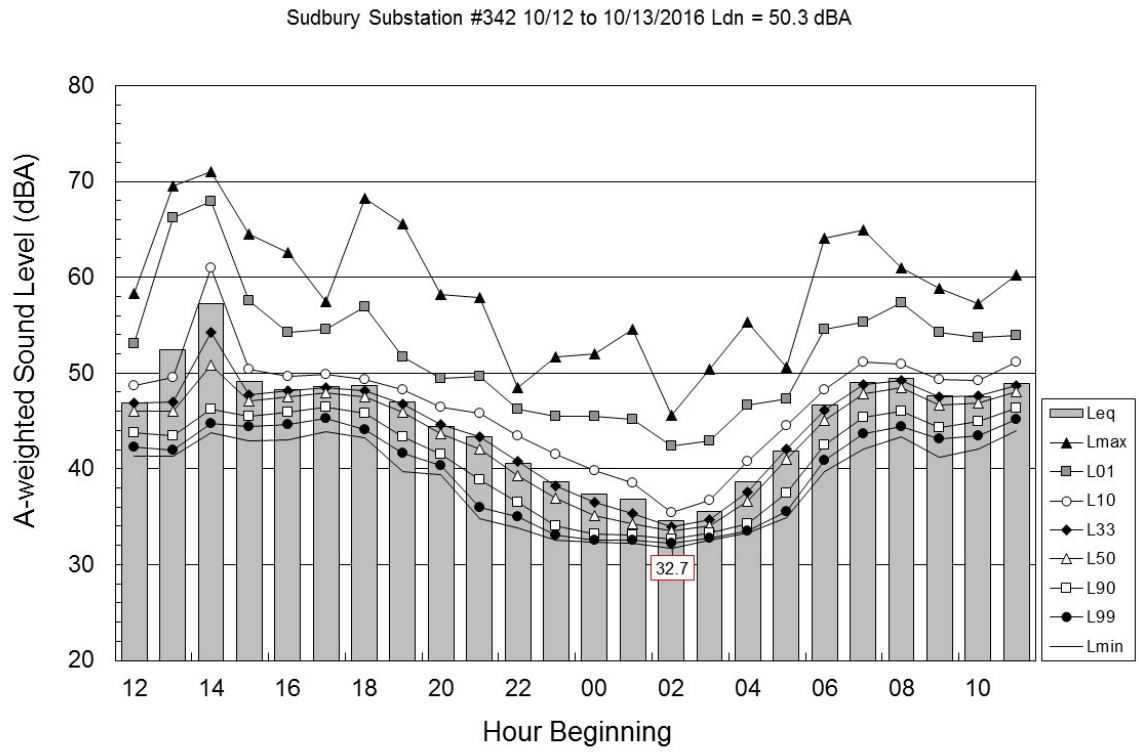


Figure 2 Long-term Ambient Sound Monitoring Time History Results

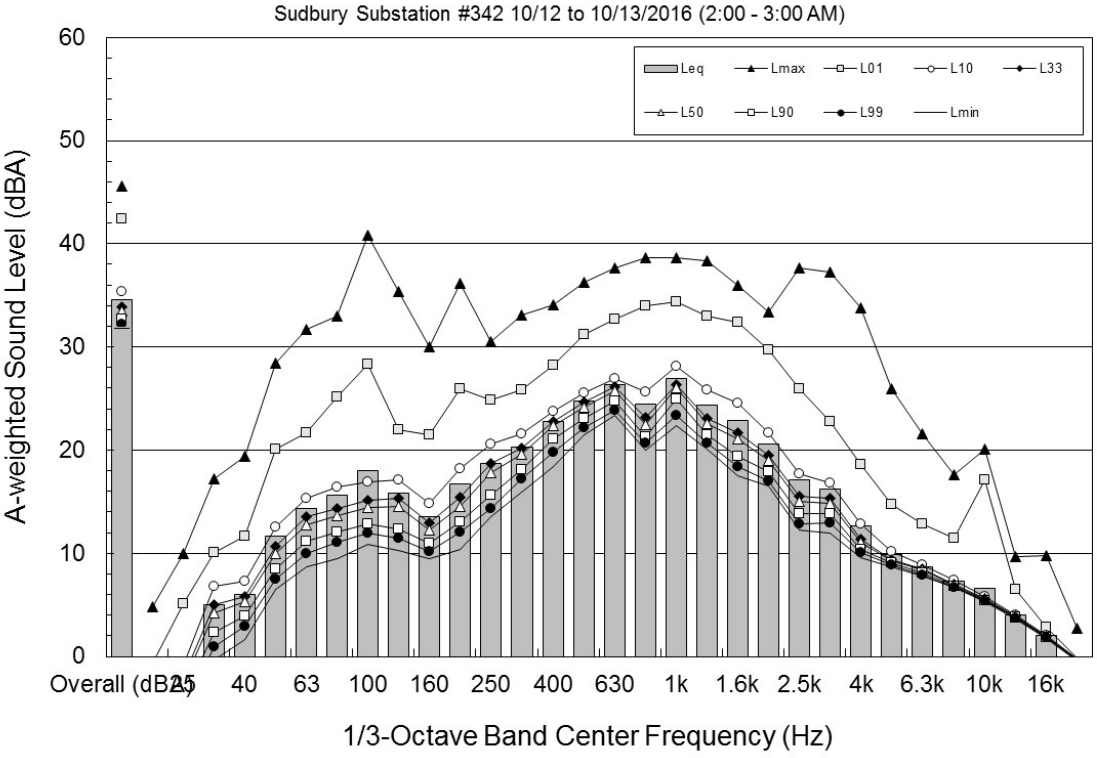


Figure 3 Long-term Ambient Sound Monitoring Spectra Results

Sudbury Substation Existing Equipment Sound Level Emissions

Measurements were conducted of significant sound-generating equipment at the existing Sudbury Substation to identify existing sources of sound in the study area. Measurements were conducted of Transformer 110A (at 20 feet), Transformer 110B (at 20 feet), a 230 KV Transformer (at 22 feet) and a similar Shunt Reactor (at 12 feet).

The results of the sound level measurements are presented in Table 2.

Table 2 Sound Level Results of Existing Substation Equipment

Equipment	Overall (dBA)	Octave-Band Sound Level (dBA)								
		31.5	63	125	250	500	1k	2k	4k	8k
Transformer 110A at 20 ft	49.2	16.2	29.1	46.6	39.3	42.2	37.2	35.2	33.1	28.0
Transformer 110B at 20 ft	56.4	21.4	33.8	45.8	46.3	54.7	45.3	39.7	40.2	29.7
Shunt Reactor at 12 feet	68.1	16.7	26.8	68.0	43.5	43.7	43.3	46.0	41.6	39.8
230KV Transformer at 22 feet	66.8	15.8	27.0	60.0	60.9	64.0	47.3	31.6	29.0	23.3

Source: VHB, 2016.

This table shows that the overall A-weighted sound level of the equipment at distances of 12 to 20 feet ranged from 49 to 68 dBA.

5. Sound Level Predictions and Impact Assessment

Sound generated by the proposed shunt reactor has been predicted at the back yard property lines of the three closest residential receptors at #260, #266 and #272 Landham Road, as shown in Figure 1. These receptors are approximately 750 feet west of the Sudbury Substation. Sound predictions were made using Cadna-A prediction software which implements the internationally accepted method described in International Standards Organization Standard 9613 "Attenuation of sound during propagation outdoors".

The overall A-weighted reference sound pressure level of the proposed shunt reactor is 70 dBA at a distance of 2 meters (6.5 feet) with a rated current of 100A[2]. Based on this reference sound level and frequency content measured of the existing shunt reactor, sound levels from this new sound source have been modeled at sensitive receptors.

Table 3 presents the existing and future overall A-weighted sound levels at the three receptors. Future sound levels would increase approximately 0.3 to 0.4 dBA. Since sound levels would not increase by more than 10 dBA, even during the quietest period of the night, there would be no noise impact according to the MassDEP criterion due to the proposed equipment.

Figure 2 shows the ambient L_{90} sound levels, including overall A-weighted level and un-weighted octave band levels, and future sound levels including ambient sources and the contribution of the new shunt reactor. This figure shows that there would be no pure tone condition, as defined by MassDEP policy and there would be no noise impact.

Therefore, introduction of the proposed shunt reactor for the Sudbury-Hudson Transmission Line Underground Design would not cause sound levels in excess of the MassDEP regulation or The Town of Sudbury Zoning By Laws Performance Standards and, accordingly, there is no need to implement mitigation measures.

Table 3 Existing and Future Overall Sound Levels

	Nighttime Sound Levels		
Receptor Location*	Existing	Build	Difference
Receptor 1 – 272 Landham Rd	32.7	33.1	0.4
Receptor 2 – 266 Landham Rd	32.7	33.0	0.3
Receptor 3 – 260 Landham Rd	32.7	33.0	0.3

Source: VHB, 2016.
* Refer to Figure 1 for receptor locations.

[2] Information provided by HasGo Power Equipment representative of Trench Electric, manufacturer of the existing shunt reactors.

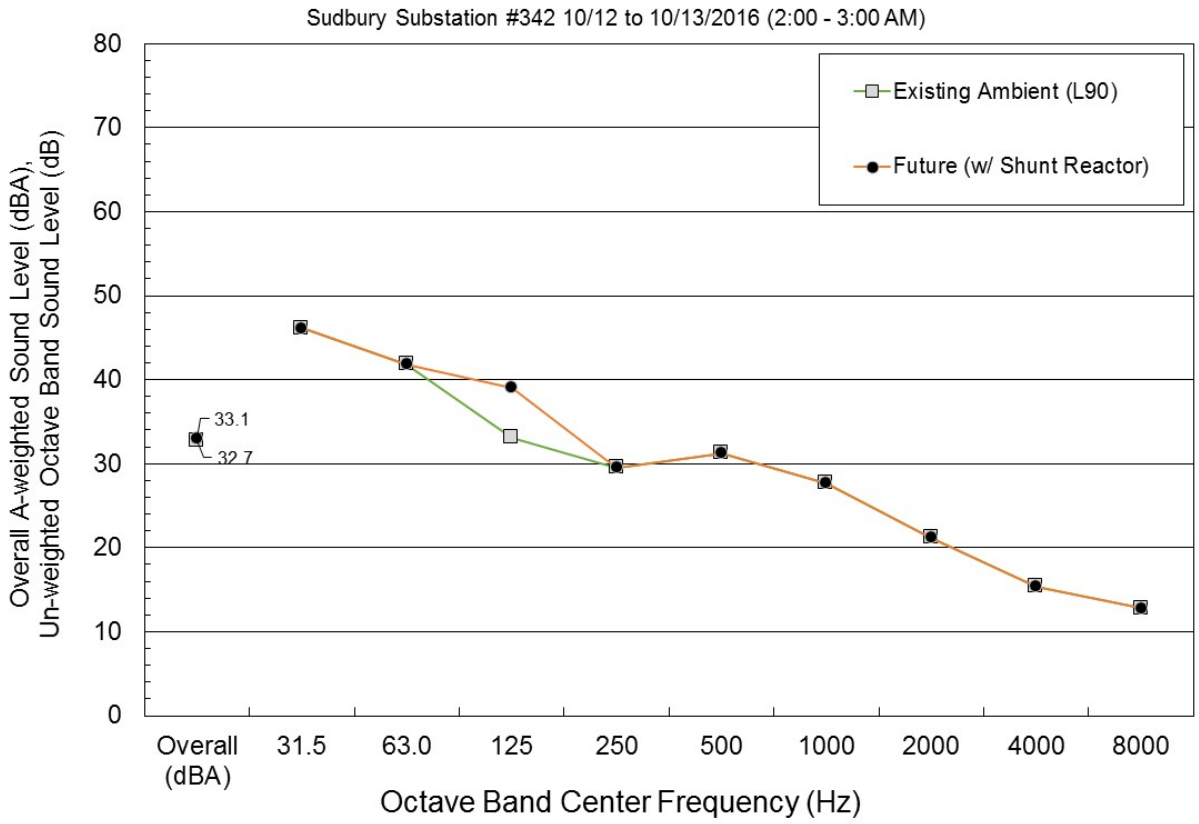


Figure 4 Existing and Future Sound Level Spectra at 272 Landham Rd

6. Conclusions

VHB has conducted a sound study for Eversource Energy to assess potential noise impact from the proposed installation of a 20 MVAR air core shunt reactor and associated switching and protection equipment at Sudbury Substation #342 on Boston Post Road. Potential noise impact was assessed according to the MassDEP regulation (310 CMR 7.10(1)) and the Town of Sudbury Zoning By Laws (2003 Zoning Bylaws, Noise Performance Standard 3422).

VHB conducted a long-term (24-hour) sound measurement at the existing substation site to characterize the ambient sound level conditions in the study area. The measurement was representative of the existing sound levels at the backyard property lines of the closest residences at #260, #266 and #272 Landham Road. The ambient measurements show that the typical background sound levels (L_{90}) range between 33 and 46 dBA with the quietest period of 32.7 dBA between 2:00 and 3:00 AM.

Sound generated by the proposed shunt reactor was predicted at the back yard property lines of the three closest residential receptors using Cadna-A prediction software which implements the internationally accepted method described in

International Standards Organization Standard 9613 "Attenuation of sound during propagation outdoors".

Overall A-weighted sound levels would increase only approximately 0.3 to 0.4 dBA due to the proposed equipment. Additionally, there would be no pure tone condition. Since sound levels would not increase by more than 10 dBA and there would be no pure tone condition, even during the quietest period of the night, there would be no noise impact from the Sudbury-Hudson Transmission Line Underground design according to the MassDEP criterion and the Town of Sudbury Zoning By Laws Performance Standards and, therefore, no need to implement mitigation measures.

7. Photos and Calibration Certificate

Photos of the sound level monitoring locations and calibration certificates of the measurement equipment are provided.





Photos: Transformer 110A (left), Existing Shunt Reactor (right)



Photo: Transformer 230KV



Photo: Long-Term Ambient Location

Calibration Certificate

Certificate Number 2015006853

Customer:
Vanasse Hangen Brustlin
101 Walnut Street
Watertown, MA 02471, United States

Model Number	831
Serial Number	0002555
Test Results	**Pass**
Initial Condition	AS RECEIVED same as shipped
Description	Larson Davis Model 831

Procedure Number	D0001.8384		
Technician	Ron Harris		
Calibration Date	21 Jul 2015		
Calibration Due	21 Jul 2016		
Temperature	23.11	°C	± 0.01 °C
Humidity	49.9	%RH	± 0.5 %RH
Static Pressure	86.39	kPa	± 0.03 kPa

Evaluation Method

Tested with:
PRM831, S/N 019119
377B02, S/N 122951

Data reported in dB re 20 µPa.

Compliance Standards Compliant to Manufacturer Specifications and the following standards when combined with Calibration Certificate from procedure D0001.8378:

IEC 60651:2001 Type 1	ANSI S1.4-2014 Class 1
IEC 60804:2000 Type 1	ANSI S1.4 (R2006) Type 1
IEC 61252:2002	ANSI S1.11 (R2009) Class 1
IEC 61260:2001 Class 1	ANSI S1.25 (R2007)
IEC 61672:2013 Class 1	ANSI S1.43 (R2007) Type 1

Issuing lab certifies that the instrument described above meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the SI through the National Institute of Standards and Technology (NIST), or other national measurement institutes, and meets the requirements of ISO/IEC 17025:2005.
Test points marked with a ‡ in the uncertainties column do not fall within this laboratory's scope of accreditation.

The quality system is registered to ISO 9001:2008.

This calibration is a direct comparison of the unit under test to the listed reference standards and did not involve any sampling plans to complete. No allowance has been made for the instability of the test device due to use, time, etc. Such allowances would be made by the customer as needed.

The uncertainties were computed in accordance with the ISO Guide to the Expression of Uncertainty in Measurement (GUM). A coverage factor of approximately 2 sigma (k=2) has been applied to the standard uncertainty to express the expanded uncertainty at approximately 95% confidence level.

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Standards Used

Description	Cal Date	Cal Due	Cal Standard
SRS DS360 Ultra Low Distortion Generator	06/24/2015	06/24/2016	006311
Hart Scientific 2626-H Temperature Probe	06/17/2015	06/17/2016	006798
Larson Davis CAL200 Acoustic Calibrator	08/06/2014	08/06/2015	007027
Larson Davis Model 831	03/05/2015	03/05/2016	007182
1/2 inch Microphone - P - 0V	03/11/2015	03/11/2016	007185
Larson Davis CAL291 Residual Intensity Calibrator	09/26/2014	09/26/2015	007287

Larson Davis, a division of PCB Piezotronics, Inc
1681 West 820 North
Provo, UT 84601, United States
716-684-0001

ACCREDITED Cert. #3622.01

LARSON DAVIS
A PCB PIEZOTRONICS DIV.

Acoustic Calibration

Measured according to IEC 61672-3:2013 10 and ANSI S1.4-2014 Part 3: 10

Measurement	Test Result [dB]	Lower Limit [dB]	Upper Limit [dB]	Expanded Uncertainty [dB]	Result
1000 Hz					
As Received Level: 113.87 Adjusted Level: 114.00					

-- End of measurement results--

Acoustic Signal Tests, C-weighting

Measured according to IEC 61672-3:2013 12 and ANSI S1.4-2014 Part 3: 12 using a comparison coupler with Unit Under Test (UUT) and reference SLM using S-time-weighted sound level

Frequency [Hz]	Test Result [dB]	Expected [dB]	Lower Limit [dB]	Upper Limit [dB]	Expanded Uncertainty [dB]	Result
125	-0.17	-0.20	-1.20	0.80	0.21	Pass
1000	0.13	0.00	-0.70	0.70	0.21	Pass
8000	-3.09	-3.00	-5.50	-1.50	0.21	Pass

-- End of measurement results--

Self-generated Noise

Measured according to IEC 61672-3:2013 11.1 and ANSI S1.4-2014 Part 3: 11.1

Measurement	Test Result [dB]
Low Range, 20 dB gain	64.27

-- End of measurement results--

-- End of Report--

Signatory: *Ron Harris*

Calibration Certificate

Certificate Number 2015006798

Customer:
Vanasse Hangen Brustlin
101 Walnut Street
Watertown, MA 02471, United States

Model Number	CAL200	***Procedure Number***	D0001.8386		
Serial Number	8541	***Technician***	Scott Montgomery		
Test Results	**Pass**	***Calibration Date***	16 Jul 2015		
Initial Condition	AS RECEIVED same as shipped	***Calibration Due***	16 Jul 2016		
		Temperature	24	°C	± 0.3 °C
Description	Larson Davis CAL200 Acoustic Calibrator	***Humidity***	35	%RH	± 3 %RH
		Static Pressure	101.0	kPa	± 1 kPa

Evaluation Method The data is aquired by the insert voltage calibration method using the reference microphone's open circuit sensitivity. Data reported in dB re 20 µPa.

Compliance Standards Compliant to Manufacturer Specifications per D0001.8190 and the following standards:
IEC 60942:2003 ANSI S1.40-2006

Issuing lab certifies that the instrument described above meets or exceeds all specifications as stated in the referenced procedure (unless otherwise noted). It has been calibrated using measurement standards traceable to the SI through the National Institute of Standards and Technology (NIST), or other national measurement institutes, and meets the requirements of ISO/IEC 17025:2005.
Test points marked with a ‡ in the uncertainties column do not fall within this laboratory's scope of accreditation.

The quality system is registered to ISO 9001:2008.

This calibration is a direct comparison of the unit under test to the listed reference standards and did not involve any sampling plans to complete. No allowance has been made for the instability of the test device due to use, time, etc. Such allowances would be made by the customer as needed.

The uncertainties were computed in accordance with the ISO Guide to the Expression of Uncertainty in Measurement (GUM). A coverage factor of approximately 2 sigma (k=2) has been applied to the standard uncertainty to express the expanded uncertainty at approximately 95% confidence level.

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Standards Used

Description	Cal Date	Cal Due	Cal Standard
Agilent 34401A DMM	09/04/2014	09/04/2015	001021
Sound Level Meter / Real Time Analyzer	04/07/2015	04/07/2016	001051
Microphone Calibration System	08/20/2014	08/20/2015	005446
1/2" Preamplifier	10/09/2014	10/09/2015	006506
Larson Davis 1/2" Preamplifier 7-pin LEMO	08/20/2014	08/20/2015	006507
1/2 inch Microphone - RI - 200V	07/25/2014	07/25/2015	006511
Pressure Transducer	05/07/2015	05/07/2016	007310

Certificate Number 2015006798

Output Level

Nominal Level [dB]	Pressure [kPa]	Test Result [dB]	Lower limit [dB]	Upper limit [dB]	Expanded Uncertainty [dB]	Result
114	101.4	114.00	113.80	114.20	0.13	Pass
94	101.0	94.01	93.80	94.20	0.14	Pass

-- End of measurement results--

Frequency

Nominal Level [dB]	Pressure [kPa]	Test Result [Hz]	Lower limit [Hz]	Upper limit [Hz]	Expanded Uncertainty [Hz]	Result
94	101.0	1,000.04	990.00	1,010.00	0.20	Pass
114	101.4	1,000.04	990.00	1,010.00	0.20	Pass

-- End of measurement results--

Total Harmonic Distortion + Noise (THD+N)

Nominal Level [dB]	Pressure [kPa]	Test Result [%]	Lower limit [%]	Upper limit [%]	Expanded Uncertainty [%]	Result
94	101.0	0.38	0.00	2.00	0.25	Pass
114	101.4	0.35	0.00	2.00	0.25	Pass

-- End of measurement results--

Level Change Over Pressure

Tested at: 114 dB, 24 °C, 35 %RH

Nominal Pressure [kPa]	Pressure [kPa]	Test Result [dB]	Lower limit [dB]	Upper limit [dB]	Expanded Uncertainty [dB]	Result
101.3	101.3	0.00	-0.30	0.30	0.04	Pass
108.0	108.1	-0.01	-0.30	0.30	0.04	Pass
92.0	92.0	0.04	-0.30	0.30	0.04	Pass
83.0	82.7	0.05	-0.30	0.30	0.04	Pass
74.0	73.8	0.02	-0.30	0.30	0.04	Pass
65.0	64.8	-0.09	-0.30	0.30	0.04	Pass

-- End of measurement results--

Frequency Change Over Pressure

Tested at: 114 dB, 24 °C, 35 %RH

Nominal Pressure [kPa]	Pressure [kPa]	Test Result [Hz]	Lower limit [Hz]	Upper limit [Hz]	Expanded Uncertainty [Hz]	Result
108.0	108.1	0.00	-10.00	10.00	0.20	Pass
101.3	101.3	0.00	-10.00	10.00	0.20	Pass
92.0	92.0	0.00	-10.00	10.00	0.20	Pass
83.0	82.7	0.00	-10.00	10.00	0.20	Pass
74.0	73.8	0.00	-10.00	10.00	0.20	Pass
65.0	64.8	-0.01	-10.00	10.00	0.20	Pass

-- End of measurement results--

Certificate Number 2015006798

Total Harmonic Distortion + Noise (THD+N) Over Pressure

Tested at: 114 dB, 24 °C, 35 %RH

Nominal Pressure [kPa]	Pressure [kPa]	Test Result [%]	Lower limit [%]	Upper limit [%]	Expanded Uncertainty [%]	Result
108.0	108.1	0.34	0.00	2.00	0.25	Pass
101.3	101.3	0.35	0.00	2.00	0.25	Pass
92.0	92.0	0.37	0.00	2.00	0.25	Pass
83.0	82.7	0.38	0.00	2.00	0.25	Pass
74.0	73.8	0.41	0.00	2.00	0.25	Pass
65.0	64.8	0.44	0.00	2.00	0.25	Pass

-- End of measurement results--

Signatory: *Scott Montgomery*

Larson Davis, a division of PCB Piezotronics, Inc
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ACCREDITED Cert. #3622.01

LARSON DAVIS
A PCB PIEZOTRONICS DIV.

Appendix 5-2





MASSACHUSETTS BEST MANAGEMENT PRACTICES MANUAL

December 2010

Prepared By:

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Section 1 Introduction

1.1 NSTAR Statement of Policy

NSTAR is committed to excellence in its environmental performance and compliance with all laws and regulations that apply to company operations. In conducting business and making operational decisions, all of NSTAR's and its contractor's employees are held accountable for meeting all environmental requirements that apply to their assigned responsibilities, and for using this information in planning and completing their work.

NSTAR demonstrates environmental leadership by fostering environmental stewardship and sustainable business practices in balance with maintaining safe, secure, reliable and low-cost service by:

- Meeting or surpassing all environmental laws and regulations applicable to its operations. NSTAR strives to conduct all its operations in an environmentally and economically sound and responsible manner.
- Monitoring and assessing the environmental impact of NSTAR's operations, using the results to improve its efforts. Continually seeking opportunities to prevent or reduce pollution, conserve natural resources and use eco-friendly products and services.
- Striving to prevent or reduce waste through re-use, recycling and effective work-planning programs.
- Seeking opportunities to prevent or reduce greenhouse gas emissions through energy conservation, efficient operating practices, renewable or low-carbon-emission energy sources, technology, consumer education and infrastructure that supports or enables these opportunities.

As a matter of company policy regarding environmental stewardship and in accordance with local, state, and federal regulations, all construction and maintenance projects shall use environmentally sound best management practices (BMPs) to minimize or eliminate environmental impacts that may result from construction activities. Regardless of whether a specific permit is needed for the work, construction and maintenance projects must follow clear and enforceable environmental performance standards, which is why these BMPs have been compiled. In most cases, maintenance activities are exempt from regulatory authorization. Permits are typically required for new work. Contractors will be provided with copies of any project specific permits, and may be required to certify in writing their receipt of and agreement to adhere to any and all provisions of the permit(s). Permit conditions that are more detailed than the BMPs outlined in this manual should always be given deference. However, where certain construction elements are not addressed by permit conditions, or where permitting is not required, or not prudent (i.e., emergencies), these BMPs shall be considered as NSTAR's standards. In some cases, and at the discretion of NSTAR Management, the BMPs presented herein may be modified to be more appropriate for site-specific conditions.

1.2 Scope and Applicability

These BMPs primarily address the disturbance of soil, water, and vegetation incidental to construction within on- and off-road utility corridors, substations, including the establishment of access roads and work areas, in and near wetlands, watercourses, or

other sensitive natural areas, including storm drain systems (e.g. catch basins). Types of construction include, but are not limited to, underground and overhead utilities, substations and other facilities, and maintenance activities.

Section 2
BMP Types and Selection

During all project activities (e.g. maintenance, construction), federal, state, and local regulatory authorities require steps be taken to avoid, minimize, and/or mitigate environmental impacts. BMPs have been developed to aid in this process and should be carefully selected and implemented based on the proposed activities and the nature of sensitive area(s) encountered at each site.

Proper selection of BMPs should take into consideration the project goals, permit requirements, and site specific information. Once an assessment of the area has been made and requirements of the project have been established, all plausible BMPs should be considered.

Sections 3 through 8 provide detailed information on specific BMPs, with typical drawings provided as appropriate. A table summarizing applicable BMPs is presented on the following page.

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Table 2-1
Summary of BMPs

SECTION	BMP Type	Applications	Limitations	Relative Costs
3.1	Preserving Existing Vegetation	Erosion and sedimentation control; habitat and aesthetic preservation; reduce landscaping costs	Access needs of ROW; required distance between underground utilities and mature trees.	Low
3.2	Hay or Straw Bales, or Wood Chip Bags	Erosion and sedimentation control; mulch	Frozen ground (for installing stakes); generally only effective for 3-6 months (hay) or 6-12 months (straw) before replacement.	Low (hay) to moderate (straw)
3.2	Silt Fencing	Erosion and sedimentation control; work limits; temporary animal barrier	Frozen or rocky ground (for installing stakes); may prevent critical movements of sensitive wildlife species; disposal.	Low
3.3	Compost Filter Berms	Erosion and sedimentation control; mulch; work limits	Small contributing drainage area restrictions.	Low to moderate
3.4	Straw Wattles	Erosion and sedimentation control; work limits	Not for steep slopes.	Low
3.5	Catch Basin Protection Plan	Erosion and sedimentation control	For small quantity and velocity stormwater flows; hay bales hard to stake into paved areas.	Low
3.5	Catch Basin/Inlet Protection – Stone or Sod Mound Drop Inlets and Filter Baskets	Erosion and sedimentation control	Sod for areas which will eventually be vegetated; filter baskets generally used in combination with another catch basin protective measure.	Moderate
3.6	Erosion Control Blankets	Slope stabilization; erosion and sedimentation control	Not recommended for very steep slopes or on rocky soils; mulches may be more effective on flatter areas.	Moderate
3.7	Stormwater Conveyance – Swales and Channels	Convey stormwater away from work area and/or improve water quality and reduce peak runoff	No flow allowed to vegetated swales until vegetation is strongly established; need to have adequate bottom stabilization to prevent scouring.	Low to high
3.8	Level Spreaders	Erosion and sedimentation control	Down-gradient area must be adequately vegetated and 100 wide before surface waters; No vehicle traffic over level spreader.	Moderate to high
3.9	Check Dams	Erosion and sedimentation control	Hay bale check dams - frozen ground (for installing stakes).	Low
3.10	Temporary and Permanent Diversions and Water Bars	Erosion and sedimentation control	Need enough area to divert flows to; can impede vehicular movement.	Low
3.11	Temporary Sediment Trap and Sediment Basins	Erosion and sedimentation control	Needs to be adequately sized based on expected rain events and the contributing drainage area.	Moderate
3.12	Construction Entrance Track Pad	Erosion and sedimentation control; roadway protection	Stone may need to be removed and refreshed and/or cleaned as needed if the pad becomes clogged with soil; muddy conditions may warrant the use of a tire wash station.	Moderate
3.13	Temporary and Permanent Trench Breakers	Keeping work areas dry; long-term stabilization of soil (preventing sinkholes)	If water accumulates behind the trench breaker, it should be pumped to a filtering device, preferably in a well-vegetated, upland area.	Low to moderate

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SECTION	BMP Type	Applications	Limitations	Relative Costs
4.1	Existing Access Roads	Site access	Site specific vehicle traffic needs; often require other erosion and sedimentation control BMPs.	Low to moderate
4.2	New Access Roads	Site access	Generally only allowed when existing roads are not adequate; constructing roads to cross wetlands or streams requires extensive permitting.	Moderate to high
4.3	Temporary Stream Crossings Without Bridges	Stream crossings	Driving through streams limited to where existing access roads are present; stone crossings limited to intermittent streams; pole fords limited to streams with gently sloping adjacent land.	Low (drive through) to moderate (stone and pole fords)
4.4	Temporary Stream Crossings With Bridges	Stream crossings	Timber mats and culverts only effective for narrow spans; culverts may have permitting time of year restrictions on use and pose an obstacle to fish and aquatic wildlife.	Moderate (timber mats) to high (culvert, bridges)
4.5	Timber Mats and Wetland Crossings	Wetlands crossings; rut minimization	Timber mats need to be installed with heavy machinery; Alturnamats limited to smaller vehicles and equipment; equipment operators should remain cautious so as not to drive or slip off the side of the mats.	Moderate (Alturnamats) to high (timber mats)
5.1	Topsoil Segregation for Work in Wetlands and Agricultural Areas	During excavation in wetlands and agricultural areas	May be site-specific limitations; otherwise none.	Low
5.2	Dewatering Activities	Dewatering	Overland flow limited to sites with appropriate upland area; pumps should be overseen at all times; filter bags clog and need to be replaced; frac tanks have limited capacity and are expensive.	Low (overland flow), moderate (filtering), high (frac tank)
5.3	Waterbody Utility Crossings	Sedimentation and turbidity control	Wet crossings not preferred by regulatory agencies and limited to intermittent streams; dam and pump limited to little stream flow.	Low (wet crossings) to moderate (dry crossings)
5.4	Cofferdams	Dewatering; turbidity control	Construction of coffer dams for in stream work is site specific; follow permit guidelines and requirements and the project engineer's instructions at the time of construction.	Moderate to high
5.5	Staked and Floating Silt Barriers	Turbidity control	Must be rated to withstand anticipated flow velocity and quantity.	Low (floating barrier) to moderate (staked barrier)
5.6	Protection of Existing Culverts	Utility crossings of existing culverts	May be site-specific limitations; otherwise none.	Moderate to high
5.7	Horizontal Directional Drilling	Utility crossings of large or sensitive waterbodies or wetlands	Directional drilling is site specific; follow any permit guidelines and requirements and the project engineer's plans and instructions at the time of construction.	High
5.8	Standard Bore (Jacking)	Utility crossings of large or sensitive waterbodies or wetlands	Standard Boring is site specific; follow any permit guidelines and requirements and the project engineer's plans and instructions at the time of construction.	High

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SECTION	BMP Type	Applications	Limitations	Relative Costs
7.5	Dust Control	Airborne erosion and sedimentation control; reduce accidents; decrease respiratory problems	Vegetative cover limited to areas outside of active work area; Calcium chloride use is site specific and requires consulting an expert.	Low (vegetative cover, water sprinkling, tarps); moderate (barriers), high (stone, calcium chloride)
8.1	Surface Roughening	Erosion and sedimentation control; slope stabilization	Method specific to grade of slope.	Low (tracking); moderate (disking); high (stair stepped)
8.2	Permanent Seeding and Mulching of Upland Areas	Erosion and sedimentation control; soil stabilization; site restoration	Limited to non-jurisdictional, upland areas; seed and mulch type dependent on site conditions.	Low (hay, wood chips) to moderate (straw, hydroseed, compost)
8.3	Wetlands and Waterways Restoration	Erosion and sedimentation control; soil or bank stabilization; site restoration	Only use plant species native to the project area.	Low (mulch) to moderate (regrading, wetland seed)
8.5	Private Property Access Restoration of Upland Areas	Erosion and sedimentation control; soil stabilization; site restoration	Non-degradable erosion controls (i.e. silt fence) must be removed from site after area has stabilized with vegetation.	Low to moderate

SECTION 3

SEDIMENTATION AND EROSION CONTROLS

Appendix 5-2

SECTION 3.1
PRESERVING EXISTING VEGETATION

The preservation of natural, existing vegetation (groundcovers, vines, shrubs, trees) on a site wherever possible, primarily to increase soil stability and decrease the amount and velocity of runoff. This also includes identification and protection of certain trees either for aesthetic or erosion and sediment control benefits. Preserving existing vegetation by reducing the width of a cleared right of way at stream crossings is also extremely advantageous and required to some degree.

Advantages:
- Reduces soil erosion rates and improves aesthetics.
- Reduces landscaping costs.
- Provides habitat for wildlife and provides noise buffers.

Where:
- Preserve natural vegetation wherever possible. Use construction phasing whenever possible by preserving vegetation in areas where activities are not scheduled to occur, or will occur at a later time.
- Preserve natural vegetation particularly on steep slopes, near drainageways, or drainage swales.
- Select and protect trees along roadways where aesthetics demand and wherever possible.
- Reduce nonessential right of way clearing when approaching streams and wetlands.

Vegetation Selection:
- Examine the area to identify vegetation to be saved. Consider saving vegetation with desirable aesthetic, shading, or screening qualities.
- Select healthy, relatively young vegetation that will not interfere with the installation or maintenance of utilities.

Tree Preservation for Roadway or Residential Construction:
- Select healthy trees, the majority less than 40 years old.
- Place barriers around trees including wooden and wire fencing made from scrap lumber, or snow fencing. Place at least five feet out from the trunk.
- Construct the fence before the bulldozer arrives and leave in place until the last piece of machinery is gone.
- If fencing is not feasible, mark the selected trees with bright flagging.
- Trench as far from the trunks, as well as outside of the canopy drip line as possible. If roots are encountered, consider trenching under them.

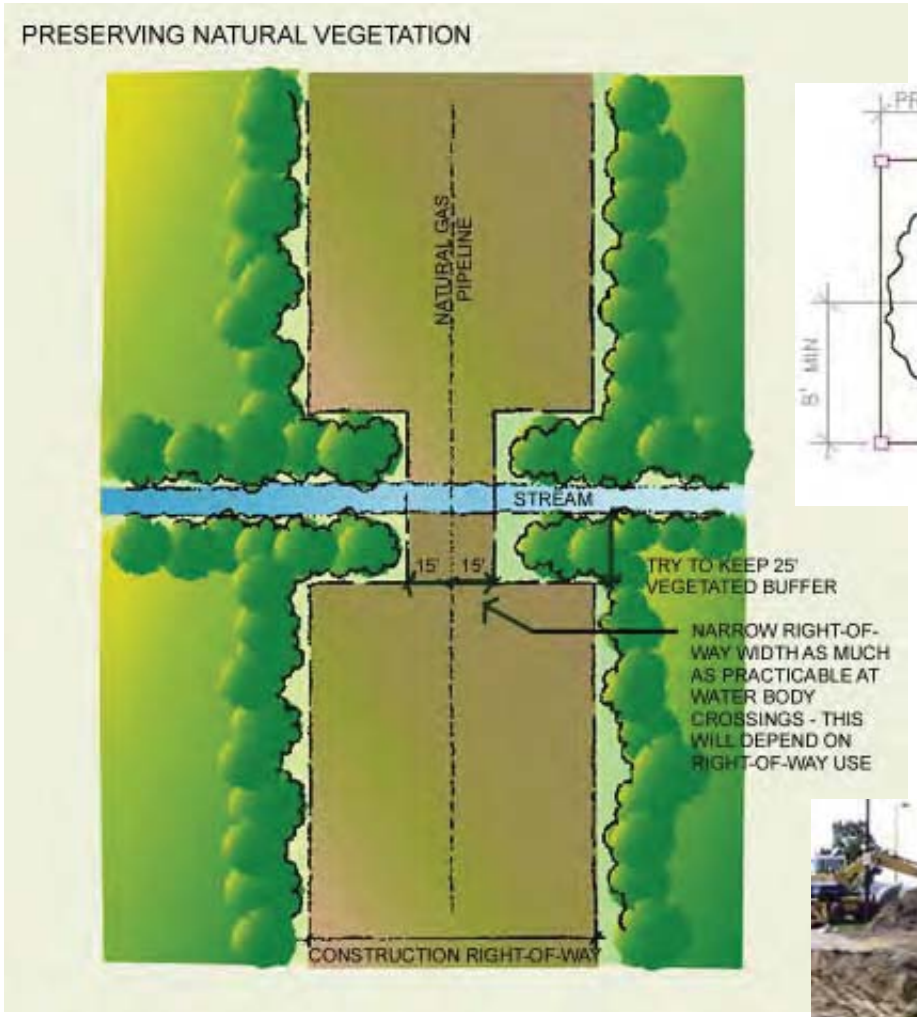
Maintenance for Tree Preservation:
- Inspect flagged or barricaded areas and replace flagging and repair/replace barriers as needed.
- Inspect tree roots. Re-cover or re-seal roots that have been exposed or injured by construction activity.

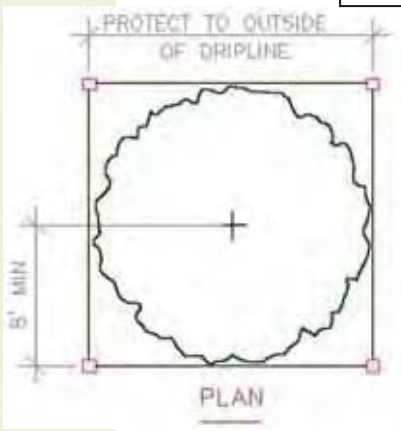
Reducing Widths of Cleared Pipeline Rights of Way:
- When approaching a stream crossing, limit the amount of clearing of existing stream bank and riparian vegetation.
- Reduce the width of the cleared right of way to only the areas essential for construction and maintenance.
- Attempt to maintain a 25-foot wide vegetated buffer between the stream bank and the cleared right of way, except where the line is directly installed.
- Federal guidelines suggest 15 feet on either side of a buried pipeline should remain clear of mature trees. The width of the reduced right of way will vary depending on what the designated use of the corridor is.

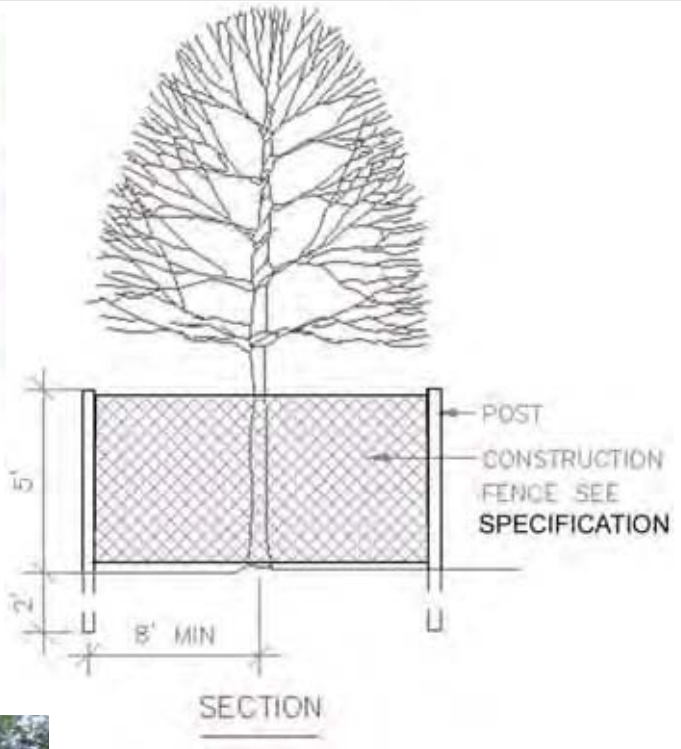
Appendix 5-2

PRESERVING EXISTING VEGETATION

★ Identify and protect individual trees and areas of vegetation either for aesthetic, or erosion and sediment control benefits. Reducing the width of the cleared corridor at stream crossings will also facilitate final stabilization.









NSTAR ELECTRIC GAS

SECTION 3.2
PERIMETER SILT FENCE AND HAYBALES OR WOOD CHIP BAGS

Staked silt fence and hay bales or wood chip bags can be utilized separately or in conjunction as erosion control barriers. They are staked in a line around perimeters of disturbed areas, especially those adjacent to wetlands, waterways, roadways or at the base of slopes. Perimeter barriers intercept, filter, and reduce the velocity of stormwater run-off.

STAKED HAYBALES OR WOOD CHIP BAGS

Where:

- Install at toe of slope, downgradient from disturbed areas with maximum slope length of 150 ft and max. drainage area of 1 acre.
- Install at wetland or waterway boundaries as well as at roadways, adjacent to disturbed areas.
- Can be used in conjunction or interchanged with silt fence.
- Install in minor swales with a maximum contributing drainage area of 1 acre or less.

Installation:

- Bales should be wire bound or string tied. The bales should be placed so that the bindings are on the sides of the bales rather than against the ground.
- Install bales/bags in a single row, lengthwise on the contour. Place ends of bales tightly against each other.
- Entrench bales/bags to a minimum depth of 4 inches.
- Backfill around the base of the bale/bag.
- Anchor bales using two stakes driven through the bale and into the ground (Drive 1st stake towards the previously laid bale).

Maintenance:

- Requires close attention for maintenance and repair.
- Inspect before a forecasted storm event.
- Inspect daily during a prolonged rain event.
- Remove accumulated sediment when it reaches two thirds the height of the bale/bag.
- Replace rotted or sediment covered bales/bags as necessary.

SILT FENCE

Where:

- Install in areas downgradient from disturbed areas subject to sheet flow and/or rill erosion with a maximum slope length less than 150 feet and drainage area less than 1 acre.
- Can be used in conjunction or interchanged with haybales.
- Do not install across streams, ditches, or waterways.
- Install at least 10 feet from the toe of steep slopes.

Installation:

- Dig a trench approximately 8” deep and 4” wide, or a V-trench on the upslope side of the fence line.
- Drive posts securely at least 16” into the ground, on the downslope. side of the trench. (Posts should be 4” diameter pine or 1.33 lb/linear ft steel).
- Space posts at a 8-foot maximum if fence is supported by wire, 6 feet if extra strength fabric is used without support wire. (Use 14 gauge support wire with 6” mesh).
- Fasten fabric and then support wire securely to the upslope side of the fence post with wire ties or staples. Extend wire 6” into the trench.
- Place the bottom 1 ft of fabric in the trench and Backfill with compacted earth or gravel.
- The fence should be level along most of its length.
- Flare 10-20 feet of fabric at each end slightly uphill.

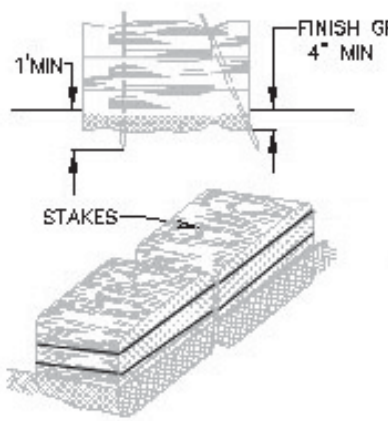
Maintenance:

- Same as for haybales. Remove sediments when they have accumulated up to a depth of 12 inches.

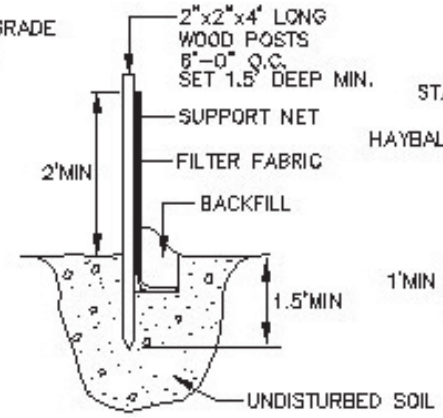
PERIMETER SILT FENCE AND HAYBALES



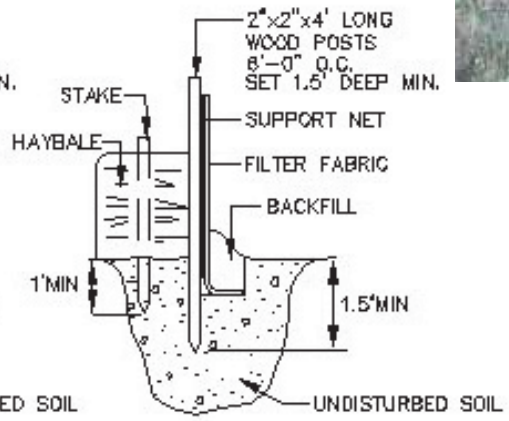
★ Remember to place haybales so that the twine is not against the ground. →



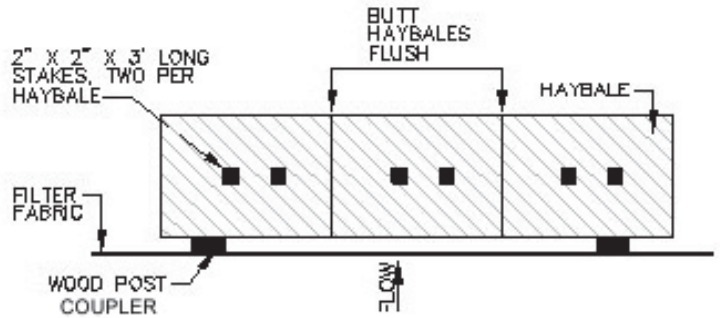
(SINGLE ROW HAYBALES)

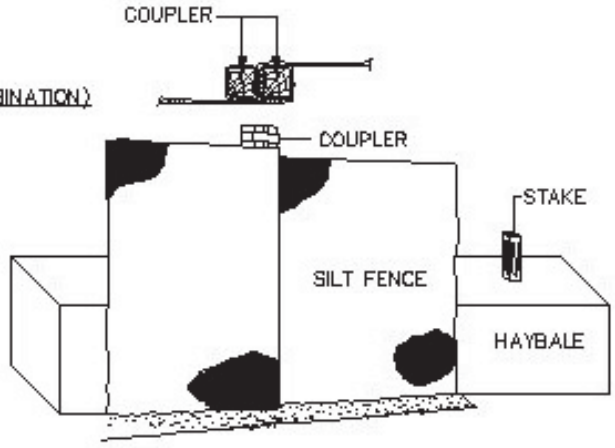


(SILT FENCE)



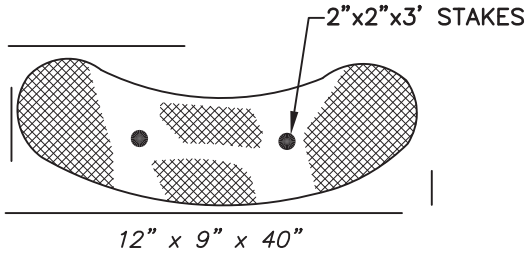
(HAYBALE / SILT FENCE COMBINATION)



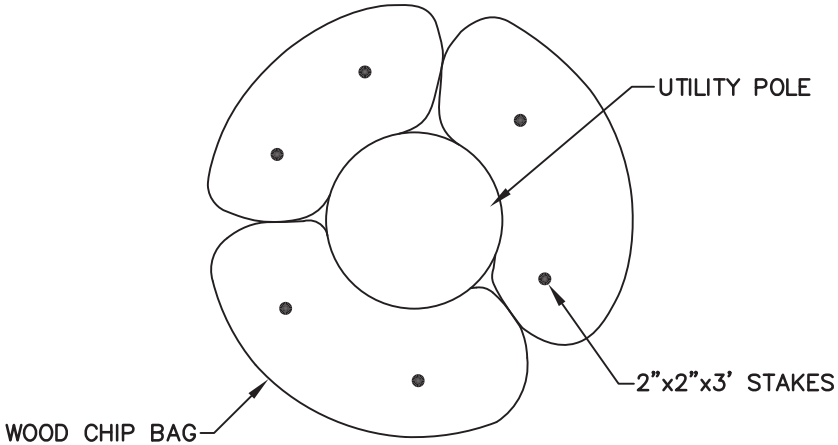


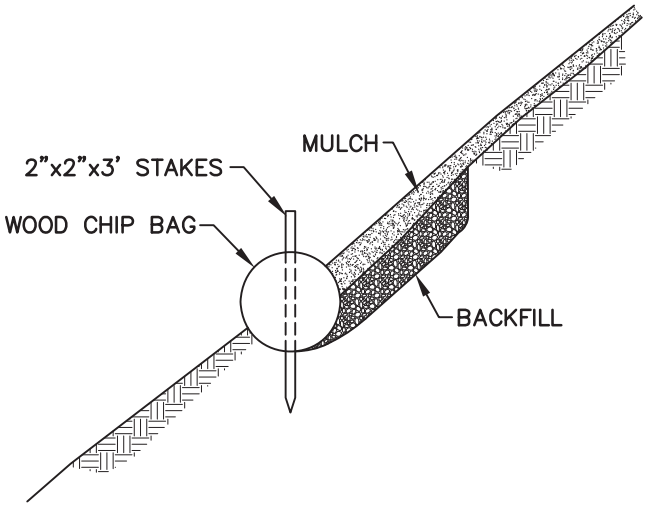
NSTAR ELECTRIC GAS

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PLAN





ENTRENCHED ON SLOPE

NOTE:
1. A MINIMUM OF TWO (2) WOOD STAKES ARE REQUIRED PER WOOD CHIP BAG.

TYPICAL
WOOD CHIP BAG USAGE

SCALE: NONE

NSTAR ELECTRIC GAS

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SECTION 3.3
COMPOST FILTER BERMS

A sediment barrier composed of a long term, wood fiber mulch that can be installed as a berm at the toe of slope and downgradient from disturbed construction areas. The berm is meant to intercept and filter small amounts of sediment from disturbed areas. This type of sediment barrier has become popular with a number of highway departments due to its effectiveness along the edges of most roadways during road construction or repair. The erosion control mix mulch should contain primarily fibrous, elongated, organic material such as shredded or composted bark, stump grindings, and fragmented wood in a well graded mixture of particle sizes. Wood chips, bark chips and reprocessed wood products will not be acceptable. The compost must pass 100% through a 6-inch screen with a minimum of 70% but a maximum of 85% passing though a 0.75-inch screen.

Where:

- Use to prevent sediment from entering an adjacent wetland or waterbody or from compromising a storm drain system.
- The contributing drainage does not exceed ¼ acre foot per 100 feet of barrier and the maximum contributing slope is 2:1.
- Do not use in areas of concentrated flows unless additional support is provided with silt fence.
- Never construct compost filter berms in stream channels or swales.

Installation:

- The filter berms should be installed prior to disturbing soil in the up-gradient drainage area.
- Woody vegetation and tall grasses may need to be removed before installing the berm to prevent voids that would allow sediment under the berm.
- The berm must be a minimum of 12” high and 2 feet wide at slopes less than 5% or slopes steeper than < 2:1 and up to 20 ft long. If the slope is longer and steeper, the berm must be built wider to accommodate the flow.
- The approved mulch mixture can be mechanically sprayed into place or installed with hand tools.
- Use without silt fence reinforcement at the base of shallow slopes, on frozen ground, bedrock, and rooted, forested areas.
- Silt fence should be used in conjunction at low points of concentrated runoff, below culvert outlets, at the base of slopes more than 50 feet long, and in places where stand alone mulch berms have failed.
- When construction activities are completed, the berm and trapped sediments can be spread into the surrounding landscape, seeded and mulched.
- Berms can also be planted with woody vegetation, and seeded with legumes for additional stability.

Maintenance:

- Inspect filter berms regularly and after rain events. Repair as needed with additional mulch/compost.
- Sediment deposits should be removed when they reach half the height of the berm. Berms should be reshaped and repaired when they have eroded, or have become sediment clogged or ineffective.

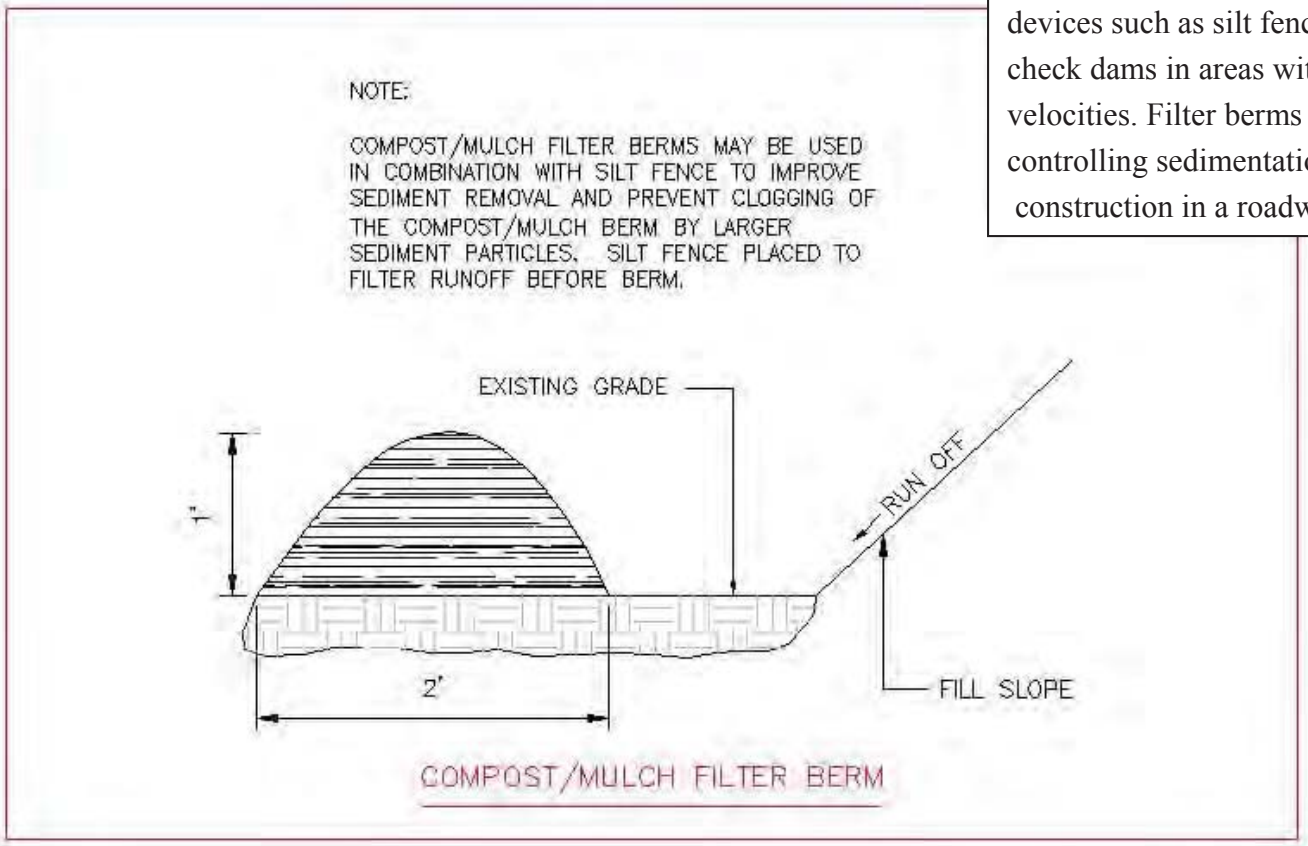
Problems:

- If flow is evident around the edges of the installed berm, extend the barriers or evaluate replacing them with temporary check dams.
- If there is erosion or undercutting at the base or sides of the berm, or large volumes of water are being impounded behind the berm, the berm may be reinforced with an additional sediment control measure such as silt fence or a temporary rock check dam.

(Source: State of Maine, Department of Environmental Protection, Information Sheet; Interim Guideline, Erosion Control Mix-Sediment Barriers)

COMPOST FILTER BERMS

★ Filter berms can be used in conjunction with other erosion control devices such as silt fence or temporary check dams in areas with higher run-off velocities. Filter berms are practical for controlling sedimentation due to construction in a roadway or shoulder.



SECTION 3.4
STRAW WATTLE

Straw wattles are used as an erosion control device to slow runoff velocities, entrain suspended sediments, and also promote vegetation growth until an area is stabilized. They are not generally intended for steep slopes, but rather, to stabilize low to moderate grades where there is a broad area of disturbance. They should be placed lengthwise, perpendicular to the direction of runoff. Straw wattles may also be used along small stream banks to protect areas before vegetation has stabilized the soils. The wattles are constructed from a biodegradable netting sock stuffed with straw and may be left in place once a project is complete.

Where:

- Use to prevent sediment from entering an adjacent wetland or waterbody or from compromising a storm drain system.
- Do not use in areas of concentrated flows unless additional support is provided with silt fence.

Installation:

- Woody vegetation and tall grasses may need to be removed before installing the wattles to prevent voids that would allow sediment under the wattles.
- The spacing of each row of wattles on a slope depends on the angle of the slope, and typically ranges from about 10 to 40 feet apart. Additionally, the texture of the soil should also be taken into consideration – for soft, loamy soils, wattles should be placed closer together; for coarse, rocky soils, they may be placed further apart.
- The ends of each row of wattles on a slope should be slightly turned downhill to prevent ponding behind them.
- Where straw wattles are installed end-to-end, the wattles should be butted tightly together so as not to allow water/sediments to flow between them.
- Straw wattles should be placed in a shallow trench to assure stabilization and soil should be packed against the wattle on the uphill side.
- Straw wattles should be staked securely to the ground by driving a stake directly through the wattle approximately every four feet. A portion of each stake should remain approximately 2 to 3 inches above the wattle.
- Straw wattles should be installed prior to disturbing soil in the up-gradient drainage area.
- Use without silt fence reinforcement at the base of shallow slopes, on frozen ground, bedrock, and rooted, forested areas.
- Silt fence should be used in conjunction at low points of concentrated runoff, below culvert outlets, at the base of long slopes, and in places where stand alone wattles have failed.
- Wattles can also be planted with woody vegetation, and seeded with legumes for additional stability.

Maintenance:

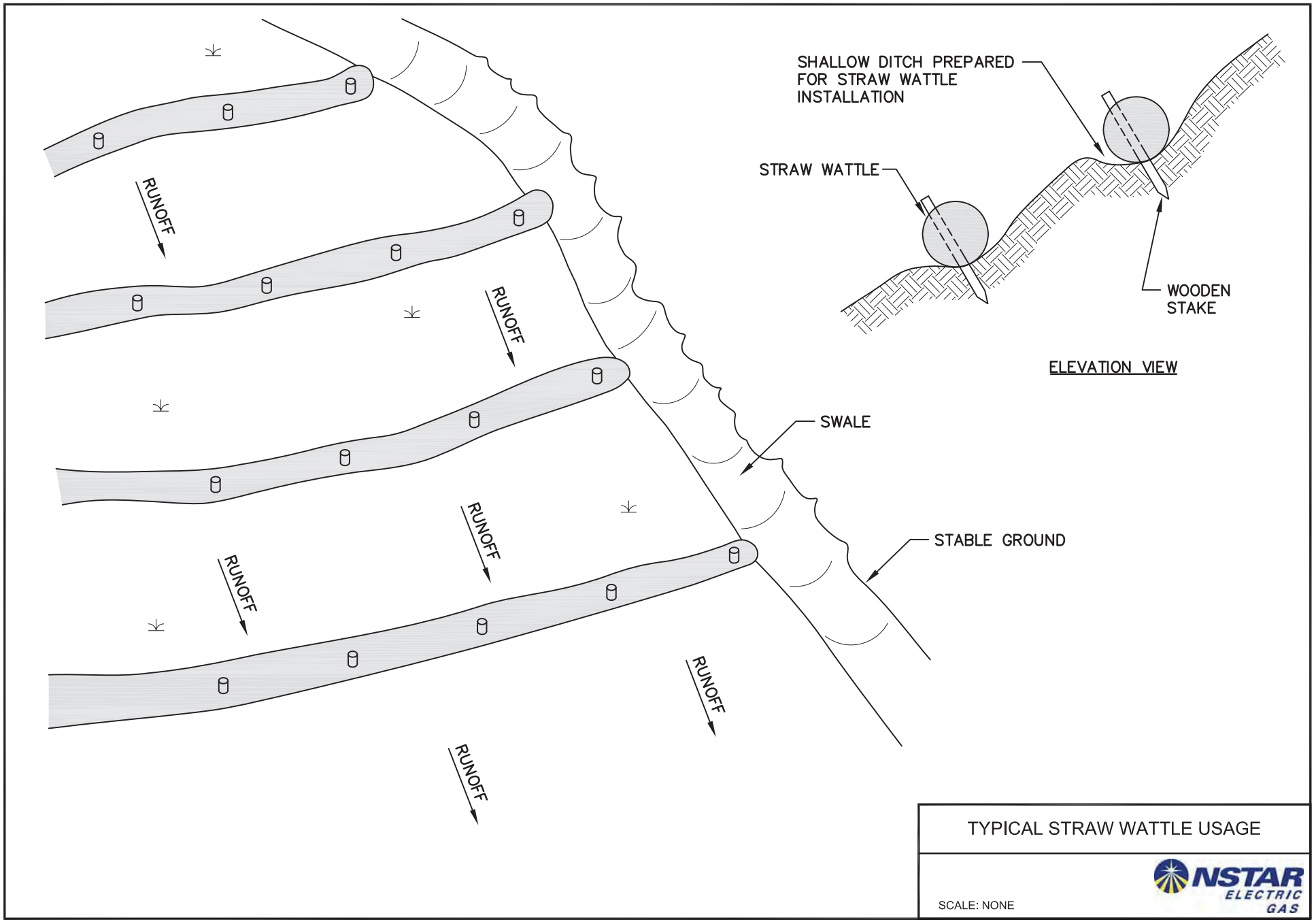
- Inspect wattles regularly and after rain events. Repair as needed with additional wattle and/or stakes.
- Sediment deposits should be removed when they reach half the height of the wattle. Wattles should be reshaped and repaired when they have eroded, or have become sediment clogged or ineffective.

Problems:

- If flow is evident around the edges of the installed wattle, extend the barriers or evaluate replacing them with temporary check dams.
- If there is erosion or undercutting at the base or sides of the berm, or large volumes of water are being impounded behind the berm, the berm may be reinforced with an additional sediment control measure such as silt fence

.

Appendix 5-2


SHALLOW DITCH PREPARED FOR STRAW WATTLE INSTALLATION
STRAW WATTLE
WOODEN STAKE
ELEVATION VIEW
RUNOFF
RUNOFF
RUNOFF
RUNOFF
RUNOFF
RUNOFF
SWALE
STABLE GROUND
TYPICAL STRAW WATTLE USAGE
SCALE: NONE
NSTAR ELECTRIC GAS

SECTION 3.5
CATCH BASIN/INLET PROTECTION

Temporary devices placed around and within existing catch basin inlets to protect the stormwater management system from high sediment loads and high velocities, while disturbance due to construction is occurring in the drainage area.

HAYBALES

Where:
- Areas where stormwater runoff is relatively small and velocities are low.
- Areas where shallow sheets of run-off are expected.
- Optimal in areas which are not paved in order to stake the haybales, however haybales can be placed on pavement without stakes.
- Areas which have the storage space to allow temporary ponding since haybales are one of the least permeable protection methods.

Installation:
- Installation is similar to perimeter haybale barriers.
- Bales should be wire bound or string tied. The bales should be placed so that the bindings are on the sides of the bales rather than against the ground.
- Bales should be installed in a box configuration around the drop inlet and the ends of the bales should be placed tightly against each other.

FILTER FABRIC

Where:
- Areas where stormwater runoff is relatively small and velocities are low.
- Areas where shallow sheets of run-off are expected.
- Use where the inlet drains a small, nearly level area.

Installation:
- Cut fabric from a single roll.
- Place fabric beneath catch basin grate.

Maintenance for both:
- Inspect weekly and after each major rain event.
- Remove accumulated sediment when it reaches ½ of the height of the bales or fabric.
- Replace haybales or repair fence as necessary.
- Remove after area is permanently stabilized.

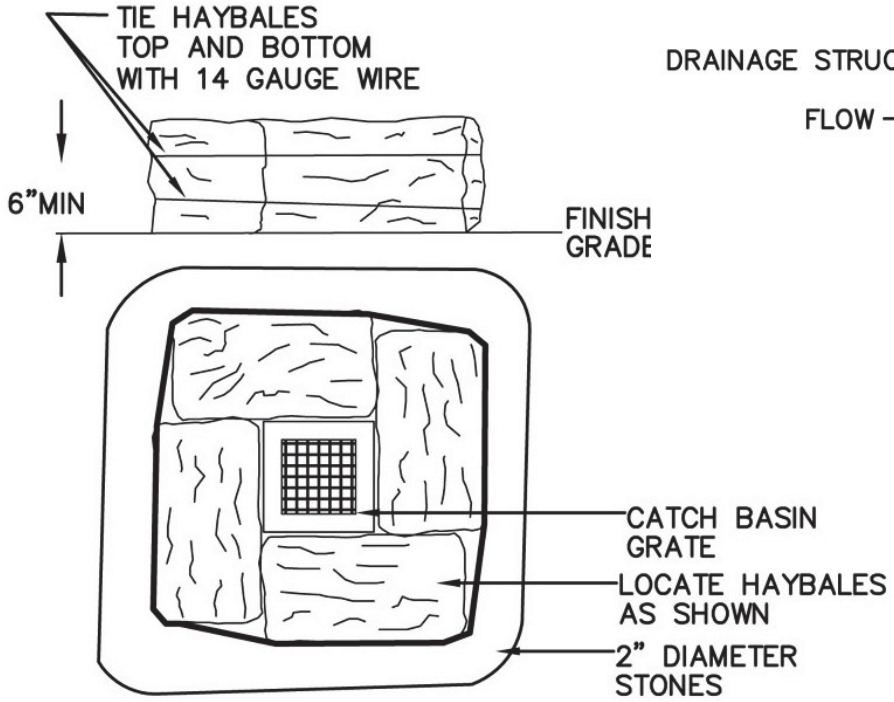
FILTER BASKETS

Where:
- To be installed within catch basins in combination with haybales, fabric, stone or sod drop inlets.
- Can potentially be used alone where drainage area is small with shallow flows.

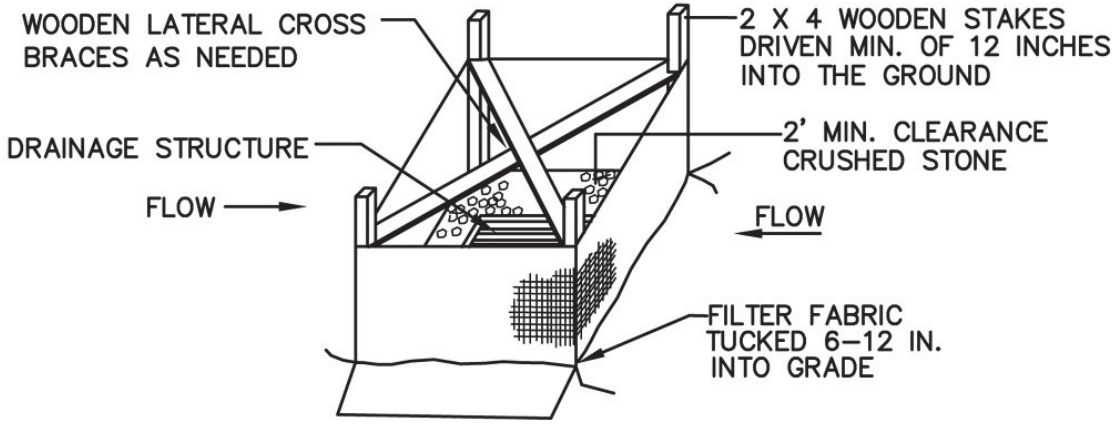
Installation:
- Several trademarked/name brand filter baskets exist and should be installed per the manufacturer's instructions.
- Almost all consist of a porous fabric bag which is fitted under the catch basin grate.
- Sediments are filtered out of the stormwater and accumulate in the basket or bag.

Maintenance:
- Inspect inlet and fabric weekly and after each major rain event.
- Remove sediment when the bag is halfway full.
- Replace bags as necessary due to wear or ripping.

CATCH BASIN / INLET PROTECTION – HAYBALE AND FABRIC DROP INLETS



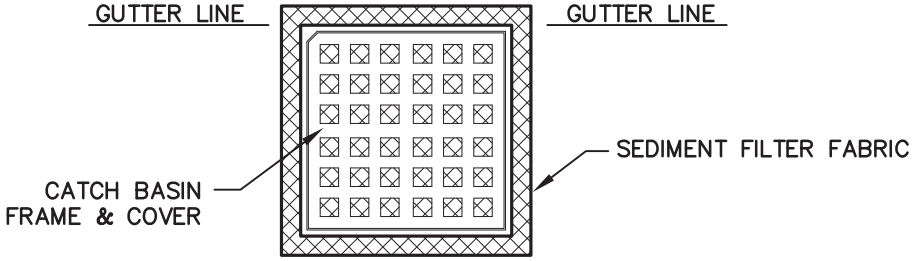
HAYBALE INLET PROTECTION



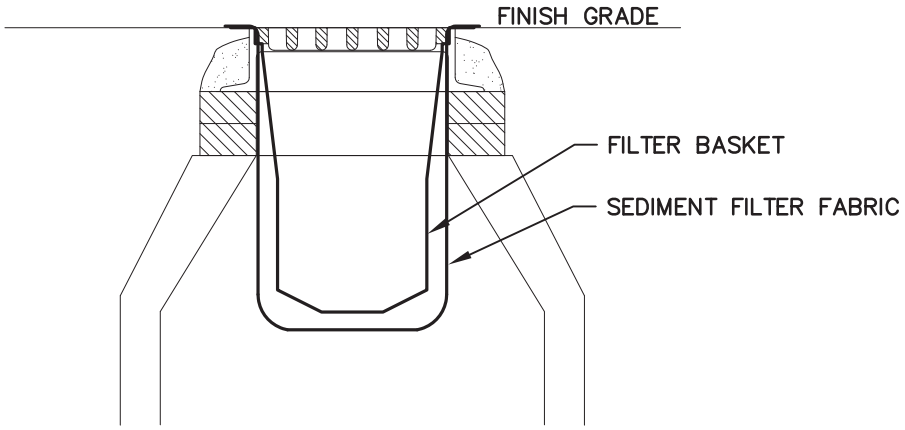
FABRIC DROP INLET

★ Haybale and Fabric Drop inlet protection can be used in areas where stormwater runoff volume is relatively small and velocities are low. They are most applicable in areas which are not paved.

Appendix 5-2



PLAN VIEW



ELEVATION VIEW

NOTES:

1. FILTER BASKET SHALL BE "SILT SAK" BY JENNIAN, MELROSE, MA; "DANDY BAG" BY DANDY PRODUCTS (1–800–591–2284); DRAIN PAC (91–800–272–2832); OR APPROVED EQUIVALENT.
2. FILTER BASKETS SHOULD BE USED IN COMBINATION WITH ANOTHER INLET PROTECTION MEASURE SUCH AS SEDIMENT FILTER FABRIC IF DRAINAGE AREA IS SMALL WITH SHALLOW FLOWS.

TYPICAL
CATCH BASIN / INLET PROTECTION
WITHIN PAVED ROAD SURFACE
SEDIMENT FILTER FABRIC
AND FILTER BASKET

SCALE: NONE

NSTAR ELECTRIC GAS

Appendix 5-2

CATCH BASIN / INLET PROTECTION – STONE OR SOD MOUND DROP INLETS AND FILTER BASKETS

Temporary devices placed around and within existing catch basin inlets to protect the stormwater management system from high sediment loads and high velocities, while disturbance due to construction is occurring in the drainage area.

SOD OR STONE MOUND DROP INLETS

Where:

- Areas where stormwater run-off is relatively heavy and overflow capacity is necessary.
- Sod should only be used in well vegetated areas and when the general area around the inlet is planned for vegetation.
- Sod is well suited for lawns.
- Stone mounds are well suited for the heaviest flows in all instances.

Installation:

- For Sod: A mound of permanently vegetated sod should be placed around the perimeter of the inlet to a minimum height of 6 inches.
- For Stone: Stone can be used alone or in combination with stacked concrete blocks. Gravel alone will slow drainage time and increase settlement.
- Place wire mesh with ½" openings over the inlet with 1 foot extending on each side. Overlay with filter fabric.
- Surround inlet with mound of gravel, 1" diameter or smaller, to a minimum height of 6", placed over the mesh.
- If blocks are used, stack them around the inlet, between 12 and 24" high, place mesh over the openings and pile the gravel against the outside face of the blocks.

Maintenance:

- Inspect weekly and after each major rain event.
- Remove accumulated sediment when it reaches ½ of the height of the filter mound. Stone especially must be regularly maintained.
- Repair erosion as necessary.

Problems:

- Storm flow bypassed inlet and causes erosion:
  - The top of the structure is too high.
- The trap is not efficient and/or there is sediment overload:
  - The drainage area is too large to handle load. Consider constructing a temporary sediment trap.
- Scour holes develop (if blocks are being used):
  - Blocks are not placed snugly against the inlet grate.

FILTER BASKETS/SILT BAGS

Where:

- To be installed within catch basins in combination with haybales, fabric, stone or sod drop inlets.
- Can potentially be used alone where drainage area is small with
- shallow flows.
- May cause ponding or may rip under heavier flows without the additional external filtering method.

Installation:

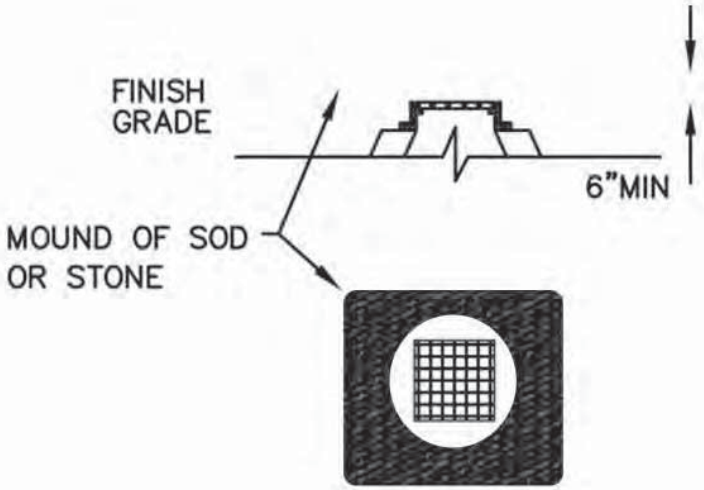
- Several trademarked/name brand filter/silt bags exist and should be installed per the manufacturer's instructions.
- Almost all consist of a porous fabric bag which is fitted under the catch basin grate.
- Sediments are filtered out of the stormwater and accumulate in the bag.

Maintenance:

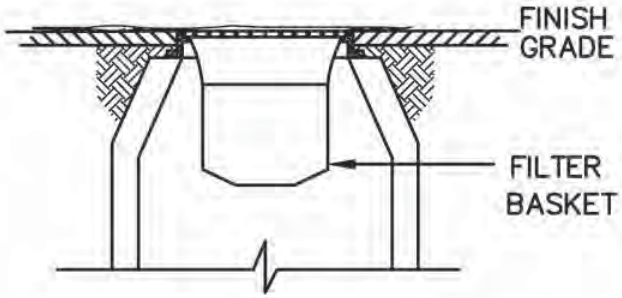
- Inspect inlet and fabric weekly and after each major rain event.
- Remove sediment when the bag is halfway full.
- Replace bags as necessary due to wear or ripping.

CATCH BASIN / INLET PROTECTION – STONE OR SOD MOUND DROP INLETS AND FILTER BASKETS

★ Stone or Sod Drop inlet protection should be used where run-off is relatively heavy. Sod should be used where the surrounding area will be eventually vegetated, while stone can be used in the heaviest flows.



STONE/SOD DROP



FILTER BASKET SHALL BE
"SILT SAK" BY JENNIAN, MELROSE, MA;
"DANDY BAG" BY DANDY PRODUCTS (1–800–591–2284);
DRAIN PAC (1–800–272–2832); OR APPROVED EQUIVALENT.

FILTER BASKET

★ Filter baskets should be used in combination with another inlet protection measure unless the drainage area is small with shallow flows.

NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 3.6
EROSION CONTROL MATS AND BLANKETS

Organic or synthetic materials applied to the soil surface as a continuous sheet. Used to protect disturbed areas from erosion and to enhance seed growth, typically where moving water is likely to wash out new vegetative plantings and mulches are ineffective. Commonly used techniques include **Erosion control blankets** which are made of mulch material surrounded by a plastic netting, **Jute mats** which are sheets of woven jute fiber, and **Turf reinforcement matting** which is usually a geotextile matrix most effective for channels.

Where:

- Especially effective on steep slopes, ditches and channels where mulch is ineffective. This includes stream banks.
- Effective option during winter construction for temporary stabilization of extreme slopes.
- Mulches may be more effective for flatter areas.

Installation:

- The mats and blankets must be installed correctly to work effectively.

Erosion Control Blankets	Jute Mats	Turf Reinforcement Matting
• Secure to the ground using long metal staples. • Ensure that erosive volumes of water cannot flow under the blanket.	• Secure to the ground using long metal staples. • Leave to degrade in place over time.	• Place mats on soil surface and cover with topsoil and seed.

Maintenance:

- Inspect weekly and after major precipitation events.
- Check for movement of topsoil or erosion.
- If washout, breakage or erosion occurs, repair surface, reseed, replace topsoil, and install new netting.
- Inspect until vegetation is firmly established.

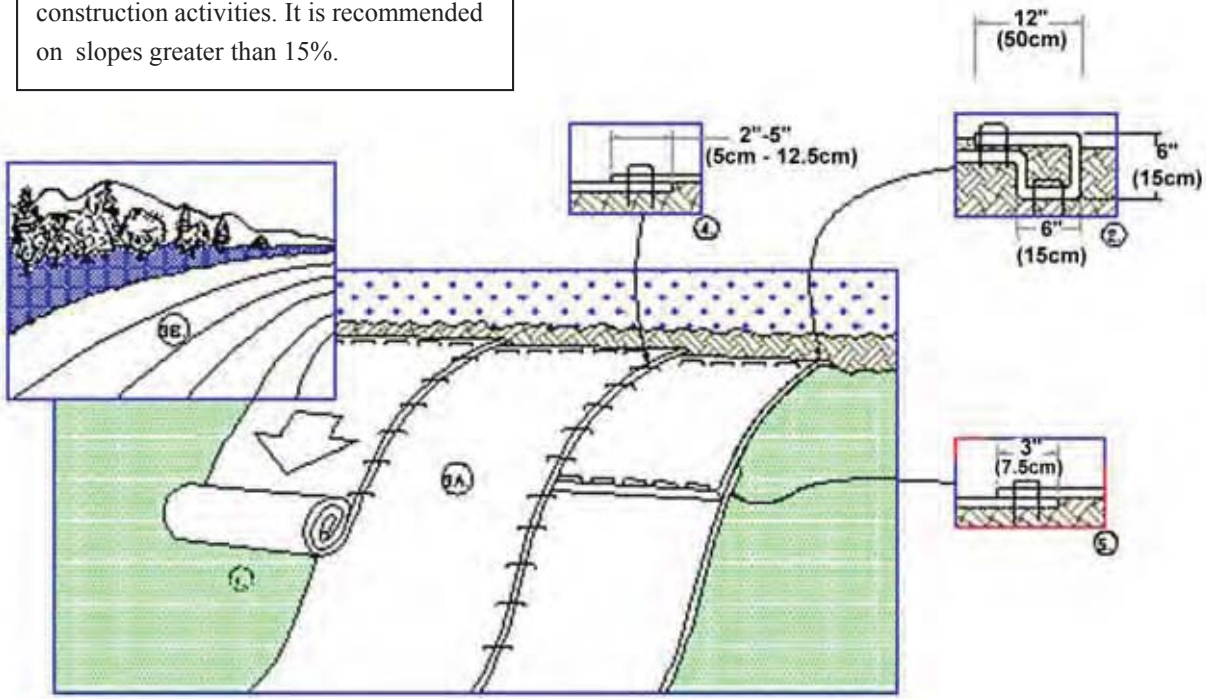
Potential Problems:

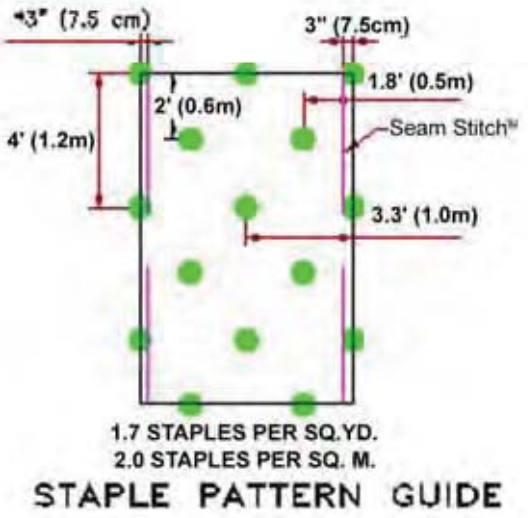
- Erosion, washout or poor plant establishment:
  - Inadequate coverage.
- Erosion of the channel bottom:
  - Channel grade and liner not appropriate for streambank/ditch substrate.
  - Make modifications in material if necessary.
- Seed, topsoil and mulch lost to wind and runoff:
  - Staple spacing is not sufficient.
  - Install additional staples.

EROSION CONTROL MATS AND BLANKETS

Erosion control blankets are often used to stabilize streambanks following construction activities. It is recommended on slopes greater than 15%.







EROSION MATTING AND BLANKETS

NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 3.7
STORMWATER CONVEYANCE – SWALES AND CHANNELS

Grass lined channels, riprap lined channels, and vegetated swales are all natural or constructed waterways or outlets utilized to convey stormwater away from the work area to a stable location, while at the same time, reducing the velocity and turbidity of the flow. Use in all areas where concentrated run-off would otherwise cause erosion/flooding.

GRASS LINED CHANNELS (Stabilized with vegetation)

Where:
- Slopes are less than 5% and space is available for large cross section.
- Vegetative lining will provide sufficient stability.

Installation:
- Remove trees, brush and stumps.
- Excavate and shape channel to dimensions on plans. Overcut 0.2 ft for vegetative growth.
- Install temporary liner or riprap at inflows and stabilize outlets.
- Vegetate immediately after construction and divert water until grass establishes. Install matting if flow cannot be diverted.
- Install sod rather than seeding where slopes approach 5%.
- Spread topsoil to a minimum of 4 inches where soil conditions are unfavorable. Seeded channels should be mulched.

VEGETATED SWALES (Stabilized with dense vegetation)

- The vegetated swale is used for water quality improvement and peak runoff reduction, while the grassed waterway is used to convey runoff at a non-erosive velocity.

Where:
- Dense vegetation can be established and a stable outlet constructed.
- Small drainage areas w/ relatively small amount of impervious cover.
- Highway medians as an alternative to curb and gutter systems.

Installation:
- Minimum length 200 ft., Min. capacity 10 year, 24 hour storm.
- Maximum design velocity 1ft/second in 10 year storm.
- Recommended slope 2-4%.
- Vegetate with water resistant grasses and divert flow until established.

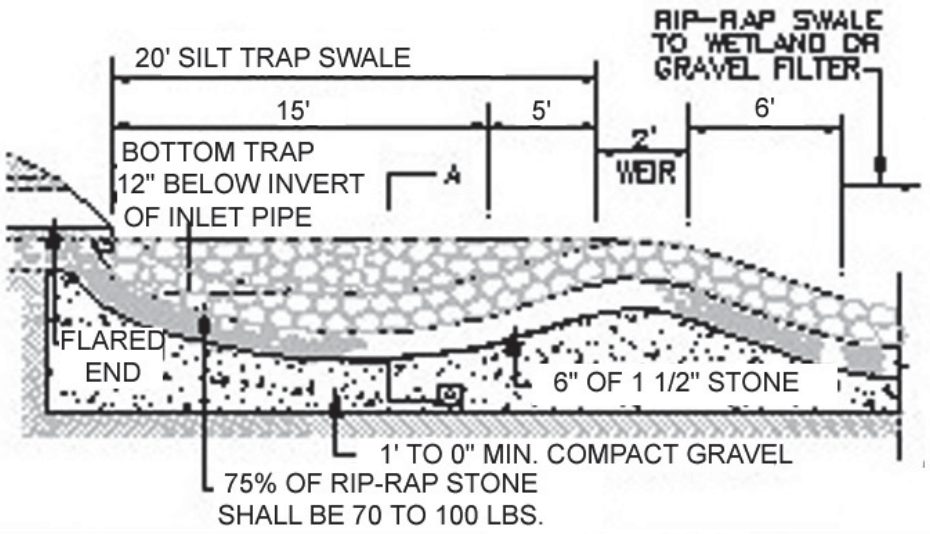
RIPRAP LINED CHANNELS (Contains lining of riprap or stone)

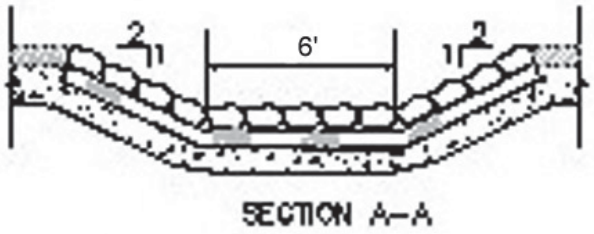
Where:
- Use on sites where channel flow velocities exceed those acceptable for grass lined waterway.
- Use where vegetative establishment is not possible or there are steep grades, wetness, highly erodible soils, seepage or prolonged base flow.

Installation:
- Remove trees, brush and vegetation from channel area.
- Stabilize inlets and install outlet protection.
- Construct channel and install filter and lining as shown on plan.
- Use the maximum stone size for riprap plus thickness of filter.

Maintenance for all three:
- Inspect swale/channel after every rain event (0.5” or >).
- Repair and/or reseed rill or gully erosion.
- Remove accumulated sediments reaching a depth of 6 inches.

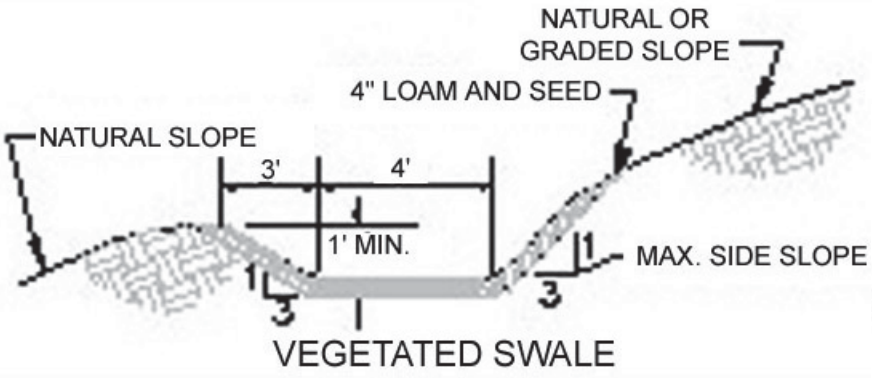
STORMWATER CONVEYANCE – SWALES AND CHANNELS



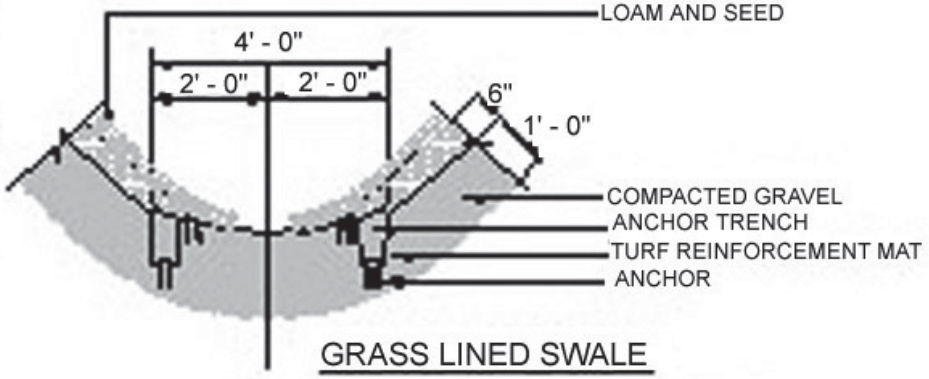


RIP RAP SWALE





VEGETATED SWALE



GRASS LINED SWALE

NSTAR ELECTRIC GAS

SECTION 3.8
LEVEL SPREADER

Also referred to as grade stabilization structures, level spreaders are excavated depressions constructed at zero percent grade across a slope. They convert concentrated flow into sheet flow and outlets it to stable areas without causing erosion.

LEVEL SPREADER

Where:
- Drainage area is 5 acres or less.
- Soil is undisturbed (not fill).
- A level lip can be installed without filling.
- The area directly below the spreader is stabilized by existing vegetation.
- Water will not become concentrated below the spreader and can be released in sheet flow down a stabilized slope without causing erosion.
- There is at least 100 feet of vegetated area between the spreader and surface waters.
- The slope of the area below the spreader lip is uniform and a 10% grade or less.
- There will be no construction traffic over the spreader.

Installation:
- The grade of the channel for the last 20 feet entering the level spreader should be no steeper than 1%.

Grade:	0% (Flat)	
Length:	Minimum 5 ft	Maximum 50 ft
Width:	At least 6 ft	
Depth:	6 inches (Measured from the lip and should be uniform)	

- Stabilize the level spreader with an appropriate grass seed mixture.
- Mulch if necessary.
- Protect the level lip with an erosion stop and jute netting/excelsior matting.
- The downgradient area should have stable, complete, erosion resistant vegetative cover.

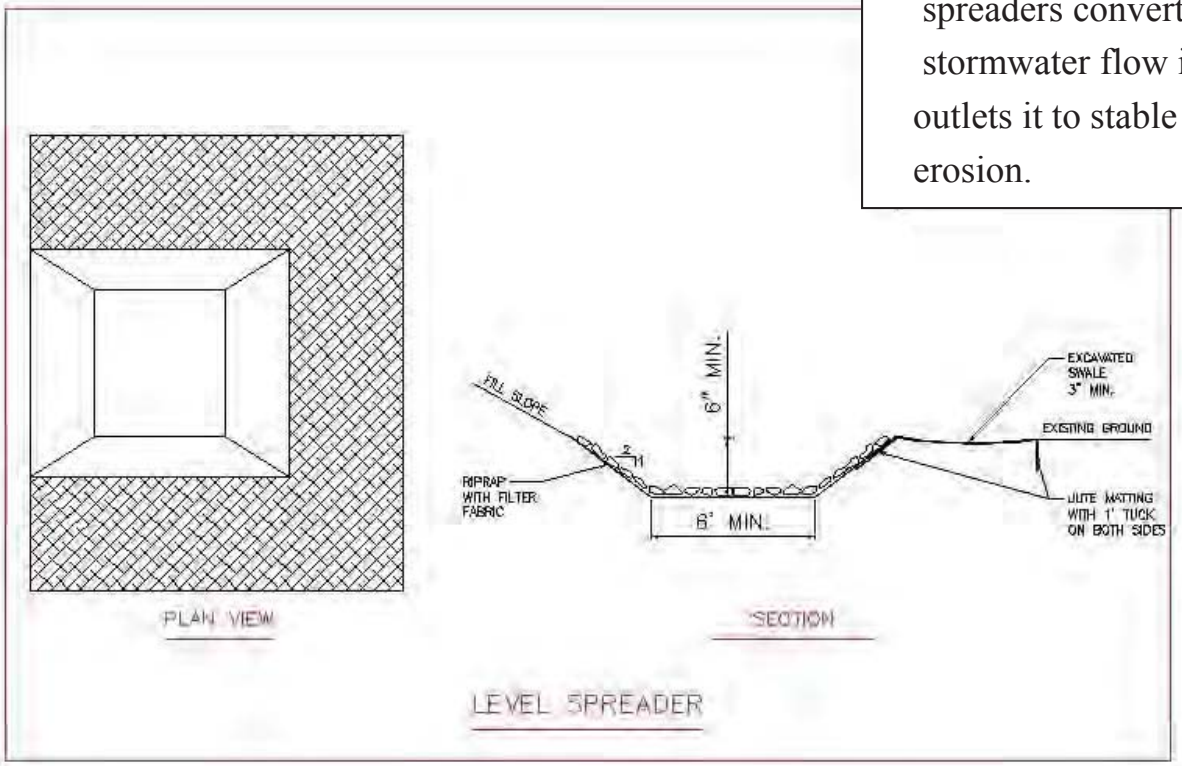
Maintenance:
- Inspect after every rain event and remove accumulated sediment.
- Repair erosion damage and re-seed as necessary.
- Mow vegetation occasionally to control weeds and the encroachment of woody vegetation.

Problems:
- Formation of channels and erosion in level spreader:
  - Level spreader is not uniformly flat.
  - Repair low spots in the level spreader.
- Erosion is occurring downgradient of the level spreader:
  - The vegetation is not stable. Re-seed the area.
  - Level spreader is not long enough or not wide enough.

Appendix 5-2

LEVEL SPREADER

★ Level spreaders are excavated depressions constructed at zero percent grade. When built across a slope, level spreaders convert concentrated stormwater flow into sheet flow and outlets it to stable areas without causing erosion.



NSTAR ELECTRIC GAS

SECTION 3.9
CHECK DAMS

Check dams are small, temporary dams constructed across a drainageway to lower the velocity of stormwater flows and create a temporary basin for collecting sediment. They are often used within grass lined and rip rap lined channels, or vegetated swales. They can be constructed of haybales or rock.

ROCK/STONE CHECK DAM

Where:
- Temporary channels.
- Permanent channels where vegetation has not yet been established.
- Channel lining is infeasible.
- Velocity checks are required.
- Drainage area is less than 2 acres.

Installation:
- Maximum height of check dam should be 2 feet.
- The center of the check dam should be at least 6 inches lower than the outer edges.
- The stone used should be approximately 2-3" stone.

Maintenance:
- Inspect after each major rain event.
- Remove accumulated sediment.
- Repair eroded areas.
- Replace or add rock as necessary.
- Remove after area is permanently stabilized.

Problems:
- Stone displaced from face of dam:
  - Stone size too small and/or face too steep.
- Erosion downstream from dam:
  - Install stone lined apron.
- Erosion of abutments during high flow:
  - Rock abutment height too low.
- Sediment loss through dam:
  - Inadequate layer of stone on inside face or stone too coarse to restrict flow through dam.

HAYBALE CHECK DAM

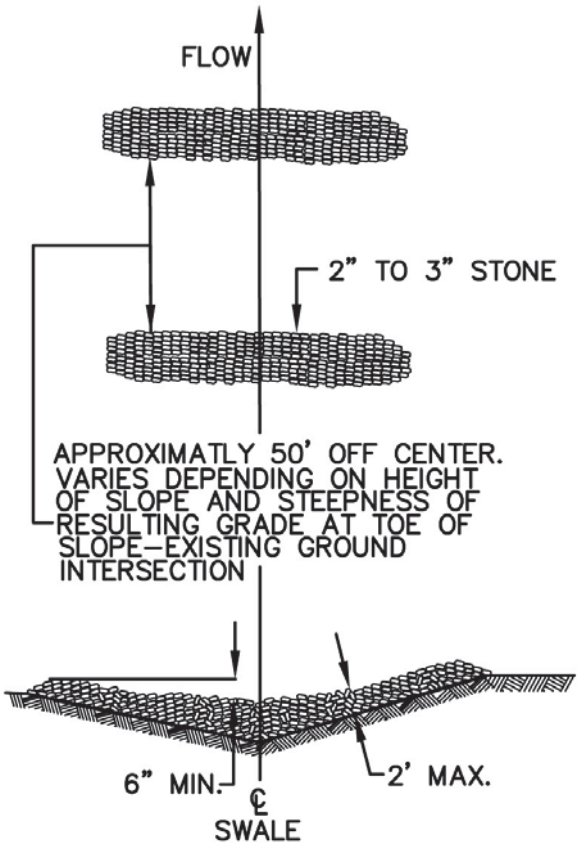
Where:
- Temporary channels.
- Permanent channels where vegetation has not yet been established.
- Channel lining is infeasible.
- Velocity checks are required.
- Drainage area is less than 2 acres.

Installation:
- Double stake haybales in single row, lengthwise and perpendicular to the channel.
- The ends of the bales should tightly abut each other.
- The top of the center bales of the check dam should be at a lower elevation than the bottom of the outer bales.

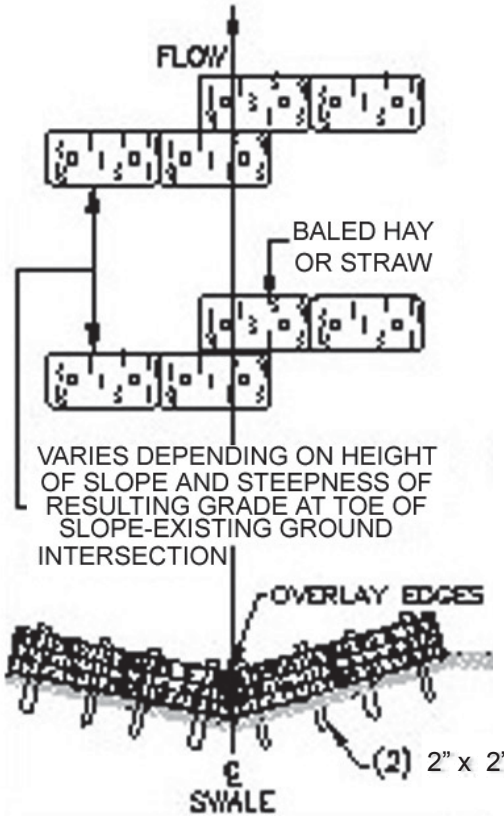
Maintenance:
- Inspect after each rain event.
- Remove accumulated sediment.
- Repair eroded areas.
- Replace worn out bales as necessary.
- Remove after area is permanently stabilized.

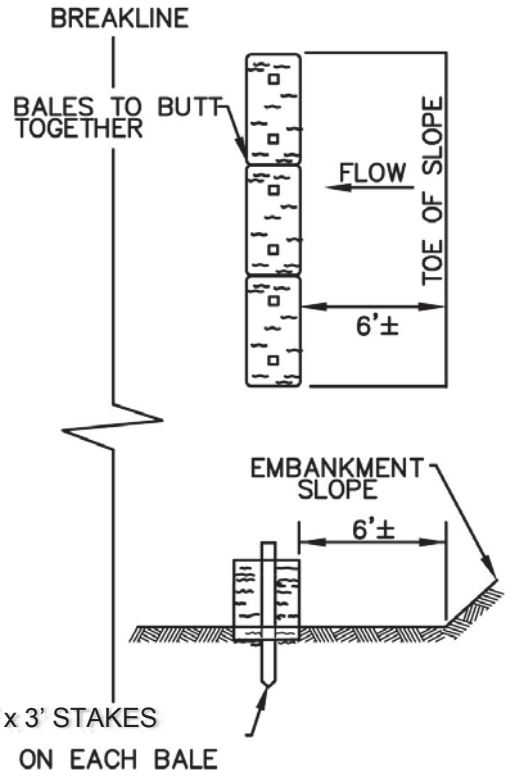
Problems:
- Water is moving around the dam rather than through or over it:
  - Ensure that bales are at proper relative elevations.

CHECK DAMS



STONE CHECK DAM





HAYBALE CHECK DAM

★ Use check dams to slow the velocity of stormwater flows in drainageways and swales.

NSTAR ELECTRIC GAS

SECTION 3.10
TEMPORARY AND PERMANENT DIVERSIONS AND WATER BARS

All three practices are intended to control and convey runoff from slopes in order to prevent and reduce erosion. Diversions are ridges or channels constructed across steep slopes that convey the runoff to a stable outlet at a non-erosive velocity. Water bars are built diagonally across sloping roads or right-of-ways in order to divert the runoff at selected, non-erosive intervals.

PERMANENT DIVERSION

Where:
- Use on slopes with high runoff velocities to break up concentrated flow.
- Can be installed as temporary diversion and completed as permanent when the site is stabilized, or it can be installed in final form initially.

Installation:
- Before construction, remove woody vegetation and fill and compact ditches and gullies which must be crossed.
- Remove vegetation around the proposed location of the base of the diversion ridge so a strong bond between the ground and fill is formed
- Stabilize the outlet of the diversion channel which can include natural or constructed vegetated outlets, level spreaders which discharge to areas with good sod or erosion resistant litter covers, or sediment traps.
- Stabilize the diversion channel with riprap, vegetation, paving, or stone
- To prevent sediment accumulation, install a filter strip of close growing grass above the channel.

Maintenance:
- Inspect bi-weekly and repair any erosion problems.
- Remove accumulated sediment and debris.

WATER BAR/TEMPORARY DIVERSION

Where:
- To prevent erosion on a sloping right of way, less than 100-feet in width.
- Must be designed to be stable throughout their useful life and meet the criteria in the table, otherwise, permanent diversions should be used.

Installation:
- Maximum capacity should be the peak runoff from a 10-year storm.
- Set water bar direction to utilize stable outlets and do not allow upslope water bar runoff to converge with down slope water bars.
- Construct the bar immediately after vegetation has been cleared on constant or slightly increasing grades, not exceeding 2%. Avoid reverse grades.
- Mark the location and width of the ridge and disk the entire length.
- Fill ridge to above the design height and compact with wheeled equipment to the design cross section.
- Construct sediment traps or outlet stabilization measures as needed.
- Seed and mulch diversions intended for use for more than 30 days.
- After the area has been permanently stabilized, remove the ridge and channel to blend with the natural ground level.

Maintenance:
- Inspect each week and after rain event and repair damage caused by construction traffic or erosion.
- Remove accumulated sediment and stabilize outlets as necessary.
- If necessary, repair ridge to a positive grade and cross section, and add gravel at crossing areas.

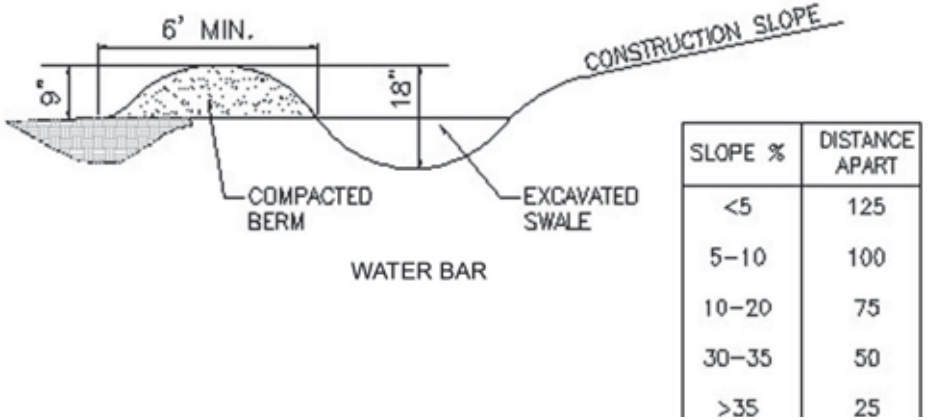
Minimum Cross Section:

Top Width	Height	Side Slopes
0ft	1.5ft	4:1
4ft	1.5ft	2:1

Maximum Recommended Spacing:

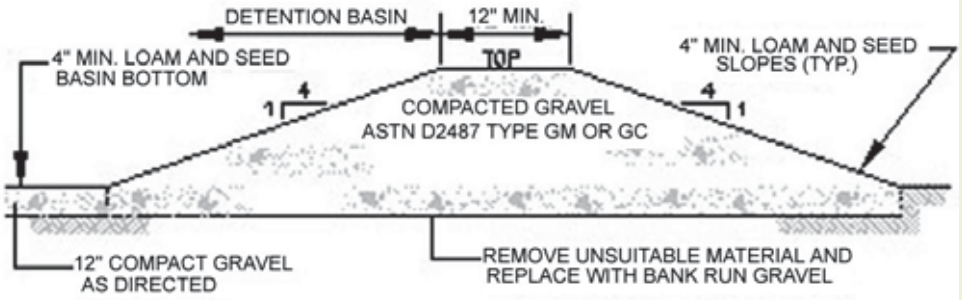
Land Slope (%)	Spacing (ft)
1 or less	300
2	200
3-5	150

TEMPORARY AND PERMANENT DIVERSIONS AND WATER BARS



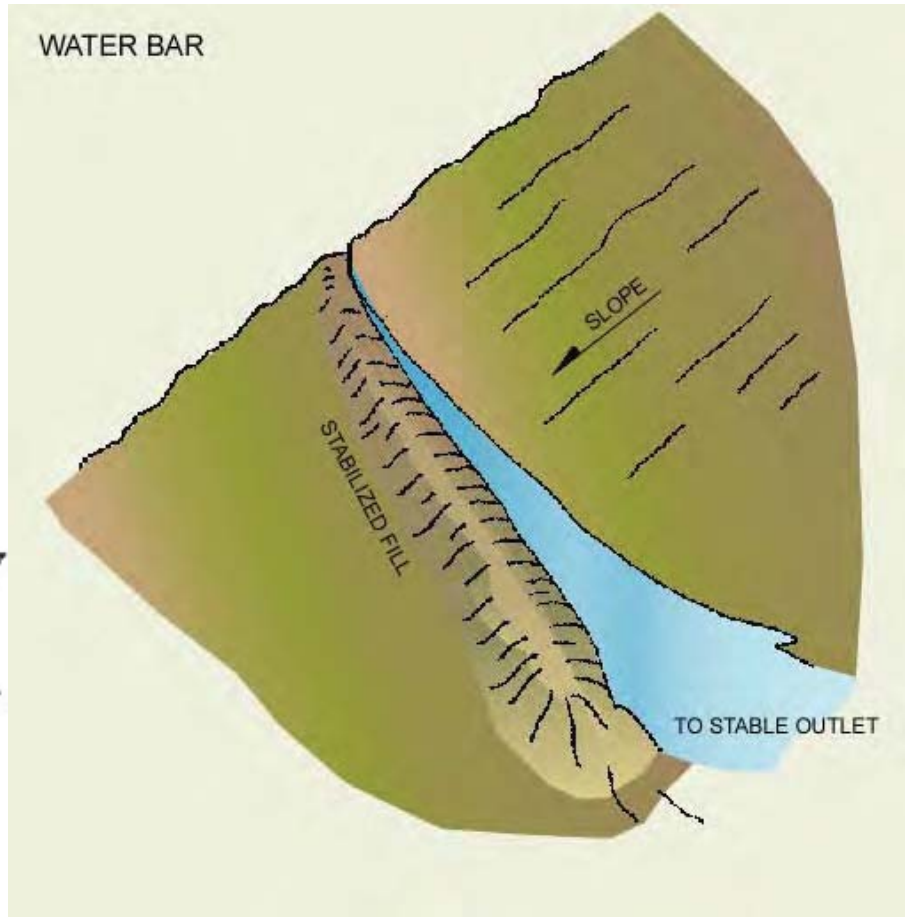
WATER BAR

SLOPE %	DISTANCE APART
<5	125
5–10	100
10–20	75
30–35	50
>35	25



NOTE:
FILL FOR DIKES SHALL BE A COMBINATION OF GRAVEL, SAND AND SILT TO ENSURE WATER TIGHTNESS AND STABILITY.

DETENTION BERM



NSTAR ELECTRIC GAS

SECTION 3.11
TEMPORARY SEDIMENT TRAP AND SEDIMENT BASIN

Both structures are used to intercept stormwater runoff and retain it long enough for sediment to settle out. The sediment trap is a temporary measure installed in drainage ways and used more to detain run-off while the sediment basin is a more permanent measure that can store runoff and sediment in areas where other erosion control measures are not adequate to prevent off-site sedimentation.

TEMPORARY SEDIMENT TRAPS

Where:

- Drainage area 5 acres or less.
- Formed by excavating a pond or placing an earthen embankment across a low area or drainage swale.

Installation:

- Clear, grub and strip all vegetation and root material from area of embankment and place embankment fill in 9-inch lifts, maximum.
- Compact fill and construct side slopes 2:1 or flatter.
- Overfill embankment to 6” above design elevation.
- Excavate trapezoidal outlet section from compacted embankment. Allow for thickness of stone side slopes.
- Install filter fabric under riprap and extend fabric up the sides to the top
- Install specified stone to lines and grades shown on plans and work smaller stones into the voids.
- Extend outlet apron below toe of dam on level grade until stable conditions are reached (5 feet minimum).
- Cover inside face of stone outlet section with a 1-foot layer of ½ to ¼ inch aggregate.
- Vegetate embankments, spillways and disturbed areas down stream of the structure immediately with temporary or permanent species.

Maintenance:

- Inspect after every rain event and remove accumulated sediment, remove erosion and piping holes, clean or replace the spillway gravel and inspect vegetation.
- Install a stake with a marking at ½ the design depth. Remove sediment when it reaches this mark.

Problems:

- Over topping of dam may result due to inadequate spillway size.
- Inadequate storage capacity may be due to the need to remove sediment more frequently.
- Erosion of the embankment may be due to inadequate vegetative cover.

SEDIMENT BASINS

Where:

- Install only where there is sufficient space and appropriate topography so that the basin is large enough to handle the maximum expected amount of site drainage.
- Install in areas with drainage areas of 100 acres or less.

Installation:

- Locate the basin in an easily accessible upland area, not wetland area.
- Locate the basin so that it intercepts the largest possible amount of runoff from the disturbed area.
- Divert sediment-laden water to the upper end of the sediment pool to improve trapping effectiveness.
- Basin should have a minimum volume based on ½ inch of storage for each acre of drainage area.

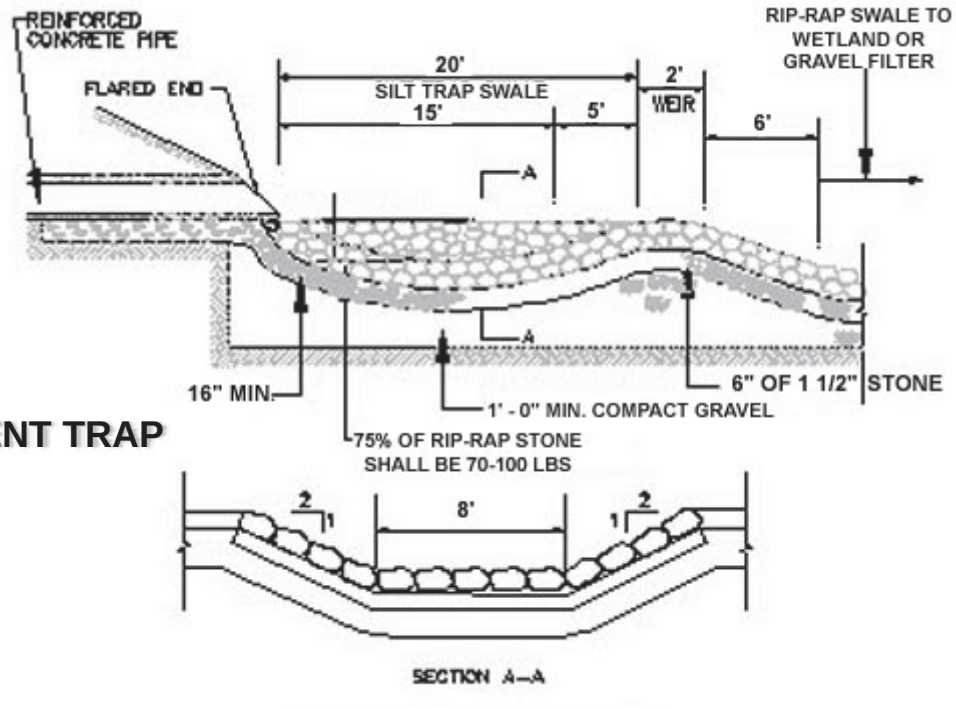
Maintenance:

- Inspect basin after each rain event.
- Remove and properly dispose of sediment when it accumulates to one-half design volume (marked by a reference stake).
- Monitor embankment, spillway, and outlet for erosion. Repair erosion problems immediately.
- Clean and or replace gravel when needed.

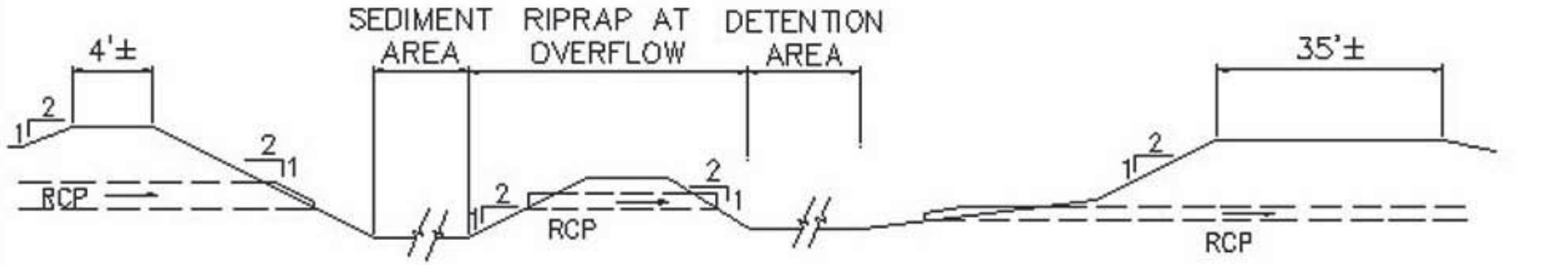
TEMPORARY SEDIMENT TRAP AND SEDIMENT BASIN

★ Use temporary sediment traps or permanent sediment basins to intercept run-off and retain it long enough for sediment to settle out during construction.





SEDIMENT TRAP



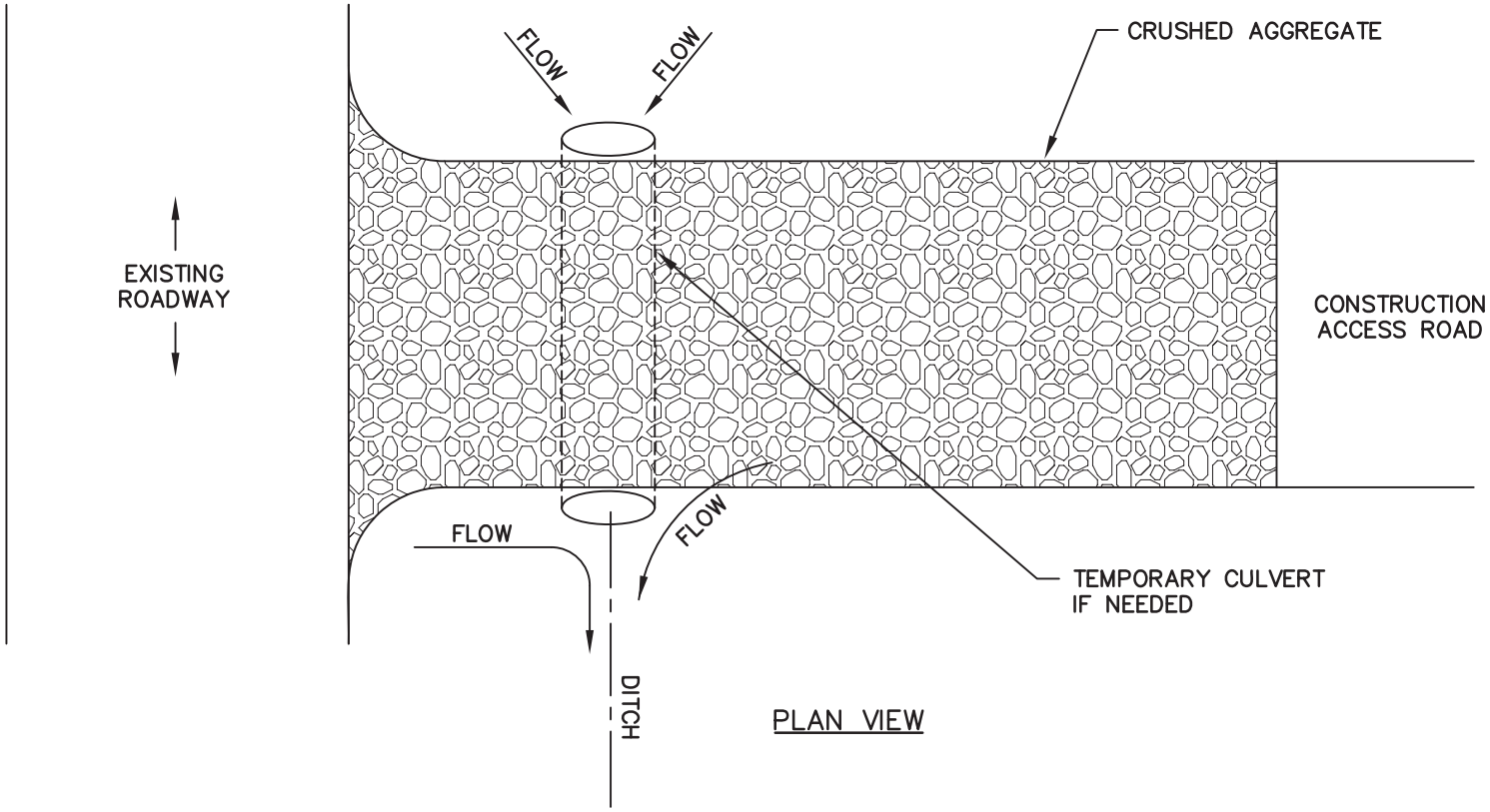
SEDIMENT BASIN

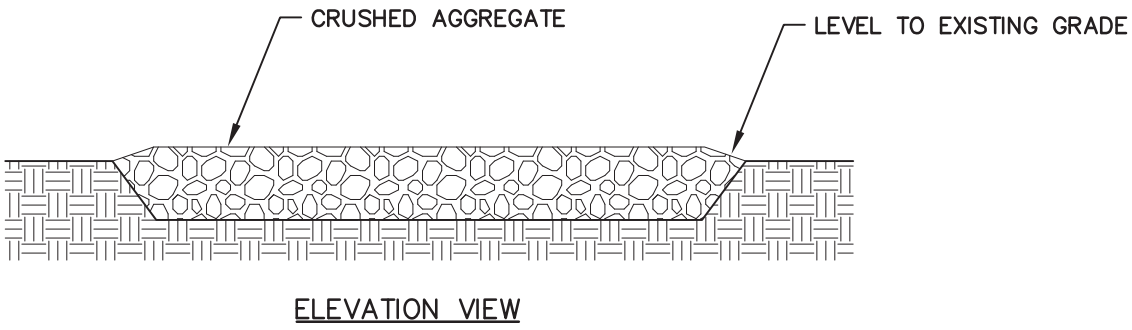
NSTAR ELECTRIC GAS

SECTION 3.12
CONSTRUCTION ENTRANCE TRACK PAD

Where access roads or construction areas connect to paved roads, a stone track pad must be installed at the construction entrance to prevent construction machinery from tracking soil onto paved roadways. Materials appropriate to construction site soil conditions should be employed and/or replenished, as necessary. Further, muddy conditions may warrant the use of a tire wash station and procedures should be established to ensure soils are not tracked off site. Stone in an entrance track pad may also need to be removed and refreshed and/or cleaned as needed if the pad becomes clogged with soil.

Appendix 5-2





TYPICAL
CONSTRUCTION ENTRANCE TRACK PAD

NSTAR ELECTRIC GAS

SCALE: NONE

SECTION 3.13
TEMPORARY AND PERMANENT TRENCH BREAKERS

Temporary trench plugs are used to slow the movement of groundwater and surface runoff within the trench to downstream working areas, while permanent trench breakers are left in the trench and backfilled to slow the movement of subsurface water along the trench. This helps to prevent subsurface flow from undermining the stability of the right of way and causing sinkholes or erosion.

TEMPORARY TRENCH PLUGS

Where:

- Use on slopes where runoff draining to downgradient work areas in the trench has been a problem.
- Place adjacent to waterways and wetlands to prevent water from seeping into work areas or disrupting the hydrology of the resource areas.

Installation:

- Temporary trench plugs can consist of soft plugs where compacted subsoil or sandbags are placed into the ditch following excavation.
- A second option includes hard plugs where small portions of the ditch are left unexcavated at certain intervals.
- Temporary trench plugs should be used at the same intervals as used for temporary slope breakers or water bars. (See table).

Maintenance:

- If water accumulates behind the trench breaker, it should be pumped to a filtering device, preferably in a well-vegetated, upland area.
- Inspect trench breakers regularly for signs of any instability, and repair any erosion problems.

PERMANENT TRENCH BREAKERS

Where:

- Use on slopes throughout all types of land uses (including agricultural and residential) to slow velocity of subsurface flow.
- Place at the base of slopes adjacent to waterways and wetlands and where necessary to avoid disrupting the hydrology or prevent draining of the resource area.
- Install trench breakers upslope of each permanent slope breaker or waterbar.

Installation:

- Trench breakers can be composed of sandbags or polyurethane foam. Topsoil should not be used to construct trench breakers.
- The trench breaker should be built under and around the pipeline at intervals specified by the local soil conservation service or as shown in the following table.
- Trench breakers can be constructed at the same intervals as permanent slope breakers or water bars and placed upgradient of the bar to effectively divert water and slow its velocity.
- If sandbags are used, the trench breakers will need to be constructed at a minimum of two bags wide.
- The top of the trench breakers should be backfilled along with the rest of the trench. The entire area should be graded to the original contours and stabilized.

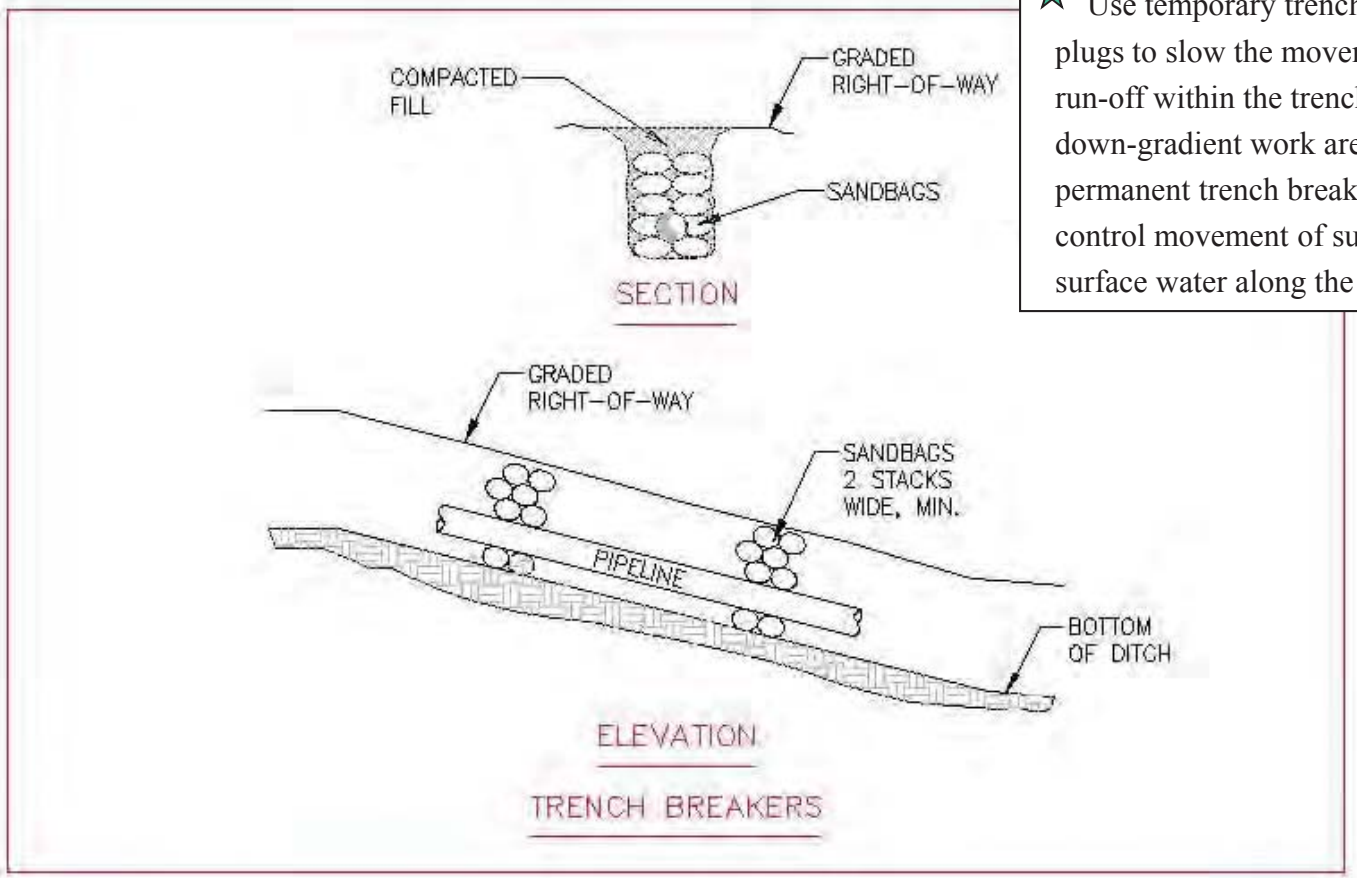
Maintenance:

- Trench breakers should be observed for stability and effectiveness before the trench is backfilled.
- Future inspections performed on the completed right of way should observe the ditch line for any unusual settling or erosion and wetlands and waterways should be inspected for any change to their original hydrology.

Recommended Spacing:

Land Slope (%)	Spacing (ft)
5-15%	300
>15-30%	200
>30%	100

TEMPORARY AND PERMANENT TRENCH BREAKERS



★ Use temporary trench plugs to slow the movement of run-off within the trench to down-gradient work areas. Use permanent trench breakers to control movement of sub-surface water along the trench.

NSTAR ELECTRIC GAS

SECTION 4

SITE ACCESS

Appendix 5-2

SECTION 4.1
Existing Access Roads

Construction access roads are unpaved roadways which work crews use to access a site. Use only designated roads. Travel by construction equipment and general traffic to reach a particular portion of right-of-way must be via the designated access road and route. Changes in the location of the access road or the use of alternate roads must be approved by the NSTAR representative prior to their construction or use. Access road routes have been selected to prevent degradation of the utility corridor, and must be constructed, used, and maintained in accordance with this manual, as well as federal, state, and local regulations, and other project plans.

Existing access roads should generally be used for site access whenever practicable and are preferred over constructing new access roads or using swamp mats for access through wetlands. Though in some situations they may be necessary, constructing duplicate roadways should be avoided to the greatest extent possible. Access road repairs should generally be made on an as needed basis to existing access roadways that become unsuitable for vehicle passage. In some cases, local fire authorities request maintenance of these roads for use by fire apparatus.

Following any necessary vegetative clearing, the roadway shall be graded and filled with gravel or other approved fill, sloping edges to the surrounding contours as required. In areas that are frequently wet or require more frequent usage, crushed stone may be used as fill material. In rare situations where there are steep slope areas, the surface may be finished with other material, such as crushed stone or lattice style concrete grid pavers. Any stream beds encountered that cross access roadways are left as is, unless culverts are being repaired.

During wet weather these roadways can generate significant quantities of sediment if not suited with adequate stormwater management and erosion control measures. Several BMPs may be used in the maintenance of access roads. When any ground disturbing activities occur near wetlands or watercourses the appropriate sedimentation and erosion controls should be used. Access roads may require additional BMPs to handle run-off and prevent erosion. These may include the construction of swales and channels, level spreaders, check dams, water bars and sediment basins. The use of such measures is at the discretion of applicable permit conditions or in the case of exempt maintenance activities, the contractor completing the work.

Where:

- Wherever access roads provide practicable and safe access to the work area.

Points to Consider when Evaluating the use of Existing Access Roads:

- Is the existing access road wide enough for the largest vehicle or heavy machinery that needs to use the road?
  - This is especially important to consider when the road is bordered by wetlands or other environmentally sensitive areas because swamp mats may be need to be installed adjacent to narrow roads.
- Are there any steep hills or tight turns that large vehicles or equipment may not be able to pass?

Maintenance:

- Clear vegetation as required. Preserve existing vegetation as much as practicable to help stabilize soil adjacent to the roads.
- Grade and fill with gravel if applicable.
- Slope edges to the surrounding contours as required.
- If required, use crushed stone as fill material.
- In rare cases like steep slopes, the surface may be finished with a different material, like a lattice style concrete grid system.
- Inspect weekly and after major precipitation events.
- Check for movement of topsoil or erosion.
- If washout, breakage or erosion occurs, repair as necessary.

Potential Problems:

- Erosion, washout and/or sedimentation into nearby wetland resource areas.
- Vehicle tires or tracks driving outside of access road and impacting adjacent wetlands or other sensitive areas.

Some appropriate reasons for suggesting alternate routes are:

- Poor site conditions along preferred route because of weather or season;
- Property rights constraints, or owner's preference;
- Clearly unanticipated equipment requirements;
- Clearly unanticipated off-site access limitations along existing roads; and/or
- Unanticipated access opportunities (e.g., ice, snow, other developments) which may avoid environmental impact and/or reduce cost.

SECTION 4.2
New Access Roads

Construction access roads that require new grading and/or filling, or are to be heavily used require the creation of a stable, tractable, load-bearing surface resistant to erosion. If the existing soil and subsoil are not well drained, it may be necessary to import an aggregate road base (i.e., gravel borrow) such as that meeting the requirements of aggregate found in the Commonwealth of Massachusetts Department of Public Works (MassHighway) Standard Specifications for Highway and Bridges, Section M1.03.0. When the construction access road follows the same route as the permanent design road, constructing the grades and subgrade for the permanent roadway early in the construction sequence is recommended.

Construction access roads shall not exceed 16 feet in width except for passing points, where necessary. Subgrading shall not extend beyond the space required for the finished road and normal side slopes. Where possible, construction access roads should conform to the contours of the land, avoiding grades steeper than 10 percent and creating side slopes no steeper than a ratio of 2:1. If the side slopes are steeper than 2:1, then use of engineered slope stabilization methods is imperative. Consider the volume and type of construction traffic as well as the extent that natural ground must be altered to accommodate the traffic. If no grading is required and the construction traffic is very intermittent (e.g., access roads used to maintain utility lines) the measures used may be limited to water bars, or some top dressing with gravel or stone in areas where the vegetation over soft soil is destroyed by traffic.

Inspection of the construction access road and the associated erosion and sedimentation measures should occur at the end of each day the road is used, and repairs to controls made immediately. If the road is not used for more than a week, then inspection of the erosion and sedimentation controls should occur at an appropriate frequency as dictated by the specific measures used and extent of heavy rain events. Repairs may include regrading and/or top dressing the traveled surface with additional aggregate to eliminate ruts, as well as those repairs required by each erosion and sedimentation measure used.

Construction access roads that are constructed in or across wetlands require the following, additional considerations:

- Avoid putting the construction access road in a wetland whenever possible. Explore all feasible and prudent alternatives before determining that a wetland crossing is absolutely necessary. When avoidance is not possible, consider crossings that will result in the least impact. This may involve locating the construction access road so that it crosses the wetland at its narrowest width or uses areas previously disturbed for access or other purposes.
- Minimize the width of the construction access road through the wetlands (generally no wider than 16 feet). It is preferable to have a passing point created before and after the wetland crossing, but internal passing points may be needed if the crossing is very long or critical sight line restrictions exist.
- Consider the soil conditions. Expect deep organic wetland soils to require geotextiles, timber/swamp mats, or other materials during use to keep imported road materials separated from wetland soils. In shallow organic, or saturated soils thick plywood sheets or AlturnaMATS® may be sufficient to support a stable travel surface for small, lightweight vehicles.
- Prevent obstructions to surface and subsurface flow across and through the construction access road. Provide adequate drainage. This may require the use of crushed stone, timber mat bridges, or multiple cross culverts, particularly if the wetland does not contain a well-defined watercourse channel and/or the crossing is long. If the wetland soils are susceptible to seasonal high groundwater tables or flooding, then give additional consideration for maintaining flows across and/or over the construction access road without causing erosion or siltation during such times.
- Plan in advance how the construction access road will be removed and the wetland restored. A road stabilization geotextile can facilitate the segregation of imported soils and crushed stone from the native wetland soils and make wetland restoration easier. However, after the end of an extensive project and a highly traveled crossing, stone removal from the wetland surface will still usually have to occur, even when placed in conjunction with geotextile.

Appendix 5-2

Erosion and Sedimentation Control:

- A construction entrance track pad should be used where the construction access road meets a paved access point (also see "Control of Tracked Soils" below).
- Temporary diversions and/or temporary lined channels should be used to control concentrated flows where they enter and cross the construction access road.
- Temporary stream crossings should be used to carry concentrated flows beneath the construction access road.

Erosion and Sedimentation Control (continued):

- Outlet protection, a level spreader, or a stone check dam may be used to de-energize concentrated flows from diversions and in temporary channels.
- Water bars should be installed to generally maintain natural drainage patterns and break flow lines within the construction access road.
- Geotextile silt fencing and hay or straw bale barriers may be utilized to provide protection at the toe of fill slopes and discharges from water bars.
- Side slopes can be protected by installing erosion control blankets and seeding the area with a fast-growing native or annual grass mix.
- Dust control should be employed when construction access road conditions create airborne dust in or near sensitive areas.

Control of Tracked Soils:

- Where access roads or construction areas connect to paved roads, a stone track pad must be installed at the construction entrance to prevent construction machinery from tracking soil onto paved roadways. Materials appropriate to construction site soil conditions should be employed and/or replenished, as necessary. Further, muddy conditions may warrant the use of a tire wash station and procedures should be established to ensure soils are not tracked off site. Stone in an entrance track pad may also need to be removed and refreshed and/or cleaned as needed if the pad becomes clogged with soil.

Minor Grading/Stockpile Management:

- Where access roads or construction areas require grading to mineral soil, the topsoil shall, wherever possible, be preserved through temporarily stockpiling and later re-spread, seeded, and mulched. Topsoil stockpiles must be prevented from eroding into adjacent undisturbed or sensitive areas. Covering topsoil stockpiles with plastic sheeting can accomplish this, and offers the added benefits of preventing soil moisture loss, and isolating the soils from wind-borne weed seeds.

Fences, Gates, and Barricades:

- No fence on the utility corridor or access routes may be cut or removed without permission of the NSTAR representative. Fences cut or removed for any temporary purpose shall be repaired immediately upon completion of work. Gates should be left as they were found. Gates providing access to company-owned property must be left closed and locked at the end of each workday. Stone, concrete block, or pole barricades or access control berms that are required to be removed for the conduct of work shall be replaced in equal or better condition immediately after the work is completed. Among other things, the existence of fences and other barriers along NSTAR ROWs minimizes illicit use of these ROWs by off-road vehicles (ORVs), damage to NSTAR and adjacent property owners' land, and helps to minimize liability associated with trespassing.

SECTION 4.3
TEMPORARY STREAM CROSSINGS WITHOUT BRIDGES

There are a number of BMPs that can be selected to minimize impacts to streams. Each situation should take the current site and project needs into consideration to select the best method which will be most cost-effective and incur the fewest secondary impacts. Additional erosion and sedimentation controls (e.g. hay or straw bales) may be required in conjunction with the following stream crossing BMPs to protect sensitive areas. The stream crossing methodology chosen will depend largely on the equipment required for a particular task, the existing environmental conditions, and the duration of the crossing. Soil should never be used to construct or stabilize a bridge. Often permitting effort is less when any in-stream work occurs outside of the time-of-year restrictions for any species present in the stream to be crossed and listed in the Massachusetts Department of Marine Fisheries (DMF) document, and outside of October 1st to June 30th for any inland stream not listed by DMF. Generally appropriate permitting efforts must be completed prior to any in-stream work or fill.

LIMIT TURBIDITY

- In some situations such as routine or emergency maintenance with small ATVs or equipment, it may be acceptable for equipment to simply travel (perpendicularly) through a stream.
- Generally considered acceptable where there is a stable stream bottom (rock or sand/gravel), where an existing or historic access road is present, and/or where the crossing is at a relatively narrow reach of the stream and any adjacent wetlands.
- Streams should be crossed slowly to minimize in-stream turbidity.

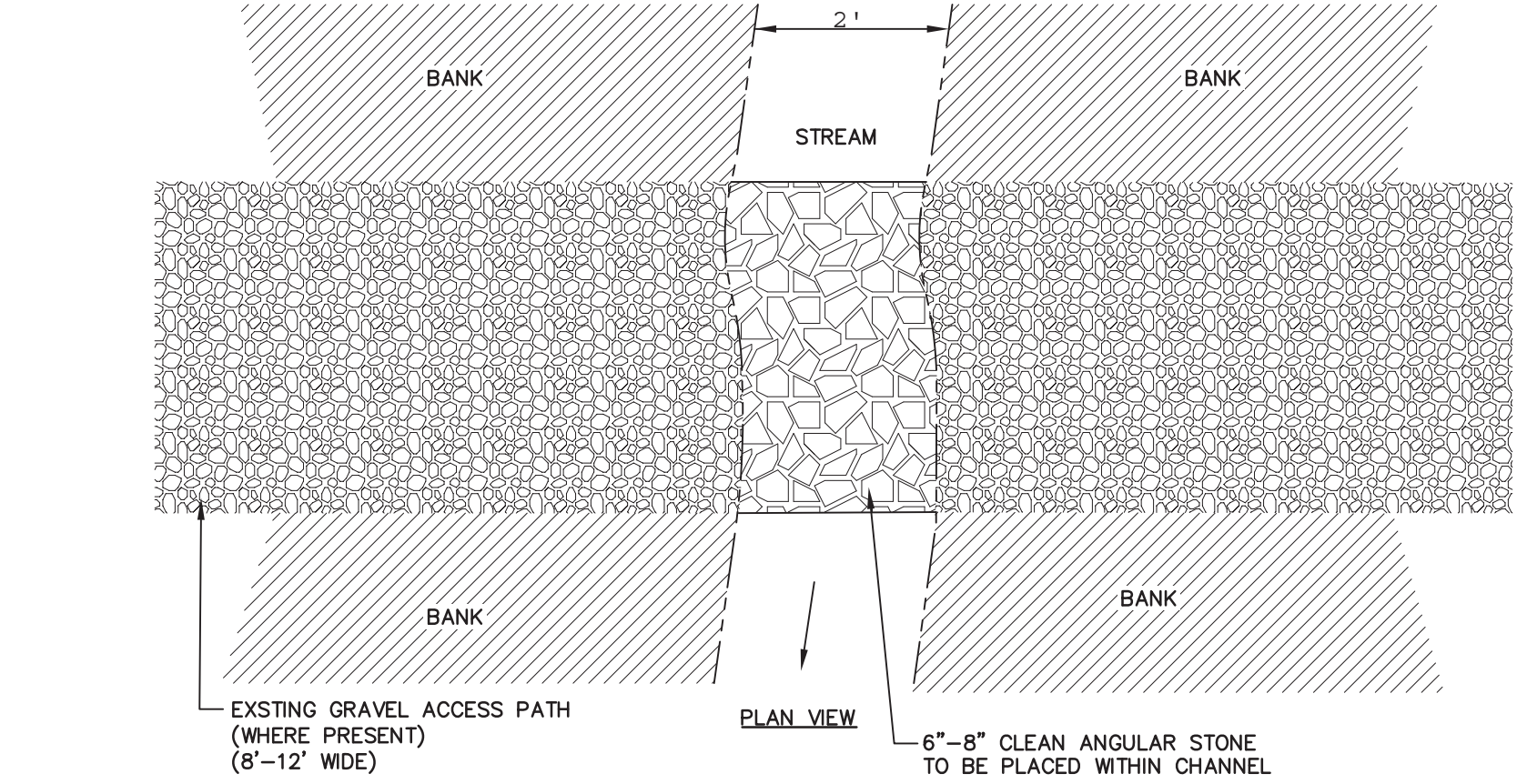
STONE CROSSINGS

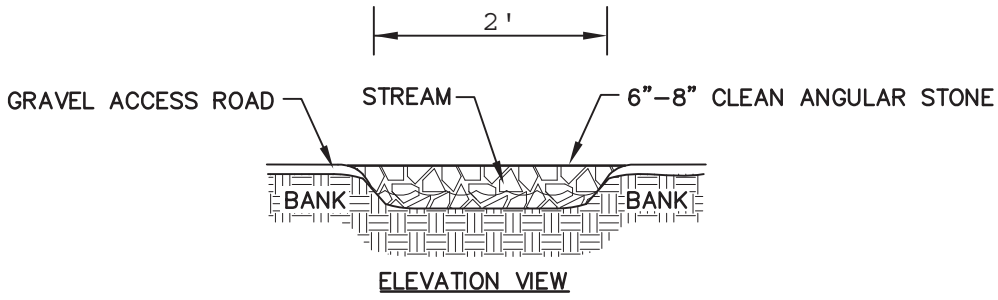
- The placement of clean 6-inch to 8-inch angular stone may be used in some circumstances along existing access roads. The placement of stone should be limited to the width of the existing access road.
- As a rule of thumb, angular stone should only be used in small (less than 2-feet wide or braided) intermittent streams which do not appear on USGS topographic maps, and have a downstream section with a gradient greater than 20%. The use of angular stone is not suitable in areas where there could be a potential for fish passage.
- Depending on applicable regulations and permitting, it may be allowed to leave stone in place permanently.

POLE FORD

- Typically used in remote locations where a stream crossing requires a functional BMP, but it is impractical to bring in such materials. Appropriate where the road is gently sloping into and out of the stream at a maximum ration of 1:5 (V:H).
- Wood poles or saw logs of sufficient length and diameter are laid in the streambed parallel to the stream flow. Engineering fabric covered by an aggregate bed should be installed in the access road at the approach and exit, if necessary, to limit disturbance to the riparian area
- Poles need to be removed after the crossing is no longer needed.
- Installing poles is considered “fill” by some regulatory programs and may require permitting even for temporary use.

Appendix 5-2



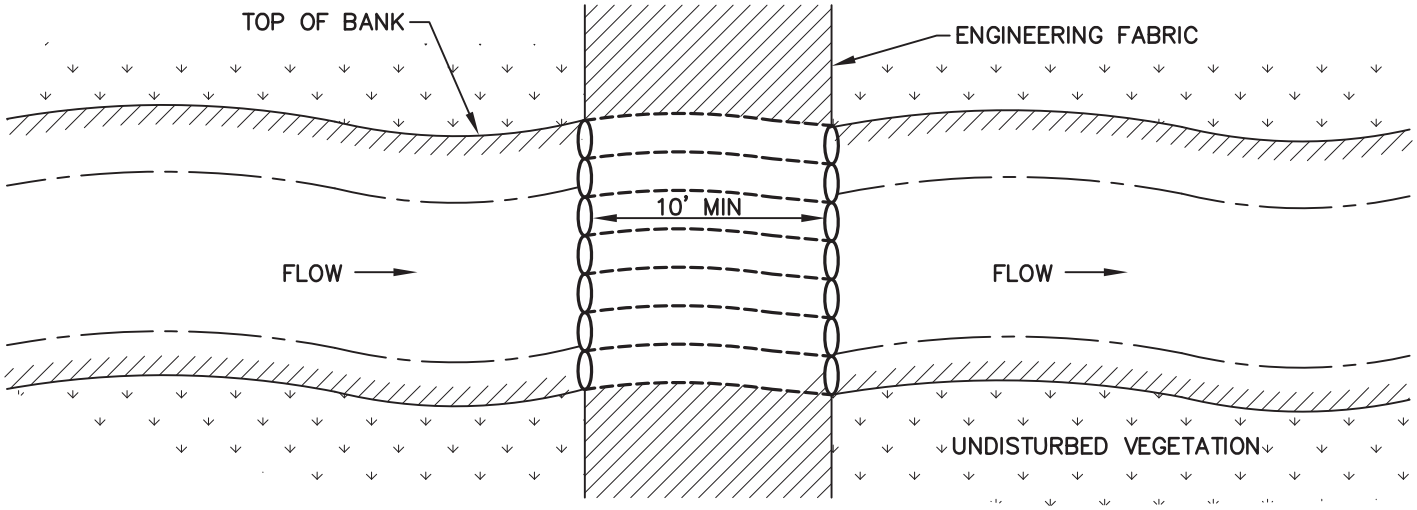


TYPICAL INTERMITTENT STREAM CROSSING

SCALE: NONE

NSTAR ELECTRIC GAS

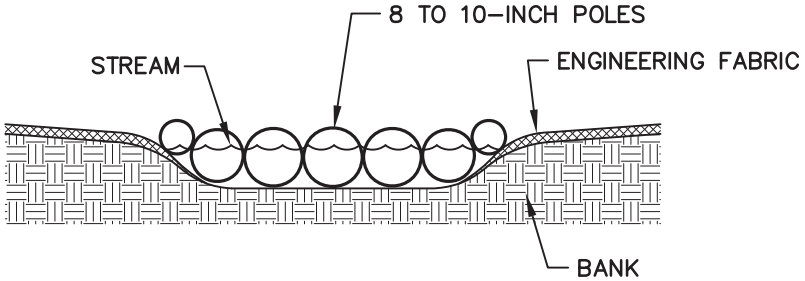
Appendix 5-2



PLAN VIEW

NOTES:

1. POLES MUST BE REMOVED IMMEDIATELY AFTER USE.
2. LENGTH OF POLES SHALL BE AT LEAST 10 FEET.



ELEVATION VIEW

TYPICAL POLED FORD FOR
TEMPORARY STREAM CROSSING

SCALE: NONE

NSTAR ELECTRIC GAS

SECTION 4.4
TEMPORARY STREAM CROSSINGS WITH BRIDGES

When it is necessary for construction equipment to cross a minor (≤ 10 feet wide), an intermediate (> 10 and < 100 feet wide), or a major (> 100 feet wide) waterbody, it may need to be done so on an approved equipment bridge crossing, sometimes with proper permit approval. Equipment crossings provide stability to the machinery, and help to prevent damage to the streambanks and the streambed. Clearing of vegetation should be minimized and haybales should be placed along both streambanks, leaving a gap to insert the bridge. Soil should never be used to construct or stabilize a bridge. Often permitting effort is less when any in-stream work occurs outside of the time-of-year restrictions for any species listed by the Massachusetts Department of Marine Fisheries (DMF) as present in the stream to be crossed, and outside of October 1st to June 30th for any inland stream not listed by DMF. Generally appropriate permitting efforts must be completed prior to any in-stream work or fill.

TIMBER MAT BRIDGE

Where:

- Timber mat bridges are most often used on minor stream crossings. They can be used in conjunction with flumes in order to be used on larger streams. Flumes are especially important if the stream is a coldwater fishery
- Even if a stream is intermittent and is dry at the time of construction, a timber mat bridge should often be used to minimize damage to the channel.

Installation:

- A sturdy, prefabricated timber mat should be placed so it rests on the banks and traverses the stream. If the stream is too wide, a different technique should be investigated.
- Two layers can be used to strengthen the bridge and distribute the weight of the equipment if necessary.
- Haybales should be placed along both edges of the timber mat bridge and connected with those on the banks to prevent sedimentation to the stream. (Silt fence, haybales or sand bags may be used interchangeably- subsoil may not be used).
- Equipment operators should remain cautious so as not to drive or slip off the side of the mats, and the bridge should be temporarily removed if high water levels render it unsafe for crossing.

ROCK CULVERT BRIDGE

Where:

- Rock culvert bridges are generally used to cross intermediate sized streams with the potential for higher flow.

Installation:

- The number and size of flume pipes will be designed to handle the maximum expected flow of the stream at the time of construction.
- A rock base will be placed across the stream bed and sand bag dams will be created on both sides, directing the stream flow into the flume pipes resting on the rocks. Rocks should be filled in around the flumes and piled to the height of the banks and sand bags. Only clean, silt-free rock should be used.
- Haybales should be placed along both edges of the bridge and connected to those along the banks.
- The rock culvert bridge may be used with or without a timber mat placed on top of the bridge.

PORTABLE BRIDGE

Where:

- Portable, flexi-float, or rail car bridges are generally used on intermediate or major stream crossings or wide, deep crossings.

Installation:

- Used rail car frames can be used for crossing larger and deeply incised streams where timber mats are unsuitable. The rail car frame is placed across the stream from bank to bank perpendicular to the direction of flow (on a timber frame footing if necessary). Timber matting is then placed upon the rail car frame to provide vehicle access.
- Prefabricated bridges are anchored and/or tied off to anchor blocks for stability.
- Where appropriate, haybales should be placed along both edges of the bridge and connected to those along the banks.

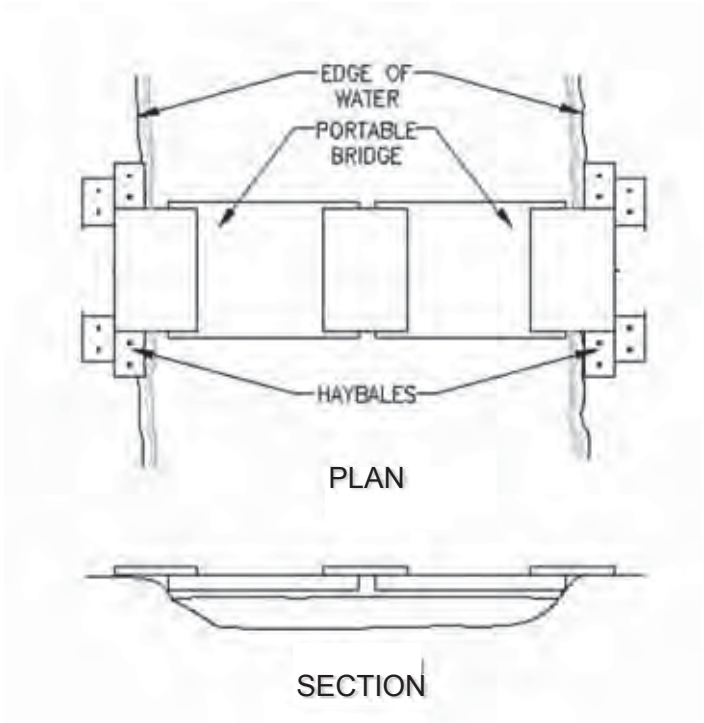
Maintenance for all three bridge types:

- Inspect bridge daily and keep it clear of excess sediment.
- Inspect and maintain erosion control on a daily basis as well.
- The bridge must remain in place until the area is under final restoration and all bridges will be removed from the waterbody when work activities are completed, including all rock used when building a rock culvert bridge.

Appendix 5-2

TEMPORARY EQUIPMENT CROSSINGS

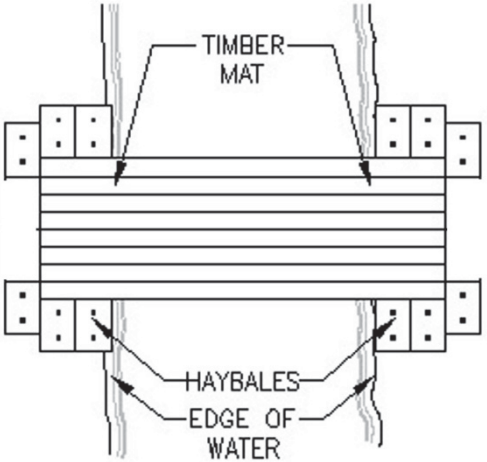
★ Please note that all applicable permit approvals must be obtained prior to construction of bridges.



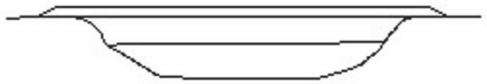
PORTABLE BRIDGE



TIMBER MAT BRIDGE

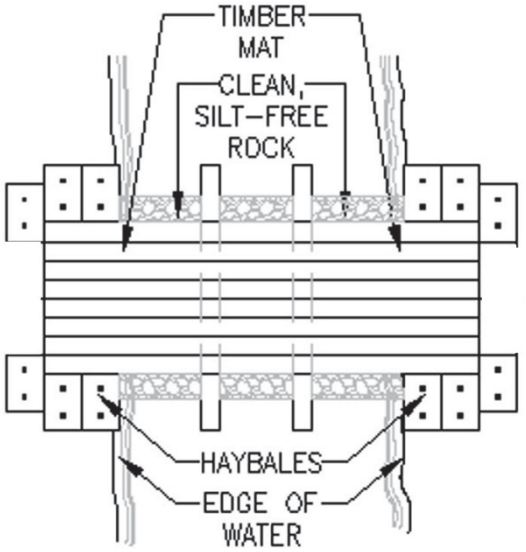


PLAN



SECTION

★ Rock culvert bridges can be used with or without a timber mat cover.



PLAN

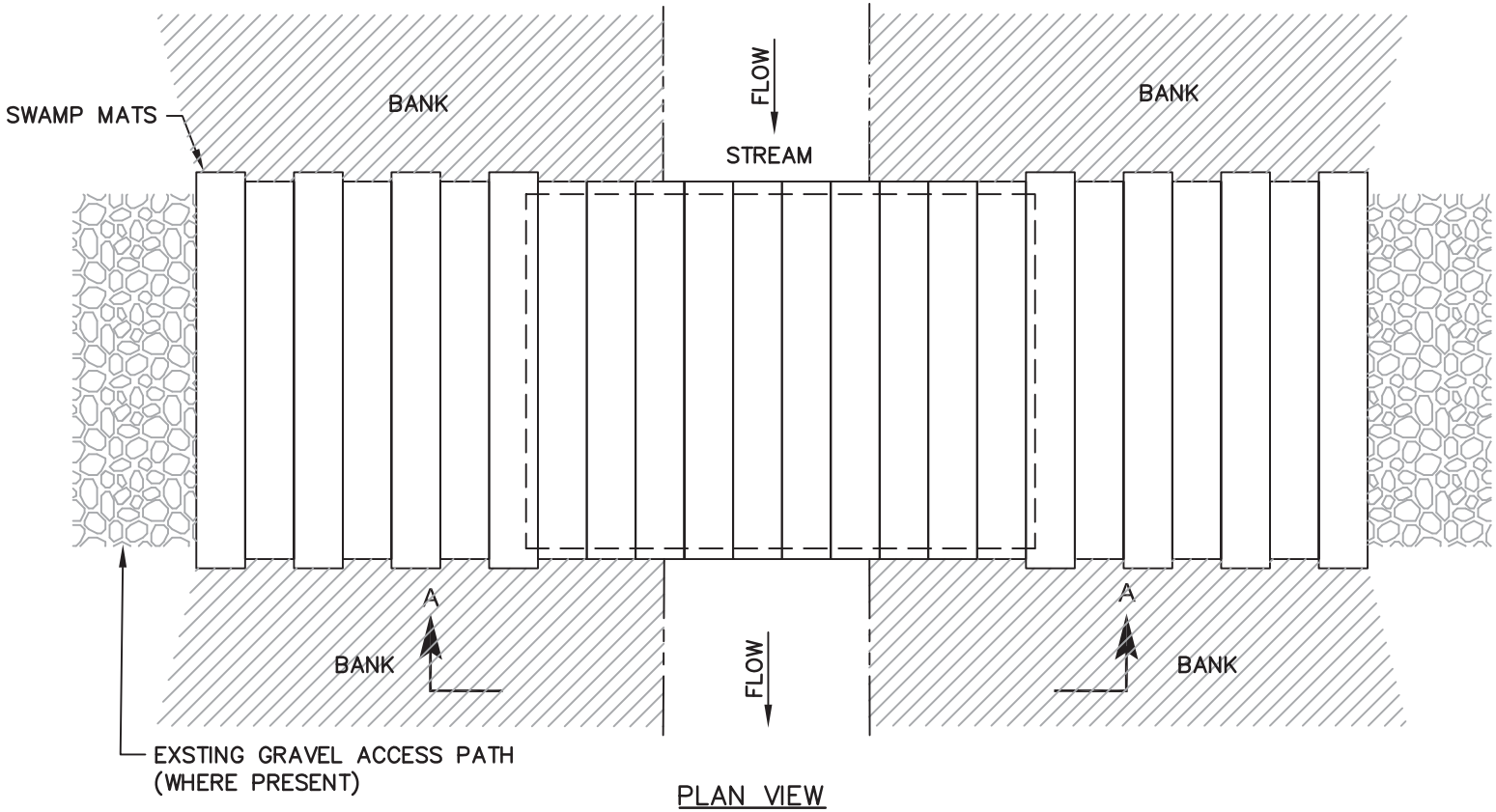


SECTION

ROCK CULVERT/ TIMBER MAT BRIDGE

NSTAR ELECTRIC GAS

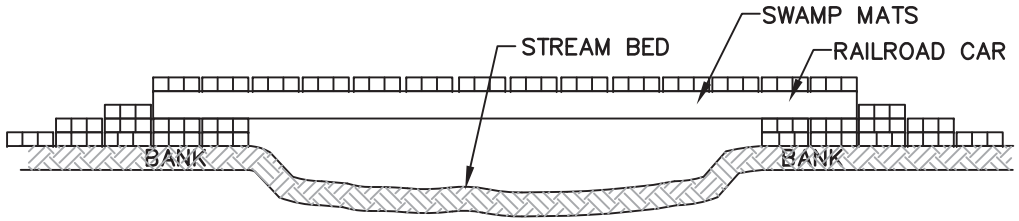
Appendix 5-2



PLAN VIEW

NOTES:

1. SWAMP MATS SHOULD BE PLACED CLOSELY TOGETHER SO THERE IS A SMALL GAP BETWEEN EACH MAT SECTION.
2. ADDITIONAL MEASURES MAY BE REQUIRED.
3. SWAMP MAT DIMENSIONS OF 12'x4'x6", 16'x4'x8" OR OTHER TO BE USED.



SECTION A–A

TYPICAL TEMPORARY RAILROAD CAR BRIDGE CROSSING

SCALE: NO SCALE

NSTAR ELECTRIC GAS

SECTION 4.5
TIMBER MATS AND WETLAND CROSSINGS

When work in a wetland is proposed, certain precautions must be taken and certain best management practices must be utilized. Wetland substrates are often composed of soft, saturated, organic soils up to several feet deep which don't provide proper support for equipment access. Timber mats are commonly placed end to end within a wetland to provide a temporary access road and staging area for the equipment. Timber mats also help to distribute the weight of the machinery and protect the wetland surface from rut damage and additional sedimentation. Timber mats may also be placed on top of each other for several layers, if necessary, to provide a stable surface.

Lightweight, easy to maneuver alternatives to traditional mats, such as AlturnaMATS®, are also available. AlturnaMATS® are half-inch thick polyethylene slip-resistant ground protection mats. They are available in dimensions up to 4 feet by 8 feet and range in weight from 21.5 to 86 pounds. These mats are used similarly to traditional wooden timber mats, although with more strict limitations on vehicle or equipment size and weight.

Equipment and swamp mats that are used in wetlands have the potential to spread invasive plant species. During site reconnaissance each wetland area planned to be crossed or impacted will be assessed for the presence of such species. If invasive species are noted, special precautions will be employed to prevent the transport of vegetative material to an un-impacted wetland. Following removal from an impacted wetland, wooden swamp mats will be allowed to dry and then vegetative debris and soils will be removed by a mechanical sweeping device. Equipment which has been operated within an area impacted by invasive species will be cleaned manually before entering other wetlands.

TIMBER MATS AND WORK IN WETLANDS

Where:

- Use timber mats in any wetlands with saturated or soft soils which may not provide proper stabilization for equipment access.
- Even if the ground is stable enough to hold equipment, mats should also be used where the wetland could sustain damage from ruts.
- Use as required by regulatory agencies and permit approvals.

Installation:

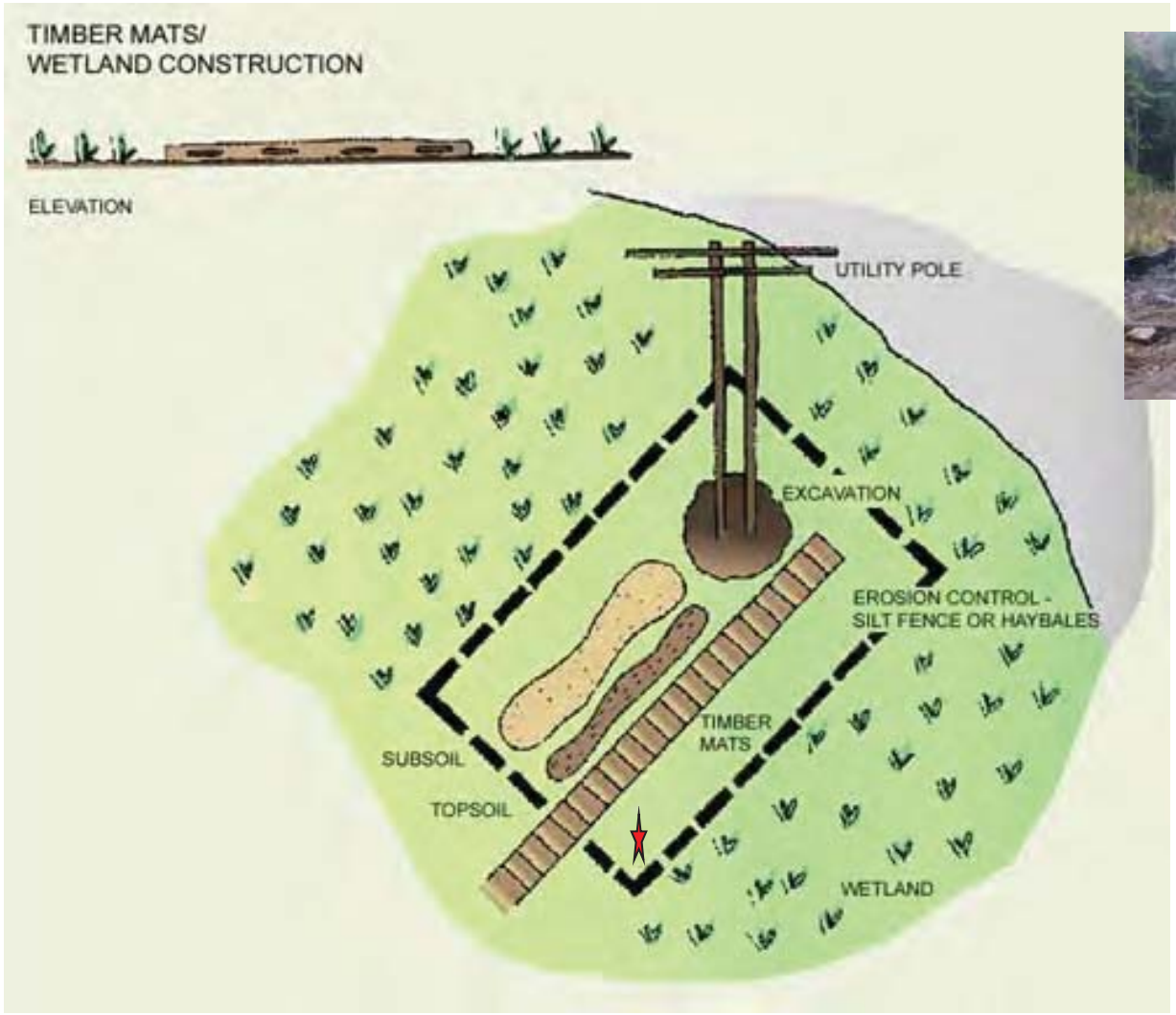
- If the mats were last used in wetlands impacted by invasive species, prior to installation mats will be allowed to dry and then vegetative debris and soils will be removed by a mechanical sweeping device. Equipment which has been last operated within an area impacted by invasive species will be cleaned manually prior to entrance into a different wetland.
- Proper erosion control should be installed along the edge of the work area in all wetlands.
- Prefabricated timber mats should be set in place with heavy machinery. The mats can be placed directly on top of existing herbaceous and shrubby vegetation, although woody vegetation generally regenerates better if it is cut prior to installing over it.
- The mats should be laid end to end, providing a temporary road into the work area. In extremely marshy wetlands, several layers of mats may be used if necessary.
- Equipment operators should remain cautious so as not to drive or slip off the side of the mats.
- When excavation occurs, wetland soil should be segregated into topsoil and subsoil piles and replaced back into the trench in the proper order when the activities are complete (See *Topsoil Segregation* for more details).
- All spoil and stockpiles must remain within the area contained by the erosion control barriers.

Maintenance:

- Inspect mats regularly and remove excess sediment to an appropriate upland location where it will not erode back into the wetland.
- Remove all mats from the wetland when work activities are completed. Following removal from an impacted wetland, mats will be allowed to dry and then vegetative debris and soils will be removed by a mechanical sweeping device before being used again. Equipment which has been operated within an area impacted by invasive species will be cleaned manually before entering other wetlands.
- Leaving mats in place for greater than 3 months may require more permitting effort than using them for a shorter period of time.

Appendix 5-2

TIMBER MATS AND WETLAND CROSSING PROCEDURES



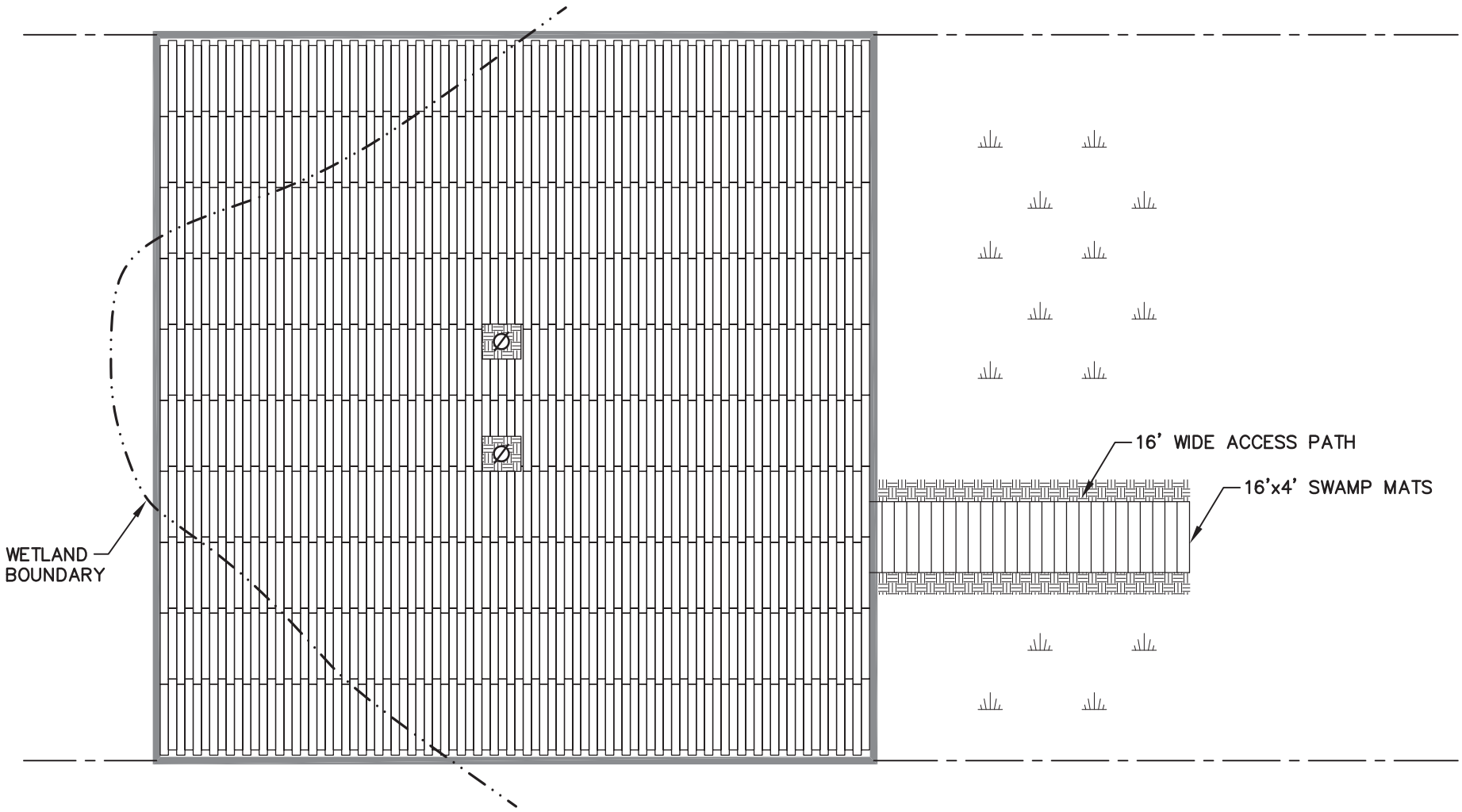


Timber mats help to stabilize machinery when traversing soft wetland soil, as well as protecting the wetland from rut damage and additional sedimentation.

Please note that all applicable permit approvals must be obtained prior to construction of dams.

NSTAR ELECTRIC GAS

Appendix 5-2



LEGEND

Ø REPLACEMENT POLE LOCATION

SWAMP MAT – 16'x4'x6" OR 8" TYPICAL SIZE. 12'x4'x6" OR OTHER SIZE ACCEPTABLE.

WORK SPACE REQUIREMENTS

LIMIT OF RIGHT–OF–WAY

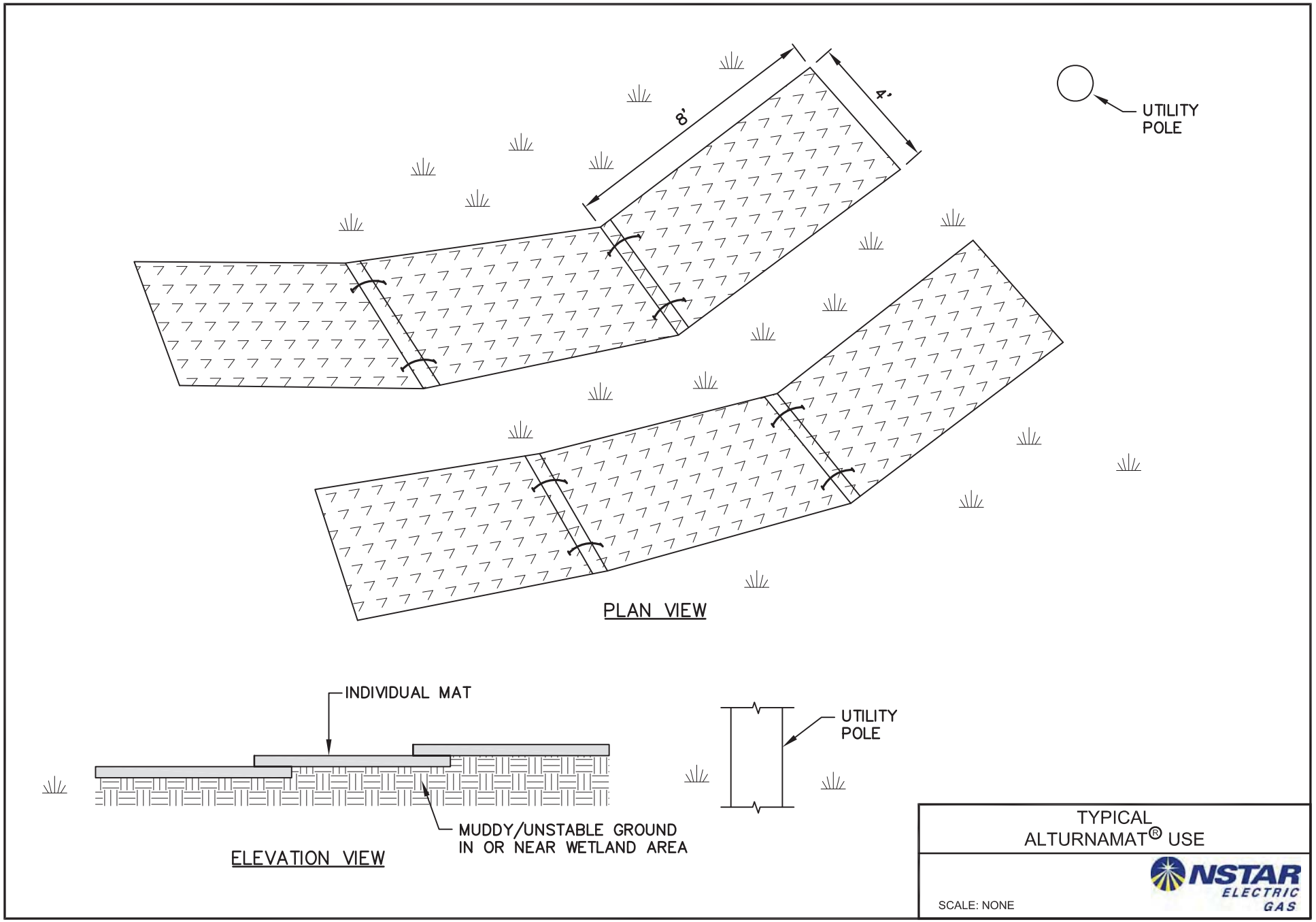
WET/MUDDY AREA

TYPICAL
SWAMP MAT LAYOUT FOR LINE WORK

SCALE: NONE

NSTAR ELECTRIC GAS

Appendix 5-2


8'
4'
UTILITY POLE
PLAN VIEW
INDIVIDUAL MAT
MUDDY/UNSTABLE GROUND
IN OR NEAR WETLAND AREA
ELEVATION VIEW
UTILITY POLE
TYPICAL
ALTURNAMAT® USE
NSTAR ELECTRIC GAS
SCALE: NONE

SECTION 5

WETLANDS AND WATERCOURSES

Appendix 5-2

SECTION 5.1
TOPSOIL SEGREGATION FOR WORK IN WETLAND AND AGRICULTURAL AREAS

Generally, the top 12 inches of soil are the most important for providing nutrients and a suitable growth medium to the existing vegetative cover in an area, as well as containing the root stock and seed bank of the plant community. When digging a trench for installation or maintenance of a pipeline or conduit, or excavating for the installation or replacement of the base of a utility pole, it is good practice to segregate the first 12 inches of topsoil and stockpile it separately from the subsoil until the layers can replaced into the excavation in the proper order. Topsoil segregation should be performed in wetlands and agricultural areas as it allows for more rapid revegetation and restoration of the original plant species. In some cases, it may be necessary to strip topsoil off the areas where the subsoil will be stockpiled as well.

Where:

- Topsoil segregation is a good practice in any area, including uplands in order to provide a suitable growth medium and more rapid revegetation.
- Topsoil segregation is recommended for the first 12 inches if soil in all wetlands and agricultural land.
- Additional topsoil can also be brought into an upland or residential area if necessary where the existing soil is too shallow to provide adequate rooting depth, moisture and nutrients, or too much topsoil was lost during construction.

Implementation:

- Proper erosion control such as haybales or silt fence should be set up around the work area before any excavation begins near wetland areas.
- Before construction, the contractors should have an idea or plan of how the work area should be set up and what side of the trench or excavation will the stockpiles be located.
- Stockpiles should be located away from active work areas to the extent practicable.
- The excavator should remove the top twelve inches of topsoil from the trench or excavation where available, or the entire layer of soil where less than 12 inches exist.
- The topsoil should be placed in a separate stockpile than the layers of excavated subsoil.
- Additional lines of erosion control can be placed around the stockpiles to control sedimentation if necessary.
- Side slopes of soil stockpiles should not exceed 2:1.
- If the unlikely situation where stockpiles will remain exposed for more than 21 days, they should be stabilized with temporary seeding or plastic covering.
- When work activities are completed, backfill the trench with the proper soil layers; subsoil followed by topsoil. Backfilling should take place immediately after activities are completed, and grading and site stabilization should take place within 10 days following backfilling.

Maintenance:

- Inspect and maintain erosion control on a regular basis and observe the stockpiles for any signs of sedimentation or mixing.
- A reasonable effort should be made in all residential and agricultural areas to remove all rocks larger than 4 inches in diameter from the topsoil, which had been turned up during construction.

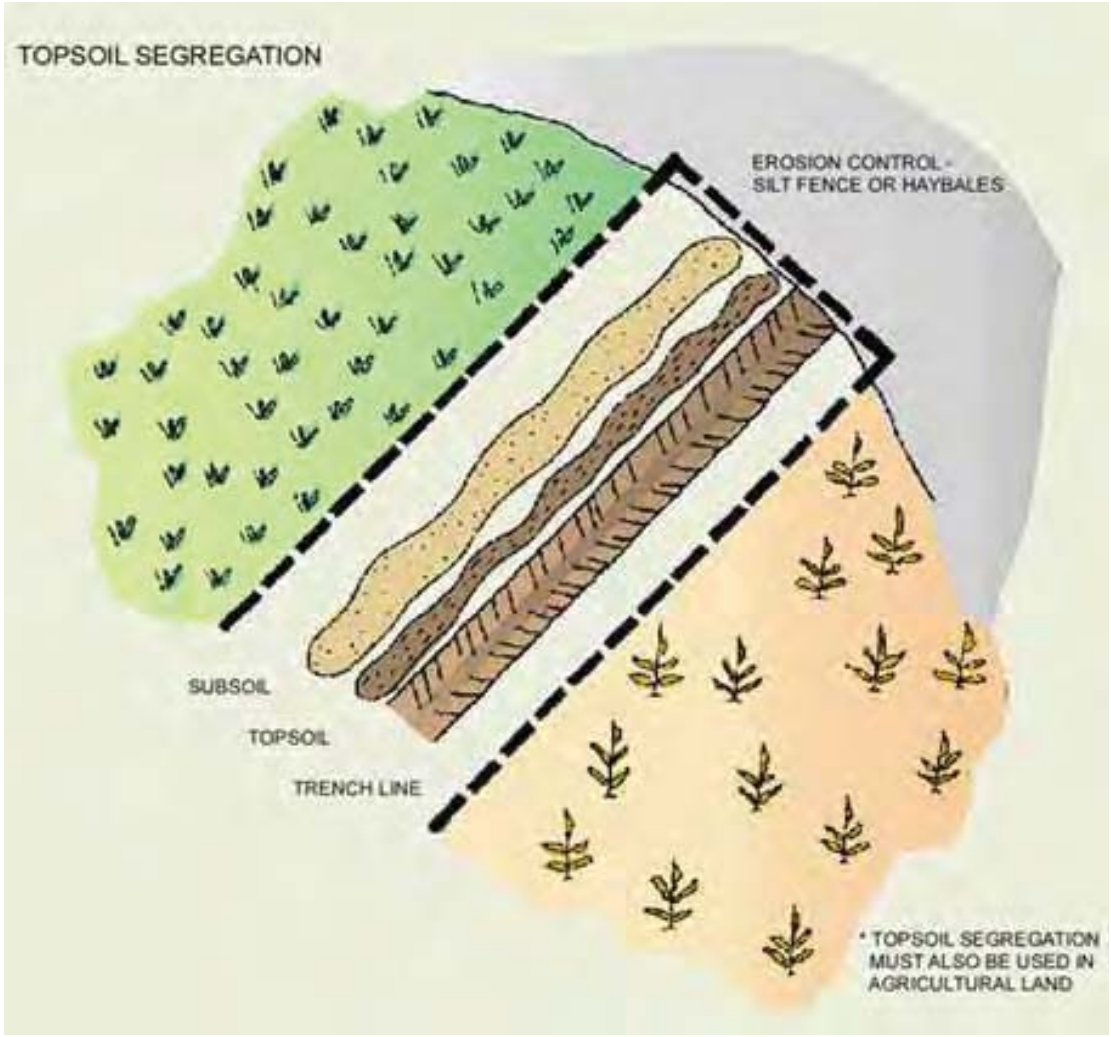
Problems:

- Topsoil and subsoil stockpiles are mixing:
  - The piles are located too close together. Try placing the separate stockpiles on opposite sides of the trench or work area.
  - The topsoil stockpile could also be individually enclosed in haybales or silt fence. This will help create a barrier, keeping it separate from the subsoil.
  - Avoid working with large amounts of trench or excavation open when heavy rains are predicted.

Appendix 5-2

TOPSOIL SEGREGATION

(FOR WORK IN WETLAND AND AGRICULTURAL AREAS)





★ Generally, the nutrients found in the first 12 inches of soil are the most essential for successful plant growth. The root stock and existing seed bank are also located within the first few inches of soil. When excavating, topsoil should be stripped and segregated from the subsoil until the layers can be backfilled in the ditch in the proper order. This facilitates restoration and revegetation.

NSTAR ELECTRIC GAS

SECTION 5.2
DEWATERING ACTIVITIES

During excavation activities for installation or replacement of the utility poles or natural gas pipelines, it may become necessary to dewater the trench in the instance that high groundwater or saturated soil is present. Dewatering is often necessary in wetlands or near streambanks to expose the ditch line and provide drier workspace. Discharges should only be conveyed to one of the following options.

OVERLAND FLOW

- If a discharge location is available where there is no potential for discharged water flowing overland into wetlands or waterbodies, water may be discharged overland without any filtering to well drained, vegetated upland areas and allowed to naturally infiltrate into soils.

FILTER BAGS AND HAYBALE CONTAINMENT AREA

Where:

- Use filter bags and/or haybale containment areas for discharge when there is the potential for discharged water to flow overland into wetlands or waterbodies.
- Dewatering sites should be located in well-vegetated areas within the right of way or within approved work areas.
- If practicable, discharges should be located outside of wetlands and over 100 feet from a streambank or waterbody.

Installation:

- Pump should be placed in a containment structure, such as a plastic, child-sized pool to avoid any fuel leaks to the wetlands or waterways.
- Properly place the discharge hose into a pre-manufactured, geotextile filter bag per the manufacturer's instructions.
- Place the filter bag in a well-vegetated area outside of a wetland area and over 100 feet from a waterbody if practicable.
- The intake hose should be elevated off the trench bottom, and a sump should be created with clean rock in order to avoid pumping additional sediment.
- If the water must be discharged within 100 feet of a wetland or waterbody, or near an especially sensitive area, a haybale corral should be built around the filter bag.
- Stake a double vertical line of haybales in an "L " or "U" shape on the downgradient sides of the bag. This will further filter the discharge water.

Maintenance:

- If the pump requires refueling, it should be done within the plastic containment structure or over 100 feet from the wetland or waterbody.
- The pump should be manned at all times.
- The filter bag should be checked regularly during pumping activities to ensure that it is not reaching its holding capacity.
- If the bag appears to be nearing its limits, dewatering should cease until more water has filtered out and the bag can be replaced.
- Used filter bags and the trapped sediment they hold, must be disposed of in the proper manner.

FRAC TANKS

- Frac tanks are pre-fabricated self-contained units that are shipped to construction sites. They contain a series of baffles that allow fine materials to settle out of the water column. Use of frac tanks is most appropriate when work that requires dewatering will occur in an area with contaminated groundwater and/or very silt laden water.



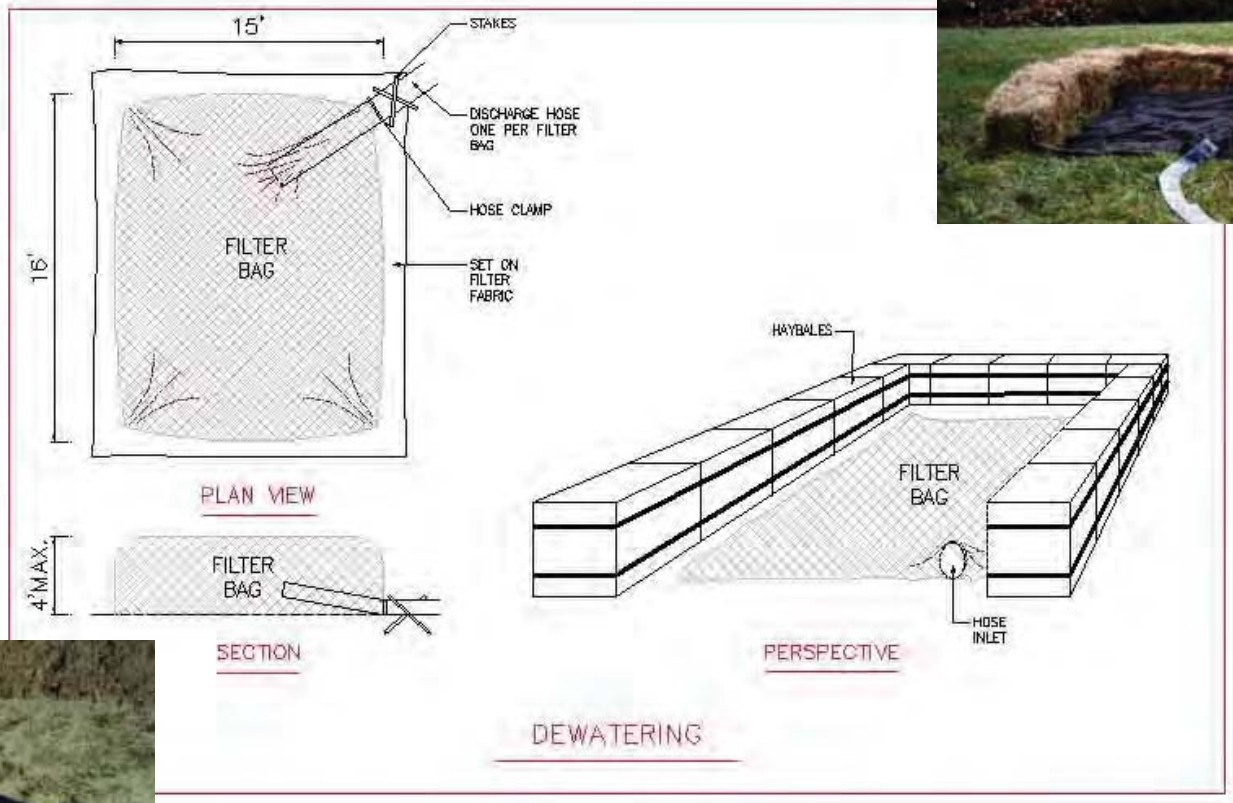
REMEMBER

Under no circumstances should trench water, or other forms of turbid water, be directly discharged onto exposed soil or into any wetland or waterbody.

DEWATERING ACTIVITIES

★ Use in combination with a haybale corral where necessary.



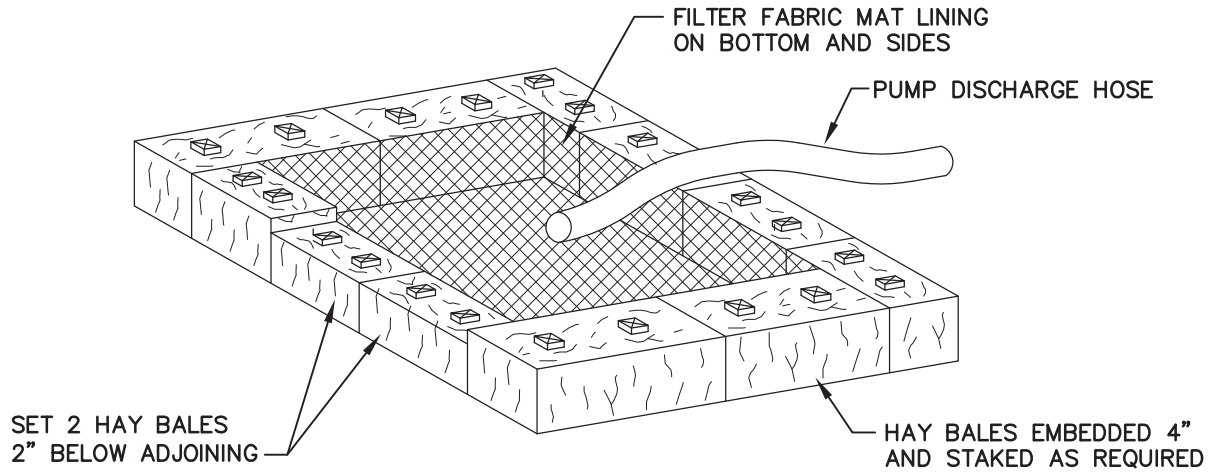




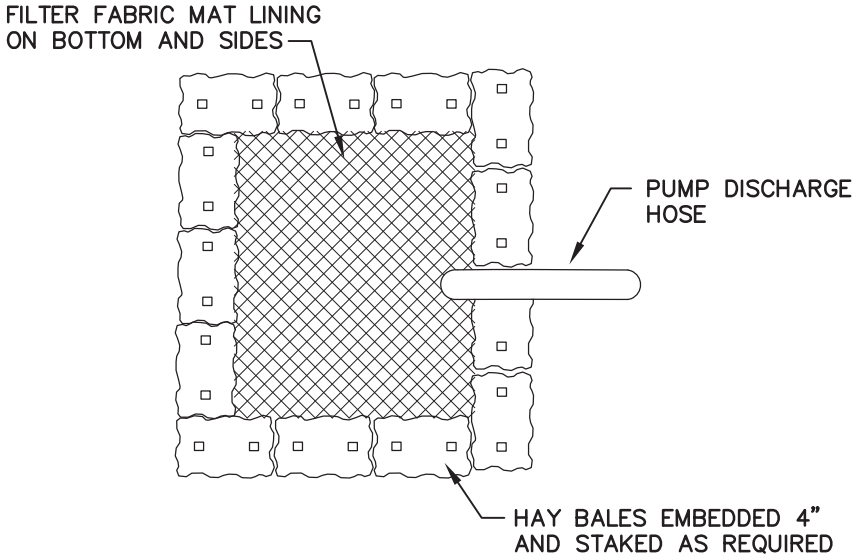
★ Place filter bags in a well-vegetated area, outside of wetlands whenever possible.

NSTAR ELECTRIC GAS

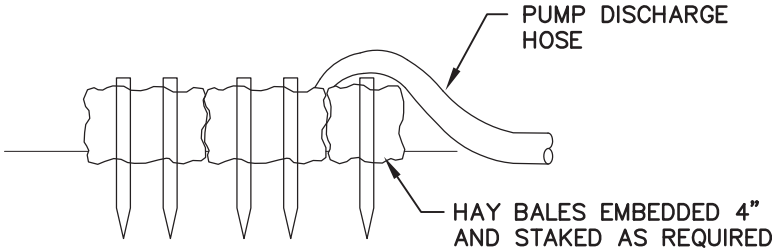
Appendix 5-2



PERSPECTIVE



PLAN VIEW



SECTION

NOTES:
PLACE DEWATERING/PUMPING SETTLING BASINS IN A WELL-VEGETATED AREA, OUTSIDE OF WETLANDS WHENEVER POSSIBLE.

TYPICAL
DEWATERING BASIN

SCALE: NONE

NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 5.3
WATERBODY UTILITY CROSSINGS

When utilities must be installed under a stream bed, several methods can be used for construction. These include wet crossings, which can only be used on intermittent and non-sensitive streams, and must be completed within 24-48 hours due to working directly in the stream flow. Open trench excavation in flowing waters sometimes requires greater permitting efforts than other options which avoid working in flowing waters. More often recommended is a dry crossing which includes a flumed crossing or a dam and pump crossing. Both methods involve temporarily bypassing the stream flow around the work area in order for the trench to be dug in a dry stream bed. Construction in and around waterbodies must be expedited and the amount of equipment and additional workspaces must be limited. Often permitting effort is less when any in-stream work occurs outside of the time-of-year restrictions for any species listed by the Massachusetts Department of Marine Fisheries (DMF) as present in the stream to be crossed, and outside of October 1st to June 30th for any inland stream not listed by DMF. Generally appropriate permitting efforts must be completed prior to any in-stream work or fill. Horizontal directional drilling or standard boring should be considered as an alternative for extremely sensitive streams and Waterbodies, or as an option to reduce required permitting efforts.

DAM AND PUMP CROSSING (BYPASS PUMPING)

Where:

- Use to maintain waterbody flows around in-stream construction activities for limited periods of time. Pumps will only be used when direct access to the streambed or trench is required and not for extended periods of time.
- Can be used on most smaller stream crossings without significant amounts of flow. Not preferred for use in streams designated as cold water fisheries or other sensitive area designations.

Installation:

- Leave as much of the bank and riparian zone vegetation in place as possible
- Plan for the crossing to occur at the narrowest point of the stream as practicable. Choose a strategic location just upstream and just downstream from the construction area in order to construct sandbag dams.
- Install haybales or other erosion control along the stream banks and protecting any adjacent wetland areas,
- Keep all stockpiles enclosed within the erosion control barriers and at least ten feet away from the edge of the stream. Hazardous materials should be stored at least 100 feet from all wetlands and waterways.
- When dam is constructed, water should be pumped downstream of the activities, maintaining stream flow. Pumps should be contained in plastic, child-sized pools or other adequate containment.
- Pumps must be manned at all times and spare pumps are to be kept handy.
- Screen and elevate the intake hose off the streambed.
- Discharge should be pumped onto a splashboard (i.e. plywood) to limit scour and through an energy dissipater such as staked haybales, before it is released downstream of the second dam.
- Check weather forecasts regularly and attempt to plan construction around significant rainfall.

FLUMED CROSSING (BYPASSING VIA GRAVITY)

Where:

- Use where unobstructed flows must be maintained at all times during in-stream construction activities and for longer periods of time than allowed in wet crossings or dam and pump.
- Preferred for use in streams that have been designated as cold water fisheries or other sensitive area designations and for larger streams with higher flow which cannot be handled by the pump around method.

Installation:

- The size of the flume pipes will be designed to handle the maximum expected flow of the stream at the time of construction.
- All general stream construction practices listed under the dam and pump installation shall apply to the flume method.
- Build sandbag dams around the ends of the flume pipe just upstream and downstream of the construction activities so that water is able to pass over the work space through the flume. Install the flume prior to excavation.
- Trenching and pipe installation will be taking place beneath the flume. Once the pipe and permanent trench breakers are installed, backfill the trench with the flume in place. Release the flow to the streambed carefully.

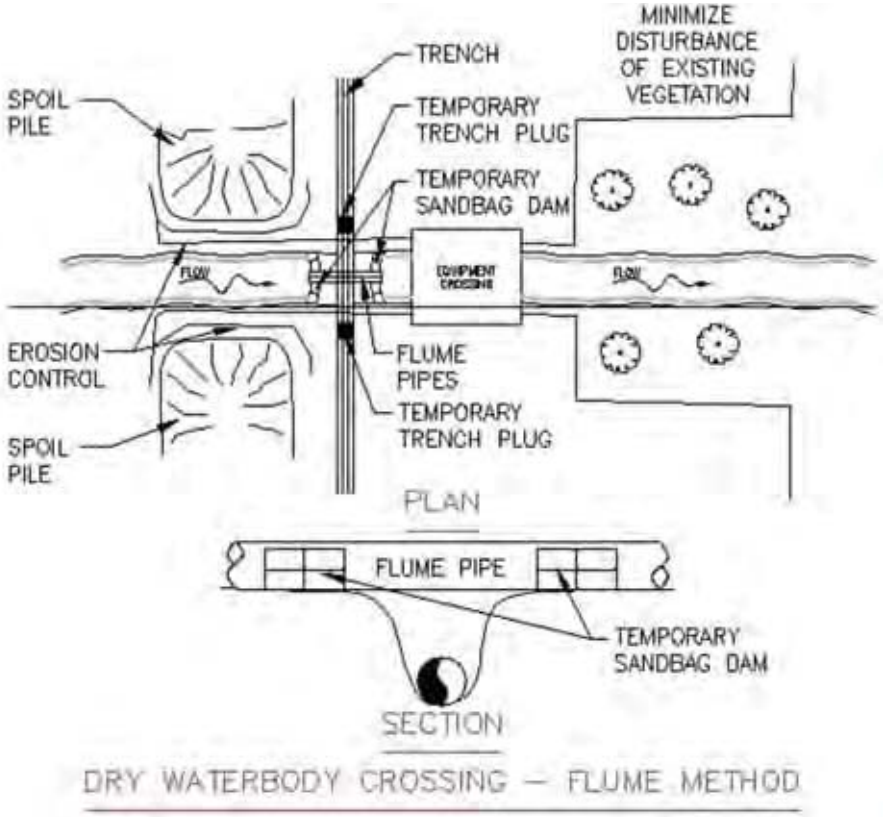
Maintenance for both:

- Inspect and maintain erosion control on a regular basis and observe sandbag dams for signs of leaking or instability.
- Streambanks and wetlands should be restored immediately after backfilling. This includes contouring the stream bed where the trenching had occurred, and placing any necessary stabilization measures on the streambanks.

Appendix 5-2

WATERBODY CROSSINGS

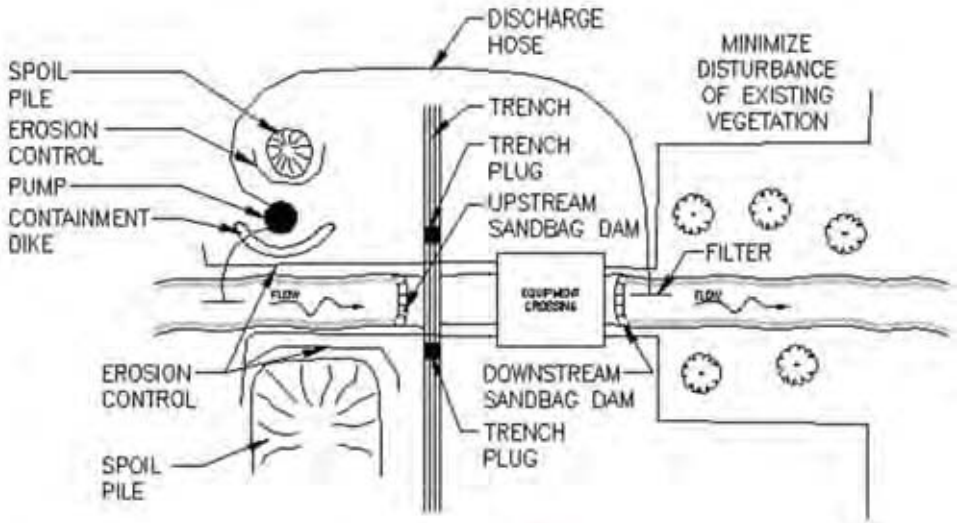
★ Please note that all applicable permit approvals must be obtained prior to construction of dams.



DRY WATERBODY CROSSING – FLUME METHOD

★ Flume crossing method is easier to get permit approval and preferred for use in streams that have been designated as cold water fisheries or other sensitive area designations.

★ Use the dam and pump method on streams where direct access to the in-stream trench is only necessary for limited periods of time.



DRY WATERBODY CROSSING – PUMP METHOD

NSTAR ELECTRIC GAS

SECTION 5.4
COFFERDAMS

A temporary structure used during instream work to enclose a work area by diverting stream flow, while containing sediment and turbidity. Cofferdams require careful installation and maintenance and can be expensive. All cofferdams must be designed to be site specific and approved by the project engineer. Please follow all site specific permits and instructions from the environmental inspector and engineer. The dams are typically constructed from rock filled timber cribs, Rockfill (should be clean and with low acid generating potential), sandbags, sheet piling or wood sheeting. Pre-manufactured products such as Aquabarrier™, a water inflated dam, also function as a cofferdam.

Construction in and around waterbodies must be expedited and the amount of equipment and additional workspaces must be limited. It is preferred that any in-stream work occurs outside of the time-of-year restrictions for any species listed by the Massachusetts Department of Marine Fisheries (DMF) as present in the stream where instream work is proposed, and outside of October 1st to June 30th for any inland stream not listed by DMF. Appropriate permitting efforts must be completed prior to any in-stream work or fill. Some regulatory programs consider coffer dams as fill, and consider dewatered areas as jurisdictional secondary impacts.

Where:

- Use in channels with high flows and current velocities where silt barrier will not be effective.
- The instream constriction caused by the cofferdam should not be large enough to produce unacceptable scour velocities in the remaining channel section.
- Do not install in channels where dams would hinder the passage of boats or fish.

Installation:

- All cofferdam installations should be designed and approved by engineering staff following geotechnical and hydrological studies.
- Place haybales or silt fence along the streambanks approaching the edges of the workspace.
- Cofferdams should be a semicircle or U-shaped and lined with a geotextile. Use clean durable rockfill or large pre-cast concrete blocks for construction**.**
- Locate the geotextile outside of the dam for the upstream half and inside for the downstream half to prevent displacement of the geotextile. Place the geotextile with a short flap (1 ft) at the base of the dam, weighted down with clean rockfill.
- Dewatering of the isolated work area may or may not be necessary or even possible. If dewatering is necessary, install an impermeable liner or clay plug.
- After the sediment in suspension has settled out, remove the cofferdam carefully so that sediment disturbance is minimized.
- If using a pre-fabricated product, follow manufacturer's instructions and engineer's guidance.

Maintenance:

- Cofferdams require careful maintenance at all times.
- Observe the stream flow for any turbidity as a result of the construction activities.

COFFERDAMS

★ Please note that all applicable permit approvals must be obtained prior to construction of dams.



★ Photo of an Aquabarrier ™ diverting flow around a large work space. (Photo from www.aquabarrier.com).

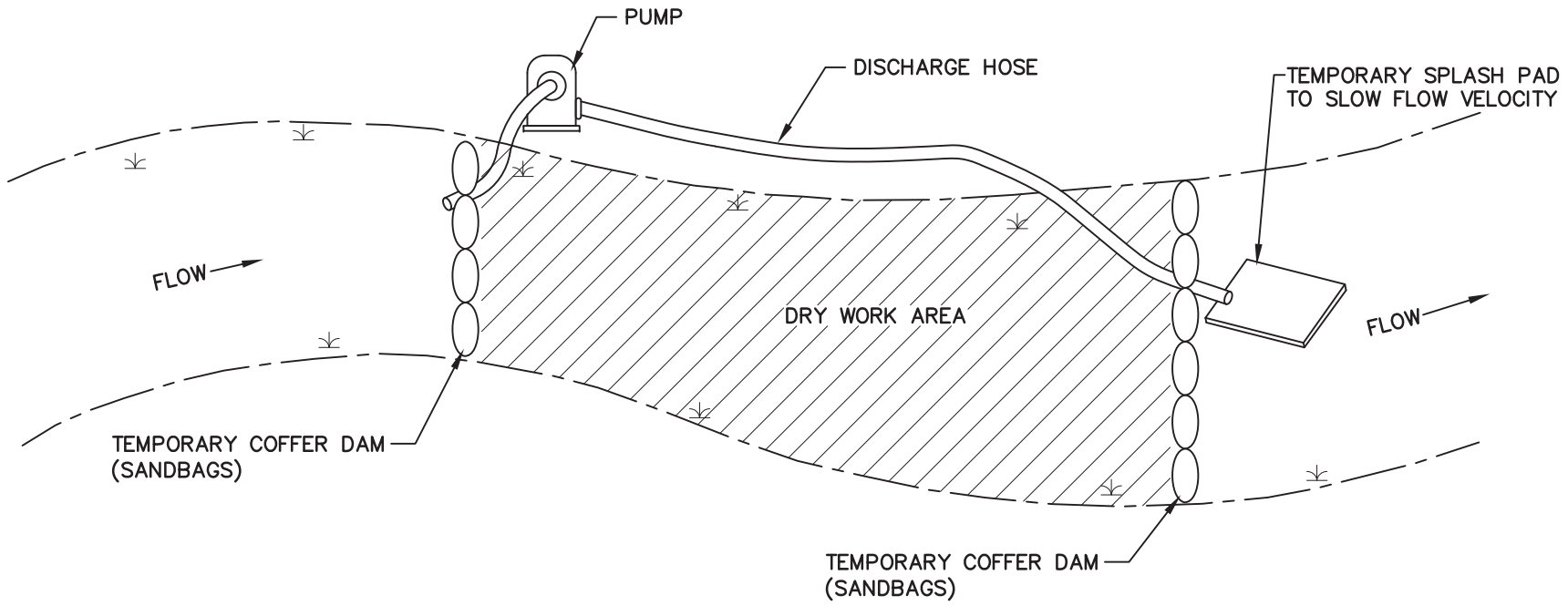
Suggested manufacturer's website:

- www.aquabarrier.com

★ Construction of coffer dams for instream work is site specific. Follow permit guidelines and requirements and the project engineer's instructions at the time of construction. Pre-manufactured products such as Aquabarriers™ serve as water inflated cofferdams and can also be used on a site by site basis according to manufacturer's instructions. Cofferdams can be constructed from a simple double layer of haybales to more complex timber, rock and concrete structures.

NSTAR ELECTRIC GAS

Appendix 5-2



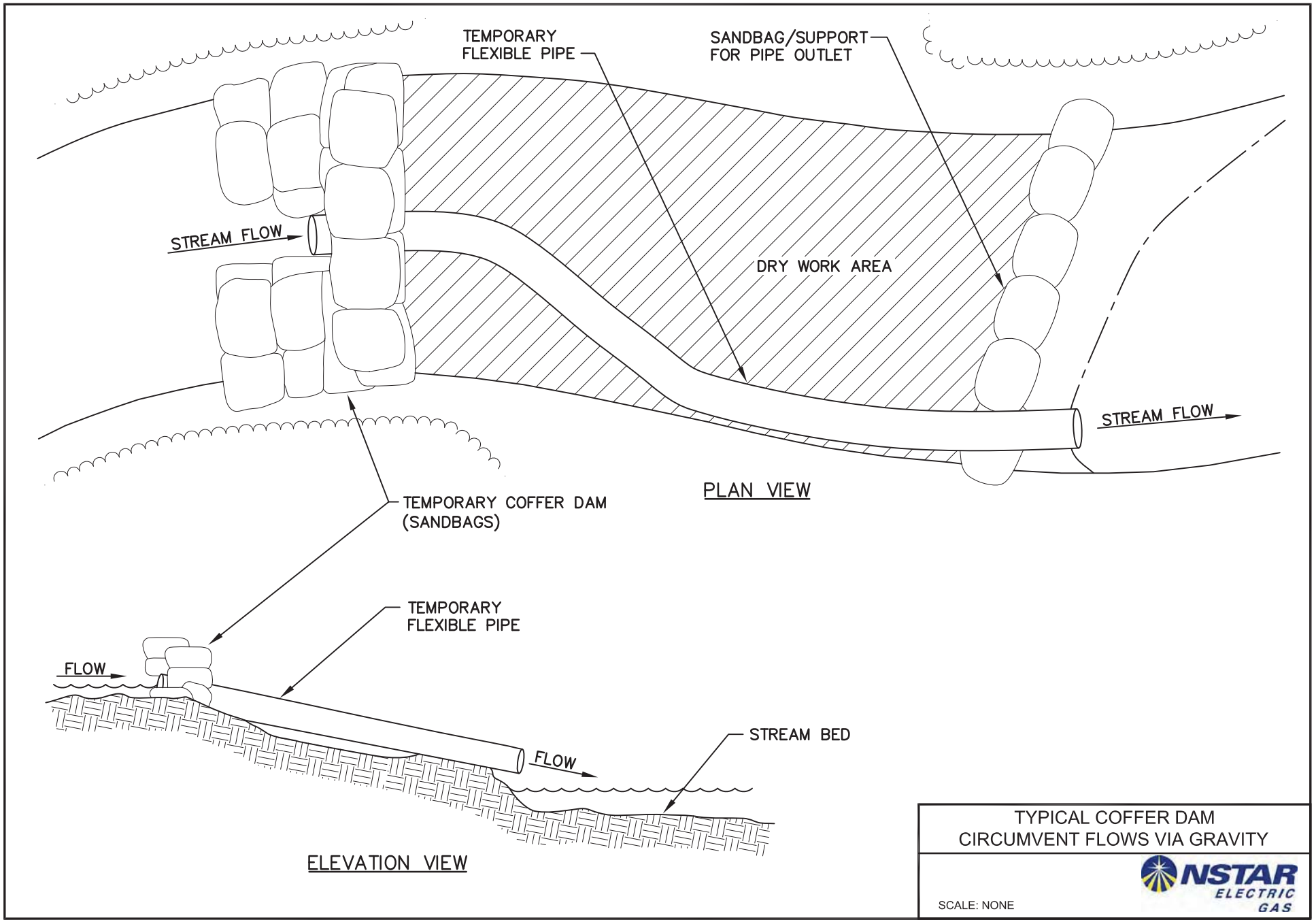
PLAN VIEW

TYPICAL COFFER DAM
TO PUMP & DIVERT STREAM FLOWS

SCALE: NONE

NSTAR ELECTRIC GAS

Appendix 5-2


TEMPORARY
FLEXIBLE PIPE
SANDBAG/SUPPORT
FOR PIPE OUTLET
STREAM FLOW
DRY WORK AREA
STREAM FLOW
PLAN VIEW
TEMPORARY COFFER DAM
(SANDBAGS)
TEMPORARY
FLEXIBLE PIPE
FLOW
FLOW
STREAM BED
ELEVATION VIEW
TYPICAL COFFER DAM
CIRCUMVENT FLOWS VIA GRAVITY
SCALE: NONE
NSTAR
ELECTRIC
GAS

SECTION 5.5
STAKED AND FLOATING SILT BARRIERS

Temporary flexible barriers used within a waterbody to separate or deflect natural flow around a work area. Barriers are placed around the source of the sediment to contain the sediment-laden water, allowing suspended soil particle to settle out of suspension and stay in the immediate area. The staked barrier consists of geotextile fabric attached to support posts and a wire support fence and a chain sewn into a sleeve along the bottom edge to allow the barrier to conform to the channel. The floating silt barriers are often called silt or turbidity curtains, and can be purchased from manufacturers or can be made on site. Construction generally includes a skirt (geotextile fabric) that forms the barrier, flotation segments such as styrofoam sealed in a seam along the top of the fabric, a ballast chain sealed into a sleeve along the bottom edge of the fabric, a loadline built into the barrier above or below the floatation segments, and piles or posts tied back to underwater or on shore anchor points.

STAKED SILT BARRIERS

Where:

- Do not use in streams/river with strong currents, strong waves, ice, floating debris, or boats and do not place barriers completely across stream channels unless they are minor or intermittent streams with negligible flow.
- For installations which only isolate a part of the stream, barriers can be used in higher flows (shallow streams with currents less than 0.5 ft/s).

Installation:

- Place the staked barrier and wire support fence at least 1ft above the waterline. Do not install in a waterbody deeper than 4 ft.
- Place support stakes 10 ft apart and drive them 2 ft into the channel bottom. Fasten the wire mesh securely against the fabric with heavy duty wire staples at least 1" long. If possible, use a continuous roll of fabric and fasten securely to the posts with heavy duty staples with a maximum spacing of 2".
- Where possible, prefabricate a staked barrier on shore. Carefully roll it up lengthwise and move it into place.
- Secure the bottom edge of fabric to the channel bottom by placing a heavy chain into a sewn sleeve along the fabric edge, or by placing clean rockfill over the edge.

FLOATING SILT BARRIERS

Where:

- Use only in negligible or low flow conditions. Can be used for instream areas between 2.6 ft and 6 ft deep and with waves potentially up to 10 feet.
- Do not use to stop, divert, or filter a significant volume of water.

Installation:

- Purchasing a pre-manufactured silt curtain such as Siltmaster® will save time constructing the barrier. Follow manufacturer's advice for the area.
- Enclose the smallest area as possible. Locate the barrier far enough away from construction equipment to avoid damage.
- Launch the furled barrier from a ramp, pier or shore. Set the shore anchor points and tie off one end of the barrier to the stream anchor point and the downstream end to a boat. Bring to the downstream point to be anchored.
- Anchor the barrier in the desired formation and make sure the skirt is not twisted around the flotation.
- Cut the furling ties and let the ballast sink to its maximum depth.
- Slant the barrier at an angle, not perpendicular to the flow. If the barrier will be exposed to reversing currents, anchor it on both sides.

Maintenance for both:

- Inspect daily for any rips or tears or turbidity in the stream flow. Repair immediately with overlapping pieces of geotextile fabric.
- Remove accumulated sediment from the base of the barrier. If necessary, dewater turbid water to an onshore filter bag before removing the barrier.
- Remove the barrier carefully when the work is completed and after suspended sediments have time to settle out.

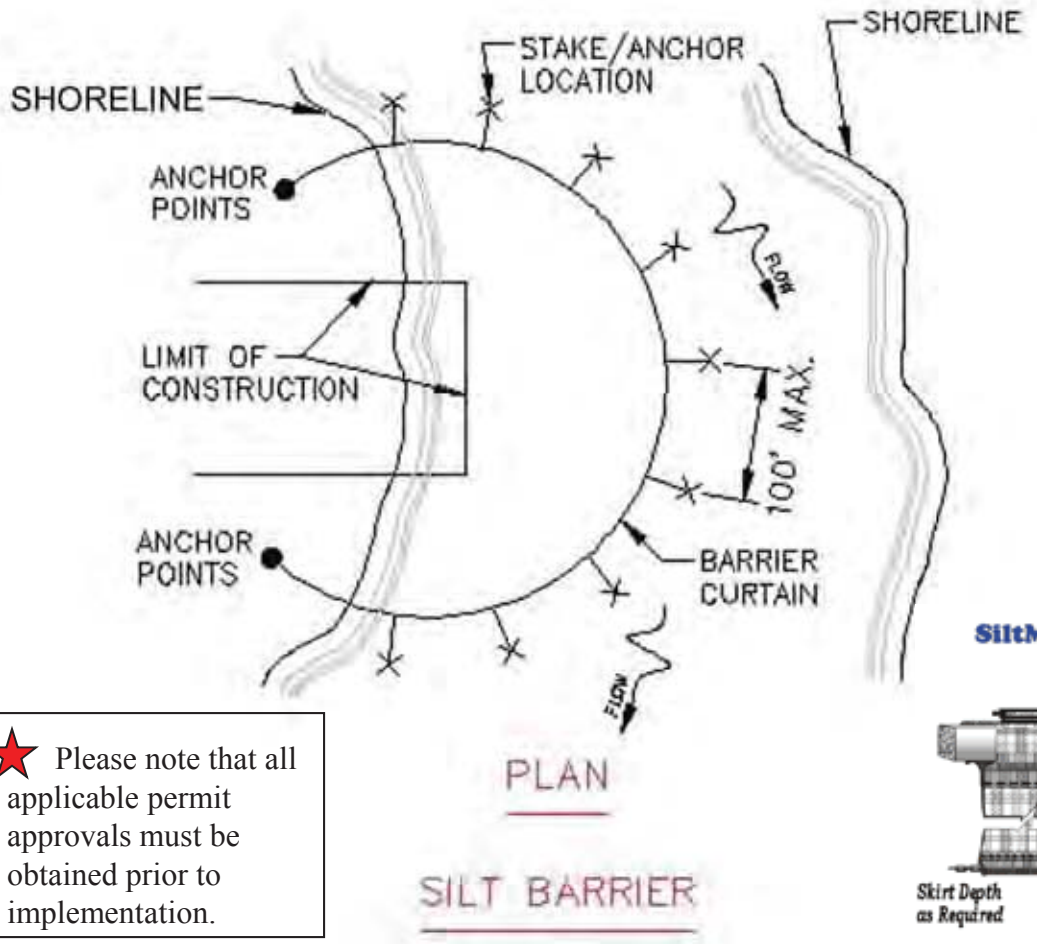
Applicable Conditions for Silt Barrier Use (Configuration)

Configuration	Parameter	Staked Barrier	Floating Barrier
Completely across Intermittent flowing swales,/ditches	With negligible flow	Applicable	Not applicable
	With flow	Not recommended	Not recommended
Completely across waterbody	With negligible flow	Applicable	Applicable
	With flow	Not recommended	Not recommended
In "U" or elliptical shape	Velocity < 0.5 ft/s	Applicable	Applicable
	Velocity 0.5 ft/s - 0.8 ft/s	Applicable	Not recommended
	Velocity >0.8 ft/s	Not recommended	Not recommended

Source: Adapted from Trow Consulting Engineers Ltd., Oct. 1997

STAKED AND FLOATING SILT BARRIERS



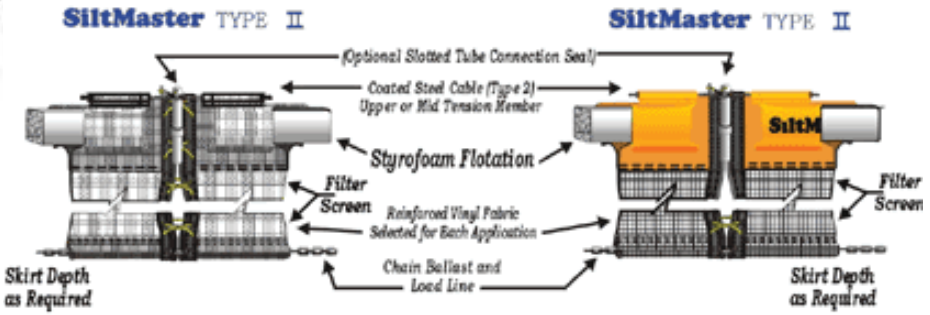


★ Pre-manufactured floating silt curtains, such as Siltmaster® or Silt Dam™ can also be used. Styrofoam is sealed into the hem of the skirt fabric to provide flotation.

★ Selected Manufacturers' Websites:

- www.spilldam.com/spilfset.htm
- www.parkersystemsinc.com/siltmaster.htm

★ Please note that all applicable permit approvals must be obtained prior to implementation.



NSTAR ELECTRIC GAS

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SECTION 5.6
PROTECTION OF EXISTING CULVERTS

Installing or repairing pipelines or electrical conduit in the shoulders of roadways may result in encountering streams which have been previously culverted in order to run under the roadway. Protection of these culverts is very similar to the protection of existing utilities such as sewer or water mains. Again, these situations should be looked at on a case by case basis and it is somewhat difficult to provide general mitigation measures. The engineers overseeing the project should be contacted for their opinion and approval. One of the main objectives is to avoid sedimentation to the stream flow, as well as preventing any damage to the culvert itself.

PROTECTING EXISTING CULVERTS

Where:

- When work in roadways encounter pre-existing culverts transporting stream flow under the roadway. These methods have been adapted from those specifications used to protect water and sewer mains.

Installation:

- All existing culverts which must be preserved in place without being temporarily or permanently relocated, shall be carefully supported and protected.
- All existing culverts should be supported sufficiently so that there is no additional stress or damage when settling occurs. Existing culverts must be supported temporarily while the trench is open, and permanently to withstand backfill loads and settling.
- All culverted stream locations within 2000 feet in advance of the trench should be clearly marked on the pavement, or by stakes in the ground. The markings must be maintained until the work has been completed in the area.
- Haybales or other appropriate erosion controls should be set along the edges of the stream and connected along the edge of the trench work.
- Disturbing the soil near the open end of the culvert should be avoided if practicable.
- As the excavation approaches the culvert or underground structure, digging with machinery should cease and digging by means of hand tools should commence.
- If the pipeline is to be installed above the stream culvert, a minimum of 6 inches of clearance is necessary between the pipes. The supporting soils should be compact and the engineer should clear whether the culvert can support the additional weight of the pipeline.
- If the pipeline is to be installed perpendicularly under the existing culvert, there are different support measures for existing pipes 12 inches and smaller or 16 inches and greater.

Culvert 12 inches or smaller

- If the existing culvert pipe is 12 inches or smaller, a timber support structure can be built with two 6-inch by 6-inch timber supports with cross members and a support base.
- The culvert should be excavated to its horizontal center line before steel or wood plank sheeting is driven into the trench.
- The support structure and sheeting installation must be approved by a professional engineer.
- The backfill around the culvert must be adequately compacted with suitable material with approval from the engineer.

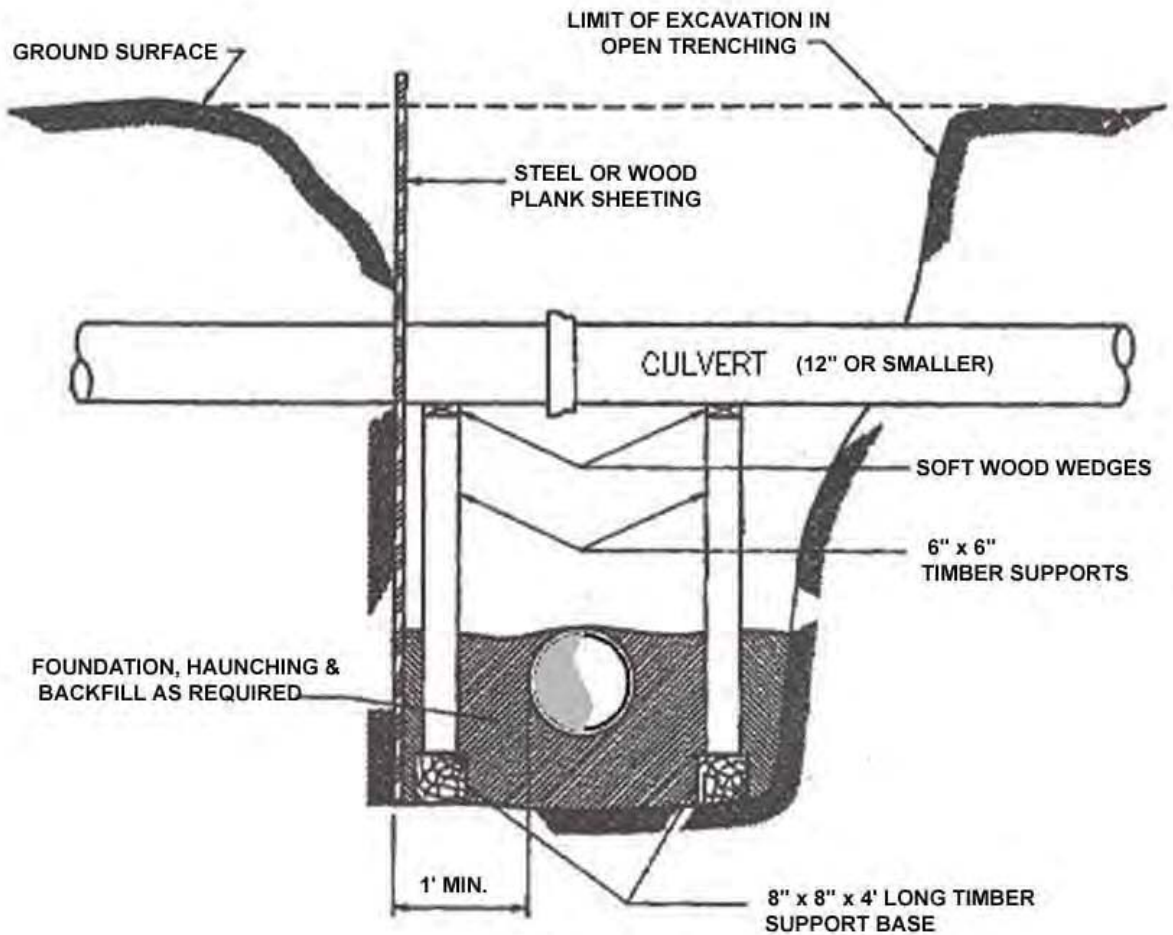
Culvert 16 inches or larger

- The engineer must give approval to details for trench sheeting and pipe support.
- The culvert should be excavated to its horizontal center line before sheeting is driven into the trench.
- The culvert must be supported with at least two temporary slings per pipe length.
- Final support for the existing culvert consists of P.S.I. concrete or solid concrete blocks to be filled around the newly installed pipeline, with 6 inches of compacted sand between the concrete and the existing culvert.
- The foundation must also be approved by the engineer.

Maintenance:

- Inspect and maintain erosion control on regular basis.
- Remain aware of any stress the existing culvert may be experiencing.
- If necessary, consider installing a floating silt curtain on the downstream side of the culvert if sedimentation is an issue during installation.

PROTECTION OF EXISTING CULVERTS



CULVERT PROTECTION

★ If the pipeline or conduit is installed above an existing culvert, there must be a minimum of 6" of clearance. When installing the utility below, all existing culverts must be supported temporarily while the trench is open, and permanently to withstand backfill weight and settling.

★ Remember to protect the inlet to the culvert to avoid turbidity to down-stream flow. Install erosion control and avoid soil disturbance near the inlet to the extent practicable

NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 5.7
HORIZONTAL DIRECTIONAL DRILLING

Utility installation is sometimes necessary in streams that are too large or too environmentally sensitive to perform open trenching or build traditional equipment crossings. In these situations, directional drilling can be used to place the pipeline under the stream bed with little to no impact to the waterbody's channel or banks. Each situation where directional drilling is necessary is extremely site specific, and therefore difficult to provide general specifications. Follow the site specific layout, permits, and instructions at the time of construction.

DIRECTIONAL DRILLING

Where:

- Directional drilling should be considered for major stream or waterbody crossings where conditions make it difficult to install pipe or cable with conventional construction methods.
- Directional drilling should also be considered where practicable for streams that are especially environmentally sensitive, such as public water supplies, and endangered species habitat where the chances of increased turbidity would be hazardous.

Installation:

- Directional drilling is a technologically advanced process where a drill bit is radio controlled and maneuvered along the construction path boring a tunnel under the waterbody.
- It requires setting up entrance and exit staging areas on either side of the waterway. Both staging areas should be planned ahead of time for the placement of all necessary equipment and containment areas.
- These staging areas and additional temporary workspace, includingstorage areas for drilling mud and borehole cuttings will be located in upland areas and out of wetlands and riparian zones wherever practicable.
- Sediment barriers/erosion control will be installed on the downgradient side of upland spoil storage areas.
- Directional drilling requires the use of drilling mud which has the potential to release or "frac out", and erupt through permeable rock or soil layers. Geotechnical studies and preparation must be done ahead of time to determine the likelihood of this in particular areas.
- Excavation at the drill entry and exit locations will be necessary to contain drilling fluids.
- Follow all site specific permit specifications instructions of the environmental inspector or engineer.

Maintenance:

- Inspect and maintain erosion control on regular basis.
- Ensure that all drilling mud is being stored properly and frac tanks are being maintained.
- Constantly monitor the returns of the volume of drilling mud to the drilling rig to identify as quickly as possible if a frac out has occurred.

Problems:

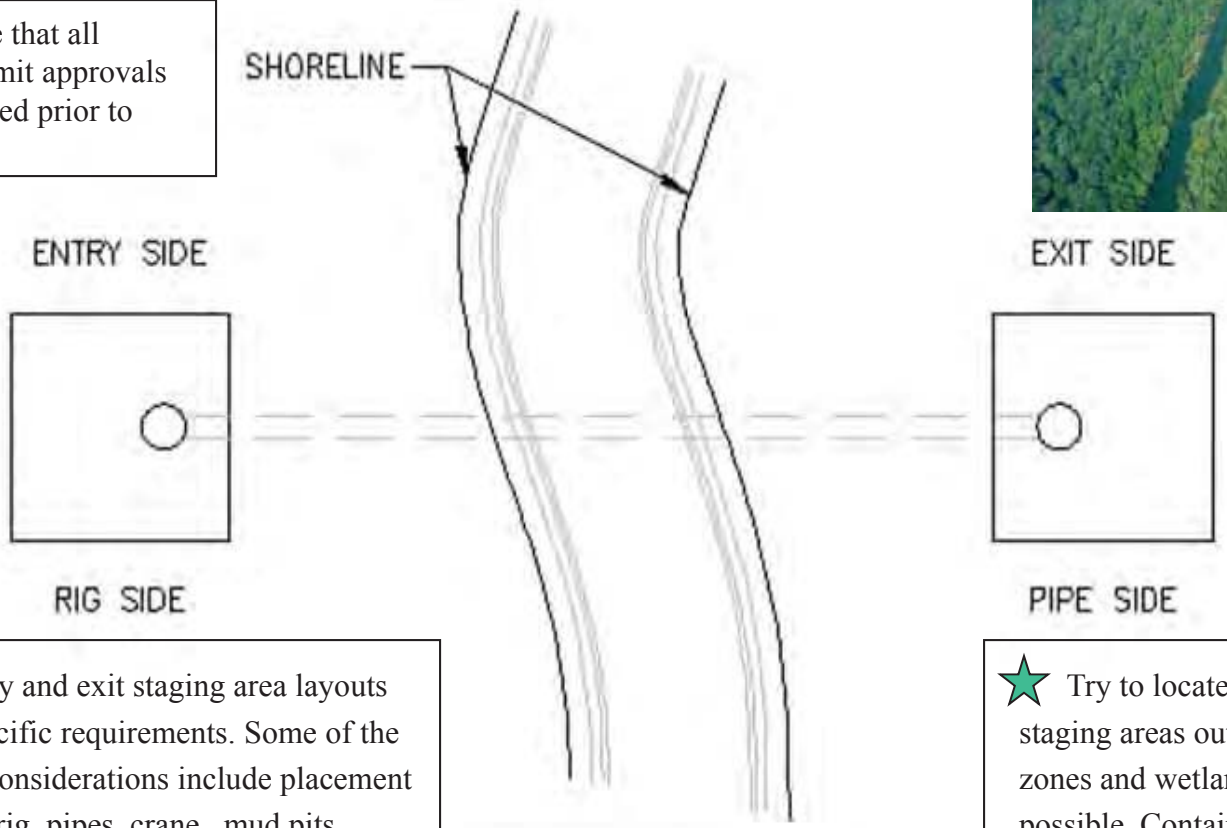
- If there is a loss of mud returns at the drill rig, it is a strong possibility that a an inadvertent release of drilling mud or a "frac out" has occurred.
    - Mitigation measures are all case by case depending on the amount of mud lost or the sensitivity of the area. A release plan should be prepared ahead of time.
    - Inspect the area thoroughly to identify the exit point of the release.
    - Reduce the pressure of the drilling muds and the drill by drilling below the resource area by drilling in an upland area down to the elevation of the drill.
    - Stop drilling to relieve pressure and volume and possibly allow for the bentonite mud to form a seal over the release site.
    - Evaluate using a thicker mixture of muds, or the effectiveness of installing a casing to drill with.
    - Implement appropriate measures to control, recover, and contain the released mud as well as mitigate for downstream impacts.
    - The release must be reported to the proper regulatory agency.

Appendix 5-2

HORIZONTAL DIRECTIONAL DRILLING



★ Please note that all applicable permit approvals must be obtained prior to drilling.



★ Plan entry and exit staging area layouts per site specific requirements. Some of the necessary considerations include placement of the drill rig, pipes, crane, mud pits, pumps, and mixing tanks, and frac tanks.

★ Try to locate entrance and exit staging areas outside of riparian zones and wetland areas where possible. Contain all stockpiles and work areas within erosion control.

DIRECTIONAL DRILL

NSTAR ELECTRIC GAS

SECTION 5.8
STANDARD BORE

Installation of utilities is sometimes necessary in streams that are too large or too environmentally sensitive to perform open trenching or build traditional equipment crossings. In these situations, standard boring can be used to place the utility under the stream bed with little to no impact to the waterbody's channel or banks. Due to site specificity, it is difficult to provide general mitigation. Please follow the site-specific layout, permits, and instructions at the time of construction.

STANDARD BORE (JACKING)

Where:

- Standard boring should be considered for major stream or waterbody crossings where conditions make it difficult to install pipe or cable with conventional construction methods.
- Boring should also be considered where practicable for streams that are especially environmentally sensitive, such as public water supplies, and endangered species habitat where the chances of increased turbidity would be hazardous.
- Standard boring can often be used in the same circumstances as horizontal directional drilling. Boring requires a fairly straight, regimented construction path while directional drilling allows more maneuverability. Boring is also slightly less expensive than drilling.

Installation:

- Standard boring requires excavating a bore pit and a receiving pit on either side of the waterway. Both areas should be planned ahead of time for the placement of all necessary equipment and containment areas.
- A 50-foot setback of undisturbed riparian zone should be maintained between the waterway and construction area.
- Maintain erosion control around the boring and receiving pits and ensure that all stockpiles are enclosed within the barrier.
- Segregate the topsoil from the subsoil when excavating the pits and temporary stockpiling.
- Proper dewatering sites should be selected away/downgradient of bore/receiving pits within a vegetated section of the right of way.
- If well points are utilized for dewatering, the well points should be located outside of the 50-foot setback, and discharges to wetlands or waterways require prior approval.
- Maintain adequate equipment access (i.e. forecast temporary workspace requirements for construction equipment, soil stockpiling and dewatering activities).
- The tunnel for utility installation must remain a minimum of 5 feet below the river bottom when it is bored.
- Follow all site specific permit specifications and instructions of the environmental inspector and/or engineer.

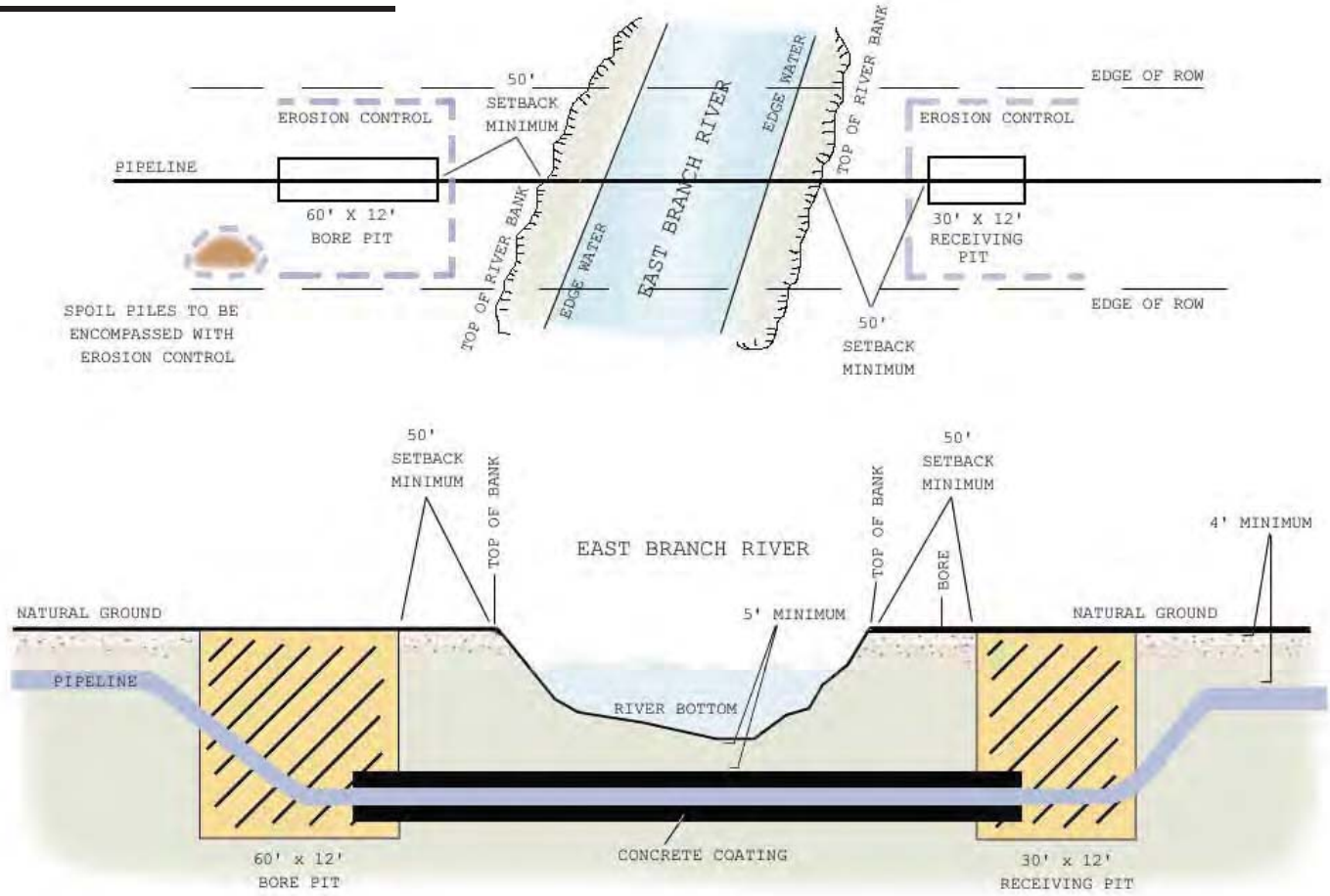
Maintenance:

- Inspect and maintain erosion control on regular basis.
- Ensure that all stockpiles and excavations are properly contained within the erosion control line.

Appendix 5-2

STANDARD BORE

★ Please note that all applicable permit approvals must be obtained prior to performing the boring



★ General mitigation is somewhat difficult to provide for bores due to site specific requirements. Follow all layouts, permits requirements and instructions at the time of construction.

★ Standard Boring should be performed on extremely sensitive waterbodies where the chance of increased turbidity due to traditional construction methods would compromise important natural resources.

NSTAR ELECTRIC GAS

SECTION 6

INSPECTION AND MAINTENANCE OF BMPS

Appendix 5-2

SECTION 6
BMP Inspection and Maintenance

6.1 Before and During Construction Period:

Routine inspection and maintenance schedules should be prepared and approved prior to the commencement of work for each project and a responsible party should be designated to manage such tasks. It may also be necessary to alter the frequency of inspections and maintenance depending on types of activity and weather events, including proactive measures when storm events are forecast.

Since construction sites and construction access roads are usually in constant use and undergoing continuous change, they should be closely monitored. Construction sites, construction access roads, and the associated erosion and sedimentation controls should be inspected at the end of each day they are used and any damage observed must be repaired immediately. If an access road is not used for more than a week, then inspection should occur at a frequency as required by the specific erosion and sedimentation measures in use and extent of heavy rain events. Repairs may include regrading and/or top dressing the traveled surface with additional aggregate to eliminate ruts as well as those repairs required by each erosion and sedimentation measure used.

All information collected during inspections, regular maintenance, and repair procedures should be documented in written form. In addition, photographic or diagrammatic logs may be kept to help record certain events and for documentation of project progress and any noteworthy observations.

6.2 Post-Construction:

Post-construction inspections of restored areas should be conducted at regular intervals throughout the growing season, as required by any applicable permits, and/or after major storm events. Sites should be inspected for success or failure of revegetation, invasive species colonization, and erosion and sedimentation. In the event additional measures are required to achieve site restoration and stabilization, corrective actions shall be identified and implemented.

All information collected during inspections, regular maintenance, and repair procedures should be documented in written form. In addition, photographic or diagrammatic logs may be kept to help record certain events and for documentation of project progress and any noteworthy observations.

SECTION 7

SITE HOUSEKEEPING

Appendix 5-2

SECTION 7
SITE HOUSEKEEPING

7.1 Maintenance of Erosion and Sedimentation Controls

Spare erosion and sedimentation control materials such as hay/straw bales and silt fencing should be kept on site or readily available. Such materials should be readily available and accessible at all times so they may be replaced if they become non-functional due to deterioration or damaged during a storm, extreme water or wind, or other unexpected event.

7.2 Vehicle Storage, Refueling and Material Staging

All storage and refueling of vehicles and other equipment must occur outside of and as far away as practical from sensitive areas such as wetlands, streams, and drinking water supplies. A proper location for refueling should be identified and designated before site work begins. In Massachusetts, the recommended minimum distance from wetland areas for refueling is 100 feet. Additionally, equipment should be checked regularly for evidence of leaks. Construction material storage should also be located at least 100 feet from wetlands.

7.3 Spill Kits

Spill kits consist of emergency cleanup and spill containment materials that can be used in the event of a fuel or other chemical spill. Spill kits should be kept on site and accessible at all times in case of an emergency spill. Such kits should generally contain multiple absorbent socks and/or pillows and wipes and temporary disposal bags. Follow the applicable NSTAR procedures.







7.4 Illegal Dumping/Use

Management of illegal dumping and use should follow existing NSTAR guidelines found in _____.

Appendix 5-2

SECTION 7.5
DUST CONTROL MEASURES

Used to reduce surface and air movement of dust from exposed soil surfaces during land disturbance, demolitions and construction activities. These practices will decrease the amount of dust in the air, decreasing the potential for accidents, respiratory problems and airborne sedimentation. To reduce the amount of areas requiring dust control, construction activities should be scheduled appropriately to have as little of the site surface as possible exposed at one time.

Where:

- Disturbed soil surfaces and exposed soil surfaces, especially during hot or dry weather periods and in areas with excessively well-drained soils.

Methods:

Type	Description/Uses
Vegetative Cover	• Most effective and practical method. • Use in disturbed areas not subject to traffic. • Follow seeding requirements as directed by EAD or permit requirements.
Stone	• Cover soil surface with crushed stone/coarse gravel.
Water/Sprinkling	• Sprinkle exposed soils until wet (Water trucks may be used depending on size of the site). • Do not excessively wet the soil as this causes run-off and also wastes water.
Barriers	• Board fences, wind fences and sediment fences control air currents and blowing soil. • Wind barriers protect soil downgradient for a distance of ten times the barrier height. • Perennial grasses and stands of existing trees also serve as wind barriers, stressing the importance of planning work phasing properly and minimizing the amount of exposed soil.
Plastic Covering	• Cover soil piles with sheets of plastic/tarp to minimize dust.
Calcium Chloride	• Loose, dry granules of calcium chloride may be applied with a mechanical spreader. • It should be applied at a rate that keeps the surface moist but not high enough to cause water pollution or plant damage. This method should be done under consultation with an expert in order to maintain this balance and to determine if the site is applicable.

Maintenance:

- Repetitive treatments should be used as needed, or required by permits, and until the surface is permanently stabilized.

DUST CONTROL MEASURES



- Anchoring plastic sheeting to a stockpile is an appropriate dust control measure. Stockpiles should also be enclosed in erosion control barriers, such as silt fence or haybales to control sedimentation off-site.

- Sprinkling dry, exposed soil with water until the surface is wet, will control dust clouds and off-site sedimentation. Do not excessively wet the soil as this causes run off as well as wastes water.

- The most effective measure for controlling dust is avoid clearing existing vegetation wherever possible. Other methods include plastic covering on stockpiles, crushed stone and wind barriers.

NSTAR ELECTRIC GAS

SECTION 8

SITE RESTORATION

Appendix 5-2

SECTION 8.1
SURFACE ROUGHENING

Roughening a bare soil surface either with horizontal grooves running across the slope, stair stepping, or tracking with construction equipment. An inexpensive and simple temporary control measure that encourages water infiltration, speeds the establishment of vegetation, and decreases runoff velocity.

SURFACE ROUGHENING

Where:

- All construction slopes require surface roughening to facilitate stabilization with vegetation.
- This is especially important for slopes steeper than 3:1.
- Implement before a forecasted storm event.
- Implement before leaving a job site for the weekend.

Installation:

- Disturbed areas that will not require mowing should be stair step graded, grooved, or left rough after filling.
-

Slopes less than 3:1	Slopes greater than 3:1 but less than 2:1	Slopes steeper than 2:1
These areas should be mowed after stabilization and should be roughened with small furrows left by disking, harrowing, raking or seed planting machinery operated on the slope face.	Surface should be roughened before seeding by driving a crawler tractor up and down the slope face, leaving track imprints parallel to the slope contours and perpendicular to the slope face.	These areas should be stair stepped with benches with steps wide enough to work with standard earth moving equipment. Each step catches sediment from above and provides a flat area for vegetation to establish.

- Rocky soils should be stair stepped graded.
- Slopes can be grooved by cutting furrows along the slope contours with bulldozers with rippers or tractors with disks.
- Tracking is the least effective method of roughening but is preferable to not roughening at all, however, try to avoid excessive compaction of soil.

Maintenance:

- Seed areas which are graded and surfaced roughened as quickly as possible.
- Inspect weekly and after every rain event.
- If rills or gullies appear, re-grade and re-seed the slope.

Problems:

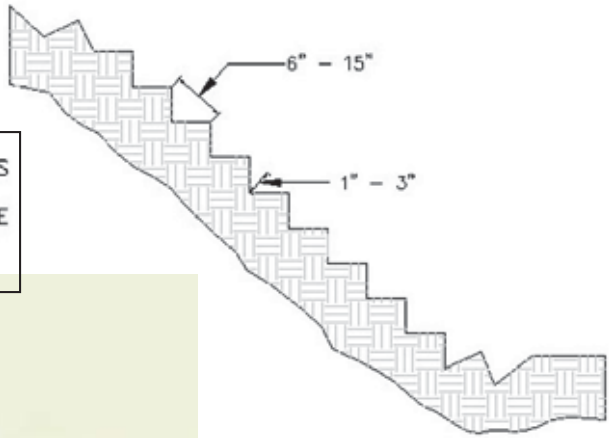
- Surface roughening is a temporary measure. If it is washed away, The surface will have to be roughened again and reseeded.
- Surface roughening is not effective for anything more than a moderate storm.

**** REMEMBER****

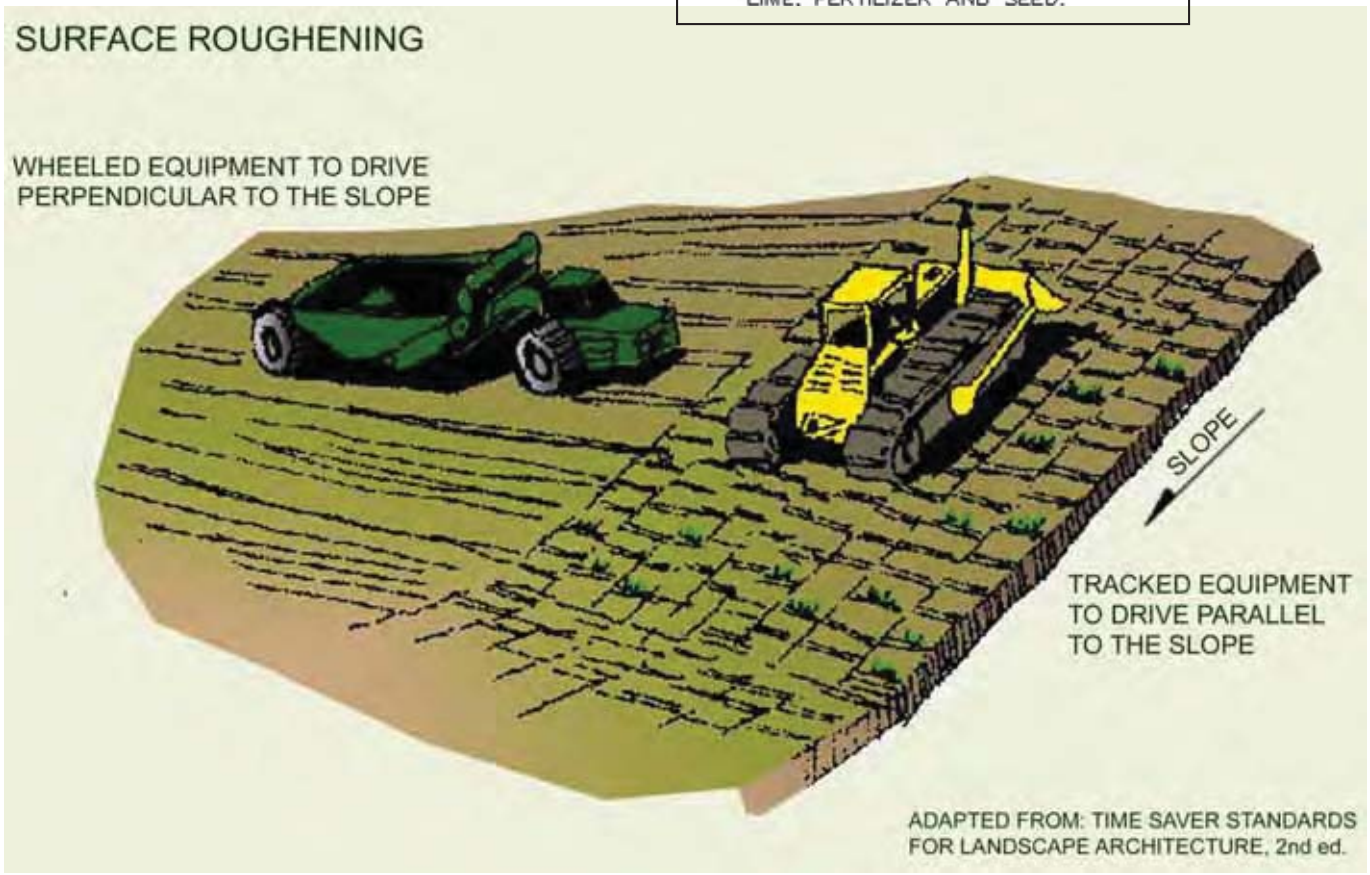
Cleat/track imprints parallel to the slope contours and perpendicular to the slope face act to reduce erosive forces while cleat/track imprints perpendicular to the slope contours and parallel to the slope grade facilitate gullying and erosive forces.

Appendix 5-2

SURFACE ROUGHENING



★ GROOVE SLOPE BY CUTTING FURROWS ALONG THE CONTOUR, CREATING IRREGULARITIES IN THE SOIL SURFACE TO CATCH RAINWATER AND RETAIN LIME. FERTILIZER AND SEED.



NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 8.2
PERMANENT SEEDING AND MULCHING OF UPLAND AREAS

This sheet and the following figure apply only to non-jurisdictional upland areas, and not jurisdictional areas including wetlands or waterbodies and their banks. Establishment of permanent perennial vegetative cover on any graded or cleared area which has either been completed or will not be brought to final grade for 12 months or more. Mulching consists of an application of a protective blanket of straw or other plant residue, gravel, or synthetic material to the soil surface to provide short term soil protection. It enhances plant establishment by conserving moisture and moderating soil temperatures, and anchors seed and topsoil in place. Mulch also reduces the velocity of stormwater runoff.

PERMANENT SEEDING

Where:

- Any non-jurisdictional, graded or cleared upland area which has been completed as designed or will not be brought to final grade for 12 months or more. Perform temporary seeding if construction has ceased at an area for 21 days or more and if the area will be exposed for up to 12 months.
- Areas in which permanent seeding is especially important include: filter strips, buffer areas, vegetated swales, and steep slopes.

Installation:

- Seed with annual rye grass during the growing season (April 1st - September 30th) and winter rye after September and until frozen ground conditions.
- Where possible, plant native species of grass and legumes.
- Before planting, scarify/roughen the soil surface and install appropriate surface drainage measures to prevent erosion and scouring.
- As needed, provide water, fertilizer, lime and mulch to the seedbed. USDA state and regional offices of NRCS will be able to provide local specifications for restoration. Follow permit requirements such as using wetland seed mix in wetlands where instructed.

Maintenance:

- Inspect seeded areas for failure and make appropriate repairs and re-seed and re-plant as necessary.
- If stand has less than 40% cover, re-evaluate selection of seeding materials and quantities of fertilizer. Lack of water may also be an issue.
- Conduct a follow up survey after one year and re-seed failed areas.

Cool Season Grasses	Warm Season Grasses
Best growth in the cool weather of fall and spring, set seed in June and July. Seed April 1-May31 and Aug1-Sept10	Growth begins in the spring, accelerates in the summer, and plants set seed in the fall. Seed April 1-May 15, dormant seeding Nov 1- Dec 15

MULCHING

Where:

- Use in areas which have been temporarily or permanently seeded.
- Mulch liberally in mid summer, prior to winter, on locations with cut slopes, and areas with southern exposure.
- Use mulch anchoring (netting) on slopes > than 3% or in concentrated flows.

Type	Description/Uses
Straw/Hay	• Straw or hay applied to surface at 2-4 tons per acre • Mechanically or chemically secured to soil surface • Provides the densest cover to protect soil and seeds
Wood Fiber/ Hydraulic Mulch	• Chopped up fibers applied to the soil surface with a hydroseeder • Tackifier when necessary can be applied with fiber, seeds and fertilizer in one step. This is best when done with fast growing seeds
Compost	• Compost acts as a soil amendment but is more expensive than most mulches • Its efficiency is comparable to wood fiber
Wood Chips	• Use of wood chips as a mulch which saves money if on-site materials are used • Effective when applied at high levels (6 tons per acre) and on up to 35% slopes

Installation:

- Determine the mulch material based on soil type, site conditions, season, etc
- Apply immediately to areas which have been temporarily or permanently seeded.

Maintenance:

- Inspect weekly and after storms until vegetation has successfully established
- If mulch washout or erosion occurs, repair surface, re-seed, re-mulch, and install new netting if appropriate.

Problems:

- Mulch spread too thickly may delay seed germination.
- Mulch on steep slopes can be washed away if not secured with netting.

Appendix 5-2

PERMANENT SEEDING AND MULCHING OF UPLAND AREAS



★ Straw mulch spread on soil surface.



★ Hydroseeding: Combines water, mulch, seed and fertilizer.

★ Beginnings of a well-vegetated, well-restored right of way.



★ Drill Seeding; Tracks seed into the soil.



NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 8.3
Wetlands and Waterways Restoration

The following techniques apply to when no permit was required for the project. When permit(s) is/are required for the project, which is the case for most new projects, all restoration activities shall be conducted in accordance with the specific conditions of the project permits.

When No Permit is Required (Some Maintenance, Repair, and Emergency Projects):

- At a minimum, all areas disturbed by construction, repair, and maintenance activities shall be restored to pre-construction conditions. For areas where swamp mats are used and no significant ground disturbance occurred, the wetlands shall generally be allowed to naturally re-vegetate. It is assumed that herbaceous wetland vegetation in these areas will naturally regenerate via intact roots or surrounding seed stock. Shrubs which required cutting are expected to regenerate naturally. No formal in-situ wetland seeding, planting or other restoration will be proposed except in areas where significant ground disturbance and/or re-grading was required.
- Following mat removal the areas shall be inspected for overall disturbance by a wetland scientist. If loose soils are identified within nearby upland areas, sedimentation and erosion controls will be installed along the wetland boundary at the direction of the wetland scientist. Nearby disturbed upland areas will be seeded with a native upland erosion control seed mix and mulched with hay/straw (See Section 8.2 for details).
- Soils excavated from wetland areas shall be segregated and stockpiled separately (i.e. topsoil/muck apart from mineral subsoil) in a dry/upland area, where they will not erode back into the wetland, to facilitate restoration activities.
- Excavated wetland soils that have been stockpiled during underground utility installations within wetlands shall be replaced in the same order (i.e. mineral subsoil beneath organic topsoil/muck) to the extent practicable and restored to pre-disturbance grades.
- If replacement of soil associated with temporary wetland or watercourse crossings for access roads is necessary, disturbed areas must be restored to pre- disturbance grades.
- Grading activities should include the elimination of ruts within the area to be restored.
- Wetland areas where significant ground disturbance occurred, including regraded and excavated areas, or unvegetated areas (i.e. vegetation did not re-vegetate naturally) will be immediately seeded and mulched with an appropriate wetland designated seed mix. For inland wetlands, New England Wetland Seed Mix available from New England Wetland Plants, Inc. in Amherst, Massachusetts or equivalent shall be used at the direction of a wetland scientist. A table depicting typical wetland seed mix composition for this product is presented on the following page. For coastal wetlands (i.e. salt marshes, estuary systems), with plants dissimilar to the above mentioned seed mix, appropriate environmental staff shall be consulted to determine appropriate wetland seed mix and/or plantings for the site.
- Measures to discourage the establishment or spread of plant species identified as non-native, invasive species by federal or state agencies shall be considered based on site and project specific details, and permit(s) if applicable.
- Any restoration plantings or seed mixes used in restoration shall consist of species native to the project area and, if feasible, from local nursery stock.
- Any stream banks and beds damaged shall be restored through use of geotextile erosion control blankets, and or coir logs.
- All seeded areas shall be treated with a layer of mulch (i.e. hay, but preferably straw) up to one inch thick to enhance moisture retention, dissipate impact from precipitation, and detract songbirds foraging on broadcast seed.
- Following construction activities the disturbed wetland areas will be revisited within 60 days of mat removal to ensure re-colonization of hydrophytic (wetland) plant species. Any additional areas will be seeded and mulched in the event re-colonization is not successful. If restoration is required as a result of the second visit, a third visit will be conducted within 60 days to confirm the re-colonization of hydrophytic plant species. If the wetland area has not naturally re-colonized with vegetation after 60 days, a wetland restoration plan shall be developed by appropriate environmental staff and will be implemented at their discretion.

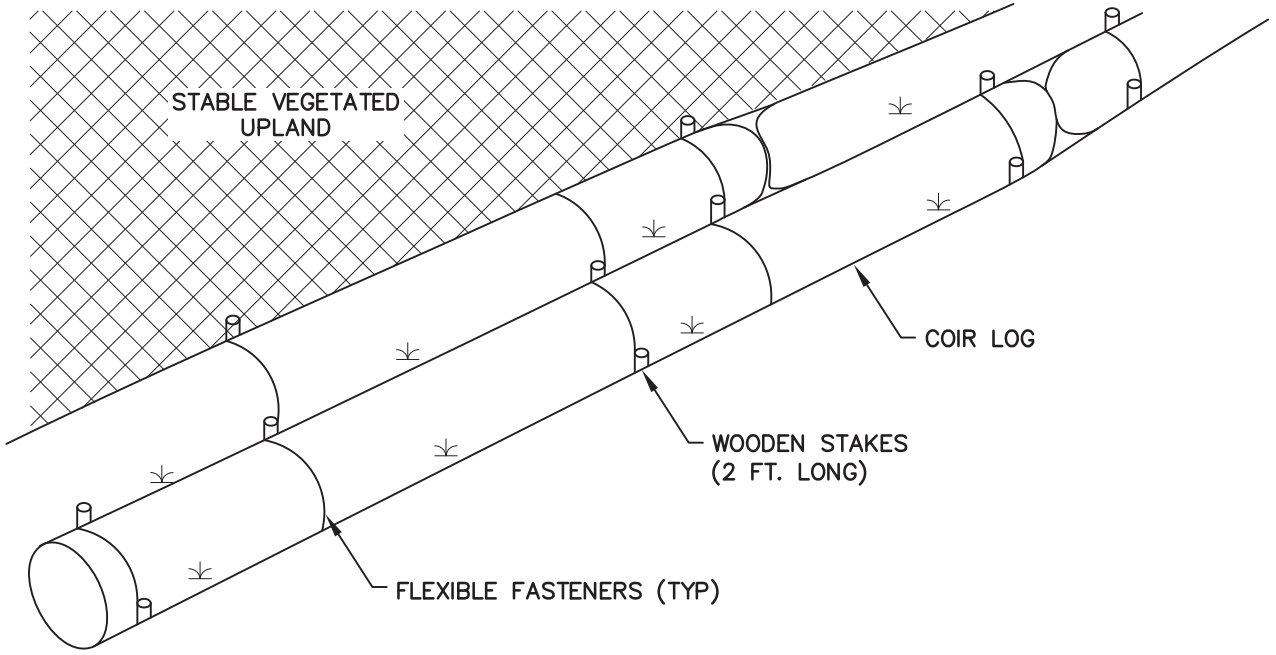
Appendix 5-2

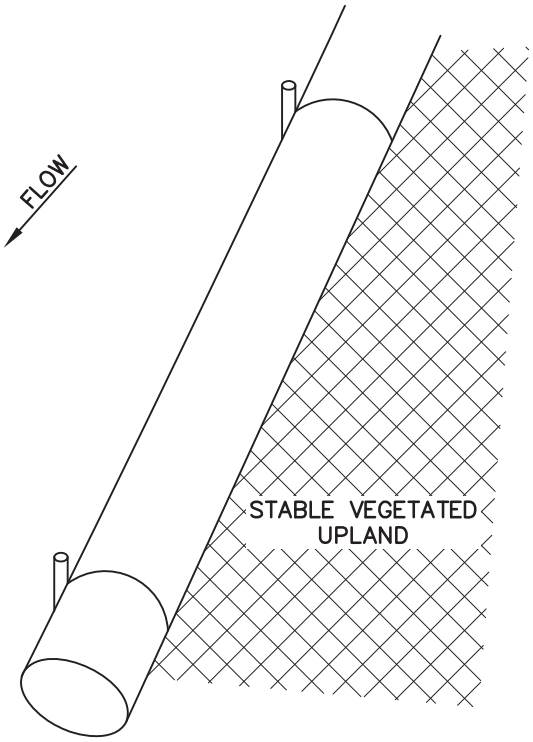
New England Wetland Seed Mix, from New England Wetland Plants, Inc. in Amherst, MA

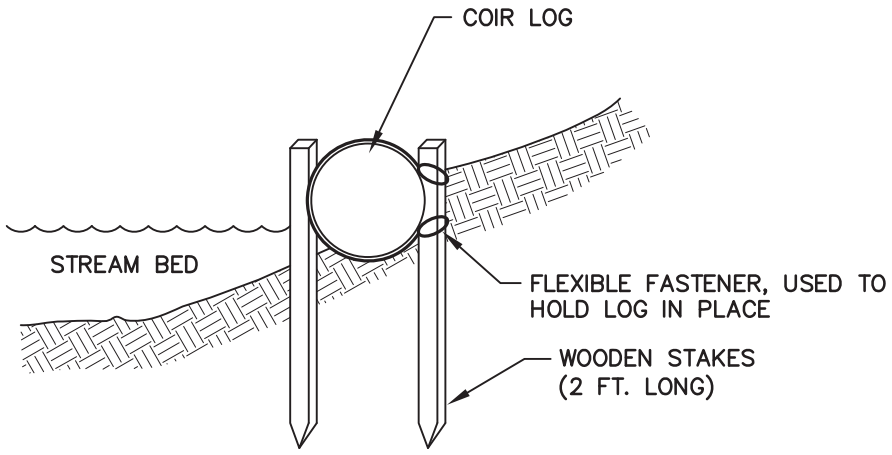
Common Name	Latin Name	Wetland Indicator Status	Percent of Mix
Mud Plantain	Alisma plantago-aquatica	OBL	varies
Swamp Milkweed	Asclepias incarnata	OBL	varies
New York Aster	Aster novi-belgii	FACW+	varies
Nodding Bur Marigold	Bidens cernua	OBL	varies
Bristly/Cosmos Sedge	Carex comosa	OBL	varies
Fringed Sedge (Nodding)	Carex crinita	OBL	varies
Hop Sedge	Carex lupulina	OBL	varies
Lurid Sedge (Shallow)	Carex lurida	OBL	varies
Blunt Broom Sedge	Carex scoparia	FACW	varies
Fox Sedge	Carex vulpinoidea	OBL	varies
Spotted Joe Pye Weed	Eupatorium maculatum	FACW	varies
Boneset	Eupatorium perfoliatum	FACW	varies
Rattlesnake Grass	Glyceria canadensis	OBL	varies
Fowl Mannagrass	Glyceria striata	OBL	varies
Soft Rush	Juncus effusus	FACW+	varies
Square Stemmed Monkey Flower	Mimulus ringens	OBL	varies
Sensitive Fern	Onoclea sensibilis	FACW	varies
Green Bulrush	Scirpus atrovirens	OBL	varies
Wool Grass	Scirpus cyperinus	FACW	varies
Soft Stem Bulrush	Scirpus validus	OBL	varies
Blue Vervain	Verbena hastata	FACW	varies
Total Seed Mix			**100%**

Application Rates – 1lb./2500 square feet
18lbs./acre

Appendix 5-2







ELEVATION VIEW

TYPICAL COIR LOG USE FOR
BANK STABILIZATION

SCALE: NONE

NSTAR ELECTRIC GAS

Appendix 5-2

SECTION 8.5
PRIVATE PROPERTY ACCESS RESTORATION OF UPLAND AREAS

The following restoration techniques apply to private property restoration in non-jurisdictional, upland areas:

- Soil excavated during construction and not used as backfill must be evenly spread onto disturbed areas to restore grades, or removed from the site. Topsoil shall be stripped and separated to the greatest extent practical, for re-use. Permanent soil protection shall be provided for all areas disturbed by construction activities.
- Topsoil removed during construction activities will be replaced, seeded, and mulched. If topsoil has not been preserved, a minimum 4-inch thick layer of loam must be imported to the site and spread prior to the application of seed.
- All seeded areas shall be treated with a layer of mulch (i.e. hay, but preferably straw) up to one inch thick to enhance moisture retention, dissipate impact from precipitation, and detract songbirds foraging on broadcast seed.
- Rehabilitation of access routes and other areas must be performed as soon as possible after construction is completed, including reestablishment of water bars or other BMPs to control erosion of the access road, and the removal and restoration of temporary wetland or waterway crossings.
- Temporary breaks in construction activities may warrant seeding and mulching of disturbed areas as interim erosion control measures.
- Erosion control measures shall remain in place until soils are clearly stabilized – either by erosion control blankets, or by robust, growing vegetation. Once soils are stable, erosion controls – especially silt fence, which presents an obstacle to movement of small animals – shall be removed and properly disposed.

COMMONWEALTH OF MASSACHUSETTS
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Commissioner

Best Management Practices for Controlling Exposure to Soil during the Development of Rail Trails

This document summarizes **Best Management Practices ("BMPs")** that should be considered before, during, and after former railroad lines are converted to recreation trails. These BMPs have been developed to eliminate or minimize potential exposures to residual oil or hazardous materials commonly found along railroad rights-of-way being converted to rail trails. This document also identifies locations and conditions for which the application of BMPs alone may not be sufficiently protective of public health and the environment.

These BMPs have been developed specifically for situations where a municipality has acquired a property interest in a rail corridor from the Massachusetts Bay Transportation Authority (MBTA) in order to convert the corridor to a rail trail[1], This fact sheet is relevant to municipalities: (1) with specific knowledge of a release of oil or hazardous materials through testing or other means and/or (2) without specific knowledge of a release, that seek to prevent the exposure of persons to oil or hazardous materials that may be present in such corridor until a responsible person conducts response action under MGL Chapter 21E.

Background Information

The waxing and waning of railroad activity in Massachusetts over the past century has left the Commonwealth a legacy of under-utilized rights-of-way that may be redeveloped for new rail service (such as the Amtrak Downeaster and the Greenbush line) or recreational trails (such as the Minuteman Trail or the Mass Central Rail-Trail).

When active, these railroad lines were important transportation corridors serving the citizens and industries of Massachusetts. Now many communities are actively seeking to convert former railroad lines to create new links -- trails that link:

- commuter's homes to workplaces;
- children's schools to the playgrounds;
- tourists' curiosity to the region's history; and
- communities to their neighbors.

[1] More specifically, only for those situations addressed under Chapter 46 of the Acts of 2003

This information is available in alternate format. Call Debra Doherty, ADA Coordinator at 617-292-5565. TDD Service - 1-800-298-2207.

DEP on the World Wide Web: http://www.mass.gov/dep
Printed on Recycled Paper

Many former rail lines were abandoned years ago and appear to be nearly reclaimed by nature. Other lines run parallel to active lines, or reveal rusted rails threading through industrial areas. In some instances adjacent industrial activities, historic loading practices, leaks during material transfers or storage, and repair activities have contaminated soil with oil or hazardous materials. In addition, residual contamination is often found along the length of the line, incidental to the maintenance and use of the railway itself.

Redevelopment of former rail lines to recreational trails can be accomplished in a way that protects public health and the environment. It requires recognizing potential problems and implementing actions to safeguard nearby residents, workers, and trail users throughout the life of the project.

Residual Contamination from Railroad Operations

Some historic railroad operations involved the use of chemicals that may have resulted in presence today of contamination. The most commonly reported contamination along rail lines includes metals, pesticides[2] (such as lead arsenate), and constituents of oil or fuel (petroleum products). These chemicals have been associated with normal railroad operations and are likely to be found anywhere along the line. For example, it would not be uncommon to find arsenic (up to ten times natural background levels) present in the soil along a right-of-way from old railroad ties dipped in an arsenic solution, arsenic weed-control sprays, and arsenic-laced slag used as railroad bed fill[3]. Lubricating oil and diesel that dripped from the trains are likely sources of the petroleum product found along the lines. Other sources of contaminants associated with historic railroad operation may include coal ash from engines, creosote from ties, and polynuclear aromatic hydrocarbons ("PAHs") from the diesel exhaust.

The BMPs outlined in this document are specifically designed to be protective of public health and provide a practical alternative to extensively testing for and possibly removing these "typical" residues expected from the historic operation of a rail line[4].

In some instances, a rail corridor may have been open for a relatively short time, during a period of time or in a region where chemicals were not used by the rail operator. Application of the BMPs would not provide any significant benefit in those instances. In the absence of good historic information, the only sure way to know whether residuals pose a risk to trail users is to collect environmental samples along the corridor. Location-specific sampling results may then be used to modify these measures or obviate the need for their use.

Elevated Contamination from Railroad Operations or Other Sources

Several potential sources of contamination along a rail line may pose significant health and environmental risks worthy of closer examination. These sources include operations at switching and repair yards, railroad accidents involving hazardous cargoes, and releases of chemicals on rail spurs and properties that abut rail lines, but which are unrelated to the railroad operations. The latter two examples may

---

[2] The application of pesticides consistent with their labeling is excluded from the definition of a "release" under M.G.L. Chapter 21E.

[3] Sampling along the abandoned Greenbush Line in the Fall of 2003, prior to its rehabilitation for commuter rail service, indicates the presence of arsenic concentrations up to 205 mg/kg, with 16% of the results greater than the MCP S-1 soil standard of 30 mg/kg, and 25% greater than the *proposed* standard of 20 mg/kg.



[4] Consistent with Section 8C of Chapter 46 of the Acts of 2003 (http://www.state.ma.us/legis/laws/seslaw03/sl030046.htm), the BMPs described in this document suitably prevent access to the residual oil or hazardous materials expected to be present along a railroad right-of-way.

involve almost any chemical, such as the phosphorus trichloride released in an April 3, 1980, tank car incident in Somerville, or the asbestos released from the Zonolite processing plant in Easthampton. The contamination in rail yards is somewhat more predictable, including petroleum; metals; pesticides and organic compounds emanating from equipment cleaning areas; fueling areas; maintenance and repair activities; and the railroad beds themselves.

An MCP Phase 1[5] level of investigation, tailored to the nature of the contaminant and source, would be appropriate to address these sources of elevated chemical contamination. A Phase 1 Preliminary Investigation would typically contain sufficient information in the following areas to determine the need for a Response Action or further detailed investigation:

- General Disposal Site Information (description of location and potential receptors in the area);
- Disposal Site Map (description of the property itself, with buildings, drains, and sampling locations noted);
- Disposal Site History (description of ownership, releases, chemical use, management of waste, compliance history);
- Site Hydrogeological Characteristics (description of groundwater flow, borings, wells, and the results of any investigations);
- Nature and Extent of Contamination (description of evidence of releases, laboratory results, thickness of NAPL, approximate location of contamination);
- Migration Pathways and Exposure Potential (description of contamination in air, water, soil, and discussion of potential human and environmental receptors);
- Evaluation for Immediate Response Actions; and
- Conclusions.

The results of such an investigation would be used to determine appropriate measures to implement to eliminate or reduce current and future exposure to the contaminated soils. Such measures could be similar to the BMPs proposed in this guidance, more extensive than these BMPs, or less stringent, depending on the outcome of the investigation.

Identifying Areas of Concern

As described above, locations along rail corridors could exhibit a wide range of chemical contamination, depending on the use of the line and adjacent properties. Trail developers can conduct historic research to categorize segments of a rail corridor by level of concern.

DEP has identified four categories of interest for the purpose of implementing the soil BMPs. Any given rail-trail may be comprised of one or more of these areas.

Residential, undeveloped or rural rights-of-way

These are stretches along a rail line that border historically residential, undeveloped or rural properties. These areas are likely to have been affected only by the normal operation of the rail line, with a residual level of contamination. The BMPs outlined in this document are considered appropriate for these locations, absent evidence of a specific release.

[5] The general content of a Phase I "Initial Site Investigation Report" is described in the Massachusetts Contingency Plan, 310 CMR 40.0483.

Stations and crossings
These relatively small stretches along a right-of-way would be expected to be associated with contamination elevated over the residual levels, due to more frequent/intense use of pesticides to improve sight lines and greater frequency/intensity of human activities. The BMPs outlined in this document are considered appropriate for these locations, absent evidence of a specific release.

Industrial corridors
Many rail-trails include segments that pass through industrial areas, even the predominantly rural trails of western and central Massachusetts. These stretches have a higher ***potential*** for contamination within the right-of-way that is unrelated to the historic railroad use. The BMPs outlined in this document may not be sufficiently protective of public health and the environment at these locations. A preliminary review is recommended in order to establish whether site-specific concerns indicate a need for further investigation, including soil testing. Absent a site-specific concern, the BMPs outlined in this document are considered appropriate for these locations.

Switching and Repair Yards
As discussed earlier, switching and repair yards have a greater range of potential contaminants of concern and a higher likelihood that the contaminants are present at significant levels. The BMPs outlined in this document are not considered sufficient by themselves to protect public health and the environment at these locations, absent further investigation.

Figure 1 outlines the decision-making steps trail developers should follow in identifying locations of interest along the corridor they are developing and whether the BMPs apply without the need for further site investigation, including soil testing.

Goals of Best Management Practices

DEP's goals in publishing BMPs for use in developing rail-trails include:

- promoting rail-trail conversions that are both health-protective and cost-effective[6];
- recognizing the potential presence of oil or hazardous material along the right-of-way;
- recognizing the potential health and environmental risks associated with developing the right-of-way;
- expediting trail development to prevent (or minimize) risk to current users of "beaten paths" along inactive rail corridors;
- preventing (or minimizing) exposures to oil or hazardous material before, during, and after construction of rail-trails; and
- preventing (or minimizing) off-site migration of contaminants before, during, and after the construction of rail-trails.

These BMPs are intended to be applied to those rail corridor segments where residual contamination from historic railroad operations is assumed to be present. Trail developers always have the option to conduct soil testing to rule-out the presence of contamination and tailor soil management practices to actual site conditions.

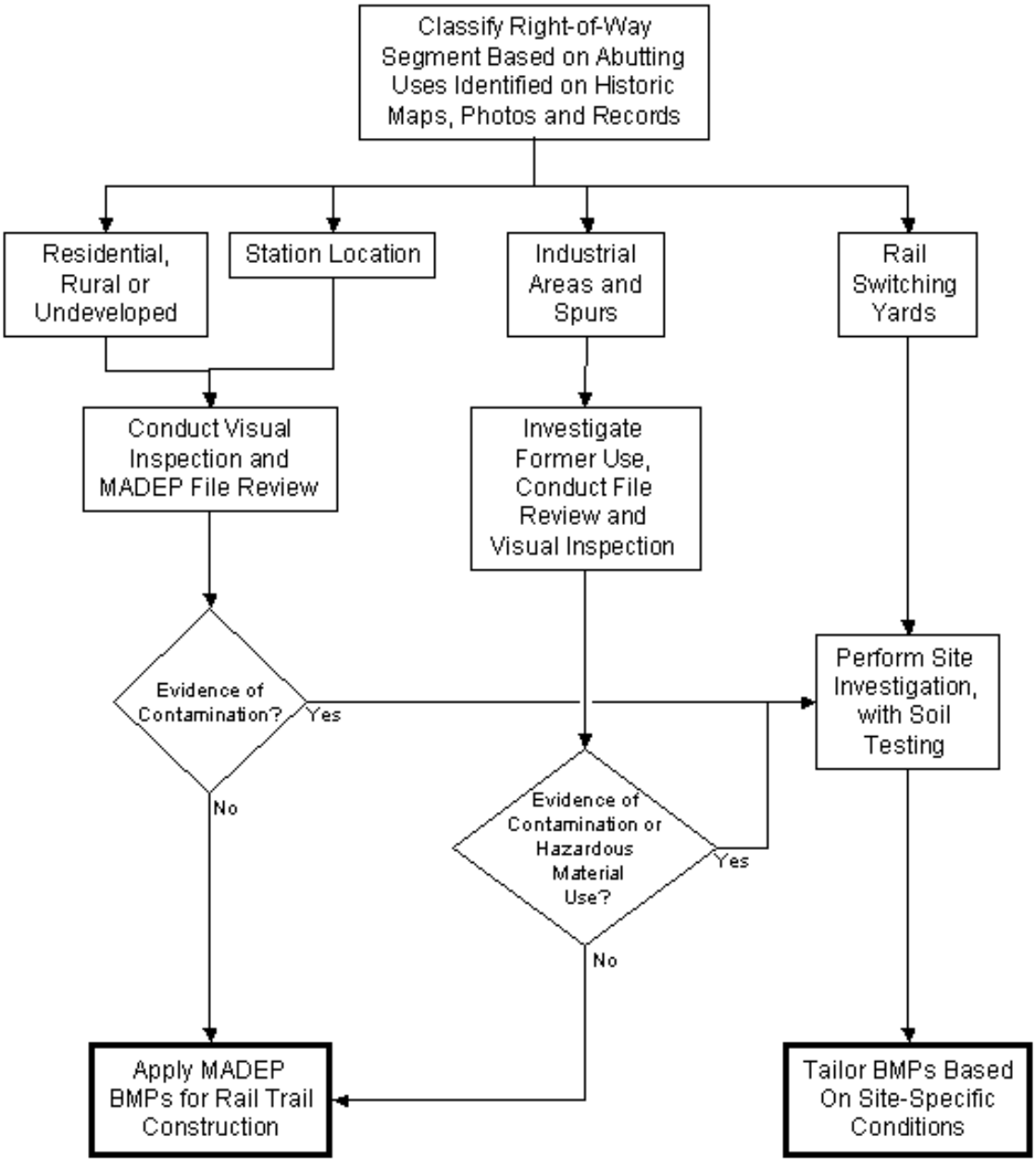
In addition to reducing risk of exposure to contaminants, the focus of this guidance, trails promote public health by encouraging active and healthy lifestyles.

The application of these BMPs to any portion of a rail corridor converted to residential use in conjunction with rail trail development is not appropriate. Only a site-specific investigation, including soil testing, can determine whether conversion to residential use is health protective.

Figure 1

Application of MADEP Best Management Practices at Rail Trail Conversions

(Pursuant to Section 8C of Chapter 46 of the Acts of 2003)



BMP Applicability

These BMPs were developed primarily for residential or rural rights-of-way, and stations and crossings. The BMPs will also be applicable in many industrial corridors, but those locations may need case-by-case review to determine the likelihood of contamination beyond the residual levels assumed here.

DEP does not believe that these BMPs are, by themselves, sufficient and appropriate for use without more extensive site investigation in industrial areas with known or likely non-railroad sources, or in rail yards.

Note that the focus of these BMPs is the potentially contaminated soil along the right-of-way and the human exposures and environmental exposures that may result from improperly managing that soil at or near the surface. This document is not intended to be a summary of all environmental requirements, such as wetlands permitting or Underground Storage Tank (UST) removal that may apply to a project. Municipalities developing rail trails are also obligated to contain the further release or threat of release of oil or hazardous materials from any structure or container within the corridor.

Phases of Project/Exposures of Concern

Rail-trail development occurs in three main phases, or time periods. Each phase has unique exposures that must be considered to identify appropriate BMPs. These phases are pre-construction, construction, and post-construction.

Pre-Construction Phase

The pre-construction phase covers the period up to the time construction actually begins. Depending on project finances and construction sequences, this phase may last several years as communities seek funds to develop a project. Trail design also occurs during the Pre-construction Phase.

While the right-of-way is not a designated rail-trail at this point, a potential may exist for people to be exposed to contaminated soil on or from the right-of-way. Dirt bikers, hikers, or children taking shortcuts, and adjacent residents may receive runoff or dust from the rail bed in its unimproved condition. Many future rail-trails also serve as utility corridors. Workers repairing or installing subsurface utilities (such as sewer lines) may have the highest potential for exposure, albeit short-term.

During trail design, developers should identify which soils will be handled during construction and plan the areas where people will congregate once the trail has been completed.

As the final grades are established, areas for playgrounds identified, and trailheads located, long-term exposures may be created to any contaminated soil remaining along the trail. By following the design guidelines provided below, designers can ensure that any long-term exposures are eliminated or minimized.

If any soil will be excavated from the right-of-way and reused off-site, the potential for exposure should also be considered.

Construction Phase

The construction phase has the potential to create significant exposures to contaminated soil as the old rail line is cleared, the right-of-way is prepared, and the trail is constructed. While construction activities may be sporadic and short-term on any given stretch of the line, the project itself may continue for many months, or even longer than a year.

The receptors of concern during the construction phase include:
demolition workers (clearing the brush; and removing the rails, ties, ballast, and debris);
construction workers (grading and shaping the trail; and creating, moving, and dissipating soil stockpiles);
adjacent residents (inhaling dust generated from the project; exploring the partially-built trail; coming in contact with soil pushed onto their property, etc...); and
environmentally sensitive areas/species.

Post –Construction Phase

After construction, trail managers must monitor activities along the trail corridor to ensure that the steps taken to reduce exposure remain effective. Trail managers should be involved in decisions to excavate material from the trail corridor to ensure that users are protected both during and after such excavation. Workers repairing or installing subsurface utilities (such as sewer lines) may have the highest potential for exposure, albeit short-term. Maintenance activities will be necessary to ensure the integrity of the trail surface, structures and landscaping that help serve to eliminate exposures.

Recommended BMPs

Absent analytical evidence to the contrary, all soil along the right-of-way should be presumed to have at least residual levels of lead, arsenic, and PAHs from historic railroad operations, as described above. The following BMPs should be considered for the pre-construction, construction, and post-construction phases of rail-trail development, as appropriate.

Pre-Construction

1. Conduct a thorough, pre-construction paper review of the right-of-way and adjacent properties.
    - Investigate the rail line history; locate old stations, crossings, spurs, and rail yards. The Valuation Plans and historic aerial photos for the properties abutting the rail line can provide much of this information[7].
    - Investigate site use and the history of adjacent properties; identify commercial and industrial stretches. The Valuation Plans and Sanborn Insurance maps can provide much of the information for the snapshot in time when they were developed. Local historical societies may have information on leading local industrialists and their local businesses.
    - Review the existing list of known or suspected disposal sites to see if any are located along the right-of-way[8]

[6]Rails-to-Trails Conservancy provides additional guidance in its publication "Acquiring Rail Corridors" p 95-97. (http://www.trailsandgreenways.org/resources/development/acquis/arc_book.asp)

- Inquire with neighbors, fire department personnel or the local historical society for further information on train crashes, accidents, and other incidents that may have released chemicals.[9]

2. Conduct a thorough, visual inspection of the right-of-way, looking for:
   - contaminated soil as evidenced by discoloration, odors, differences in soil properties, pipes, or buried debris;
   - signs of illegal dumping of waste from businesses or industry (not simply household trash);
   - stressed vegetation or "dead zones";
   - areas of soil run-off, both away from the right-of-way and toward the right-of-way;
   - signs of wind erosion sufficient to create a dust inhalation exposure;
   - signs of public use of the existing right-of-way (condoned or trespassing), such as dirt-bike trails, play forts, beverage cans, and fire pits.

3. Control current (pre-construction) exposures to soil in areas of concern by implementing one or more of the following measures, as indicated by site conditions:
   - install signs to redirect people from areas of concern; or
   - strategically place barriers to control use in the areas of concern; or
   - implement other measures to eliminate contact with soils in areas of concern.

   In the event these three measures do not prove successful, trail developers should consider covering areas of exposed soil or planting bushes (such as puckerbrush) to divert people away from areas of concern.

Design Guidelines to Reduce Exposure

While developing the design for the trail, the design engineer or architect should follow these guidelines in order to reduce potential exposures.

1. Within the tread way[10] and in areas designated for recreational use along the trail (such as rest areas, picnic areas, and playgrounds), eliminate contact with potentially contaminated soil by implementing one or more measures, as appropriate:
   - Place potentially contaminated soil under pavement or an equivalent layer of compacted stone dust; or
   - Place potentially contaminated soil under at least 12 inches of clean fill and mark with a geosynthetic barrier immediately above the potentially contaminated soil; or
   - Remove and appropriately dispose of potentially contaminated soil off-site. Replace with clean material (soil, stone dust, wood chips, etc.) to establish the path and maintain grade.

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[7]The Massachusetts DEP databases (http://Mass.Gov/dep/cleanup/sites/sdown) have spills information from the early 1980's and list known and suspected locations of contamination by street address. If evidence exists that an off-site source may have contaminated the right-of-way, further investigation is needed. DEP files may contain sufficient information to determine whether the right-of-way has been affected.

[8]If evidence exists that an incident may have contaminated the right-of-way, further investigation is indicated. DEP files may contain sufficient information to determine the extent of the problem.

[9]The tread way includes any area intended for active use including jogging side paths and equestrian trails

2. Outside of the tread way, control contact with potentially contaminated soil by implementing one or more measures to minimize or eliminate contact with potential residual contamination, including:
   - Design landscaping, including the nature, location, and density of plantings, that channels recreational users of the trail to the tread way, disrupts the creation of informal tread ways (such as single track trails) and directs users away from potentially contaminated soil;
   - Create areas of congregation, such as benches, rest areas, and scenic areas, that draw recreational users of the trail and encourage congregation away from potentially contaminated soil;
   - Install signs informing users of upcoming congregation areas and/or advising users to remain on the path;
   - Stabilize the soil through plantings, grading, or other erosion control measures;
   - Install guardrails, curbing, or fences in areas to encourage users to stay the tread way; or
   - Implement other design features that would minimize or eliminate contact with residual contamination in the soil.

3. The design should identify areas where potentially contaminated soil will be removed and areas within the corridor where such soils can be safely stored temporarily so that the Construction Contractors can re-use as much material on-site as possible.

During Construction

The following BMPs presume the trail construction includes excavation, movement, placement and grading of soil. Trail construction activities that involve no movement of soil may be carried out with the application of standard dust control measures, such as spraying soil with water.

The following guidelines should be followed during construction involving soil grading and excavation and be incorporated into the construction bid documents in order to ensure the proper handling of soils during trail construction:

1. Hire an independent environmental monitor or task existing staff to oversee the Construction Contractor[11]. The monitor will:
   - Verify that construction-related plans and training are in place before construction begins ;
   - Oversee all excavation,
   - Visually inspect material that will be moved, and
   - Ensure proper management of soil along the right-of-way and the implementation of BMPs.

   During construction, the environmental monitor should be present whenever known contaminated soil will be excavated and should inspect construction-related BMPs several times each week.

[10]For example, a municipality may enter into an agreement with Mass Highway to manage a trail construction funded with federal transportation appropriations. The agreement should require that the construction contract include provisions requiring the contractor to follow the BMPs and the directions of the independent environmental monitor.

2. Minimize or eliminate exposure of construction workers to potentially contaminated soil.
   - Prepare site-specific soil management and health and safety plans.
   - Have employees and subcontractors complete a safety-training program covering the potential hazards associated with working with contaminated soil likely to be present along a rail line, before excavation work begins.
   - Educate employees and subcontractors in identifying contaminated soil and on handling and disposal procedures for contaminated soil.
   - Hold regular meetings to discuss and reinforce the health and safety procedures.
   - Prevent visible dust during excavation, transportation, and placement operations. Implement dust control measures, such as spraying soil with water, during excavation or grading operations. Exercise caution to prevent soil spillage during transport.

3. Minimize or eliminate exposure of adjacent residents and curious trespassers to potentially contaminated soil.
   - Prevent visible dust during excavation, transportation, and placement operations. Implement dust control measures, such as spraying soil with water, during excavation or grading operations. Exercise caution to prevent soil spillage during transport.
   - Install temporary signs and/or security fence to surround and secure areas where potentially contaminated soil may pose an Imminent Hazard to human health.
   - Avoid temporary stockpiling of potentially contaminated soils. Take the following precautions stockpiling, as necessary:
     - Identify long-term stockpile locations that are away from residences, schools or playgrounds;
     - Cover the stockpile with plastic sheeting or tarps to prevent dust generation and erosion;
     - Install a berm, hay bales, and/or silt fences around the stockpile to prevent runoff from leaving the area;
     - Do not stockpile in or near storm drains or watercourses; and
     - Clean-up materials should be staged near the storage area.

4. Minimize or eliminate the migration of potentially contaminated soil off-site.
   - Protect gutters, storm drains, catch basins, and other drainage system features on the site with hay bales and/or silt fences during construction. They should be cleaned following the completion of site work.
   - Prevent visible dust during excavation, transportation, and placement operations. Implement dust control measures, such as spraying soil with water, during excavation or grading operations.
   - Exercise caution to prevent soil spillage during transport.
   - Stabilize exposed areas of potentially contaminated soil and prevent run-off.

5. Prevent new leaks and spills and notify DEP, as appropriate, if they occur.

6. Transport and dispose potentially contaminated soil in accordance with the applicable rules and regulations of the United States Department of Transportation (USDOT), the United States Environmental Protection Agency (USEPA), and the Massachusetts Department of Environmental Protection (MADEP) (the specifications for the off-site management of contaminated soil supersede the procedures outlined in this BMP).

Post- Construction

1. Establish a protocol to ensure that future workers performing maintenance or construction within the right-of-way are made aware of the need for appropriate BMPs, including:
   - Posting of signage indicating that a permit from the trail manager is necessary before any excavation of the corridor begins.
   - Sending notice of the existence of such requirement to easement holders and the municipal engineer and/or public works department; and
   - Developing Standard Operating Procedures with local utilities, easement holders, DPWs, and other municipal offices for work in the right-of-way.

2. Establish a procedure for the trail manager to periodically travel the corridor and inspect the integrity of the trail surface, structures and landscaping and require appropriate action to correct any problems observed.

DEP Contact

For further information, please contact Paul Locke in the DEP Bureau of Waste Site Cleanup at (617) 556-1160 or Paul.Locke@state.ma.us.



NSTAR ELECTRIC & GAS
FIVE YEAR VEGETATION MANAGEMENT PLAN
2013-2017

Submitted by:
NSTAR Electric and Gas

Prepared By:
Vegetation Control Service, Inc.

Submitted: February 26, 2013

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1. INTRODUCTION

NSTAR Electric and Gas, a service company of Northeast Utilities (NSTAR) hereby submits this Vegetation Management Plan (VMP) in compliance with 333 CMR 11.00, *Rights of Way Management* regulations (Appendix 3); Chapter 132 B, *Pesticide Control Act* (Appendix 4); all pertinent clauses in *Chapter 85 of the Acts of 2000* (Appendix 8); MESA; MGL c.131, *Massachusetts Endangered Species Act* and its regulations, 321 CMR 10.00, *Massachusetts Endangered Species Regulations,* and 310 CMR 10.00, *Wetlands Protection* regulations. NSTAR also acknowledges the pertinent parts of 310 CMR 22.00, *Drinking Water* regulations of the Massachusetts Department of Environmental Protection, and all applicable Federal Occupational Safety and Health Act, Department of Transportation and Department of Environmental Protection regulations.

NSTAR delivers electricity to approximately 1.1 million electric customers in 81 municipalities and natural gas to approximately 300,000 gas customers in 51 municipalities. Electricity and natural gas is transmitted over hundreds of miles of distribution and transmission rights-of-way (ROW) throughout the central, eastern, southeastern, and cape and islands regions of Massachusetts. To ensure safe, reliable electric and gas service, NSTAR must keep these ROWs free from hazards and encroachments.

NSTAR Electric must also comply with Federal Energy Regulatory Commission standards including *NERC Standard FAC-003-1, Commissioner Order 69*. NSTAR Gas must comply with all applicable federal regulations including, but not limited to, the *Endangered Species Act*, *Migratory Bird Treaty Act*, all applicable Federal Energy Regulatory Commission (FERC) standards and the *FERC Wetland and Waterbody Construction Mitigation Procedures, and* Pursuant to the *Federal Natural Gas Act*, 15 U.S.C. §§ 717 et seq.; the *Federal Natural Gas Pipeline Safety Act*, 49 U.S.C. §§ 60101 et seq., and the *Federal Hazardous Materials Transportation Act*, 49 C.F.R., Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety

Standards), NSTAR Gas is required to adopt and implement an ongoing Operations and Maintenance Plan for purposes of maintaining the integrity and safety of its pipeline facilities. Additionally, in compliance with 49 CFR, Part 192, Subpart L (Operations), NSTAR Gas must maintain its easement to allow for aerial surveillance of pipeline conditions; to enhance its Damage Prevention Program; to facilitate planned cathodic protection surveys, and to allow access for both routine pipeline maintenance and emergency repairs.

NSTAR is, therefore, committed to managing vegetation at all of its facilities in a safe, environmentally responsible and efficient manner in full compliance with all applicable laws and regulations. In this effort, NSTAR is responsible for maintaining its ROWs free from hazards and encroachments. Vegetation is one of the items that can interfere with electric and gas service therefore NSTAR must stabilize the vegetation communities on its ROWs at an early stage of plant succession (low growing) to ensure the delivery of safe and reliable energy products to every customer.

Using an Integrated Vegetation Management Program (IVM), NSTAR‘s program is based on a 3-5 year selective herbicide application and mechanical treatment cycle. This program allows for the safe delivery of reliable electric and gas service while also minimizing the impact on property owners and supports a healthier, more diverse habitat for wildlife that depends upon early successional landscapes.

2. GOALS AND OBJECTIVES

NSTAR's VMP outlines and explains the standards of vegetation control expected from a carefully planned Integrated Vegetation Management (IVM) program. The primary objective of this VMP is to document the most appropriate practices and procedures designed to control non-compatible vegetation on the entire cleared width of its ROWs while reducing the risk of unreasonable adverse effects to the health and well being of humans, animals and the environment.

It also serves as an educational and communication link for state and municipal officials and the public. This objective will not only be accomplished through the VMP, Yearly Operational Plans (YOPs) and notification processes required by 333 CMR 11.00 and for Transmission Lines under Chapter 216, *An Act Relative to the Emergency Service Response of Public Utility Companies*, but with professionalism and courtesy on the part of NSTAR and contract field personnel.

The following are individual objectives of NSTAR's vegetation management program:

- To maintain ROWs that ensures the safe and dependable delivery of energy products
- To minimize and control vegetation that impedes ground and aerial inspections or interferes with the ability to access the ROWs and structures for maintenance or emergencies
- To encourage stable early successional ecological communities of primarily low growing plant communities
- To utilize an integrated vegetation management program on a three to five year cycle designed to maximize control of undesirable vegetation on the full width of the ROWs
- To remove or control non-compatible vegetation within the cleared width of the ROWs, along access roads, around structures, gates and the perimeter of electric substations
- To encourage the establishment of wildlife habitat that is compatible with and does not interfere with the primary function of the ROWs
- To protect the Priority Habitat of State-Listed species
- To control invasive, poisonous and other noxious plant species
- To follow all *sensitive areas* restrictions listed in 333 CMR 11.04

- To ensure that all vegetation management operations are conducted in a safe, effective manner and in conformity with all federal and state laws, regulations, and permit conditions
- To use experienced, trained vegetation management personnel with Massachusetts pesticide applicator licenses working under the direct supervision of a certified pesticide applicator
- To allow for unplanned tasks for which all precautions are taken to utilize the correct treatment methods and to protect sensitive areas (construction, restorations, hazard tree removal, etc.)
- To maintain the flexibility necessary to accommodate unique situations and the need for more appropriate techniques in accordance with new regulations, scientific advances, operational experience and/or comments from municipalities, state agencies and contractors (when necessary, following the procedures in 333 CMR 11.05(4)(d)).
- To promote positive public relations with landowners, state and municipal officials, contractors, and the public

3. CHAPTER 132B AND 333 CMR 11.00

> The purpose of this chapter is to conform the laws of the commonwealth to the Federal Insecticide, Fungicide, and Rodenticide Act, Public Law 92-516, as amended, and the regulations promulgated there under and to establish a regulatory process in the commonwealth. The exclusive authority in regulating the labeling, distribution, sale, storage, transportation, use and application, and disposal of pesticides in the commonwealth shall be determined by this chapter. *(MGL 132B, Section 1)*

Chapter 132b (Massachusetts Pesticide Control Act) was created to ensures a clear and uniform set of standards for the entire Commonwealth of Massachusetts ***in order to protect the public from the negative impacts that arise from fragmented, decentralized, sets of standards***. In this effort, the Commonwealth, through the Department of Agricultural Resources (DAR) retains the sole right to regulate the use of pesticides, including herbicides, throughout Massachusetts. DAR takes this responsibility extremely seriously and the regulations promulgated under Chapter 132b are stricter than Federal standards.

> The purpose of 333 CMR 11.00 is to establish a statewide and uniform regulatory process which will minimize the uses of, and potential impacts from herbicides in right of way on human health and the environment while allowing for the benefits to public safety provided by the selective use of herbicides *(333 CMR 11.01)*.

333 CMR 11.00 is the most comprehensive rights of way regulation in New England. It requires an Integrated Pest Management (in this case IVM) approach to right of way vegetation management; the establishment of standards and procedures to prevent unreasonable risks to humans or the environment, and a multi-layered system of public and municipal notification that requests input about environmentally and culturally sensitive areas. All of this is outlined in NSTAR's VMP, annual YOPs, *The Environmental Monitor* Notice, 21 day notification, Public Water Supplier notification and 48 hour newspaper notice which serve as guides for the public, state and municipal officials, vegetation management contractors and NSTAR personnel.

To ensure compliance with Chapter 132b and 333 CMR 11.00, DAR performs routine inspections of rights-of-way treatment crews, retains chemists, and perform further tests before approving a limited list of herbicides approved for use in Sensitive Areas (pursuant to 333 CMR 11.04 (1)(d)).

As detailed in the VMP and YOP, NSTAR's IVM program strictly adheres to all the requirements of Chapter 132b and 333 CMR 11.00. NSTAR only retains herbicide application treatment contractors that hold Massachusetts' certifications and licenses to apply pesticides. These licenses are only granted after comprehensive testing and require ongoing training to maintain. All Sensitive Areas (see section V) are treated appropriately using either mechanical treatment methods or Commonwealth of Massachusetts recommended herbicides for use in Sensitive Areas. In fact, NSTAR only uses these recommended herbicides on the entire length and cleared width of its ROW corridors.

Beyond the requirements of 333 CMR 11.00, NSTAR, in compliance with all applicable state and federal laws and regulations and common courtesy, also notifies "abutters" (houses and businesses that abut the rights-of-way being treated in that year) within view of the ROWS before treatments begin. Treatment contractors are required to leave door hangers or talk personally with abutters which allow the contractor to answer site specific questions, identify private wells and help explain the program.[1]

[1] On Transmission ROWs, as defined by section 1 of chapter 164 of the General Laws, NSTAR and its contracts shall make a good faith effort to notify ROW abutters not less than 30 days before any vegetation maintenance, except emergencies occurs on Transmission ROWs. NSTAR will comply with all regulations promulgated under Chapter 216, *An Act Relative to the Emergency Service Response of Public Utility Companies*.

4. IDENTIFICATION OF TARGET VEGETATION

NSTAR ELECTRIC ROWS

Pursuant to the policy and intent set forth in NSTAR's VMP, all vegetation must be removed that obscures the ROW corridors and grows tall enough to interfere with the safe, efficient and legal operation of an electrical power line. In the wire zone, trees and brush are targeted, and native, low growing plant communities that have a mature height less than 3' are established. In the border zone, incompatible trees and brush are targeted, and the growth of native trees and shrubs that have a mature height less than 15' is encouraged.

The primary target is all incompatible tree species (woody vegetation with a mature height > 15' tall at maturity) within the cleared width of the ROW; except those species that are under the purview of the Natural Heritage and Endangered Species Program of the Massachusetts Division of Fisheries and Wildlife (NHESP) which will be treated on a case by case basis. Examples of target species include, but are not limited to:

Alder	Cherry	Pine
Aspen	Hemlock	Maple
Beech	Hickory	Oak
Birch	Locust	Sassafras

There are more non-target vegetation species on an Electric ROW than targets. In fact, ROW's are one of the primary early successional plant communities remaining in New England. As a result, many plant and animal species use ROWs as their homes, feeding grounds or nurseries. Certain plant species, therefore, are generally encouraged on the ROW through the use of an IVM program:

- Most herbaceous growth is acceptable and encouraged
- Shrubs that mature less than 15 feet in height are not usually targets *unless* due to their location or attributes they interfere with the function of the ROW.

Certain categories of non-tree species are targets under some circumstances, because of their location and/or their nature. Dense woody vegetation, shrubs and vines are targets where they are capable of interfering with the inspection and maintenance of the poles, wires, and along access roads, paths and gates which need to be kept clear,

especially for emergencies. Additionally, as will be discussed below, noxious plant species including invasive, poisonous and nuisance plant species are considered targets.

Examples of non-tree species, including noxious plant species generally considered targets, include, but are not limited to:

Autumn Olive	Hawthorne	Purple Loosestrife
Blackberry	Honeysuckle	Sumac (Staghorn
Buckthorn	Japanese Knot Weed	and Poison)
Common Reed	Multiflora Rose	Virginia Creeper
Grapevines	Oriental Bittersweet	Willow
Greenbriar	Poison Ivy	

NSTAR GAS ROWS

NSTAR Gas's goal for its natural gas pipelines is necessarily different than NSTAR Electric's power lines. To meet regulatory compliance, NSTAR Gas must establish stable, predominately grass, forbs and low growing herbaceous plant communities along its pipeline ROWs. According to Title 49, Part 195.146 of the Federal Code of Regulations, NSTAR must regularly patrol its pipelines by ground and/or aerial inspections. Tall, dense vegetation impedes the detection of leaks and other potential problems, and woody vegetation obstructs the visibility of and access to valve sites, pipe corrosion test stations, mile marker posts, and other pipe location markers. Additionally, the routine removal of tall vegetation renders the ROW, and its buried high pressure natural gas pipeline, distinguishable from adjacent properties which may prevent third-party damage.

The primary target vegetation on NSTAR's gas ROWs, therefore, includes the same vegetation as on the electric ROWs, plus most woody vegetation including all shrubs. This includes those that mature under 12 feet, including, but not limited to:

Dogwood	Sumacs
High Bush Blueberry	Viburnums
Mountain Laurel	Witch Hazel
Speckled Alder	

A partial list of compatible early successional plants includes, but is not limited to, Low-bush Blueberry, Huckleberry, Sweet fern, grasses, forbs, ferns and wildflowers; however, the first three items on the list are not acceptable around pipeline facilities/structures such as valve sites, pipe corrosion test stations, mile marker posts, and other pipe location markers.

NOXIOUS WEEDS (INCLUDES INVASIVE PLANTS, POISONOUS PLANTS AND NUISANCE PLAT SPECIES) [2]

NSTAR intends to control "noxious weeds," including invasive, poisonous and nuisance plant species with herbicides and mechanical treatment methods. Invasive plant species have become an increasing concern throughout Massachusetts in areas that include ROW corridors where they can spread rapidly and then move into the adjacent landscape. NSTAR also plans on treating poisonous and nuisance plant species at sites on its ROWs identified as having a high risk of posing a health hazard to all individuals working on or traversing a ROW and can impede a rapid response in an emergency.

Invasive Plant Species

The control of invasive plant species is of growing concern in Massachusetts. Many of these non-native plant species were planted for their showy flowers, vigorous growth, erosion control and abundant fruits that attract wildlife (not all introduced species are defined as "invasive"). According to The National Invasive Species Council: "An invasive species is a non-native species whose introduction does or is likely to cause economic or environmental harm or harm to human, animal, or plant health."[3] They are characterized by their ability to spread extremely rapidly and they have already spread well beyond their original cultivated areas; effected areas are often simultaneously impacted by multiple species.

Traits held by invasive plant species include, but are not limited to:

- Aggressive growth and maturity
- Quick spread by seed and/or rhizome
- Little or no natural pests or diseases
- Tolerance of many environments
- Difficult to remove or control
- Tend to overwhelm native species

Recognizing this serious threat to our environment, NSTAR's IVM program takes into account the control of invasives using both mechanical and/or chemical control

[2]"NOXIOUS WEED.—The term ''noxious weed'' means any plant or plant product that can directly or indirectly injure or cause damage to crops (including nursery stock or plant products), livestock, poultry, or other interests of agriculture, irrigation, navigation, the natural resources of the United States, the public health, or the environment." (Public Law 106–224—June 20, 2000, Title IV—Plant Protection Act).
[3]Taylor, Jeff. VELCO 2012 Contractor Training, December 2012.

techniques, as necessary in specific locations. Some examples commonly found on ROWs include, but are not limited to:

Autumn Olive	Honeysuckle	Oriental Bittersweet
Black Locust	Japanese Knot Weed	Phragmites
Glossy Buckthorn	Multiflora Rose	Purple Loosestrife

Poisonous Plants

Massachusetts, particularly the southeast, has an abundant population of poison ivy and other poisonous plants. This poses a health hazard to NSTAR personnel, contractors and the public-at-large and leads to increased incidences of first aid and OSHA recordable incidents. Mechanical methods do not reduce the spread of these populations—particularly poison ivy—therefore NSTAR plans to use herbicides to spot treat poisonous plants at sites identified as having a high risk of posing a health hazard.

Nuisance Vegetation

Nuisance vegetation are plant species that pose a risk to the safety and health of individuals working on or traversing a ROW and it can impede a rapid response in an emergency. These plants have heavy thorns, dense foliage and/or impenetrable stems (many are also invasive plant species); examples include, but are not limited to:

Blackberries and raspberries	Greenbrier
Common and Glossy Buckthorn	Hawthorne
Grapevines	Multiflora Rose

NSTAR plans to use a combination of mechanical and chemical treatment methods to reduce their spread.

IDENTIFICATION METHODS DURING VEGETATION MANAGEMENT ACTIVITIES

To insure the accurate identification of target and non-target vegetation, all vegetation management contractors are required to supply personnel trained to recognize plant species typically found growing on utility sites and to recognize the difference between target and non-target vegetation; including the ability to identify the appropriate early successional communities preferred on electric and gas ROWs.

5. INTEGRATED VEGETATION MANAGEMENT

NSTAR's VMP takes into consideration all factors involved in the maintenance and operation of electric and pipeline ROWs. It reflects NSTAR's intent to prevent any unreasonable adverse effects to the environment and to the safety and health of animals and humans while supporting NSTAR's primary obligation of delivering energy products. The purpose in implementing the vegetation control program in this VMP is to advance the consistent and safe operation of NSTARs ROWS using a three part IVM program consisting of mechanical, chemical and natural controls (see Illustration 1).

Utility IVM programs are designed to work in concert with certain stages of ecological succession. Plant life is by its nature unstable, it is, however, governed by a relatively predictable process of change in composition or structure known as ecological succession. In New England, succession strives towards the climax forest, but is interrupted by natural or man-made disturbances both intentionally and accidentally.

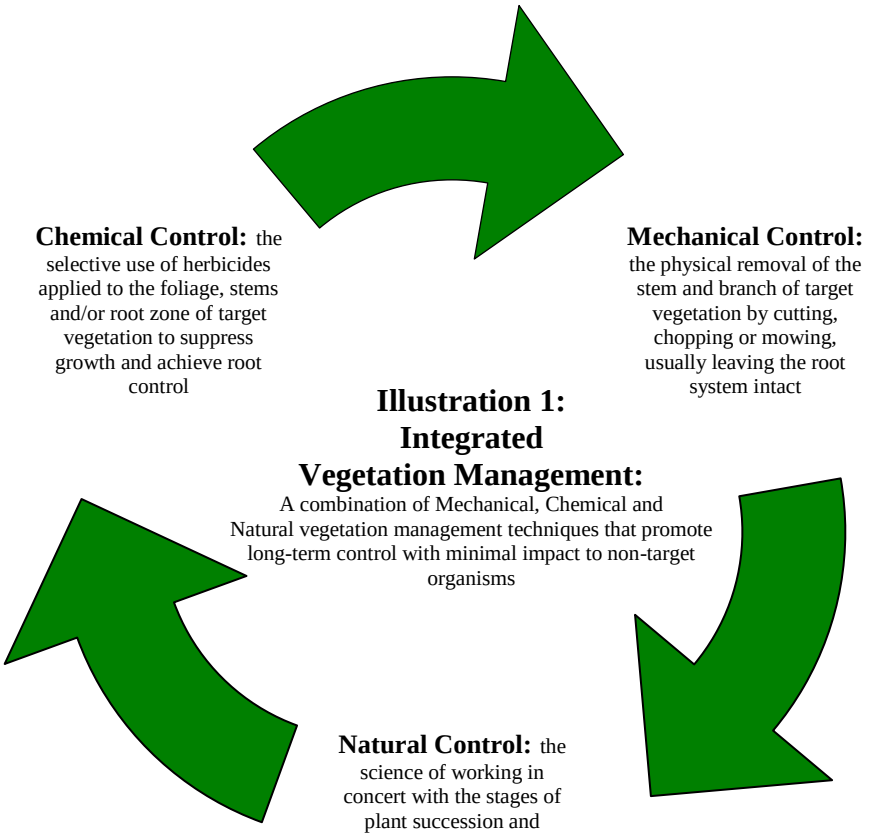


Illustration 1:
Integrated
Vegetation Management:
A combination of Mechanical, Chemical and Natural vegetation management techniques that promote long-term control with minimal impact to non-target organisms

Utility IVM programs are an intentional man-made disturbance that supports the need to deliver energy products by encouraging the stabilization of early successional ecological communities by discouraging the establishment of and when necessary removing certain types of vegetation.

Many New England early successional ecological communities are compatible with NSTAR's ROWs. Depending upon if an electric or gas ROW, these may include shrub-lands, barrens, grasslands, fields, meadows, wetlands, vernal pools and heaths all of which, if left alone, are not stable. All of these sites support diverse, well-dispersed plant, animal and insect species populations, including many that are threatened or endangered. The only difference between electric and gas ROWs is that gas pipelines can only support the lowest growing plant communities consisting of primarily of grasses, forbs and herbaceous growth.

Mechanical and chemical controls are the direct techniques used to target undesirable vegetation and include mowing, hand-cutting and herbicide applications. Utilizing these direct techniques results in the natural control component of this IVM program; desirable, lower growing plants are given the opportunity to form dense thickets or communities. According to many decades of on-going field observation and research, these low growing plant communities inhibit the germination and growth of tree seedlings through competition (for light, moisture, nutrients), assisted by depredation of wildlife (browsing/feeding) and possibly by allelopathy.[4] In other words, natural controls lower the dependence on chemical and mechanical controls. However, natural controls are only possible through the selective use of chemical and mechanical controls.

All three components of IVM depend upon the others in a continuous cycle that employs the unique advantages of each. Without combining all three, target plant species can develop increased stem densities that require more intense control measures, and ecological succession can run its course. A non-selective chemical only program would only result in an equal environmental impact and without mechanical and chemical controls; natural controls would not successfully discourage succession.

[4]Research is still underway about the "natural herbicide action" of allelopathy, the chemical inhibition of the germination or growth of plants by other plants. Although scientists have been studying allelopathy since the 1880s, our understanding is not complete, the processes are extremely complicated and the research is still ongoing, as a result, it is still under debate. What is clear is that certain plants move into and dominate an area.

There is fifty years' worth of evidence in New England showing that this approach has actually, over time, significantly reduced the per-acre application rate of herbicides on utility ROWs and reduced the need for intensive mechanical controls. [5] This is primarily due to the success of natural controls that have helped reduce the stem densities of target vegetation. Throughout New England, the average herbicide application rate at utilities with established IVM programs (including NSTAR) is approximately one pint to two quarts per acre per treatment year in a three to five year treatment cycle.[6] Studies in New York have documented similar reductions in herbicide use through stable plant community management (natural control).[7]

In addition to the reduction of direct control techniques, an IVM program is also well suited to treating environmentally sensitive areas. With careful thought and planning, an IVM program has the flexibility to manage these sensitive areas because of the ability to apply different control techniques to the appropriate areas. For example, to manage wildlife habitat for native species might require the removal of certain plant species, including some that would otherwise be non-targets and others that are considered invasive species. This includes the removal of Purple Loosestrife and Phragmites to re-establish Cattail swamps.

NSTAR's application of its IVM program takes into account instances in which culturally sensitive areas, such as inhabited and agricultural areas, require the application of limited or adapted IVM techniques and control methods. These are areas of a right-

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[5]Environmental Consultants, Inc. *Study of the Impact of Vegetation Management Techniques on Wetlands for Utility Rights of Way in the Commonwealth of Massachusetts*. Final report prepared for New England Electric et.al, 1989; Environmental Consultants, Inc. *Determination of the Effectiveness of Herbicide Buffer Zones in Protecting Water Quality on New York State Powerline Rights-of-Way*. Final report for the Empire State Electric Energy Research Corporation, 1991; K.H. Deubert. *Studies on the Fate of Garlon 3A and Tordon 101 Used in Selective Foliar Application in the Maintenance of Utility Rights of Way in Eastern Massachusetts*. Final Report prepared for New England Electric et. al.,1985; N.H. Nickerson, G.E. Moore and A.D. Cutter. *Study of the Environmental Fates of Herbicides in Wetland Soils on Electric Utility Rights-of-Way in Massachusetts over the Short Term*, Final Report prepared for New England Electric et.al, December 1994; Matt Hickler, NHESP approved Review Biologist, Reports for TransCanada, National Grid, NSTAR Electric, and Northeast Utilities under 321 CMR 10.00 Massachusetts Endangered Species Act Regulations, 2006-2010.

[6]*Utility Transmission Forestry Herbicide Use Summary Records* for NSTAR Electric, Vermont Electric Power Company, TransCanada Hydro Northeast, Inc and National Grid USA Electric Companies (see National Grid *5 year VMP 2009-2013*, p. 9).

[7]C.A. Nowak and L.P. Abrahamson, *Vegetation Management on Electric Transmission Line Rights-of-Way in New York State: The Stability Approach to Reducing Herbicide Use,* Proceedings of the International Conference on Forest Vegetation Management, Auburn University, April 1993.

of-way in which the economic, agricultural, social and recreational use of the landscape affect the decision making processes. Examples include: golf courses, residential areas, Christmas tree farms, active pasture and crop lands, or where unique situations warrant this consideration. This does not preclude the use of chemical and/or mechanical controls. Instead, these landscapes can limit or alter their application; for example, target vegetation might not grow in well-kept lawns but may still grow around poles, guywires, cathodic protection installations and appurtances.

In conclusion, to utilize the most protective and effective IVM program, NSTAR will continue to monitor the most current research in treatment methods and products. Furthermore, in maintaining early successional ecological communities, NSTAR will also continue to support the habitat of invertebrates, vertebrates and plants that require this type of habitat, many of which are state-listed as endangered, threatened or rare.[8]

[8]There are many texts on this subject, some of which are listed in the short bibliography in Appendix 10, this is just one excellent example: James D. Oehler ed., Darrel F. Covell, ed, Steve Capel, ed and Bob Long, ed. *Managing Grasslands, Shrublands and Young Forests for Wildlife; A Guide for the Northeast*. The Northeast Upland Habitat Technical Committee, 2006.

6. MECHANICAL CONTROLS

Mechanical controls include hand cutting and mowing of brush, and side trimming and removal of mature trees. They are used in conjunction with chemical controls and help establish natural controls when used in a fully implemented IVM program. The following section defines all three mechanical control methods, lists their uses and sets some basic guidelines.

HAND CUTTING

Definition:

The use of chainsaws and brush saws to remove the stem and/or branches from the plant's root system.

Uses:

- Target vegetation 15' tall at maturity and over
- Conifers exceeding 6' in height or all conifers in wetlands
- In easement restricted areas
- In chemical restricted Sensitive Areas
- In visual buffers in conjunction with cut stump surface treatments (see below)
- Allows for selectivity in target vegetation.

Operational Practices:

- Trees are cut as close to the ground as possible so that stump height is no higher than root swell
- Cut stems are windrowed and diced or chipped
- Depending on the situation windrows are positioned parallel along the edge of the ROW corridor
- Cut woody vegetation in yards or recreational sites will be chipped and disposed of, or removed to adjacent areas
- Diced woody vegetation should not exceed 2 ft. in height
- Larger trees are limbed and lopped
- Cut woody vegetation is not left on or across paths, roads, fence lines, stone walls or in waterways or in such a manner that would permit it to wash into these areas
- The placement of cut woody vegetation must comply with applicable State Fire Marshall's regulations
- Chipping is used on sites designated by NSTAR when dicing or piling is prohibited or impractical. When necessary, wood chips will be removed
- No chips shall be left in wetlands
- All cut cherry is removed from active pastures.

MOWING

Definition:

The cutting, severing or shattering of vegetation by large rotary or flail mowers.

These heavy-duty mowers, usually ranging from 3-8 feet wide, are typically mounted on large four-wheel drive rubber tired tractors or tracked vehicles.

Uses:

- Can be the preferred mechanical technique, especially on sites where extremely tall and dense target vegetation makes hand cutting inefficient and expensive
- Where herbicides are prohibited
- On non-restricted sites, mowing may be used to remove tall target vegetation followed by herbicide treatment to the resprouts during the following growing season.

Operational Practices:

- Mowing may be restricted by terrain conditions such as steep, rocky sites or wet soils
- It necessitates the use of hand cutting methods next to obstructions such as stone walls and fence lines
- Mowing brush can throw large chips and debris great distances from the cutting equipment
- Extreme care must be exercised to insure the safety of the general public
- In populated areas it requires employing someone to prevent people and animals from coming too close to the work site

SIDE PRUNING

Definition:

Side pruning or removal of encroaching tops and/or branches of trees growing on or near a ROW. This management technique is usually accomplished by the use of an aerial lift mounted on either a large truck or off-road vehicle. Tree climbing is sometimes employed in situations where terrain prevents the passage of equipment.

Uses:

- Maintaining the edge definition of the ROW corridor
- Easier inspections of vegetation conditions during aerial patrols
- Necessary to stay in compliance with *NERC Standard FAC-003-1*.

Operational Practices:

- All trimming activities are performed in accordance with proper arboriculture practices to insure the health and aesthetic value of the trees (see Operational Guidelines for Applicators)

- All trimming activities are in compliance with all current applicable regulations.

REMOVALS

Definition:

Removal of trees that have become a hazard to the ROW or that may have been overlooked in previous treatment cycles and allowed to encroach the ROW and the lines and conductors. In these cases, Trees will be removed in such a way that they cannot strike wires, guy wires, structures, appurtenances and adjacent properties. In most cases these trees will be addressed using aerial lift equipment, but may require climbing where terrain dictates. Larger overhanging limbs may require rigging to safely control the fall of cut material. Trees that do not overhang or directly threaten the line may be "pieced down" by removing material from the top down in small sections that cannot strike the line or cause damage. In cases of severe encroachment on a larger scale, qualified and appropriate timber harvesting equipment and contractors may be employed to clear the ROW up to the edge of easement.

Uses:

- Maintaining the edge definition of the ROW corridor
- Easier inspections of vegetation conditions during aerial patrols
- Necessary to stay in compliance with *NERC Standard FAC-003-1*.

Operational Practices:

- All removal activities will be performed by qualified line clearance arborists
- Care will be taken to accurately locate the bounds of activity, to minimize erosion and unnecessary hydrological damage due to ruts, and to minimize impact to the environment.
- Measures may include matting of wetland areas, installation of silt fences and chipping and removal of all debris.

7. MECHANICAL CONTROLS: BENEFITS AND LIMITATIONS

An IVM program does not function without mechanical controls. Between regulatory restrictions and the need to open access to treatment areas, chemical controls cannot work without mechanical controls. Likewise, mechanical controls and chemical controls work together to support the establishment and viability of natural controls and it takes all three components of an IVM program to support wildlife habitat.

In some areas, mechanical controls are the preferred method; the use of herbicides may be prohibited or restricted in various sensitive areas leaving mechanical treatment methods as the only options. These include defined distances around drinking water supplies both private and public, wetlands or water over wetlands, rivers, certified vernal pools, and agricultural or inhabited areas (see sensitive area section below). Certain Priority Habitats defined by NHESP call for the use of mowing instead of/or in conjunction with herbicide applications to encourage the health or restrict the height of various host plants.

Mechanical treatment methods are also used on vegetation over 15 feet in mature height in preparation for herbicide treatments; in individual areas deemed as sensitive; around structures; access roads, and in areas of thick impenetrable vegetation. Mechanical treatment methods may be combined with chemical controls, including foliar and cut stump treatments, to prevent resprouting. Alternately, where large areas of high density target species have exceeded maximum herbicide treatment heights, a mechanical treatment may be more practical followed, in one or two growing seasons, by an herbicide application to obtain effective control.

On their own however, mechanical controls are only a short-term solution to many vegetation control problems on a ROW system. With the exception of most conifer species (pitch pine does resprout), cut vegetation resprouts from dormant buds on the root collar resulting in a stem density significantly greater than the original vegetation. An annual program that uses only mechanical treatment cycles therefore generally increases dense areas of woody vegetation. This vegetation competes with and dominates the low growing vegetation NSTAR wishes to encourage. As a result, bio-diversity is diminished; wildlife habitat is degraded; and access to the ROWs and the ability to perform maintenance and emergency activities are all limited.

When relying on mechanical control methods alone, dense areas of target vegetation also become costly and dangerous to hand-cut with power saws and are best controlled by mowing. Large mowing equipment, although an excellent IVM tool, can have a negative impact on non-target plant communities whose establishment is crucial to developing successful natural controls. The scarification of the soil surface also creates a potential seedbed for fast growing, pioneering target species such as poplars, cherries, birches and various invasive species. This can increase the frequency of the maintenance cycle and destroy the dominance of stable, diverse early successional plant communities. Similarly, sensitive areas, such as wetlands and residential areas can be adversely impacted when crossed by mechanical maintenance equipment.

Mowers, chainsaws and brush saws also represent a higher risk to workers than herbicide applications.[9] Mowing machines throw rocks and pieces of wood and objects great distances exposing both the workers and the public to safety risks from flying objects. No matter how carefully executed, at the conclusion of mechanical treatment operations, stumps are left on the ROW, which are a tripping hazards to both workers and the general public; they can also puncture tires and damage equipment.

This section is not intended to discourage the use of mechanical controls ***instead*** it supports the fact that all three components of an IVM program have their limitations. This is actually the strength of an IVM program. Understanding the limitation is just as important as understanding the strengths of mechanical as well as chemical and natural controls. Then, when crafting an IVM program that suits the conditions of individual ROWs the limitations are restricted while the benefits can be utilized to meet the goals of reliability in the most responsible fashion possible.

[9] See Appendix 10.

8. CHEMICAL CONTROLS

Chemical controls are herbicide applications which include foliar, basal and cut stump surface treatments (CST). They are a vital year-round component of an IVM program in establishing and stabilizing early successional plant communities and the development of natural controls to maintain this goal. The following sections define all three control methods, lists there uses and sets some basic guidelines.

GENERAL GUIDELINES

- **Sensitive Area Approved Herbicides** (see Section 9 below for definition) will be the preferred materials applied on NSTAR's ROWs in their IVM program, but new herbicides are being developed and released and NSTAR reserves the right to set up experimental plots to test their effectiveness and their use in protecting the ecological communities on NSTAR's ROWs.
- An advance person or "prep-cutting" crew will patrol the ROWs before the herbicide application operation
- Sensitive areas will be identified and buffers appropriately measured and flagged, then verified and recorded when appropriate
- Herbicides will NOT be applied during the following adverse weather conditions:
  - ✓ During high wind velocity, per 333 CMR 11.03
  - ✓ Foliar applications during periods of dense fog, or moderate to heavy rainfall per 333 CMR 11.03
  - ✓ CST or basal applications during periods of heavy rainfall
  - ✓ Foliar applications of volatile herbicides during periods of high temperatures (90 plus degrees Fahrenheit) and low humidity
  - ✓ CST or Basal application when deep snow (i.e. 6" plus or ice frozen on stem or stump) prevents adequate coverage of target plants to facilitate acceptable control
  - ✓ Basal applications when the stems are excessively wet from moisture
- Herbicides are not applied:
  - ✓ To target vegetation standing in surface water
  - ✓ Within chemical restricted Sensitive Areas per 333 CMR 11.00
  - ✓ To active pasture land unless arrangements are made with land owners to move livestock to an alternative location
  - ✓ Under unique circumstances that might unreasonably jeopardize the health and safety of animals, humans or the environment
- All conifers over six feet tall will be controlled by cutting. Where appropriate, all pitch-pine stumps will be treated with an herbicide to prevent resprouts.

FOLIAGE APPLICATIONS

Definitions:

The application of herbicides to fully developed leaves, stems, needles or blades of a plant.

Low Volume Foliar:

Hand-operated pumps or motorized, backpack sprayers with herbicide concentrations usually ranging from 3-20% The backpack sprayer produces an air current that delivers the herbicide mixture from the portable spray tank to the target vegetation. The hand sprayer uses a column of water. In both cases, the amount of herbicide solution applied only dampens or lightly wets the target vegetation, instead of being applied to the point of run-off. This minimizes the amount of excess herbicide drip from target species onto desirable ground cover. Low volume applications also eliminate the need to bring heavy equipment on the ROW for the transportation of large quantities of herbicide solution.

Modified Low Volume Foliar:

Uniform, penetrating herbicide mixtures delivered to dense target vegetation. This technique usually involves 200-500 gallon hydraulic sprayers mounted on a truck or tractor equipped with several hundred feet of hose and hand held spray guns. The herbicide mixture, usually a 1-2% concentration, can be directed to specific target vegetation for spot treatments or broadcast for uniform coverage in dense thickets of nuisance plants such as poisonous, noxious or invasive plant species.

General Uses:

- An economical and effective control method in medium and high brush densities
- Effective control of invasive, noxious and poisonous vegetation
- Contributes to establishing and stabilizing early successional plant communities
- Allows for selectivity in targeting vegetation.

General Guidelines:

- Herbicides are mixed or diluted with water
- Herbicides are applied as a uniform spray over the entire plant's foliage
- Low pressure foliar application equipment will be adjusted to apply a spray pattern that achieves effective control at the lowest application rate

- Application period usually extends from early June through the beginning of leaf abscission in early fall
- Anti-drift agents are added to the mix or solution in all foliage applications to reduce the potential of herbicide drift beyond target vegetation—drift control agents reduce the break-up of sprays into fine droplets and offer increased selectivity, leaf tissue penetration, and herbicide deposition on target plants
- Foliar applications can be made, and are effective, in light mist conditions
- When foliar applications are stopped by rainfall treatment will not resume until the rain ends and is not actively running off the leaf surface
- Foliage application operations cease in wind conditions that make it impossible to prevent herbicide movement beyond the target area.

LOW-VOLUME STEM BASAL

Definition:

The selective application of herbicides in an oil solution to the lower portion of the plant stem.

Uses:

- Year-round application technique, except during deep snow conditions that cover the target area
- Typically employed during the non-foliage season when target stems are easier to identify without the interference of lush, tall grasses or ferns.

Guidelines:

- Utilizes hand-operated backpack sprayers
- Utilizes special blended light petroleum oil as the dilutent, enabling the herbicide solution to penetrate the bark tissue and translocate within the target plant species
- Not an appropriate method to control high target stem densities due to high herbicide rates per acre and unreasonable labor costs
- Extending the herbicide treatment period beyond the foliage season justifies using this technique for appropriate vegetation conditions
- May be the appropriate choice for visually sensitive areas or where extreme selectively is desirable.

CUT STUMP SURFACE TREATMENT (CST)

Definition:

The application of an herbicide mixture to the cut surface of a stump immediately following or during a cutting operation using an herbicide concentration, usually 50% diluted in water or a non-freezing solution.

Uses:

- Year-round applications except during deep snow conditions that prevent cutting the stumps low enough
- Offers the opportunity to chemically treat undesirable vegetation in sensitive areas where other methods are not possible.
- Commonly used to prevent resprouts when hand cutting vegetation over twelve feet in height in preparation for a foliage application.

Guidelines:

- Application equipment includes low-volume, backpack, hand-pump sprayers; hand held squirt bottles; paintbrushes, or sponge applicators
- It is only necessary to treat the phloem and cambium tissue, regardless of the stump diameter
- Ideally, treatment should be made to freshly cut stumps
- It is best to avoid using it during the season of high sap flow
- Not practical in moderate to heavy stem densities.

Plant Growth Regulators

Definition:

Tree Growth Regulators (TGR's) are plant growth regulator chemicals that manage or reduce the potential growth rate of trees.

Uses:

- They are useful tools especially along street distribution lines where repetitive trimming is necessary to maintain adequate tree-wire clearances
- Their use can lengthen the time frame between trimming cycles and improve the aesthetics of street and yard trees that may otherwise require removal or severe pruning.
- They are a type of "spot" treatment and are not a general IVM management tool.

Guidelines:

- Applied as basal drench around the base of the tree or

- Applied as a soil injection next to the buttress root zone
- Unless included in the *Sensitive Area Material List* kept by DAR, they will not be used in any Sensitive Areas, including within 100 feet of an inhabited area.

9. CHEMICAL CONTROLS: JUSTIFICATION, RATIONALE FOR USE AND GUIDELINES AS PART OF AN INTEGRATED VEGETATION MANAGEMENT PROGRAM

State and federal regulations require NSTAR to deliver energy products to its customers in a safe and efficient manner and to control vegetation on its ROWs. To meet these obligations in an ecologically sound manner is, according to a wide range of studies, best completed by stabilizing the early successional vegetation communities on the ROWs.[10] To do this, NSTAR needs to use all the treatment methods available while encouraging the establishment or stability of a landscape that is both accessible and which supports the health and hopefully growth of native plant and wildlife habitat.

In an IVM program, chemical controls are the method that achieves long term vegetation control because the entire target plant, *including the roots*, is controlled by the use of herbicides, stopping their spread by resprouts, adventitious root suckering and rhizomes. Eliminating the ability of the treated targets to return also increases the length of time between treatment cycles by reducing their recurrence and stem counts. This is achieved by scheduling herbicide applications to sustain acceptable vegetation control at minimal application rates.[11] When all of these factors are taken into consideration herbicide applications can minimize the amount of manpower and equipment and their repeated impact on the environment, including unintended petroleum and hydraulic fluid leaks from mechanical equipment.

NSTAR chooses herbicide formulations that, when used appropriately, are a safe method of vegetation control, are low in acute toxicity, are not known to bio-accumulate and, as applied, have a short half-life with low soil mobility.[12] These formulations are

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[10]Belisle, Francis. "Wildlife Use of Riparian Vegetation Buffer Zones in High Voltage Powerline Rights-of-Way in the Quebec Boreal Forest." 7th International Symposium on Environmental Concerns in Rights-of-Way Management, 1999; Confer, John L. "Management, Vegetative Structure and Shrubland Birds of Rights-of-Way," 7th International Symposium on Environmental Concerns in Rights-of-Way Management, 1999; CVPS. "Central Vermont Public Service Corporations 2006 Strategy; T&D Forestry,"' Rutland, VT, 2006; Niering, William A. "Roadside Use of Native Plants: Working with Succession, An Ecological Approach in Preserving Biodiversity." Roadside Use of Native Plants: http://www.environment.fhwa.dot.gov/ecosystems/vegmgmt_rdsduse.asp.

[11]*Utility Transmission Forestry Herbicide Use Summary Records*; Priestley, p. 9; Nowak & Abrahamson.

[12]USDA, 1984; USEPA. *Environmental Stewardship Strategy for Electric Utility Rights-of-Way*, Pesticide Environmental Stewardship Program, Edison Electric Institute Vegetation Management Task Force, August 1996; Massachusetts. *333 CMR 11.00, Right of Way Management*; K.H. Deubert. *Studies on the*

then applied selectively by low-volume methods that dry quickly on the plant surface, which significantly restricts the greatest potential for off-target exposure. Additionally, anti-drift adjuvants that can be adjusted to accommodate changes in wind velocity are included in all foliage applications to further limit the likelihood of unintentional exposure to non-target organisms. Applications are also not made in situations when there is a reasonable expectation that herbicides will drift from the target, or during measurable precipitation.

The DAR established a *Sensitive Area Material List* to help reduce the potential of any negative impact by the use of herbicides in sensitive areas defined in 333 CMR 11.04. All of the herbicides on this list have gone through extensive testing to be considered for registration by Federal EPA and before being included on the *Sensitive Area Materials List* they go under further scrutiny by the Massachusetts Department of Agricultural Resources and Massachusetts Department of Environmental Protection.[13] 333 CMR 11.00 only requires their use within limited spray sensitive areas. NSTAR's IVM program, however, considers these herbicides the primary chemical control method for their entire ROW system. Only reserving the right to set up experimental plots to test new herbicides for their effectiveness and use in protecting the ecological communities.

Selective herbicides applications do not adversely affect wetland plant composition or function according to the study cited in the *DFA Decision Concerning The Wetland Impact Study Conducted Pursuant to 333 CMR 11.04(4)(c)(2)* (Appendix 7). In fact, according to the 1989 study by Environmental Consultants, Inc. quoted in the *Decision*, mechanical vegetation control techniques result in significantly greater impact on wetland composition and function.

Fate of Garlon 3A and Tordon 101 Used in Selective Foliar Application in the Maintenance of Utility Rights-of-Way in Eastern Massachusetts, Final Report prepared for New England Electric et al., 1985; Harrison Biotech, Inc. A Generic Environmental Impact Report on the Control of Vegetation on Utility and Railroad Rights-of-Way in the Commonwealth of Massachusetts, Final Report prepared for the Department of Food and Agriculture, Commonwealth of Massachusetts, 1985; N.H. Nickerson, G.E. Moore and A.D. Cutter, Study of the Environmental Fates of Herbicides in Wetland Soils on Electric Utility Rights-of-Way in Massachusetts over the Short Term, Final Report prepared for New England Electric et.al., December 1994; Massachusetts Department of Agricultural Resources. Surface Water Monitoring of Glyphosate used in Rights-of-Way Railroad Vegetation Management (2005–2006), Report, November, 2006.

[13] A current list of the *Sensitive Area Materials List* and individual *Fact Sheets* on these herbicides are available at: http://www.mass.gov/eea/agencies/agr/pesticides/rights-of-way-vegetation-management.html.

While achieving long term control, herbicide applications can be more selective than mechanical treatment methods. Selective herbicide applications encourage plant species diversity by targeting specific plants for removal. They offer varied degrees of selectivity and favor—or release—certain types of plants; for example, broadleaf vegetation can be controlled with little or no impact to grasses. A continual cycle of selective herbicide applications as part of an IVM program, therefore, promotes low-growing plant communities while reducing the density of target species.

Also, invasive, noxious and poisonous plant species are best managed by early recognition and intervention with chemical controls before a little intrusion becomes a large infestation. A quick response with the flexibility to use the appropriate control methods will reduce the likelihood of severe infestations.

Selective herbicide applications can be much less destructive than mowing to nesting sites and the vegetation necessary for food and cover. Little site disturbance is associated with selective herbicide applications. For example: to control the dense resprouts resulting from a mowing operation requires higher per acre rates of applied herbicide to achieve acceptable control than a selective herbicide/cutting application.

This is not to say that mowing is not an important component in an IVM program. Both control methods need to be used in combination with hand cutting techniques to cover all situations. In fact, thoughtful, carefully planned, selective herbicide applications in combination with mechanical controls, where appropriate, actually promote wildlife habitat by encouraging plant species diversity.[14]

State-of the-art herbicide application equipment and the requirement that contractors apply herbicides in the most judicious manner possible further minimizes environmental site damage. Herbicides, particularly when applied selectively by low-volume methods dry quickly on the plant surface, thereby significantly restricting the greatest potential for dermal exposure. The use of anti-drift adjuvants in all foliage

[14] A short list of examples includes: W.C. Bramble and W.R. Burns. *A long-term ecological study of game food and cover on a sprayed utility right-of-way*. Purdue University. 1974. Bulletin No. 918:16; Richard H. Yahner. *Wildlife Response to More than 50 years of Vegetation Maintenance on a Pennsylvania U.S., Right-of-Way*. Journal of Arboriculture 30(2), March 2004: 123; James S. Marshall and L.W. Vandruff. *Impact of Selective Herbicide Right-of-Way Vegetation Treatment on Birds*. Environmental Management, December 2002. Vol. 30, No. 6: 801-806.

applications that can be adjusted to accommodate changes in wind velocity further limit the likelihood of unintentional exposure to non-target organisms.

The selection of the herbicides coupled with the appropriate treatment methods is made with consideration given to the environmental sensitivity of a ROW or site within a ROW. For example, target species, such as non sprouting conifers, are generally not treated since herbicide treatment is not necessary for control. Exceptions to this general guideline are made where White Pine regeneration has seeded in large thick "carpets" and mowing would be more destructive than an herbicide application.

The herbicides and treatment methods used on any given ROW are selected based on site sensitivity, target species composition and density, and treatment methods. Herbicides will not be used in certain areas if site sensitivity, regulations, new restrictions, or target species composition or height recommend otherwise. NSTAR chooses the most appropriate treatment methods to meet all of its goals, objectives and obligations and the most scientifically sound, environmentally friendly solution is to use all three components of IVM where appropriate.

10. NATURAL CONTROLS: THE INDIRECT COMPONENT OF INTEGRATED VEGETATION MANAGEMENT

Natural control is the process of working with the biological cycles of plant succession and interspecies competition to ultimately help stabilize early successional plant communities (low growing plant communities). Natural controls lower the dependence on chemical and mechanical controls. However, impeding the natural process of plant succession requires the use of all three components of IVM; IVM is a critical part of sustaining natural control. All three depend upon the others in a continuous cycle that employs the unique advantages of each to control undesirable vegetation and encourage the stability of desirable plant communities.

Facilitating the spread and stabilization of early successional plant communities that compete for light, moisture and nutrients inhibits the germination and growth of tree seedlings. It also reduces the density and inhibits the growth of undesirable plant species. As a result, natural control decreases the amount of herbicide needed for vegetation control. The link between natural, chemical and mechanical controls is a close back-and-forth relationship. Natural controls cannot be established without chemical and mechanical controls while the amount of herbicides applied is reduced by the use of natural controls.

How does this work? Early successional plant communities are established and stabilized through the use of selective herbicide and mechanical applications. For example, the removal of invasive species by chemical controls opens up a void into which native plants can return. This helps re-establish and maintain early successional native plant communities that are adapted to their environment. Promoting low growing native plants are a vital part of natural control because native plants have a much better chance for survival, especially during adverse growing conditions, than planted vegetation that often fails due to site-species incompatibility.

Chemical and mechanical controls also support the establishment of plant communities that inhibit or interfere with tree seed germination or growth. Competition for sunlight, nutrients and water along with wildlife depredation (i.e. browsing) according to the long term studies by W.C. Bramble, W.R. Burns, et al. are the primary factors in the natural control of trees on electric ROWs. Research is also still underway about the

"natural herbicide action" of allelopathy, the chemical inhibition of the germination or growth of plants by others. Scientists have been studying allelopathy since the 1880s, and many now believe that it occurs commonly around the world, although the complexity of this chemical process is still incompletely understood (see references).

Instead of relying on only one part of IVM, the combination of the direct methods of mechanical and chemical controls with natural controls has a net benefit for the environment. IVM allows for treatment cycles to be lengthened and with fewer undesirable species on the ROW that require control, the amount of herbicides applied and mechanical controls decrease in future treatment cycle until they reach minimal application rates.

11. DEFINITION, IDENTIFICATION AND TREATMENT OF SENSITIVE AREAS

Per 333 CMR 11.02, sensitive areas are "any areas within rights-of-way...in which public health, environmental or agricultural concerns warrant special protection to further minimize risks of unreasonable adverse effects." They include, but are not limited to, the following:

Water Supplies
- Zone I's[15]
- Zone II's
- IWPA's (Interim Wellhead Protection Areas)
- Class A Surface Water Sources
- Tributaries to a Class A Surface Water Source
- Class B Drinking Water Intakes
- Private Wells

Surface Waters
- Wetlands
- Water Over Wetlands
- The Mean Annual High Water Line of a River
- The Outer Boundary of a Riverfront Area
- Certified Vernal Pools

Cultural Sites
- Agricultural Areas
- Inhabited Areas

Wildlife Areas
- Certified Vernal Pool Habitat
- Priority Habitat.

Sensitive areas consist of *no-spray areas* in which herbicide use is prohibited, *limited spray areas*, and areas that require special treatment recommendations. Protecting all of these environmentally sensitive sites is accomplished by establishing limited spray and no-spray areas and treatment restrictions based on the sensitivity of each site and the requirement to minimize any unreasonable adverse impacts within that area (See Appendix 5).

[15]NSTAR's policy is to follow the strictest distance restrictions on Zone I's so that no mistakes are made on identifying well types.

> Only herbicides specified by the Department as acceptable for use in *sensitive areas* pursuant to the Cooperative Agreement [Memorandum of Understanding] executed between the Department of Agricultural Resources and the Department of Environmental Protection on July 1-2, 1987, or future amendments thereto, shall be used in sensitive areas (333 CMR 11.04(1)(d)).

The herbicides included in the resulting *Herbicides Recommended for Use in Sensitive Areas List* (*Sensitive Area Materials List*) will be applied in limited spray areas according to the application restrictions in 333 CMR 11.04 or in the case of Priority Habitat, approval of the YOP by the Natural Heritage and Endangered Species Program of the Massachusetts Department of Fisheries and Wildlife (NHESP). A current copy of the *Sensitive Areas Materials List* and Massachusetts Department of Agricultural Resources approved active ingredient fact sheets are available at:

http://www.mass.gov/eea/agencies/agr/pesticides/rights-of-way-vegetation-management.html.

IDENTIFICATION OF SENSITIVE AREAS

Sensitive areas can be divided into two additional categories that help identify and treating them: "*readily identifiable in the field*" and "*not readily identifiable in the field*." Readily identifiable in the field areas will be treated, identified and when appropriate, marked according to all applicable restrictions listed in 333 CMR 11.00. Not readily identifiable in the field areas will likewise be treated and marked when appropriate, but they are identified in the field by the use of data marked on maps and collected in the YOP and notification processes.

- Sensitive areas usually identifiable in the field, include but are not limited to: surface water, some private and public water supplies, wetlands, inhabited and agricultural areas
- Sensitive areas not usually identifiable in the field, including, but are not limited to: designated public surface water supplies, public ground water supplies, some private drinking supplies, the first 400 feet of water supply tributaries, certified vernal pools and Priority Habitat of State-listed Species.

As appropriate, therefore, sensitive areas will be identified and when necessary marked in the field by NSTAR staff, an experienced vegetation management treatment crew point person, individuals trained in the identification of sensitive areas that require the use of GIS (geographic information systems) and GPS equipment, and/or by a NHESP approved botanist trained in the delineation of state-listed species.

NSTAR and contractor personnel assigned the task of identifying sensitive areas in the field will use the following sources and methods:

- Massachusetts Department of Environmental Protection (DEP) water supply maps/GIS mapping layers available through Mass GIS
- Massachusetts Department of Agricultural Resources (DAR) records of identified private wells along the ROW
- Correspondence, meetings and input from municipalities within the forty-five day YOP and twenty-one day municipal right-of-way notification letter review and comment periods and the 48 hour newspaper notification (under 333 CMR 11.06 & 11.07 and Chapter 85 of the Acts of 2000)
- Correspondence, meetings and input from NSTAR's abutter and/or landowner notification procedure, as applicable
- NSTAR's maps, records and institutional knowledge
- Any additional pertinent information that becomes available during the YOP process and throughout the five years of this VMP
- A point person who verifies identified sensitive areas and any additional areas that may require special precautions
- USGS topographical maps
- Information from contractor's knowledge and records
- Information from Mass GIS
- Confidential information from NHESP
- A copy of the YOP and VMP
- Treatment crew(s) are required to have the following references on the job site to help identify sensitive areas:
    - ✓ Topographical maps (electronic or paper)
    - ✓ Copy of YOP
    - ✓ Any additional information that may become available.

Maps are a resource and a tool for both the public and the vegetation management crews, therefore, they contain the data needed to identify, mark and treat sensitive areas appropriately and are in compliance with all applicable regulations.

Maps included in the YOP are updated every year as new data becomes available. Some sensitive areas are contained on the base USGS topographic maps such as applicable Wetland Resource Areas (Rivers, Wetlands, etc.) The most current data available through MassGIS such as public water supplies and certified vernal pools and any data that NSTAR has collected to date on items such as private wells are then added

on top of the USGS data. At the time of treatment, additional sensitive areas will be added to the maps utilized by NSTAR's vegetation management contractors. Please note that to enable any viewer to see the important information on the maps, Zone II's and other limited spray areas are not mapped in areas where NSTAR only uses herbicides on the *DAR Rights-of-Way Sensitive Area Materials List*.

The locations of the Priority Habitats of state listed species as regulated by the Natural Heritage and Endangered Species Program (NHESP) of the Division of Fisheries & Wildlife are only included on field maps to contractors who sign a confidentiality agreement expressly for this purpose. A map layer of Priority Habitats is available to the general public at http://www.mass.gov/anf/research-and-tech/it-serv-and-support/application-serv/office-of-geographic-information-massgis but it is neither specific to areas of concern for herbicide applications nor does it include data on the individual species since the exact location and details of their habitat is protected. Please be assured that we follow all necessary precautions to stay in compliance with 321 CMR 10.00 and this YOP was approved by NHESP.

CONTROL STRATEGIES FOR SENSITIVE AREAS:

Mandated sensitive areas will be treated following the restrictions in applicable state and federal regulations. NSTAR also reserves the right to designate additional areas as areas that require special treatment considerations including, but not limited to, landowner agreements, visual or environmental impact considerations, and other considerations that arise during the treatment cycles.

Treatments in all sensitive areas will follow the operational guidelines and restrictions listed above, as well as the guidelines described in the Sensitive Area Table in Appendix 5.

Wetlands

Pursuant to 333 CMR 11.04 (4) (c) (2), based upon the results of two ROW wetland impact studies, the Massachusetts Department of Agricultural Resources in consultation with the Department of Environmental Protection and the VMP Advisory Panel, made a determination that herbicides, when used at various utilities including electric lines and gas pipelines, under the guidance of an IVM

program and other conditions as set forth in the determination, have less impact on wetlands than mechanical only techniques. Therefore in accordance with the conditions of the Department's determination, NSTAR will selectively apply herbicides to wetland sites, except within ten feet of standing and flowing water and to conifers which will be cut (Appendix 5).

Public and Private Water Supplies

Appropriate sources and references will be consulted to determine the location of public and private water supplies. NSTAR's YOP maps will include all known public and private water supplies at the time of printing using the sources listed above, and the mapping information used by contract treatment crews will be updated as necessary during the treatment cycle.

To aid in the public and private water supply identification process, under 333 CMR 11.01(3)[16], NSTAR requests that during the various federal, state and voluntary notification processes and during the treatment cycle, that public and municipal agencies and private entities and individuals share information on new or unidentified public and private water supplies.

Identified private drinking supplies within one hundred feet of a ROW are included in our permanent records and maps, and landowners are encouraged to post signs on the edge of the ROW to help identify private water supplies (the no-spray treatment area is fifty feet from a private well).

A point person will patrol the ROW to verify sensitive areas and buffers are appropriately measured and when applicable flagged, and recorded for permanent record.

Massachusetts Endangered Species Act

NSTAR recognizes the importance of the Massachusetts Endangered Species Act, M.G.L.C. 131 A, and its significance to ROW vegetation management. NSTAR will comply with all applicable portions of this Act and the

[16]333 CMR 11.01(3): "[The Specific goals of 333 CMR 11.00 are to] Ensure ample opportunity for public and municipal agency input on potential impacts of herbicide application to rights-of-way in environmentally sensitive areas."

regulations promulgated thereunder. NSTAR will also follow the rules and prohibitions directed at human activities which Take Species or alter their Significant Habitat (as of this printing there are no designated Significant Habitat in Massachusetts).

321 CMR 10.14, Massachusetts Endangered Species Act Regulations, Part II Exemptions and 333 CMR 11.04(3)(a-c) exempts utility ROW vegetation management from the permit process under the following conditions:

> (12) The management of vegetation within existing utility rights-of-way provided that the management is carried out in accordance with a vegetation management plan approved in writing by the Division prior to the commencement of work for which a review fee shall be charged, the amount of which shall be determined by the commissioner of administration under the provisions of M.G.L. c.7, § 3B…
>
> and for roadside distribution lines
>
> (6) installation, repair, replacement, and maintenance of utility lines (gas, water, sewer, phone, electrical) for which all associated work is within ten feet from the edge of existing paved roads;

To comply with exemption 10.14(12), NSTAR will submit this VMP and YOPs to the NHESP for review.

The NHESP has delineated areas as Priority Habitat based on the "Best Scientific Evidence Available" to protect State-listed species from a "take." Under the approval process, details about the Priority Habitat of state-listed species that might be affected by our activities and management recommendations are shared with NSTAR under strict confidentiality agreements.[17] Using this data and best management practices, NSTAR and contract personnel will follow the appropriate vegetation management treatment methods within these sensitive areas taking all practical means and measures to modify ROW vegetation management procedures to avoid damage to state-listed species and their habitat.

To identify Priority Habitats, NSTAR personnel, NHESP approved review botanists and vegetation management crews must use proper identification

[17] A map layer of Priority Habitat is available to the general public at http://www.mass.gov/anf/research-and-tech/it-serv-and-support/application-serv/office-of-geographic-information-massgis , but it is neither specific to the areas of concern for herbicide applications nor does it have detailed data on the species of concern; the exact location and details of their habitat is kept confidential for their protection.

procedures. Contractors are, therefore, required to train their personnel to recognize the location of Priority Habitats using one of the following tools: paper maps, GPS coordinates and/or GIS systems.

12. NSTAR DESIGNATED SENSITIVE AREAS

Above and beyond 333 CMR 11.00 and other applicable state and federal regulations, NSTAR designates two types of visual buffers to screen the general public from potentially objectionable views of structures and substations: shrub and tree/shrub buffers. These sites include, but are not limited to, locations where ROW's cross roads, recreational areas, and inhabited areas:

- Shrub buffers are mostly at road crossings. All trees and shrub species that may grow into the conductor security zone are removed

- Tree/shrub buffers are used only where sites are extremely sensitive and shrub growth is inadequate for screening. Trees and shrub species that may grow into the conductors will be removed. Selective trimming will be used where removal is not recommended or practical.

13. OPERATIONAL GUIDELINES FOR APPLICATORS RELATIVE TO HERBICIDE USE

NSTAR relies on independent vegetation management contractors and requires that they comply with all applicable federal and state laws and regulations. This VMP, the YOPs and information in the Notification documentation are the operational guidelines for applicators relative to herbicide use. Therefore, according to the regulations, at a minimum, the contractor's application crews shall have a copy of the YOP accessible at the work site.

In addition to the guidelines contained in other sections of the VMP, this section sets forth the general operational guidelines for vegetation management. All guidelines are based on the requirement that both the contractor(s) and NSTAR are responsible to insure that vegetation management activities are conducted in a professional, safe, efficient manner, with special attention directed towards minimal environmental impact.

NSTAR will alter or add to these guidelines based on possible future changes or additions to state and federal regulations that apply to herbicide applications and all changes or additions will be approved by DAR.

NSTAR PERSONNEL

- The following individual is responsible for monitoring, supervising and coordinating vegetation management programs (individual RFP's may direct contractors to communicate with other NSTAR personnel):

  William Hayes, Senior Arborist
  NSTAR Electric & Gas Corporation
  Planning, Scheduling and Contract Services Department
  One NSTAR Way, SE-370
  Westwood, MA 02090-9230
  781-441- 3932 (office)

- The arborist(s) will inform the contractor which ROWs will be treated, the range of treatment dates and any other specification required to complete the job

- NSTAR will provide ROW maps with treatment restriction lists and written instructions outlining any special treatment considerations or instructions

- Contractors will notify the NSTAR company representative(s) of any questions or complaints from the public and/or government agencies that relate to ROW vegetation management. NSTAR will deal with these complaints or questions in a timely fashion.

CONTRACTOR SAFETY, CONTRACT AND LEGAL COMPLIANCE GUIDELINES

- Contractors must provide qualified, personnel who have been trained to recognize and identify target and non-target vegetation and are knowledgeable in the safe and proper use of both mechanical and chemical vegetation management techniques
- All personnel applying herbicides in Massachusetts must hold a pesticide applicator license and must work under the on-site supervision of a certified applicator, with a Category 40 certification
- Herbicides will be handled and applied only in accordance with label instructions
- Mixing will not be done on the ROW
- Contractors are not expected to start work without the appropriate maps, restriction lists, landowner notifications and mixing rate instructions
- Contractors will be in compliance with the latest revisions of all industry standards including, but not limited to all applicable safety standards under the Occupational Safety and Health Act (OSHA), ANSI Z133 & ANSI 300 standards, and NSTAR Safety Procedures
- All contract personnel will follow label instructions regarding Personal Protective Equipment (PPE)
- All contract personnel will follow NSTAR's safety requirements as outlined in the NSTAR TVMP
- Applicators will immediately cease operations if adverse conditions or other circumstances warrant
- Access to a ROW will be through the use of established roadways whenever possible
- All bar-ways and gates shall be immediately closed
- Care shall be exercised to prevent the rutting or destruction of roadways, fields or any other form of access
- No litter of any kind will be left on the ROW or adjoining land.

CONTRACTOR DAILY TASKS

- Call the appropriate NSTAR personnel
- In compliance with both regulations and NSTAR policy, the contractors' foreman or senior crew member must complete daily vegetation management reports that include:
  - ✓ Date, name and address of vegetation management contractor(s)
  - ✓ Identification of site or work area
  - ✓ List of crew members
  - ✓ Type of equipment and hours used, both mechanical and chemical
  - ✓ Method of application and description of target vegetation
  - ✓ Amount, concentration, product name of herbicide(s), adjuvants and dilutants (EPA registration numbers must be on file)
  - ✓ Weather conditions
  - ✓ Notation of any unusual conditions or incidents, including public inquiries
  - ✓ Recording and/or verification of sensitive areas on ROW maps
- All required forms will be distributed to the contractors by the NSTAR representative(s)
- NSTAR request that contractor(s) call if they see a hazard tree
- Contractors must follow the Specifications noted in the RFP's.

EQUIPMENT

- NSTAR will not dictate the exact equipment to be used by the contractors, instead, all equipment shall be of adequate design to produce professional quality results
- Equipment must be maintained in good working condition, including being calibrated as appropriate
- Care and common sense shall be exercised when moving vehicles and equipment.

LANDOWNERS

Landowners are individuals whose property is either under NSTAR's ROW easements and/or abuts the ROW.

- Landowners will be treated with courtesy and respect at all times
- Permission must be obtained for ingress and egress if entering the ROW from private land
- If a landowner demands vegetation maintenance cease, the contractor should remove the crew and equipment off the property, inform the appropriate NSTAR

representative as soon as possible and wait for clearance before returning to that location

- When addressing serious complaints from a landowner, or other concerned person, notice will be sent to the appropriate authorities at DAR.

RESULTS

- Vegetation management programs must result in 95% control of all target species
- The contractor may be held responsible to re-treat areas that do not meet required results as long as these "touch-up" treatments follow all restrictions in 333 CMR 11.03(8) as listed in the *Control Strategies for Sensitive Area* table in Appendix 5
- Vegetation management crews will exercise care to insure that low-growing desirable vegetation and other non-target organisms are not unreasonably affected by the application of herbicides
- Unreasonable site damage or destruction during any phase of the vegetation management operation by the contractor, his agents or employees, will be repaired immediately by said contractor to NSTAR's satisfaction.

14. ALTERNATIVE LAND USES

Wherever practical, as determined by the Senior Arborist or NSTAR management, NSTAR will cooperate with landowners through whose property NSTAR own easements, to facilitate "alternative land use" practices by the landowner(s) that may reduce or eliminate the need for vegetation management by NSTAR.

15. REMEDIAL SPILL AND EMERGENCY PLAN

NSTAR contracts with independent, professional, certified herbicide applicators that are responsible for the containment, clean up and reporting of chemical spills or accidents. The following is a guide to the information sources that, according to various regulations, must be available to the treatment crew in the event of a chemical spill or emergency situation:

A. Technical Reference Materials:
   a. Product Label
   b. Product Material Safety Data Sheet (MSDS)
   c. Product Fact Sheet, if available

B. **Table 1. Herbicide Manufacturers:**

MANUFACTURER	TELEPHONE NUMBER	SPECIAL INSTRUCTIONS
BASF Corporation	800-832-4357	
Dow Agro Sciences	800-992-5994	
E.I. du Pont de Nemours and Company	800-441-3637	Medical Emergencies
Monsanto	314-694-4000	
Nufarm	877-325-1840	Medical Emergencies
Rainbow Treecare	877-272-6747	

C. **Table 2. State Agencies:**

STATE AGENCY	TELEPHONE NUMBER	SPECIAL INSTRUCTIONS
Massachusetts Pesticide Bureau	617-626-1700	A.S.A.P. (within 48 hours)
Massachusetts Department of Environmental Protection, Division of Hazardous Waste	Main Office: 617-292-5500 Southeast Region: 508-946-2700 Northeast Region: 978-694-3200 Central Region: 508-792-7650	For emergencies involving reportable quantities of hazardous materials; required info: City/town, street address, site name (if applicable), material
Massachusetts Dept of Public Health, Bureau of Env.Health Assessment Toxilogical Program	617-624-5757	
Massachusetts Poison Information Centers	800-682-9211	For medical emergencies involving suspected or known pesticide poisoning symptoms

D. **Table 3. Emergency Services:**

EMERGENCY SERVICE	TELEPHONE NUMBER	SPECIAL INSTRUCTIONS
Massachusetts State Police, Central Office	617-566-4500 or 911	
Local Fire / Police Dept.	911	
ChemTrec	800-424-9300	
Clean Harbors	800-OIL-TANK	
Pesticide Hotline	800-858-7378	PST: 6:30 am – 4:30 pm, Web: www.NPIC.orst.edu

E. NSTAR's contact in the case of a spill or accident is:

NSTAR System Control:
Ops North, 617-541-7825,
Electric Ops South, 617-541-7858,
Gas Ops, 781-441-8400

F. **Table 4. Local Emergency Numbers:**

Emergencies Services for All Municipalities: 911
(to be filled out with the appropriate towns and included in the YOPs)

Town	Board of Health	Town/City Hall	Town	Board of Health	Town/City Hall

CLEAN-UP PROCEDURES

Education and attention will constantly be directed at accident and spill prevention, however, the following is a guideline in the event of an unfortunate incident:

REPORTABLE SPILLS (Spills of reportable quantity of material): FOLLOW STEPS 1-11
NON-REPORTABLE SPILLS: FOLLOW STEPS 1, 2, 3, 4, 7, 8 & 9 and contact the NSTAR representative.

Table 5: HERBICIDE SPILL CHECK LIST

Order	ACTION		Done (√)
1	Use any and all PPE as directed by product label or MSDS.		
2	Cordon-off spill area to unauthorized people and traffic to reduce the spread and exposure of the spill		
3	Identify source of spill and apply corrective action, if possible stop or limit any additional amounts of spilled product.		
4	Contain spill and confine the spread by damming or diking with soil, clay or other absorbent materials.		
5	Report spills of "reportable quantity" to the Mass. DEP and DAR:		
	Massachusetts DAR, Pesticide Bureau	(617) 626-1700	
	Massachusetts Department of Environmental Protection, Division of Hazardous Waste	Main Office: (888) 304-1133	
		Southeast Region: (508) 946-2700	
		Northeast Region: (978) 694-3200	
6(	If the spill cannot be contained or cleaned-up properly, or if there is a threat of contamination to any bodies of water, immediately contact any of the following applicable emergency response personnel:		
	local fire, police, rescue	911	
	NSTAR: Operations	(617) 541-7821	
	NSTAR Transmission: William Hayes	(781) 441-3932	
	NSTAR Distribution - South: Paul Sellers	(508) 957-4603	
	NSTAR Distribution – North: Chris Fallon	(781) 441-3837	
	NSTAR Gas- Steve Megaro,	781-441-8959	
	Product Manufactures		
	1. BASF Corporation	(800) 832-4357	
	2. Dow Agro Sciences	(800) 992-5994	
	3. E.I du Pont de Nemours & Company	(800) 441-3637	
	4. Monsanto	(314) 694-4000	
	5. Nufarm	(877) 325-1840	
	6. Rainbow Treecare	(877) 272-6747	
	Chemtrec	(800) 424-9300	
	additional emergency personnel		
	If there is a doubt as to who should be notified, contact State Police, Central Office	(617) 566-4500 or 911	
7	Remain at the scene to provide information and assistance to responding emergency clean-up crews		
8	Refer to the various sources of information relative to handling and cleanup of spilled product		
9	If possible, complete the process of "soaking up" with absorbent materials		
10	Sweep or shovel contaminated products and soil into leak proof containers for proper disposal at approved location		
11	Spread activated charcoal over spill area to inactivate any residual herbicide		

APPENDIX 1:
ELECTRIC SYSTEM MAPS

APPENDIX 2:
LIST OF MUNICIPALITIES

APPENDIX 3:
333 CMR 11.00

APPENDIX 4:
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APPENDIX 5:
SENSITIVE AREA TABLE

APPENDIX 6:
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APPENDIX 8:
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APPENDIX 9:
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EVERSOURCE ENERGY, EASTERN MA

2016 YEARLY OPERATIONAL PLAN FOR

Central, Eastern and Southeastern Massachusetts



Submitted by:
Eversource Energy, Eastern MA

Prepared by:
Vegetation Control Service, Inc.

Submitted:
JANUARY 31, 2016

SUMMARY

In compliance with the Massachusetts Department of Agricultural Resources' Rights-of-Way Regulations (333 CMR 11.00), this Yearly Operational Plan (YOP) informs municipalities of Eversource Energy, Eastern MA's intent to utilize an integrated vegetation management plan that includes the use of herbicides on electric rights-of-way (ROW) in 2016. Our Integrated Vegetation Management program is outlined in our five year Vegetation Management Plan. ROWs treated in 2015 are included in this YOP in case they need a "touch-up" spot treatment.

This YOP identifies target vegetation; the affected rights-of-way and towns; the herbicides, rates and methods of application; alternative control methods; the individual responsible for supervising the YOP, and the qualified contractors that will perform the application. It explains how sensitive areas; and sites where herbicides are either restricted or not permitted are identified, appropriately marked, treated and protected. It addresses procedures for the mixing, handling and loading of herbicide concentrates. Finally, it includes Herbicide Fact Sheets and Labels, a list of emergency resources and telephone numbers, and maps including known sensitive areas.

The YOP process provides for a forty-five day public review and comment period, in conjunction with the twenty-one day municipal rights-of-way notification period. These review periods give communities an opportunity to provide information that will help identify additional areas that may require specific precautions or protection. Finally, notice will be published in general circulation newspapers at least 48 hours before the scheduled application.

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I. INTRODUCTION

In compliance with Commonwealth of Massachusetts' Rights-of-Way Vegetation Management Regulations (333 CMR 11.00) Eversource Energy, Eastern MA's *Yearly Operational Plan* (YOP) details our 2016 vegetation management program. This YOP is consistent with the terms and procedures set forth in the Eversource Energy, Eastern MA 2015-2017 *Five-year Vegetation Management Plan* (VMP) per 333 CMR 11.05; with the Massachusetts Pesticide Control Act (Chapter 132B); with all pertinent clauses in Chapter 85 of the Acts of 2000; with the Massachusetts Endangered Species Act (MESA; MGL c. 131 A) and regulations (321 CMR 10.00), and with all Federal and State acts and regulations that apply to right-of-way vegetation management.

Eversource Energy, Eastern MA delivers electricity to customers in 81 municipalities. Electricity is transmitted over hundreds of miles of distribution and transmission rights-of-way (ROW) in the area covered by this YOP throughout the central, eastern, and southeastern Massachusetts. To ensure safe reliable electric and gas service, Eversource Energy, Eastern MA must keep these ROWs free from hazards and encroachments. In this effort, the vegetation on the ROW corridors must be maintained at an early stage of plant succession (herbaceous plants and shrubs).

Using the Integrated Vegetation Management Program (IVM) described in the VMP, Eversource's program is based on a 3-5 year selective herbicide application and where appropriate mechanical treatment cycle. This program allows for the safe delivery of reliable electric and gas service and supports a healthier more diverse habitat for wildlife that depends upon early successional landscapes (See VMP for further description of the IVM program).

II. CHAPTER 132B AND 333 CMR 11.00

> The purpose of this chapter is to conform the laws of the commonwealth to the Federal Insecticide, Fungicide, and Rodenticide Act, Public Law 92-516, as amended, and the regulations promulgated there under and to establish a regulatory process in the commonwealth. The exclusive authority in regulating the labeling, distribution, sale, storage, transportation, use and application, and disposal of pesticides in the commonwealth shall be determined by this chapter. *(MGL 132B, Section 1)*

Chapter 132b (Massachusetts Pesticide Control Act) was created to ensures a clear and uniform set of standards for the entire Commonwealth of Massachusetts ***in order to protect the public from the negative impacts that arise from fragmented, decentralized, sets of standards***. In this effort, the Commonwealth, through the Department of Agricultural Resources (DAR) retains the sole right to regulate the use of pesticides, including herbicides, throughout Massachusetts. DAR takes this responsibility extremely seriously and the regulations promulgated under Chapter 132b are stricter than Federal standards.

> The purpose of 333 CMR 11.00 is to establish a statewide and uniform regulatory process which will minimize the uses of, and potential impacts from herbicides in right of way on human health and the environment while allowing for the benefits to public safety provided by the selective use of herbicides *(333 CMR 11.01)*.

333 CMR 11.00 is the most comprehensive rights of way regulation in New England. It requires an Integrated Pest Management (in this case IVM) approach to right of way vegetation management; the establishment of standards and procedures to prevent unreasonable risks to humans or the environment, and a multi-layered system of public and municipal notification that requests input about environmentally and culturally sensitive areas. All of this is outlined in the VMP, annual YOPs, *The Environmental Monitor* Notice, 21 day notification, Public Water Supplier notification and 48 hour newspaper notice which serve as guides for the public, state and municipal officials, vegetation management contractors and Eversource personnel.

To ensure compliance with Chapter 132b and 333 CMR 11.00, DAR performs routine inspections of rights-of-way treatment crews, retains chemists, and perform further tests before approving a limited list of herbicides approved for use in Sensitive Areas (pursuant to 333 CMR 11.04 (1)(d)).

As detailed in the VMP and YOP, this IVM program strictly adheres to all the requirements of Chapter 132b and 333 CMR 11.00. Eversource Energy, Eastern MA only retains herbicide application treatment contractors that hold Massachusetts' certifications and licenses to apply pesticides, which require ongoing training to maintain. All Sensitive Areas (see section V) are treated appropriately using either mechanical treatment methods or Commonwealth of Massachusetts recommended herbicides for use in Sensitive Areas. In fact, in 2016 Eversource Energy, Eastern MA will only use these recommended herbicides on the entire length and cleared width of its ROW corridors.

Beyond the requirements of 333 CMR 11.00 and in compliance with Chapter 216 of the Acts of 2012, Eversource also notifies "abutters" (houses and businesses that abut the rights-of-way being treated in that year) within view of the ROWs before treatments begin. Treatment contractors are required to leave door hangers or talk personally with abutters which allow the contractor to answer site specific questions, identify private wells and help explain the program.

III. LOCATION OF INTENDED TREATMENTS

In 2016 Eversource Energy, Eastern MA plans on completing herbicide applications on twleve transmission and distribution line ROWs as listed in Table I. Table II includes the eight ROWs treated in 2015 which might need "touch-up" spot treatments. At least one of the ROWs scheduled for a 2016 IVM treatment pass through the 31 municipalities in Table III. Table IV is a list of the 26 towns with at least one 2015 ROW that might need a "touch-up" spot treatment. Please note that some of these towns appear on both lists and the total number of municipalities is 49 (see Appendix I. Maps).

a. Integrated Vegetation Management Herbicide Treatments:

Table I. 2016 Rights-of-Way:

ROW Number	Line Name
25 KV Distribution Rights-of-Way	
Waterworks	New Bedford water works R/W -Freetown
146	Fairhaven to Marion
201	R/W241 - Kingston Sub also includes spur to South Duxbury Sub
210	Wareham Sub - East Wareham Tap
212	Buzzards Bay Sub - Onset Sub
215	Marshfield-Brant Rock
Transmission Rights-of-Way	
3	455 Framingham -Grid Southboro to Sta. 110 W. Roxbury
4B	Canton Tap
5	Sta. 211 - Woburn - Grid Billerica
6-6c	Sta. 478 Holbrook – Sta. 451 Whitman
7	Sta. 65 Medway – Sta. 240 Framingham
16	Tap to Whitman

Table II. List of Potential Touch-up Rights-of-Way from 2015 YOP:

ROW Number	Line Name
25 KV Distribution Rights-of-Way	
202	West Pond- Manomet 4kV sub
203	West Pond- East Carver Sub
204	S Ply Sub - R/W 202
205	Dux Sub - Pine Street, Marshfield
Transmission Rights-of-Way	
4 -A,E,W	Sta. 447 Walpole - Sta. 65 Medway - Grid tie, Sta. 146 Walpole - Sta. 150 Weymouth
13-13A	Sta. 447 Medway - Uxbridge RI line
142	Crystal Spring Tap
143	Montaup Tap, Ind. Park sub NB to High Hill Sub Dartmouth

Tables III & IV: List of Affected Herbicide Municipalities:

Table III. 2016 Herbicide municipalities:		
Abington	Framingham	Natick
Ashland	Freetown	Needham
Boston	Halifax	Plymouth#
Brockton	Hanson	Plympton
Burlington	Holbrook#	Sharon#
Canton#	Holliston	Sherborn
Dedham	Kingston	Wareham
Dover	Marion	Whitman
Duxbury#	Marshfield#	Woburn
East Bridgewater	Mattapoisett#	
Fairhaven	Medway#	

#also has a right(s)-of-way scheduled for a "touch-up" treatment

Table IV. Herbicide municipalities with 2015 Rights-of-Way that might need a "touch-up" treatment:		
Acushnet	Franklin	Norfolk
Avon	Holbrook	Plymouth
Bellingham	Marshfield	Randolph
Blackstone	Mattapoisett	Sharon
Braintree	Medway	Stoughton
Canton	Mendon	Uxbridge
Carver	Millis	Walpole
Dartmouth	Millville	Weymouth
Duxbury	New Bedford	

IV. IDENTIFICATION OF TARGET VEGETATION FOR HERBICIDE APPLICATIONS

Pursuant to the policy and intent set forth in the VMP, all vegetation must be removed that obscures the ROW corridors and grows tall enough to interfere with the safe, efficient and legal operation of an electrical power line. In the wire zone, trees and brush are targeted, and native, low growing plant communities that have a mature height less than three feet are established. In the border zone, incompatible trees and brush are targeted, and the growth of native trees and shrubs that have a mature height less than 15 feet is encouraged (see VMP for details on Wire Zone-Boarder-Zone).

The primary target is all trees species within the cleared width of the ROW; except in Priority Habitats that are under the purview of the Natural Heritage and Endangered Species Program of the Department of Fish and Game (NHESP), which will be treated on a case by case basis.

Examples of targets include, but are not limited to:

Alder	Cherry	Pine
Aspen	Hemlock	Maple
Beech	Hickory	Oak
Birch	Locust	Sassafras

There are more non-target vegetation species on an electric or gas ROW than targets. In fact, ROW's are one of the primary early successional plant communities remaining in New England. As a result, many plant and animal species use ROWs as their homes, feeding grounds or nurseries. Certain plant species, therefore, are generally encouraged on the ROW through the use of an IVM program (excluding invasive plant species):

- Most herbaceous growth is acceptable and encouraged
- Shrubs that mature less than 15 feet in height are only targets where due to their location or attributes they interfere with the function of the ROW.

Certain categories of non-tree species are targets under some circumstances, because of their location and/or their nature. Dense woody vegetation, shrubs and vines are targets where they are capable of interfering with the inspection and maintenance of the poles, wires, and along access roads, paths and gates which need to be kept clear, especially for emergencies.

Eversource Energy, Eastern MA intends to control noxious plant species including invasive, poisonous plants and vines at their facilities. Invasive plant species have become an increasing concern throughout Massachusetts in areas that include ROW corridors where they can spread rapidly and move into the adjacent landscape. Eversource Energy, Eastern MA plans to use herbicides to spot treat poisonous plants at sites under its ROWs identified as having a high risk of posing a health hazard. Noxious vegetation, likewise, poses a risk to the safety and health of all individuals working on or traversing a ROW and it can impede a rapid response in an emergency.

Examples of non-tree species generally considered targets, include, but are not limited to:

Autumn Olive	Hawthorne	Purple Loosestrife
Blackberry	Honeysuckle	Sumac (Staghorn and Poison)
Buckthorn	Japanese Knot Weed	
Common Reed	Multiflora Rose	Virginia Creeper
Grapevines	Oriental Bittersweet	Willow
Greenbriar	Poison Ivy	

V. DEFINITION, IDENTIFICATION AND TREATMENT OF SENSITIVE AREAS

Sensitive Areas are those areas within a ROW in which public health, environmental concerns or agricultural interests warrant special protection to minimize the risk of unreasonable adverse effects.

The map(s) in Appendix I are a resource and a tool for both the public and the vegetation management crews. They contain the data necessary to identify, mark and treat Sensitive Areas appropriately.

The map(s) include known Sensitive Areas available at the printing of this YOP. Some Sensitive Areas are included in the base USGS topographic maps. The most current data available through MassGIS such as public water suppliers, certified vernal pools, etc. and any data that Eversource Energy, Eastern MA has collected to date for items such as private wells are added on top of the USGS data. At the time of treatment, any additional Sensitive Areas collected will be added to the maps utilized by our vegetation management contractors. Please note that Zone II's and limited spray areas are not mapped since in 2016 Eversource Energy, Eastern, MA will only use herbicides approved for use within this type of Sensitive Area on the listed ROWs.

There is one type of Sensitive Area not included on the maps that we are not authorized to publish: the locations of the Priority Habitats of state listed species as regulated by the Natural Heritage and Endangered Species Program (NHESP) of the Division of Fisheries & Wildlife. A map layer of Priority Habitats is available to the general public at:

http://www.mass.gov/anf/research-and-tech/it-serv-and-support/application-serv/office-of-geographic-information-massgis/,

but it is neither specific to areas of concern for herbicide applications nor does it include data on the individual species since the exact location and details of their habitat is protected. Please be assured that we follow all necessary precautions to stay in compliance with 321 CMR 10.00 and this YOP was approved by NHESP.

Prior to any herbicide application, Sensitive Areas will be identified and when necessary marked in the field by an experienced vegetation management treatment crew point person, by individuals trained in the identification of Sensitive Areas that require the use of GIS (geographic information systems) and GPS equipment, and/or by a NHESP approved botanist trained in the delineation of state-listed species.

Two simple descriptions guide the complex identification of the Sensitive Areas listed in 333 CMR 11.02: *Readily identifiable in the field* and *Not readily identifiable in the field*:

A. *Readily identifiable in the field areas* will be treated and marked according to all applicable restrictions listed in 333 CMR 11.00 and the VMP.

B. *Not readily identifiable in the field areas* are identified by the use of the data marked on our maps and additional data collected in the YOP and notification processes before the time of treatment.

Eversource and contractor personnel assigned the task of identifying Sensitive Areas in the field will use the following sources and methods:

A. Massachusetts Department of Environmental Protection (DEP) water supply maps/GIS mapping layers available through MassGIS
B. Massachusetts Department of Agricultural Resources (DAR) records of identified private wells along the ROW
C. Correspondence and input from municipalities within the consecutive forty-five day YOP and twenty-one day municipal ROW notification review and comment periods and the 48 hour newspaper notification
D. Correspondence and input from Eversource Energy, Eastern MA's abutter notification procedure
E. A point person who precedes the treatment crew verifying identified Sensitive Areas and any additional areas that may require special precautions.

The following section details some of the Sensitive Areas that require special attention, particularly those that are classified as either no spray or *not readily identifiable in the field:*

A. *Limited Spray Areas*:

Per 333 CMR 11.02, the following need to be identified in the field, require the use of herbicides on the *DAR Rights-of-Way Sensitive Area Materials List*, and time restrictions between herbicide applications (see Appendix II, Sensitive Area Table). Please note that

for IVM herbicide applications on the listed ROWs, Eversource Energy, Eastern MA uses only Sensitive Area approved herbicides on our entire ROW system:

(a) any Zone II or IWPA
(b) a distance of between 100 feet and 400 feet of any Class A Surface Water Source
(c) a distance of between 10 and 200 feet of any tributary or associated surface water body where the tributary or associated surface water body runs outside the Zone A for the Class A surface water source
(d) a lateral distance of between 100 and 200 feet for 400 feet upstream, on both sides of the river, of a Class B Drinking Water Intake
(e) a distance of between 50 and 100 feet of any identified Private Well
(f) a distance of between 10 and 100 feet of any Wetlands or Water Over Wetlands
(g) a distance of between 10 feet from the mean annual high water line of any river and the outer boundary of the Riverfront Area
(h) a distance of between ten feet from any Certified Vernal Pool and the outer boundary of any Certified Vernal Pool Habitat
(i) a distance of 100 feet of any Agricultural or Inhabited Area.

Please Note that "(f)" is modified by the DAR (formerly Department of Food and Agriculture) *Decision*, dated October 12, 1995, concerning the wetland impact study conducted pursuant to 333 CMR 11.04(4)(c)(2). According to the *Decision*, Eversource may use herbicides within wetlands except on or within 10 feet of standing or flowing water (item "g" in the *no-spray areas* below was removed from the no spray list for utilities because it does not apply for the same reason).

B. *No-Spray Areas*:

Again, quoting from 333 CMR 11.02 the following no-spray areas need to be identified:

No-Spray Area, any area that is both within a Right-of-Way and within:

(a) any Zone I
(b) 100 feet of any Class A Surface Water Source
(c) 100 feet of any tributary or associated surface water body where the tributary or associated surface water body runs within 400 feet of a Class A surface water source
(d) 10 feet of any tributary or associated surface water body where the tributary or associated surface water body is at a distance greater than 400 feet from a Class A surface water source
(e) a lateral distance of 100 feet for 400 feet upstream, on both sides of the river, of a Class B Drinking Water Intake
(f) 50 feet of any identified Private Well [within 100 feet of the ROW]
…
(h) 10 feet of the mean annual high-water line of any river
(i) 10 feet of any Certified Vernal Pool.

C. Identification and Treatment of Private Drinking Water Supplies

1. No herbicide treatments will take place within fifty feet of any identified private wells located within one hundred (100) feet of the ROW.

2. Under 333 CMR 11.00, one of the primary functions of the YOP and notification processes is so that Municipal agencies assist in the identification process

3. Identified private drinking supplies within one hundred (100) feet of a ROW will be permanently recorded.

D. State-Listed Species Habitat

Eversource Energy, Eastern MA recognizes the importance of the Massachusetts Endangered Species Act, M.G.L.C. 131 A, and its significance to ROW vegetation management. Eversource will comply with all applicable portions of this Act and the regulations promulgated thereunder. Eversource will also follow the rules and prohibitions directed at human activities which Take Species or alter their Significant Habitat (as of this printing there are no designated Significant Habitat in Massachusetts).

321 CMR 10.14, Massachusetts Endangered Species Act Regulations, Part II Exemptions and 333 CMR 11.04(3)(a-c) exempts utility ROW vegetation management from the permit process under the following conditions:

> (12) The management of vegetation within existing utility rights-of-way provided that the management is carried out in accordance with a vegetation management plan approved in writing by the Division prior to the commencement of work for which a review fee shall be charged, the amount of which shall be determined by the commissioner of administration under the provisions of M.G.L. c.7, § 3B…

To comply with exemption 10.14(12), Eversource Energy, Eastern MA submits this YOP to the NHESP for review.

The NHESP has delineated areas as Priority Habitat based on the "Best Scientific Evidence Available" to protect State-listed species from a "take." Under the approval process, details about the Priority Habitat of state-listed species that might be affected by our activities and management recommendations are shared with Eversource under strict confidentiality agreements. Using this data and best management practices, Eversource and contract personnel will follow the appropriate vegetation management treatment methods within these sensitive areas taking all practical means and measures to modify ROW vegetation management procedures to avoid damage to state-listed species and their habitat.

To identify Priority Habitats, Eversource personnel, NHESP approved review botanists and vegetation management crews must use proper identification procedures. Contractors are, therefore, required to train their personnel to recognize the location of Priority Habitats using one of the following tools: paper maps, GPS coordinates and/or GIS systems.

VI. PROPOSED HERBICIDE TREATMENT METHODS

Under Eversource Energy, Eastern MA's IVM program, combined with mechanical "prep-cutting," mowing and side-trimming activities, herbicide applications will be applied on foot using selective low pressure foliage treatments with backpack sprayers and cut stump or basal treatments. Experienced, Massachusetts licensed applicators will perform the selective herbicide treatments under the direct on site supervision of a certified applicator.

Eversource Energy, Eastern MA's herbicide program is a selective program scheduled to sustain acceptable vegetation control at minimal application rates. Using backpack sprayers, very small amounts of herbicide are applied directly to the leaves, stumps or bark of the target

vegetation. The average per acre rate of herbicide mix for Eversource Energy, Eastern MA's foliar program is in the pints per acre range.

Eversource also chooses herbicide formulations that are low in acute toxicity, do not bio-accumulate and, as applied, have a short half-life with low soil mobility (see VMP, Bibliography). Above and beyond the review by the Federal EPA, these herbicides are all carefully reviewed jointly by DAR and the Massachusetts Department of Environmental Protect for use in "limited spray" sensitive areas (including Zone IIs). Eversource Energy, Eastern MA takes this one step further and only uses sensitive area approved herbicides on the entire length and width of the listed ROWs.

A. Methods:

Eversource personnel and contract personnel will utilize the most appropriate technique for the vegetation species, height, density, site and mandated restrictions. These methods as described in detail in the VMP are briefly reviewed below:

Low Volume Foliage Techniques utilize hand-operated pumps or motorized, backpack sprayers. The motorized, backpack sprayer produces an air current that delivers small amounts of herbicide mixture from a portable spray tank to the target vegetation. The low-pressure hand-pump sprayer uses a column of water. In both cases, the amount of herbicide solution applied only dampens or lightly wets the target vegetation.

Low-Volume Stem Basal: the selective application of herbicides to the lower 6"-8" of the plant stem. The herbicide concentration is applied with low-pressure, backpack sprayers with special wand attachments and positive shut-off nozzle tips with small orifices.

Cut Stump Surface Treatment (CST): the application of an herbicide mixture to the cut surface of a stump immediately following or during a cutting operation. Application equipment includes low-volume, backpack, hand-pump sprayers; hand held squirt bottles; paintbrushes, or sponge applicators.

B. Guidelines:

1. All Sensitive Area restrictions will be followed

2. Foliar and Basal treatments are used within the cleared width of the ROW for tree and shrub target species under 12 feet in height

3. CST treatments are used in conjunction with hand-cutting and in situations including but not limited to: trees and shrubs that cannot be foliar treated, at road buffers, and around structures such as poles and gates

4. Only mechanical treatment methods will be used in *no spray* Sensitive Areas, including but not limited to hand cutting, trimming and mowing.

C. Treatment of Wetlands

Herbicide applications in wetlands will be performed in accordance with 333 CMR 11.04 (4)(c)(2) relative to ROW management. Targets will be selectively treated with herbicides on the DAR's *Sensitive Area Material List* and will not be applied within ten (10) feet of standing or flowing water.

D. Treatment of State-Listed Priority Habitats

All vegetation management activities will be completed in compliance with the Massachusetts Endangered Species Act (MESA; MGL c. 131 A) and its regulations, 321 CMR 10.00.

VII. PROPOSED HERBICIDES, CARRIERS, ADJUVANTS AND RATES

Only the Commonwealth of Massachusetts recommended herbicides listed below for use in Sensitive Areas—pursuant to 333 CMR 11.04 (1)(d)—will be used on the entire length and cleared width of the listed ROWs.

Table V. Tank Mix for Low Volume Foliage Applications:

Herbicides & Adjuvants	Active Ingredient	EPA Registration Number(s)	Mix Concentration (per 100 gals. water)	Estimated Application Rate Per Acre
Rodeo	Glyphosate	62719-324	3-5%	16-128 oz.
Krenite S	Fosamine Ammonium	42750-247	6-10%	32-128 oz.
Garlon 4 Ultra	Triclopyr	62719-527	2-4%	16-128 oz.
Escort XP or Patriot	Metsulfuron-Methyl	352-439, 432-1549 or 228-391	2-4 oz.	0.125-0.8 oz.
Arsenal, Arsenal Powerline or Polaris[*]	Imazapyr[†]	241-346, 241-431 or 228-534	0.125%-0.5%	2-8 oz.
Induce, Clean Cut, MSO, or Aqua Fac or equivalent surfactant[‡]	n.a.[§]	n.a.	0.125%-1%	1-16 oz.
Point Blank, Stay Put Plus or equivalent drift retardant	n.a.	n.a.	0.125%-0.5%	1-2 oz.
Carrier: Water	n.a.	n.a.	n.a.	n.a.

[*] Imazapyr will not be applied on the same right-of-way in two consecutive years.
[†] Imazapyr will not be applied on the same right-of-way in two consecutive years.
[‡] Equivalent surfactants, drift retardants and basal oils will be used if those listed are no longer available or more effective alternatives become available.
[§] n.a.—not applicable

Table VI: Tank Mix for Poison Ivy, Vines, Noxious and Invasive Species

Herbicides & Adjuvants	Active Ingredient	EPA Registration Number(s)	Mix Concentration (per 100 gals. water)
Rodeo	Glyphosate	62719-324	2-5%
Garlon 4 Ultra	Triclopyr	62719-527	2-4%
Escort XP or Patriot	Metsulfuron-Methyl	352-439, 432-1549 or 228-391	1.25-4 oz.
Induce, Clean Cut, MSO, or equivalent surfactant	n.a.	n.a.	0.125%-1%
Point Blank, Stay Put Plus or equivalent drift retardant	n.a.	n.a.	4-16 oz.
Carrier: Water	n.a.	n.a.	n.a.

Table VII. Tank Mixes for Cut Surface Treatment (CST) Applications:

Herbicides & Adjuvants	Active Ingredient	EPA Registration Number(s)	Mix Concentration (per 100 gals. water)	Estimated Application Rate Per Acre
Rodeo	Glyphosate	62719-324	40% to 50%	Per density of target stems
Arsenal, Arsenal Powerline or Polaris	Imazapyr*	241-346, 241-431 or 228-534	3%-5% (mixed with Rodeo)	Per density of target stems
Carriers: Water or Windshield Washing Fluid	n.a.	n.a.	n.a.	n.a.

Table VIII. Tank Mixes for Low-Volume Basal or Cut Surface Treatment (CST) Applications:

Herbicides & Adjuvants	Active Ingredient	EPA Registration Number(s)	Mix Concentration (per 100 gals.)	Estimated Application Rate Per Acre
Garlon 4 Ultra	Triclopyr	62719-527	20%-30%	Per density of target stems
Polaris	Imazapyr*	228-534	3%-5% (mixed with Garlon 4 Ultra)	Per density of target stems
Carrier: Arborchem's low odor basal oil or equivalent	n.a.	n.a.	n.a.	n.a.

VIII. ALTERNATIVE MECHANICAL CONTROL TECHNIQUES

Areas not treated or prohibited from herbicide use will be maintained mechanically according to the specifications in the VMP. The following is a brief review of these methods:

Hand Cutting: the use of chain and brush saws to remove the stem and/or branches from the plant's root system; can be combined with CST except in no-chemical restricted areas.

Mowing: the cutting, severing or shattering of vegetation by large rotary or flail mowers.

Side Pruning: side pruning or removal of encroaching tops and/or branches of trees growing on or near the ROW's and access roads.

IX. COMPANIES THAT MAY PERFORM THE HERBICIDE TREATMENT

Tree Tech
6 Springbrook Rd.
Foxboro, MA 02035
(888) 873-3832

Lucas Tree
636 Riverside St.
Portland, ME 04104
(888) 845-7870

Lewis Tree Service, Inc.
300 Lucius Gordon Drive
West Henrietta, NY 14586
(585) 436-3208

Vegetation Control Service, Inc.
2342 Main Street
Athol, MA 01331
(978) 249-5348

X. INDIVIDUAL RESPONSIBLE FOR SUPERVISING THE YOP

William Hayes, Senior Transmission Arborist
Eversource Energy, Eastern MA
Transmission Vegetation Management
One NSTAR Way, SE-370
Westwood, MA 02090-9230
781-441-3932 (office)

XI. HERBICIDE FACT SHEETS

Herbicide Fact Sheets prepared and provided by the DAR, explain technical information relative to the herbicide concentrates proposed for use during the 2016 treatment cycle. These are included in Appendix III, along with the manufacturer's labels in Appendix IV.

XII. PROCEDURES FOR HANDLING, MIXING AND LOADING HERBICIDE CONCENTRATES

All herbicides will be handled, mixed and applied according to the directions in 333 CMR 11.00, which includes following Label Instructions and in compliance with all applicable federal and state laws and regulations. If possible, herbicide mixing should be done at the contractor's facilities and extreme care shall be exercised during all mixing, handling and loading in order to prevent careless spills or splashes. No herbicide concentrates will be mixed, handled or loaded on a ROW within one hundred (100) feet of a Sensitive Area.

XIII. EMERGENCY RESOURCES

Eversource contracts with independent, professional, certified herbicide applicators that are responsible for the containment, clean up and reporting of chemical spills or accidents. The following is a guide to the information sources that, according to various regulations, must be available to the treatment crew in the event of a chemical spill or emergency situation:

A. Technical Reference Materials:
   a. Product Label
   b. Product Safety Data Sheet (SDS)
   c. Product Fact Sheet, if available

B. **Table IX. Herbicide Manufacturers:**

MANUFACTURER	TELEPHONE NUMBER	SPECIAL INSTRUCTIONS
Albaugh Inc.	800-247-8013	
BASF Corporation	800-832-4357	
Bayer Environmental Science	800-334-7577	
Dow Agro Sciences	800-992-5994	
E.I. du Pont de Nemours and Company	800-441-3637	Medical Emergencies
Monsanto	314-694-4000	
Nufarm	877-325-1840	Medical Emergencies

C. **Table X. State Agencies:**

STATE AGENCY	TELEPHONE NUMBER	SPECIAL INSTRUCTIONS
Massachusetts Pesticide Bureau	(617) 626-1700	A.S.A.P. (within 48 hours)
Massachusetts Department of Environmental Protection, Emergency Response Section	Main Office: (888) 304-1133 Southeast Region: (508) 946-2700 Northeast Region: (978) 694-3200 Central Region: (508) 792-7650	For emergencies involving reportable quantities of hazardous materials; required info: City/town, street address, site name (if applicable), material
Massachusetts Dept. of Public Health, Bureau of Env. Health Assessment Toxilicology Program	(617) 624-5757	
Massachusetts Poison Information Centers	(800) 682-9211	For medical emergencies involving suspected or known pesticide poisoning symptoms

D. **Table XI. Emergency Services:**

EMERGENCY SERVICE	TELEPHONE NUMBER	SPECIAL INSTRUCTIONS
Massachusetts State Police, Central Office	617-566-4500 or 911	
Local Fire / Police Dept.	911	
ChemTrec	800-424-9300	
Clean Harbors	800-OIL-TANK	
Pesticide Hotline	800-858-7378	PST: 6:30 am – 4:30 pm, Web: www.NPIC.orst.edu

E. Eversource Energy, Eastern MA contact in the case of a spill or accident is:

System Control
Eversource Energy, Eastern MA
One NSTAR Way
Westwood, MA 02090-9230
(617)-541-7858

F. **Table XII. Local Emergency Numbers:**

Emergencies Services for All Municipalities: 911

Town	Board of Health	Town/City Hall	Town	Board of Health	Town/City Hall
Abington	781-982-2119	781-982-2100	Kingston	781-585-0503	781-585-0500
Acushnet	508-998-0275	508-998-0200	Marion	508-748-3530	508-748-3500
Ashland	508-881-0100 x681	508-881-0100 x611	Marshfield	781-834-5558	781-834-5563
Avon	508-588-0414	508-588-0414	Mattapoisett	508-758-4100 x8	508-758-4100
Bellingham	508-966-5820	508-966-5805	Medway	508-533-3206	508-533-3200
Blackstone	508-883-1500 x129	508-883-1500	Mendon	508-634-2656	508-478-2737
Boston	617-534-5395	617-635-4500	Millis	508-376-7042	508-376-7040
Braintree	781-794-8090	781-794-8000	Millville	508-883-5041	508-883-1186
Brockton	508-580-7175	508-580-7123	Natick	508-647-6460	508-647-6400
Burlington	781-270-1955	781-270-1600	Needham	781-455-7523	781-455-7500
Canton	781-821-5021	781-821-5000	New Bedford	508-991-6199	508-979-1400
Carver	508-866-3420	508-866-3400	Norfolk	508-528-7747	508-528-1408
Dartmouth	508-910-1804	508-910-1813	Plymouth	508-747-1620 x118	508-747-1620 x106
Dedham	781-751-9220	781-751-9100	Plympton	781-585-7000	781-585-2700
Dover	508-785-0032 x232	508-785-0032	Randolph	781-961-0924	781-961-0900
Duxbury	781-934-1105	781-934-1100	Sharon	781-784-1510	781-784-1515
East Bridgewater	508-378-1612	508-378-1601	Sherborn	508-651-7852	508-651-7850
Fairhaven	508-979-4022	508-979-4023	Stoughton	781-344-6960	781-341-1300 x163
Framingham	508-532-5470	508-532-5400	Uxbridge	508-278-8600	508-278-8600
Franklin	508-520-4905	508-520-4900	Walpole	508-660-7320	508-660-7300
Freetown	508-644-2202	508-644-2203	Wareham	508-291-3100 x3197	508-291-3100
Halifax	781-293-6768	781- 293-7970	Weymouth	781-340-5008	781-335-2000
Hanson	781-293-3138 x122	781-293-2131 x100	Whitman	781-618-9755	781-618-9701
Holbrook	781-767-3030	781-767-4312	Woburn	781-932-4407	781-932-4400
Holliston	508-429-0605	508-429-0601			

Appendix 5-6

Memorandum

To: Eversource Energy, Sudbury-Hudson Transmission Reliability Project File

Date: February 3, 2017

Project #: 12970.00

From: Meddie J. Perry, CGWP

RE: Groundwater Hydrology Assessment: Hudson MA Public Community Water System

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VHB has assessed whether construction of the Project or Noticed Variation is likely to affect the flow and quantity of water to the five wells that supply the Hudson, MA public community water system, based on a review of the groundwater hydrology of the aquifers associated with these municipal wells. This assessment was performed because the Project and Noticed Variation are proposed to cross through portions of the designated Wellhead Protection Areas for these municipal wells. VHB understands that the Project and Noticed Variation would follow the existing MBTA right-of-way along an unused former rail corridor through the Town of Hudson and surrounding towns. VHB's assessment is that neither option is likely to have any appreciable impact on groundwater flow or well yield, as explained below.

I. Study Performed

VHB reviewed all files, maps, reports, and data for the Hudson water system that were available from the Massachusetts Department of Environmental Protection ("MA DEP") via on-line and in-person file reviews. The information that VHB evaluated is listed in the References Cited section at the end of this memorandum, and includes well drilling logs, test well exploration reports, geologic studies, well pumping-test reports and data, groundwater flow modeling results, groundwater contour mapping, geologic cross sections and water elevation profiles, Source Water Assessment Program reports, and wellhead protection area delineations.

From the available documentation, VHB developed a conceptual model of the hydrology of the aquifers and flow to the municipal wells, and created a regional groundwater elevation map that shows the elevations of the groundwater surface under normal water system operating conditions, along with the wellhead protection areas, aquifers, and the alignment of the Project and Noticed Variation.

VHB has previously developed topographic survey plans (VHB, 2016) depicting the existing ground surface along the route. For this assessment, VHB compared the planned depth of the Project and Noticed Variation infrastructure below the ground surface to the groundwater elevations, to

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determine whether excavation and placement of subsurface components would take place within the aquifer, or above the groundwater.

In locations where the infrastructure would be below the groundwater surface, VHB analyzed the likely impact to groundwater flow and well production via a conceptual model of the regional geology and hydrology.

II. Description of Hudson Municipal Wells and Water System

The Hudson municipal water system is operated by the Town of Hudson Department of Public Works – Water Division. In 2015, the system produced over 616 million gallons of water, equivalent to 1.69 million gallons per day as an annual average (Hudson, 2016). Sources of water include a surface water intake on Gates Pond Reservoir, plus five gravel-packed wells known as the Cranberry Well, the Kane Well, and Chestnut Street Wells 1, 2, and 3. The Department treats the water from the wells to remove naturally-occurring concentrations of iron and manganese, to control corrosion, and to disinfect potential bacteria. Table 1 below summarizes the key details of the municipal wells.

Table 1:
Hudson Municipal Well Summary

Well:	Cranberry	Kane	Chestnut St. #1	Chestnut St. #2	Chestnut St. #3
Year Installed:	1967	1966	1982	1989	1991
Total Depth, Ft.:	42	64	84	56	47
Yield, gal/min:	660+	500	700	700	700
Well Type:	Gravel-packed	Gravel-packed	Gravel-packed	Gravel-packed	Gravel-packed
Aquifer:	Zone II # 150: Unconfined stratified and-and-gravel	Zone II # 120: Unconfined stratified sand-and-gravel aquifer.			

The Kane well and the three Chestnut Street wells share a common groundwater aquifer known as the Fort Meadow Brook Aquifer, while the Cranberry well obtains water from a separate aquifer. In the MA DEP Source Water Assessment Program, the Wellhead Protection Area for the Fort Meadow Brook Aquifer is listed as Zone II # 120, and the Wellhead Protection Area for the Cranberry Bog Aquifer is listed as Zone II # 150. Refer to the Hudson Groundwater Map on page 1 of the

Attachment for the locations of the wells, aquifers, Wellhead Protection Areas, and Eversource Project and Noticed Variation.

The Fort Meadow Brook Aquifer that the Kane and Chestnut Street wells obtain water from is an unconfined, stratified sand-and-gravel aquifer of glacial origin that extends over a one square-mile area between Chestnut Street on the west, Main Street to the south, Boons Pond to the east, and Sudbury Road to the north. The glacial deposits of sand and gravel originated from outwash-plain and ice-contact deposits during glacial melting approximately 10,000 years ago. These deposits are deep, ranging to approximately 100 feet below ground surface, and are underlain by poorly-sorted, dense, glacial till. The aquifer materials are highly transmissive to the flow of water, with measured transmissivities on the order of 11,600 to 19,600 ft^2/day, averaging 15,000 ft^2/day (Whitman & Howard, 1991). Permeability is approximately 90 ft/day on average, and groundwater flow velocities range from approximately 2 to 3.1 ft/day (Whitman & Howard, 1988).

The Fort Meadow Brook Aquifer is recharged with water from a combination of precipitation onto the overlying land surface, and to a large degree from water infiltrating from the Assabet River and Fort Meadow Brook. The natural groundwater flow direction is to the north, but the pumping of these wells captures water from the Assabet River located to the north, and induces localized radial flow towards the wells from all directions (Whitman & Howard, 1991).

The groundwater aquifer that the Cranberry well obtains water from is also an unconfined, stratified sand-and-gravel aquifer of glacial origin. The glacial deposits of sand and gravel originated in post-glacial lakes and streams from outwash-plains, kettleholes, and ice-contact deposits such as kames and eskers during glacial melting approximately 10,000 years ago. These deposits are less deep than at the Fort Meadow Brook Aquifer, grading below depths of approximately 40 feet into finer-grained materials that are unsuitable for productive wells. Drilling refusal, likely on the underlying bedrock, has been encountered between 70 and 100 feet below grade in the general area. The aquifer materials are highly transmissive to the flow of water (Earth Tech, 2000).

The Cranberry aquifer is recharged primarily with water from precipitation onto the overlying land surface, and to a smaller degree from water infiltrating from the Hop Brook tributary and adjacent wetlands. The natural groundwater flow direction is generally to the southeast, parallel to the Hop Brook tributary, but is complex and variable, and the pumping of the Cranberry well may induce localized radial flow (Earth Tech, 2000).

III. Description of the Eversource Project and Noticed Variation

The Sudbury-Hudson Transmission Reliability Project would consist of electric transmission lines that would follow the unused MBTA corridor through the Town of Hudson and surrounding towns. VHB understands that both the Project and Noticed Variation would follow the existing MBTA right-of-way.

For the Project, underground concrete duct-banks would contain the electric transmission cables. The duct-banks are designed to be approximately 2.7 feet tall and 3.4 feet wide, and would be buried with their base approximately 5.3 feet below grade. Trenchless crossings would be installed at stream crossings and other sensitive locations, and would consist of a direct-burial cable without any concrete encasement. These crossings would be installed with horizontal directional drilling ("HDD") or jack-and-bore techniques, at depths to be determined on a site-specific basis. The trenchless cables would have an outside diameter of 44 to 48 inches. Concrete manhole structures would be installed along the route at intervals to-be-determined, and would be 8 to 10 feet deep and approximately 10 feet wide.

For the Noticed Variation, overhead transmission wires would be supported by steel poles set upon caissons consisting of reinforced concrete. The caisson spacing interval is yet to be determined, but would generally be on the order of hundreds of feet. Caissons would be 7 feet in diameter and between 22 and 28 feet deep.

Schematic drawings of the subsurface duct-banks, trenchless crossings, manhole structures, and caissons are provided on pages 4 to 8 of the Attachment.

IV. Assessment Results

For the Project, the analysis of the elevations of subsurface features relative to the groundwater elevations has determined that the majority of the Project would be placed above the elevation of the groundwater surface, so that it would not be possible to have any effect on groundwater flow rates or directions.

In a segment of the Project near the Fort Meadow Brook crossing, manholes, if placed in this segment, would extend no more than 3 feet into the groundwater table (duct banks placed less than 7 feet below existing grade would not reach the water table). Table 2 below summarizes the analysis of groundwater levels relative to the subsurface Project components.

Table 2:
Summary of Depths to Groundwater in MADEP Wellhead Protection Areas in Hudson, MA

Sheet	Station	Associated Wellhead Protection Area	Location	Grade Elevation [1]	Min. Project Elevation [2]	Groundwater Elevation [3]	Max. Depth of Project Below Groundwater Level (Ft)
25	1002+00	Cranberry Well	White Pond Rd	194	184	184	0
26	1014+00	Cranberry Well	Cranberry Bog Area	200	190	183	0
27	1026+00	Cranberry Well	Cranberry Bog Area	214	204	182	0
28	1039+00	Cranberry Well	Parmenter Rd	210	200	189	0
31	1074+00	Chestnut St. & Kane Wells	Main St	200	190	180	0
32	1086+00	Chestnut St. & Kane Wells	Kane Industrial Park	190	180	177	0
33	1098+00	Chestnut St. & Kane Wells	Kane Industrial Park	184	174	175	1
33	1104+00	Chestnut St. & Kane Wells	Ft. Meadow Bk	182	172	175	3
34	1120+00	Chestnut St. & Kane Wells	Chestnut St.	205	195	176	0
35	1124+00	Chestnut St. & Kane Wells	Stow Town Line	198	188	177	0

Notes:
[1] Grade Elevations are from 2-Ft existing topographic contours as shown on "Eversource Transmission Line | Sudbury, Stow and Hudson, Massachusetts | Candidate Route Design Option 2" Prepared by VHB, June 27, 2016

[2] Project Elevation is estimated based on a maximum burial depth of 10 ft as indicated on "Typical Cross-Sections: Duct Bank and Manhole" from Eversource, 9/18/15, rev. 9/30/15. (Note typical burial depth for duct banks is 5.33 ft and the manholes with the greater burial depths would be spaced at intervals only).

[3] Groundwater Elevation determined by VHB from a compilation of various sources including "Zone II Map: Existing Town Wells and Proposed Well Site 20-83, Hudson, MA" by Whitman & Howard, 1991" and "SWAP Conceptual Zone II Delineation: Cranberry Well, Hudson Department of Public Works" by Earth Tech, Inc. 2000, as summarized on "Hudson Groundwater Map" 9/8/2016 by VHB.

Relative to the roughly 100-foot depth of the aquifer, the manhole placement would be small and superficial to the flow of groundwater, as shown in the cross-section diagrams on pages 2 (Fort

Meadow Brook Aquifer) and 3 (Cranberry Bog Aquifer) of the Attachment. Groundwater would be able to continue flowing as it does presently, beneath the structures. Due to the high permeability and transmissivity of the sand and gravel materials in the aquifer, groundwater would be able to flow readily around and under the structures. Potentially, minor amounts of groundwater mounding could occur on the upgradient side of the structures which would develop the hydraulic gradient sufficient to counteract any minor impediment to flow that might be caused by the manhole structure.

For the Noticed Variation, the caissons would extend below the groundwater level; however, due to the small size of the caissons relative to the distance between each, groundwater would simply flow under and around the caissons without any impact.

V. Conclusions and Recommendations

Neither the Project or Noticed Variation would have any appreciable effect on groundwater flow rates or directions, nor would either option impact the yield of the Hudson municipal wells.

With the Project, for the majority of the length of the route within Hudson and its Wellhead Protection Areas, subsurface Project features would be placed above the elevation of the groundwater, and thus could not affect it. In the localized segment of the Project near the Fort Meadow Brook crossing, deeper project components (manholes) would slightly extend into the water table, but would not alter groundwater flow rates or directions because construction would enter only a small fraction of the aquifer, which is highly permeable, allowing groundwater to flow under and around the structures in the same rates and directions and it does presently.

For the Noticed Variation, due to the small size of the caissons relative to the spacing, groundwater would simply flow under and around them without any impact.

Because the overburden is highly permeable sand and gravel, the aquifer is sensitive to surface spills and sources of contamination. Spilled liquids could rapidly seep down to the water table and enter the groundwater. Therefore VHB recommends development and implementation of a Spill Prevention and Response Plan to address project construction equipment, fuels, lubricants, and any other liquid or hazardous materials that may be on site during construction. Best Management Practices should be established for spill prevention and cleanup. If over 1,320 gallons of oil are to be stored above-ground, a Spill Prevention, Control, and Countermeasure Plan ("SPCC Plan") stamped by a professional engineer would be required in accordance with United States Environmental Protection Agency ("EPA") regulation Title 40 CFR 112, Oil Pollution Prevention.

References Cited

Earth Tech, Inc., 1998. Summary of 1996-1998 Test Well Program, Hudson, MA. December 10, 1998

Earth Tech, Inc. 2000., SWAP Conceptual Zone II Delineation: Cranberry Well, Hudson Department of Public Works.

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Whitman & Howard, 1986. Test Well and Pumping Test Report: Chestnut Street Aquifer, Hudson, Massachusetts, July 22, 1986.

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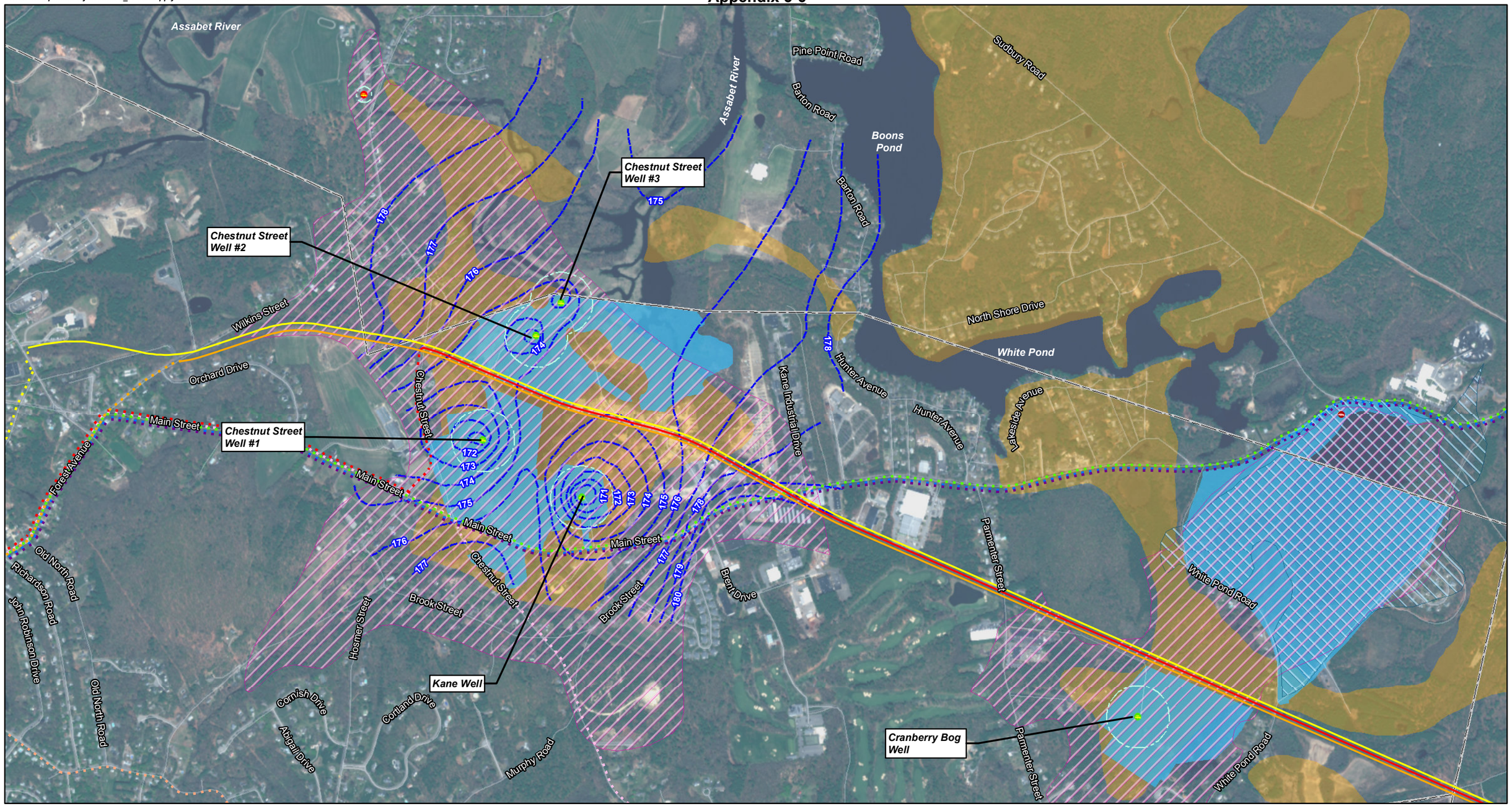
Whitman & Howard, 1991. Zone II Map: Existing Town Wells and Proposed Well Site 20-83, Hudson, MA.

Appendix 5-6

ATTACHMENT

H:\GIS\Temp\SudburytoHudson_WaterSupplyResources.mxd Date: 9/8/2016

Appendix 5-6



Sudbury to Hudson MBTA ROW Design Options with Hudson Public Roadway Routing Variations
- Option 1A/1B: MBTA ROW (OH/UG) to Chestnut
- Option 2A/2B: MBTA ROW (OH/UG) to Wilkins
- Option 3A/3B: MBTA ROW (OH/UG) to Woodrow

Sudbury to Hudson Public Roadway Routing Variations
- Option 4: Route 20 to Concord to Hudson
- Option 5: Route 20 to Union to Hudson
- Option 6: Route 20 to Horse Pond to Hudson

- Open Space Protected for Water Supply
- Aquifer
- Outstanding Resource Water

MADEP Wellhead Protection Areas
- Zone I
- Zone II

Public Water Supplies
- Community Groundwater Source
- Surface Water Intake
- Non-Community Groundwater Source
- Emergency Surface Water
- Groundwater Contour (FT)

Source: MassGIS, Whitman & Howard (1991), VHB

N

0 1,200 2,400 Feet

NOTE: Not to scale. Alignments shown are for graphical purposes only.
Lines that appear immediately adjacent to each other should be assumed to follow the same alignment.

DRAFT

EVERSOURCE

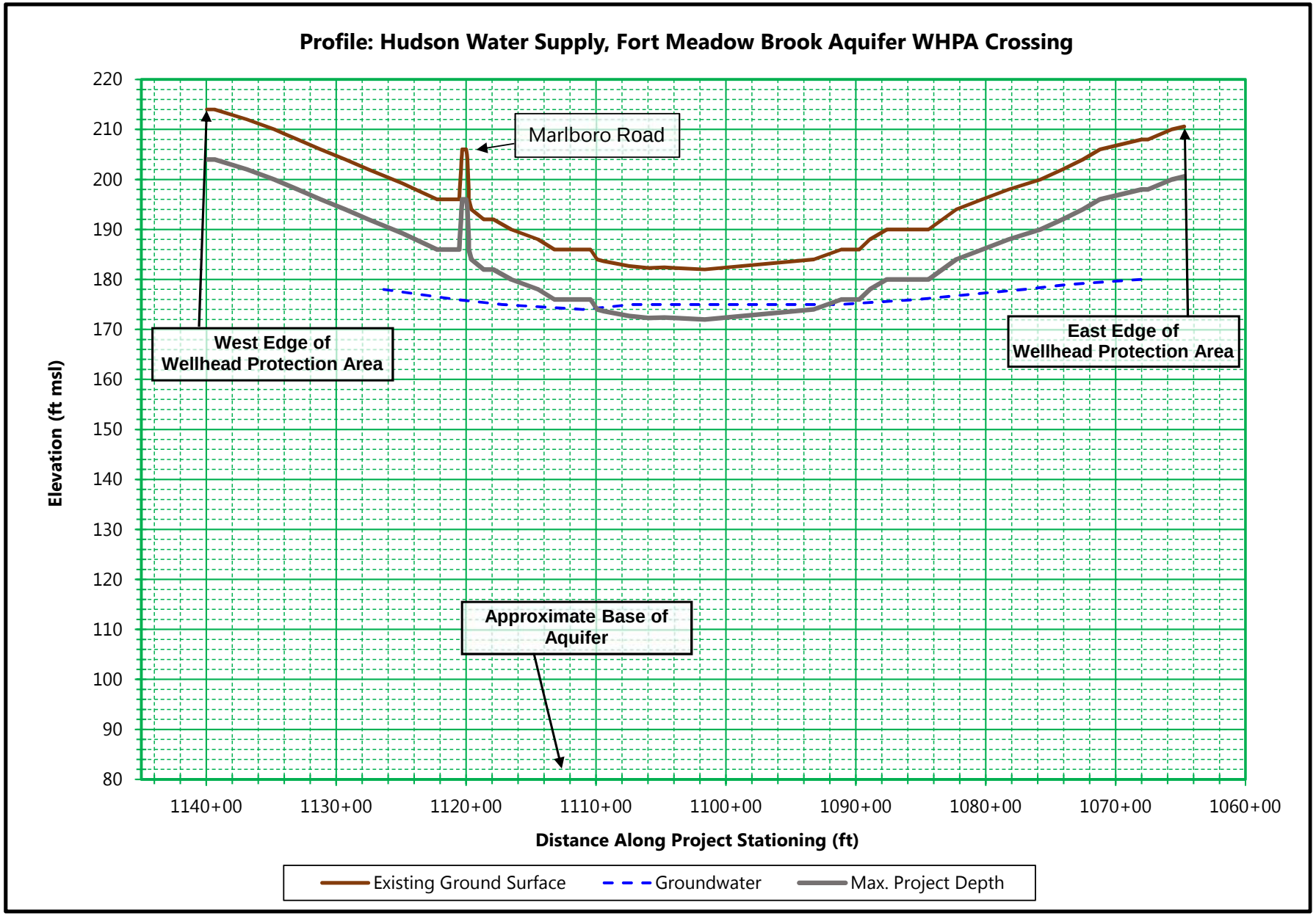
Sudbury-Hudson Transmission Reliability Project

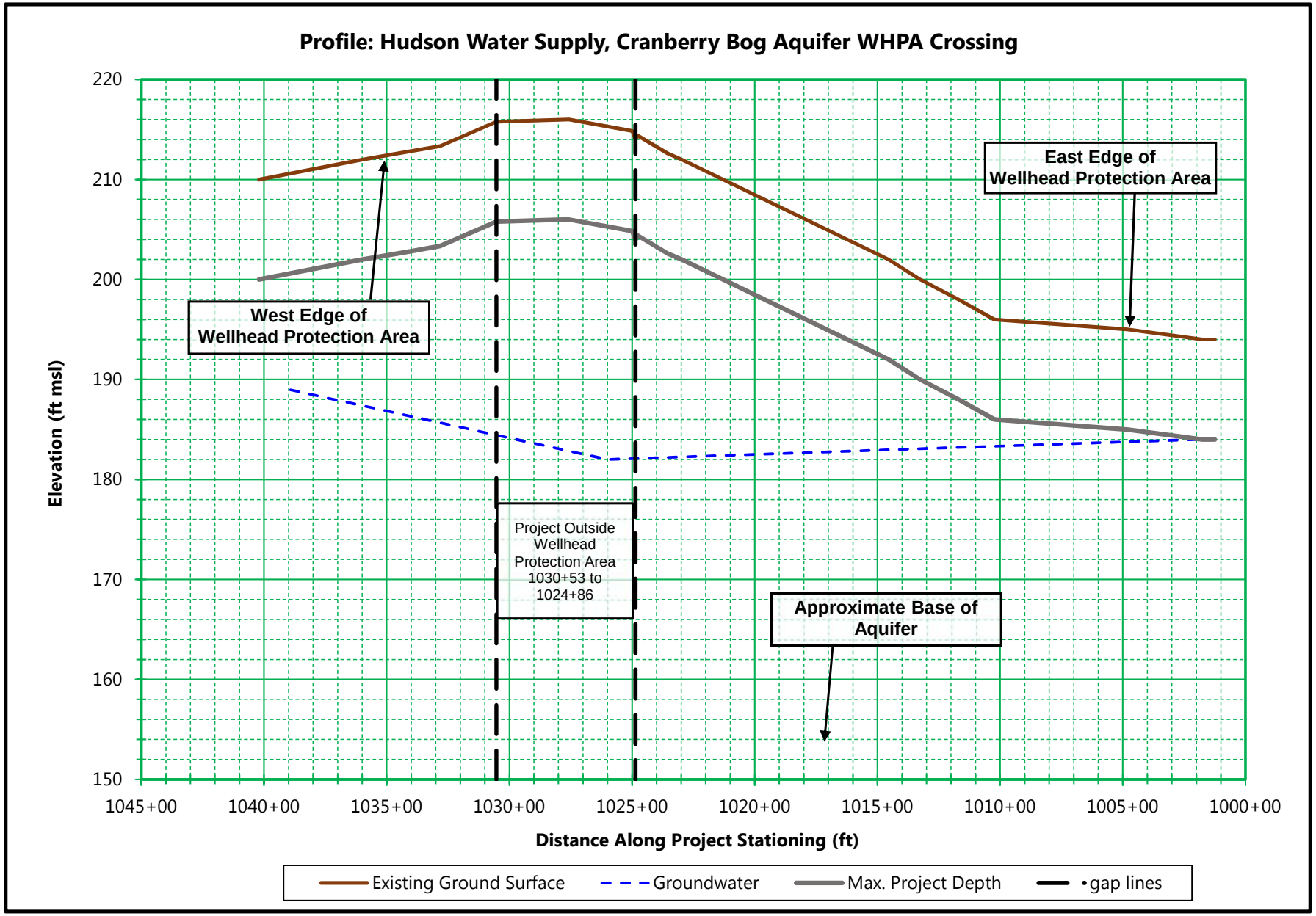
Proposed 115 kV Line Sudbury Substation to Hudson Substation

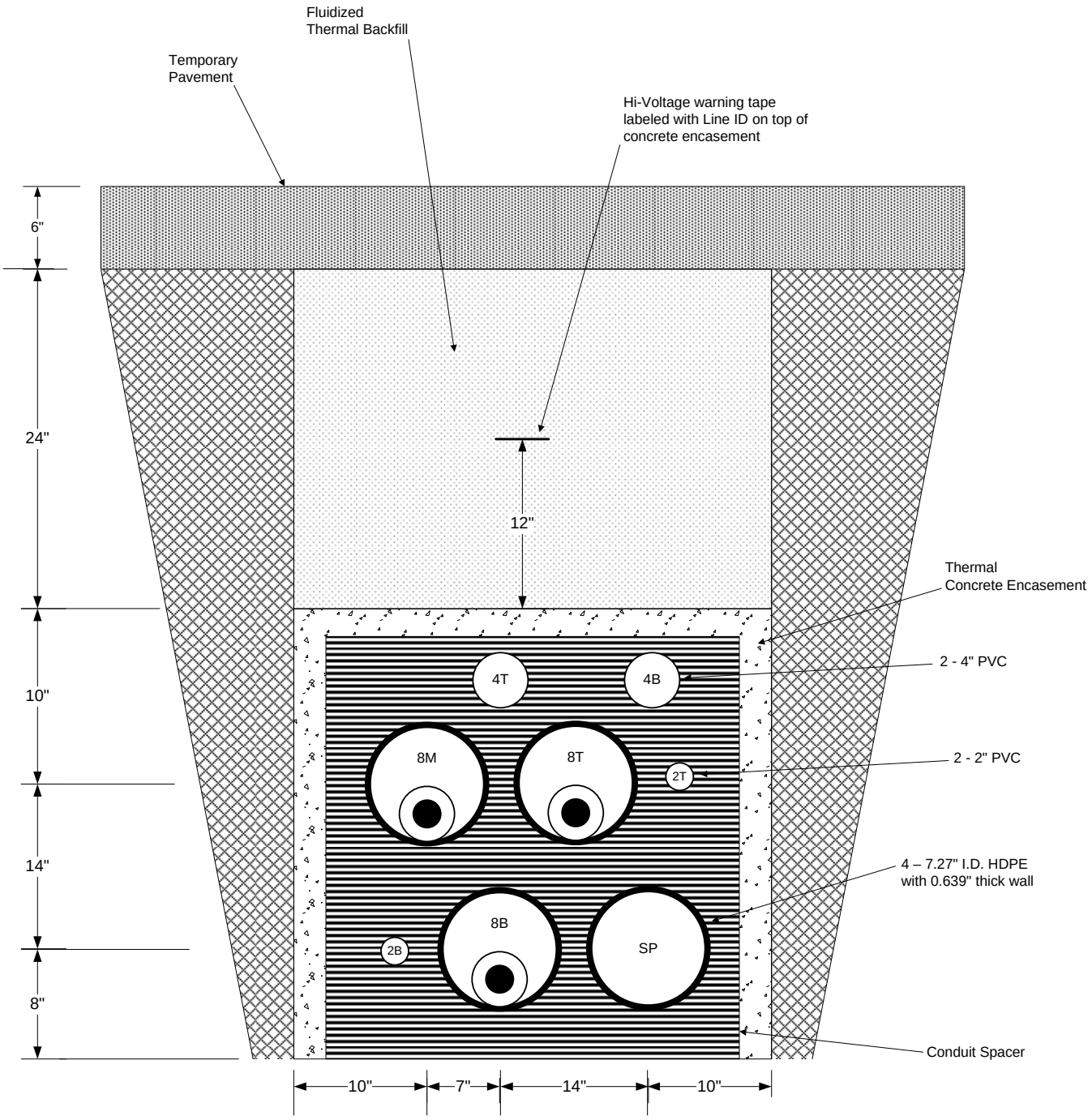
Hudson Groundwater Map

9/8/2016

vhb


Profile: Hudson Water Supply, Fort Meadow Brook Aquifer WHPA Crossing
Elevation (ft msl)
220
210
200
190
180
170
160
150
140
130
120
110
100
90
80
Marlboro Road
West Edge of Wellhead Protection Area
East Edge of Wellhead Protection Area
Approximate Base of Aquifer
1140+00
1130+00
1120+00
1110+00
1100+00
1090+00
1080+00
1070+00
1060+00
Distance Along Project Stationing (ft)
Existing Ground Surface
Groundwater
Max. Project Depth

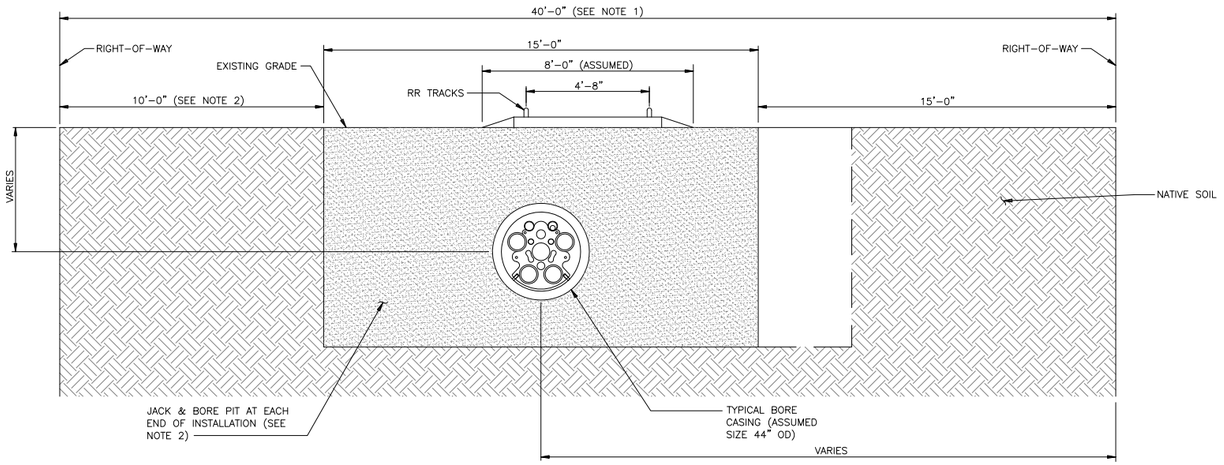

Profile: Hudson Water Supply, Cranberry Bog Aquifer WHPA Crossing
Elevation (ft msl)
220
210
200
190
180
170
160
150
1045+00
1040+00
1035+00
1030+00
1025+00
1020+00
1015+00
1010+00
1005+00
1000+00
Distance Along Project Stationing (ft)
East Edge of Wellhead Protection Area
West Edge of Wellhead Protection Area
Project Outside Wellhead Protection Area 1030+53 to 1024+86
Approximate Base of Aquifer
Existing Ground Surface
Groundwater
Max. Project Depth
gap lines



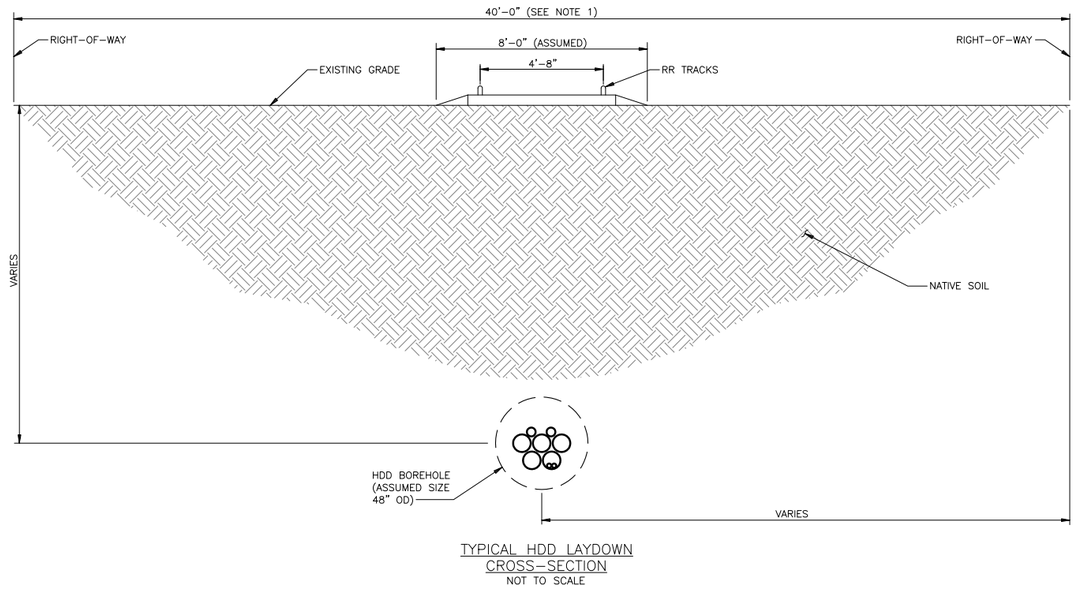
NOTE: Not to Scale

0	XX/XX/XX	Issued
Rev.	Date	Description

NSTAR ELECTRIC	115 KV / 345 KV XLPE Cross Section	Appendix XX Rev 0 Sheet X of X



TYPICAL JACK & BORE
CROSS-SECTION
NOT TO SCALE



TYPICAL HDD LAYDOWN
CROSS-SECTION
NOT TO SCALE

NOTES

1. WIDTH OF ROW IS AN AVERAGE ACROSS THE ROUTE AND CAN VARY UP TO 80' WIDE ON AVERAGE.
2. JACK & BORE PIT LOCATION WILL VARY AT EVERY BORE LOCATION. 10' SPACING TO EDGE OF ROW NEEDED FOR CONSTRUCTION PURPOSES.

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO.	DESCRIPTION	BY	DATE	APPR.
A	ISSUED FOR CLIENT REVIEW	KDM	09/30/15	ASM

REVISION

EVERSOURCE

115 kV LINE

SUDBURY TO HUDSON 115kV UNDERGROUND LINE

HUDSON, GEASONDALE, & SUDBURY

TYPICAL CROSS SECTIONS – HDD AND JACK & BORE

SCALE: unless noted	DATE	DRAWN	CH'K D.	APPR.	DRAWING NO.	REV.
NOT TO SCALE	09/18/15	SLH	KDM	ASM	015	A

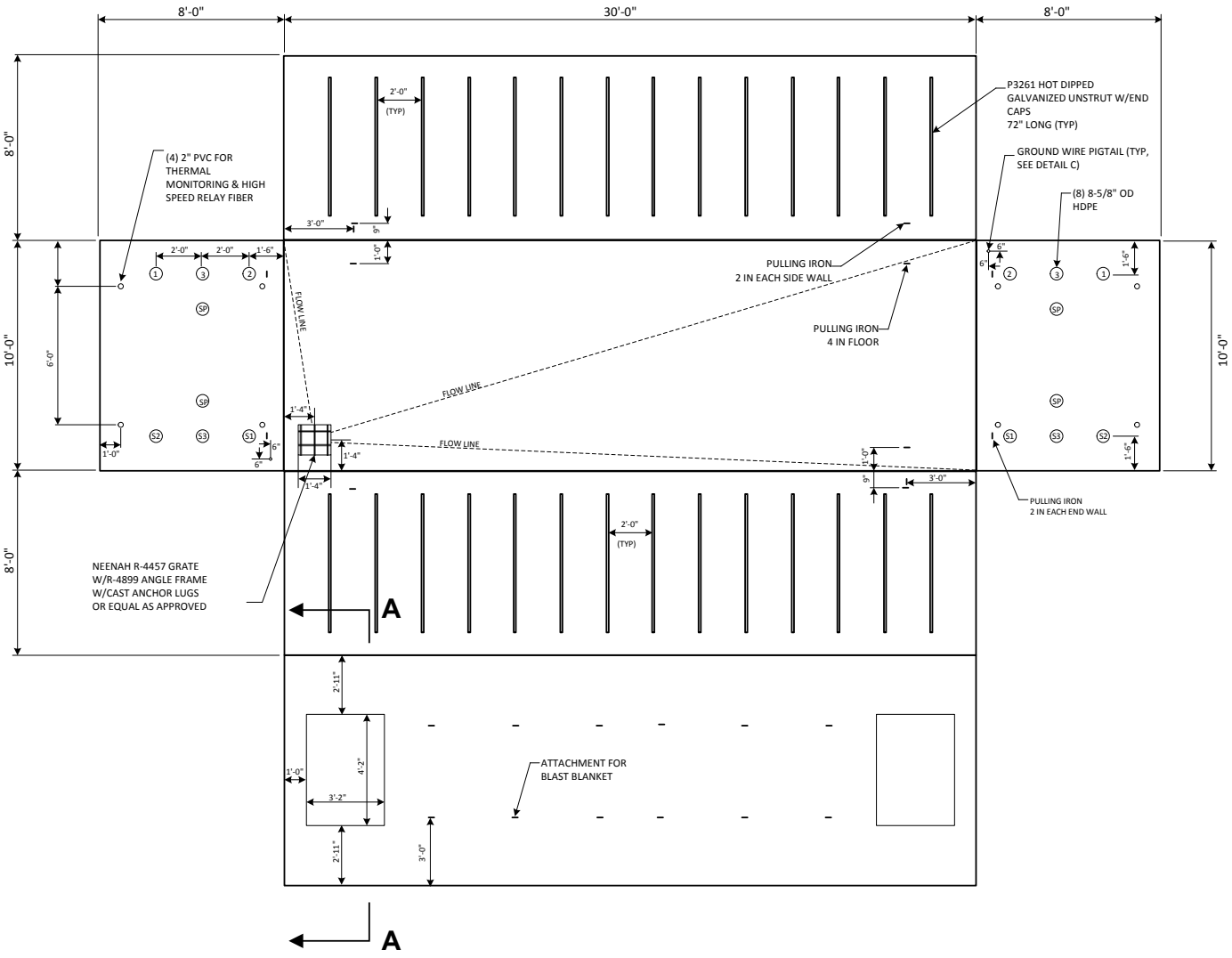


Figure 2
Typical XLPE 30' Manhole
Plan

Note – Manhole dimensions shown are inside dimensions. Manhole wall thickness is typically 12"

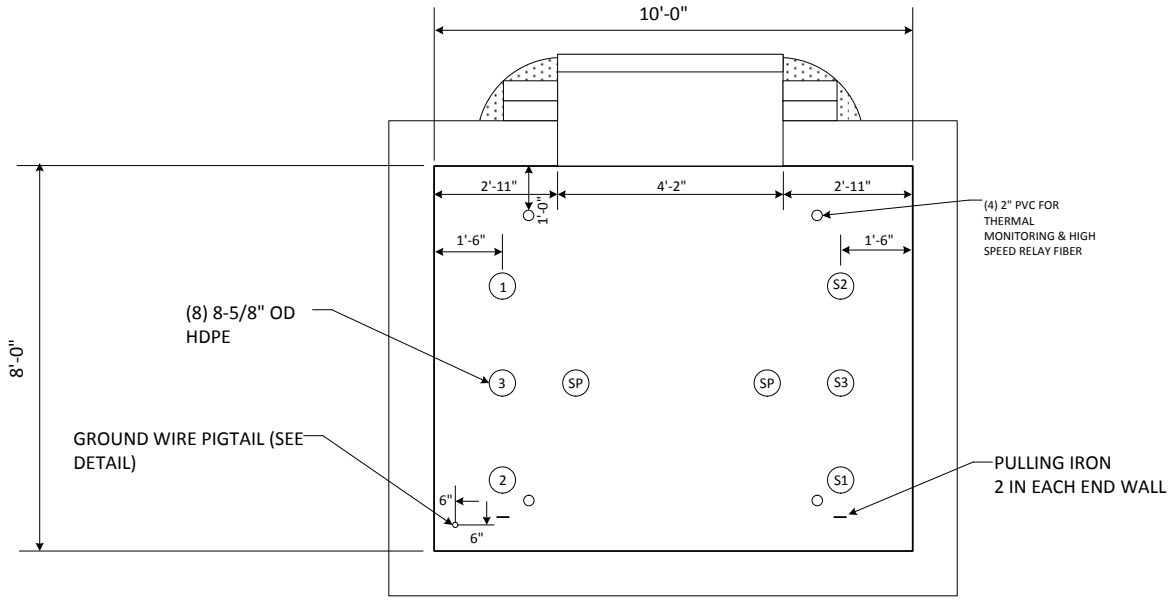


Figure 3
Section A-A
End View

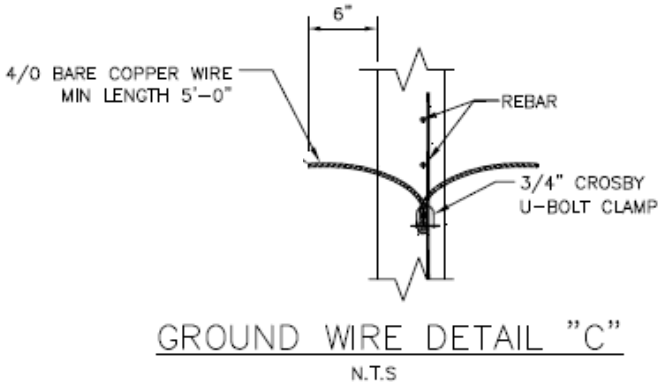
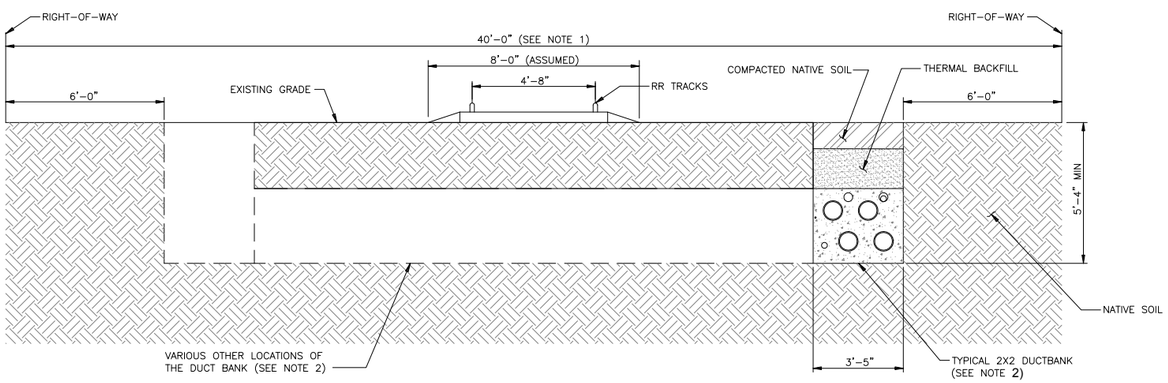
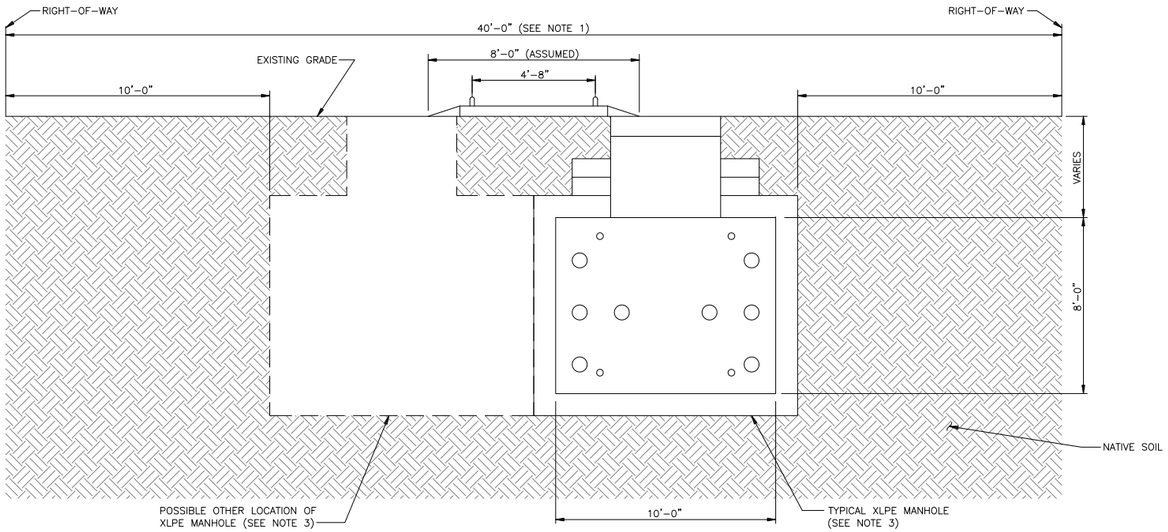


Figure 4
Detail “C”

Note – Manhole dimensions shown are inside dimensions. Manhole wall thickness is typically 12"



TYPICAL DUCTBANK LAYDOWN
CROSS-SECTION
NOT TO SCALE



TYPICAL MANHOLE LAYDOWN
CROSS-SECTION
NOT TO SCALE

NOTES

1. WIDTH OF ROW IS AN AVERAGE ACROSS THE ROUTE AND CAN VARY UP TO 80' WIDE ON AVERAGE.
2. DUCT BANK INSTALLATION LOCATION WILL VARY ACROSS THE ENTIRE ROUTE. CROSS-SECTION SHOWS EXTENTS TO WHICH IT CAN VARY. 6' SPACING TO EDGE OF ROW NEEDED FOR CONSTRUCTION PURPOSES.
3. MANHOLE LOCATION WILL VARY ACROSS THE ENTIRE ROUTE. CROSS-SECTION SHOWS THE POTENTIAL LOCATION OF EITHER SIDE OF RR TRACKS. 10' SPACING TO EDGE OF ROW NEEDED FOR CONSTRUCTION PURPOSES.

NOT TO BE USED FOR CONSTRUCTION

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NO.	DESCRIPTION	BY	DATE	APPR.
A	ISSUED FOR CLIENT REVIEW	KDM	09/30/15	ASM

REVISION

EVERSOURCE

115 kV LINE

SUDBURY TO HUDSON 115kV UNDERGROUND LINE

HUDSON, GEASONDALE, & SUDBURY

TYPICAL CROSS SECTIONS – DUCT BANK AND MANHOLE

SCALE: unless noted	DATE	DRAWN	CH'K D.	APPR.	DRAWING NO.	REV.
NOT TO SCALE	09/18/15	SLH	KDM	ASM	014	A

Appendix 5-7

Memorandum

To: Eversource Energy, Proposed 115 kV Line: Sudbury Substation to Hudson Substation Project File

Date: November 16, 2016

Project #: 12970.00

From: Meddie J. Perry, CGWP

RE: Groundwater Hydrology Assessment: Sudbury MA Public Community Water System

---

VHB has assessed whether construction of the Project or Noticed Variation is likely to affect the flow and quantity of water to the wells that supply the Sudbury, MA public community water system, based on a review of the groundwater hydrology of the aquifers associated with these municipal wells. This assessment was performed because the route is proposed to cross through portions of the designated Wellhead Protection Area for five of the nine municipal wells that supply Sudbury's water system. VHB understands that both the Project and Noticed Variation would follow the existing MBTA right-of-way along an unused former rail corridor through the Town of Sudbury and surrounding towns. In brief summary, VHB's assessment is that neither option is likely to have any appreciable impact on groundwater flow or well yield, as explained below.

I. Study Performed

VHB reviewed all files, maps, reports, and data for the Sudbury water system that were available from the Massachusetts Department of Environmental Protection ("MA DEP") via on-line and in-person file reviews. The information that VHB evaluated is listed in the References Cited section at the end of this memorandum, and includes well drilling logs, test well exploration reports, geologic studies, well pumping-test reports and data, groundwater flow modeling results, groundwater contour mapping, correspondence from the MA DEP, Source Water Assessment Program reports, and wellhead protection area delineations.

From the available documentation, VHB developed a conceptual model of the hydrology of the Raymond Road Aquifer, through which the route would cross, and of the flow to the five municipal wells in this aquifer, and created a regional groundwater elevation map that shows the elevations of the groundwater surface under water system design operating conditions, along with the wellhead protection area, wells, aquifer, and the alignment of the Project and Noticed Variation.

VHB has previously developed topographic survey plans (VHB, 2016) depicting the existing ground surface along the route. For this assessment, VHB compared the planned depth of the Project and Noticed Variation infrastructure below the ground surface to the groundwater elevations, to

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determine whether excavation and placement of subsurface components would take place within the aquifer, or above the groundwater.

In locations where the infrastructure would be below the groundwater surface, VHB analyzed the likely impact to groundwater flow and well production via a conceptual model of the regional geology and hydrology.

II. Description of Sudbury Municipal Wells and Water System

The Sudbury municipal water system is owned and operated by the Sudbury Water District, which is an independent municipality that was established in 1934 by the Massachusetts Legislature. The Sudbury Water District is not affiliated with the Town of Sudbury or the Town of Sudbury's Department of Public Works (Sudbury Water District, 2016). The Sudbury Water District's sources of water consist of a total of nine wells that are located in three separate aquifers: the Raymond Road Aquifer, the Hop Brook Aquifer, and the Great Meadow Aquifer (Sudbury Water District, 2016a).

The route would intersect the Wellhead Protection Area for the Raymond Road Aquifer, which supplies five wells: Raymond Rd Well #2A, Warrens Rd Well #4, Raymond Rd Well #6, Nobscot Rd Well #7, and Raymond Rd Well #9.

The route would not cross the District's other two aquifers and Wellhead Protection Areas. These aquifers are identified as the Hop Brook Aquifer, which supplies three wells: Pratts Mill Rd Well #3A, Pratts Mill Rd Well #8A, and Pratts Mill Rd Well #10; and the Great Meadow Aquifer, which supplies the ninth well known as North Rd Well #5.

All of the Sudbury Water District's potable water is produced from gravel wells. The District treats the water from the wells to remove naturally-occurring concentrations of iron and manganese (at Wells #2A, #6, #7, #8, and #9), to neutralize the pH and control corrosion, to remove manmade Volatile Organic Compound contaminants (at Wells #2A and #5 only), and to disinfect potential bacteria (Sudbury Water District, 2010, 2016, 2016a). Table 1 below summarizes the key details of the five municipal wells for which the route would pass through the Wellhead Protection Area.

Table 1: Summary of Sudbury Municipal Wells Within the Raymond Road Aquifer that the Route Would Intersect					
Well:	Raymond Rd Well #2A	Warrens Rd Well #4	Raymond R Well #6	Nobscot Rd Well #7	Raymond Rd Well #9
Year Installed:	1998	1962	1973	circa 1973	circa 1986
Total Depth, Ft.:	70	62	85	90 ±	80 ±
Yield, gal/min:	680	280	500	485	695
Well Type:	Gravel-packed	Gravel-packed	Gravel-packed	Gravel-packed	Gravel-packed
Aquifer:	Zone II # 147: Semi-confined stratified sand-and-gravel aquifer				

These five wells share a common groundwater aquifer known as the Raymond Road Aquifer, and occasionally referred to as the Landham Brook Aquifer. In the MA DEP Source Water Assessment Program, the Wellhead Protection Area for the Raymond Road Aquifer is listed as Zone II # 147. Refer to the Sudbury Groundwater Map on page 1 of the Attachment for the locations of the wells, aquifers, Wellhead Protection Areas, and Eversource Project and Noticed Variation.

The Raymond Road Aquifer that these five wells obtain water from is a semi-confined, stratified sand-and-gravel aquifer of glacial origin that extends over a two square-mile area. The Wellhead Protection Area covers approximately four square miles. The aquifer fills the lower-elevation terrain and is bounded on the west by the high ground of Nobscot Hill where the aquifer formation ends where it meets the glacial till and bedrock. The aquifer is bounded on the south by high terrain, on the southeast and east by the Sudbury River, on the northeast by the high terrain of Green Hill, and on the north by Hop Brook. The glacial deposits of sand and gravel originated from outwash-plain and ice-contact deposits during glacial melting approximately 10,000 years ago. These deposits are deep, ranging to approximately 100 feet below ground surface, and are most likely underlain by poorly-sorted, dense, glacial till. The aquifer materials are highly transmissive to the flow of water, with transmissivities of approximately 4,700 ft^2/day, equivalent to 35,000 gallons per day per foot (MA DEP, 1990). Permeability is typically 58 ft/day in the productive aquifer materials (H_2O Engineering, 1992).

The Raymond Road Aquifer is considered to be semi-confined, because portions of the aquifer are confined by layers of impermeable geologic materials such as clay, whereas in other locations no impermeable overburden is present, and the sand and gravel aquifer materials extend from the ground surface to the groundwater aquifer (MA DEP, 1997). For example, at Well #2A, the well drilling logs indicate unconfined conditions, with sand and gravel from the ground surface down to at least 70 feet deep, the water level approximately 22 feet deep, and the well intake screen set between 55 and 70 feet deep. On the other hand, at Well #6 the well drilling log indicates confined conditions, with clay reported from 7 to 70 feet below ground surface, the water level measured at approximately 1 foot below ground surface, and the well intake screen set between 75 and 85 feet deep (RE Chapman, 1975). Similar confined conditions were noted at Well #9 where silty clay and gravelly clay were reported from 4 to 28 feet below ground surface, with the water level measured at approximately 7 feet below ground surface and the well intake screen set between 70 and 80 feet deep (H_2O Engineering, 1992). The discontinuous extent of the clay layers above the aquifer comprises semi-confined conditions. Where the confining layer is present, minimal recharge to groundwater occurs, and the majority of the recharge occurs where the aquifer is not confined.

The Raymond Road Aquifer is recharged with water from a combination of precipitation onto the overlying land surface, and to a degree from water infiltrating from Landham Brook, a tributary of the Sudbury River which passes near the wells as it flows from southwest to northeast. The natural groundwater flow direction is to the east, but the pumping of these wells induces localized radial flow towards the wells from all directions, which captures water from the east within the boundaries of the Wellhead Protection Area (MA DEP, 1990; H_2O Engineering, 1992).

During Drought Warnings that the Massachusetts Commonwealth Office of Energy and Environmental Affairs declared for Central and Northeastern Massachusetts in 2016, the District implemented emergency water use restrictions to protect the water supply. The District banned outdoor water uses such as lawn watering, swimming pool filling, and games or toys using continuous streams of water, while other outdoor uses such as garden watering were restricted, beginning August 11, 2016. However, no actual water outages were reported, as the measures appear to have been proactive. The restrictions were lifted as of November 1, 2016 (Sudbury, 2016).

III. Description of the Eversource Project and Noticed Variation

The Sudbury-Hudson Transmission Reliability Project would consist of electric transmission lines that would follow the unused MBTA corridor through the Town of Sudbury and surrounding towns. VHB understands that both the Project and the Noticed Variation would follow the existing MBTA right-of-way.

For the Project, concrete duct-banks would contain the electric transmission cables. The duct-banks are designed to be approximately 2.7 feet tall and 3.4 feet wide, and would be buried with their base approximately 5.3 feet below grade. Trenchless crossings would be installed at stream crossings and other sensitive locations, and would consist of a direct-burial cable without any concrete encasement. These crossings would be installed with horizontal directional drilling ("HDD") or jack-and-bore techniques, at depths to be determined on a site-specific basis. The trenchless cables would have an outside diameter of 44 to 48 inches. Concrete manhole structures would be installed along the route at intervals to-be-determined, and would be 8 to 10 feet deep and approximately 10 feet wide.

For the Noticed Variation, overhead transmission wires would be supported by steel poles set upon caissons consisting of reinforced concrete. The caisson spacing interval is yet to be determined, but would generally be on the order of hundreds of feet. Caissons would be 7 feet in diameter and between 22 and 28 feet deep.

Schematic drawings of the subsurface duct-banks, trenchless crossings, manhole structures, and caissons are provided on pages 3 to 7 of the Attachment.

IV. Assessment Results

For the Project, the analysis of the elevations of subsurface features relative to the groundwater elevations has determined that the majority of the Project within the Sudbury Wellhead Protection Area would be placed above the elevation of the groundwater surface, so that it would not be possible to have any effect on groundwater flow rates or directions.

In a portion of the Project between station 830+00 near Union Avenue and Hop Brook at the eastern end of the Wellhead Protection Area, manholes, if placed in this segment, would extend no more than 5 feet into the groundwater table (duct banks placed 5.3 feet below existing grade would not reach the water table except within the eastern-most 1,000 feet of this segment, where they would enter the water table by a few inches). Table 2 below summarizes the analysis of groundwater levels relative to the subsurface Project components.

Table 2:
Summary of Depths to Groundwater in Wellhead Protection Area for Raymond Road Aquifer (Zone II #147 in Sudbury, MA

Sheet	Station	Location	Grade Elevation [1]	Min. Project Elevation [2]	Groundwater Elevation [3]	Max. Depth of Project Below Groundwater Level (Ft)
14	882+00	West WHPA boundary at Dudley Bk.	158	148	146	0
14	875+33	West WHPA boundary at Dudley Bk.	166	156	145	0
13	864+46	Horse Pond Rd	166	156	147	0
12	856+77	Near Bridle Path	162	152	148	0
12	851+02	Near Bridle Path	162	152	147	0
11	841+51	Near Trailside Circle	156	146	145	0
10	835+64	Near Raytheon	150	140	140	0
10	829+94	Near Raytheon	145	135	135	0
9	821+25	Near Union Ave	139	129	130	1
9	812+87	Near Union Ave	136	126	129	3
8	805+97	Near Boston Post Rd	134	124	129	5
7	796+04	East WHPA boundary near Hop Brook	134	124	129	5

Notes:
[1] Grade Elevations are from 2-Ft existing topographic contours as shown on "Eversource Transmission Line | Sudbury, Stow and Hudson, Massachusetts | Candidate Route Design Option 2" Prepared by VHB, June 27, 2016

[2] Project Elevation is estimated based on a maximum burial depth of 10 ft as indicated on "Typical Cross-Sections: Duct Bank and Manhole" from Eversource, 9/18/15, rev. 9/30/15. (Note typical burial depth for duct banks is 5.33 ft and the manholes with the greater burial depths would be spaced at intervals only).

[3] Groundwater Elevation determined by VHB from a compilation of various sources including "Figure 4: Groundwater Contours at End of Pumping Test, Prolonged Pumping Test at Pumping Station Site #10" by H_2O Engineering, 1990; and "Zone II Condition Heads at Pumping Station Well #9 Site" by H_2O Engineering, 1991, as summarized on "Sudbury Groundwater Map" 11/14/2016 by VHB.

Relative to the roughly 100-foot depth of the aquifer, the manhole placement would be small and superficial to the flow of groundwater, as shown in the cross-section diagram on page 2 of the Attachment. Groundwater would be able to continue flowing as it does presently, beneath the structures. Due to the high permeability and transmissivity of the sand and gravel materials in the

aquifer, groundwater would be able to flow readily around and under the structures. Potentially, minor amounts of groundwater mounding could occur on the upgradient side of the structures which would develop the hydraulic gradient sufficient to counteract any minor impediment to flow that might be caused by the manhole structure.

For the Noticed Variation, the caissons would extend below the groundwater level, however due to the small size of the caissons relative to the distance between each, groundwater would simply flow under and around the caissons without any impact.

V. Conclusions and Recommendations

Neither the Project or Noticed Variation would have any appreciable effect on groundwater flow rates or directions, nor would either option impact the yield of the Sudbury municipal wells.

With the Project, for the majority of the length of the Project within Sudbury and the Wellhead Protection Area for the Raymond Road Aquifer, subsurface Project features would be placed above the elevation of the groundwater, and thus could not affect it. In a portion of the Project between station 830+00 near Union Avenue and Hop Brook at the eastern end of the Wellhead Protection Area, some project components would slightly extend into the water table, but would not alter groundwater flow rates or directions because construction would enter only a small fraction of the aquifer, which is highly permeable, allowing groundwater to flow under and around the structures in the same rates and directions and it does presently. For the Noticed Variation, due to the small size of the caissons relative to the spacing, groundwater would simply flow under and around them without any impact.

Because portions of the overburden, where the clay layers are not present, are highly permeable sand and gravel, the Raymond Road aquifer is sensitive to surface spills and sources of contamination. Spilled liquids could rapidly seep down to the water table and enter the groundwater. Therefore VHB recommends development and implementation of a Spill Prevention and Response Plan to address project construction equipment, fuels, lubricants, and any other liquid or hazardous materials that may be on site during construction. Best Management Practices should be established for spill prevention and cleanup. If over 1,320 gallons of oil are to be stored above-ground, a Spill Prevention, Control, and Countermeasure Plan ("SPCC Plan") stamped by a professional engineer would be required in accordance with United States Environmental Protection Agency (“EPA”) regulation Title 40 CFR 112, Oil Pollution Prevention.

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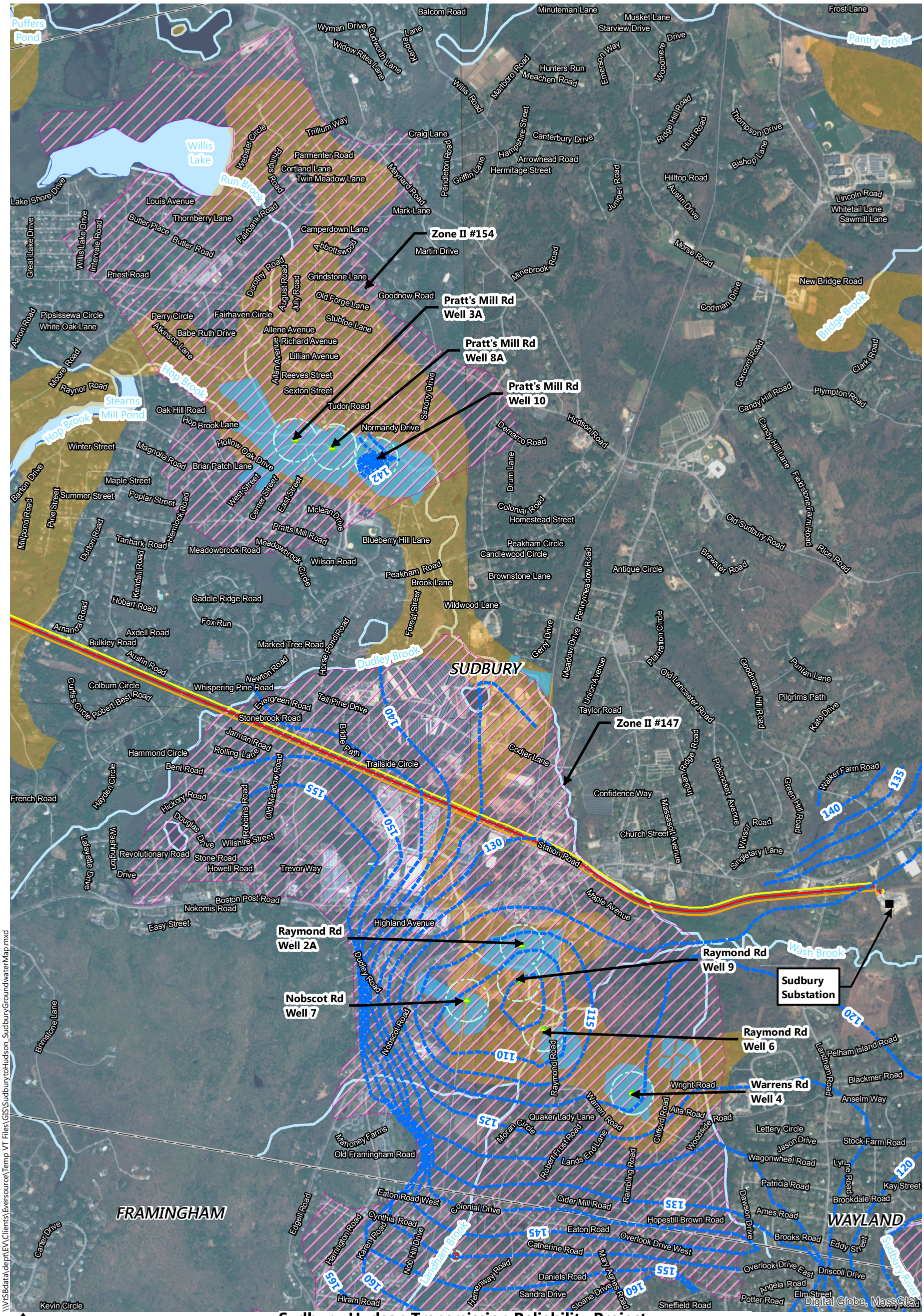
VHB, 2016. Eversource Transmission Line, Sudbury, Stow and Hudson, Massachusetts | Candidate Route | Design Option 2. Progress Plans, June 27, 2016.

Appendix 5-7

ATTACHMENT

Appendix 5-7

vhb November 16, 2016



Sudbury-Hudson Transmission Reliability Project
Proposed 115 kV Line Sudbury Substation to Hudson Substation | Sudbury, MA

- Groundwater Contours
- Aquifer (MassGIS)
- Open Space Protected for Water Supply (MassGIS)

Public Water Supplies (MassGIS)

- Community Groundwater Source
- Non-Community Groundwater Source

- Massachusetts Municipalities (MassGIS)
- Waterbodies (MassGIS)
- Streams (MassGIS)

MADEP Wellhead Protection Areas (MassGIS)

- Zone I
- Zone II

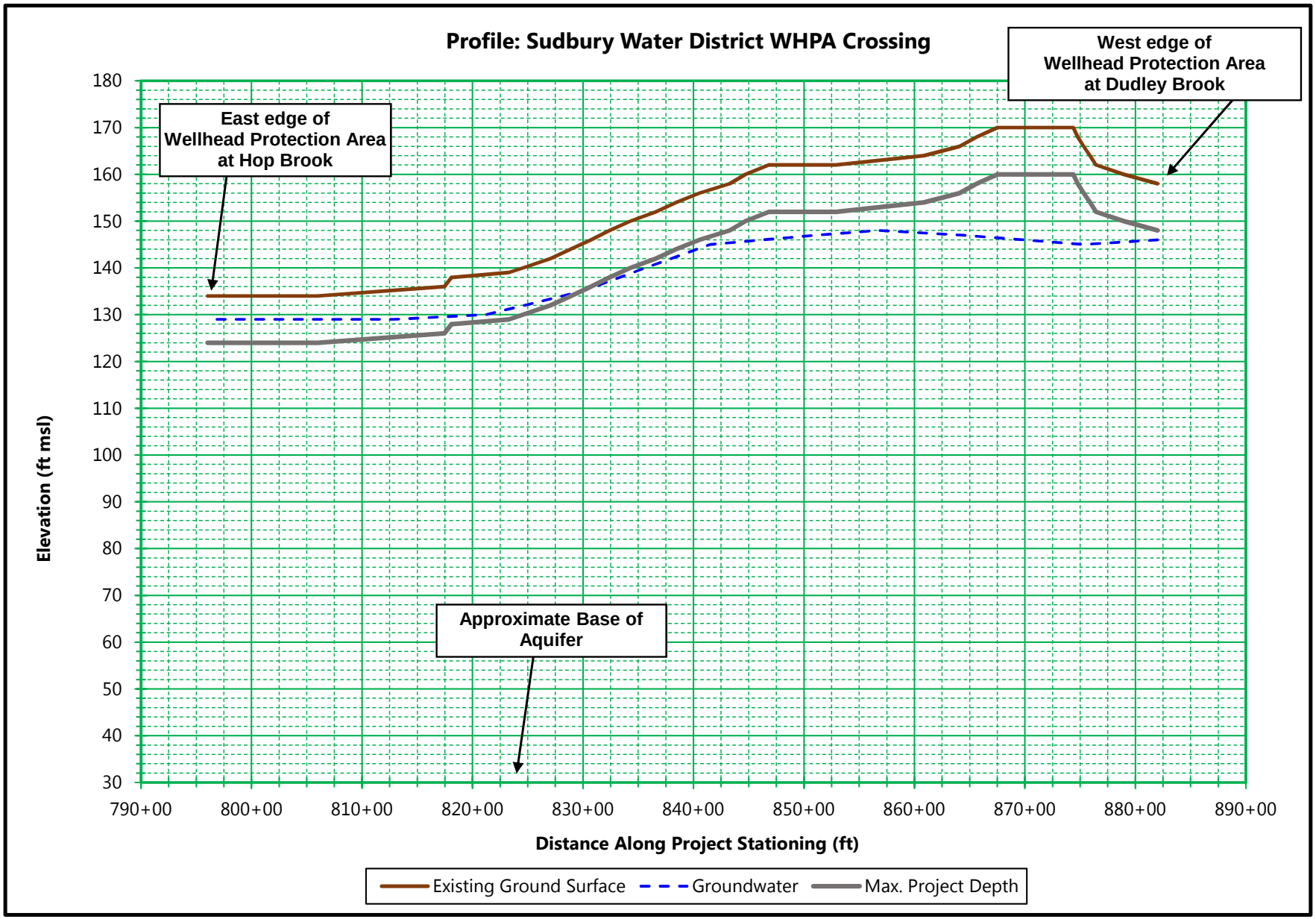
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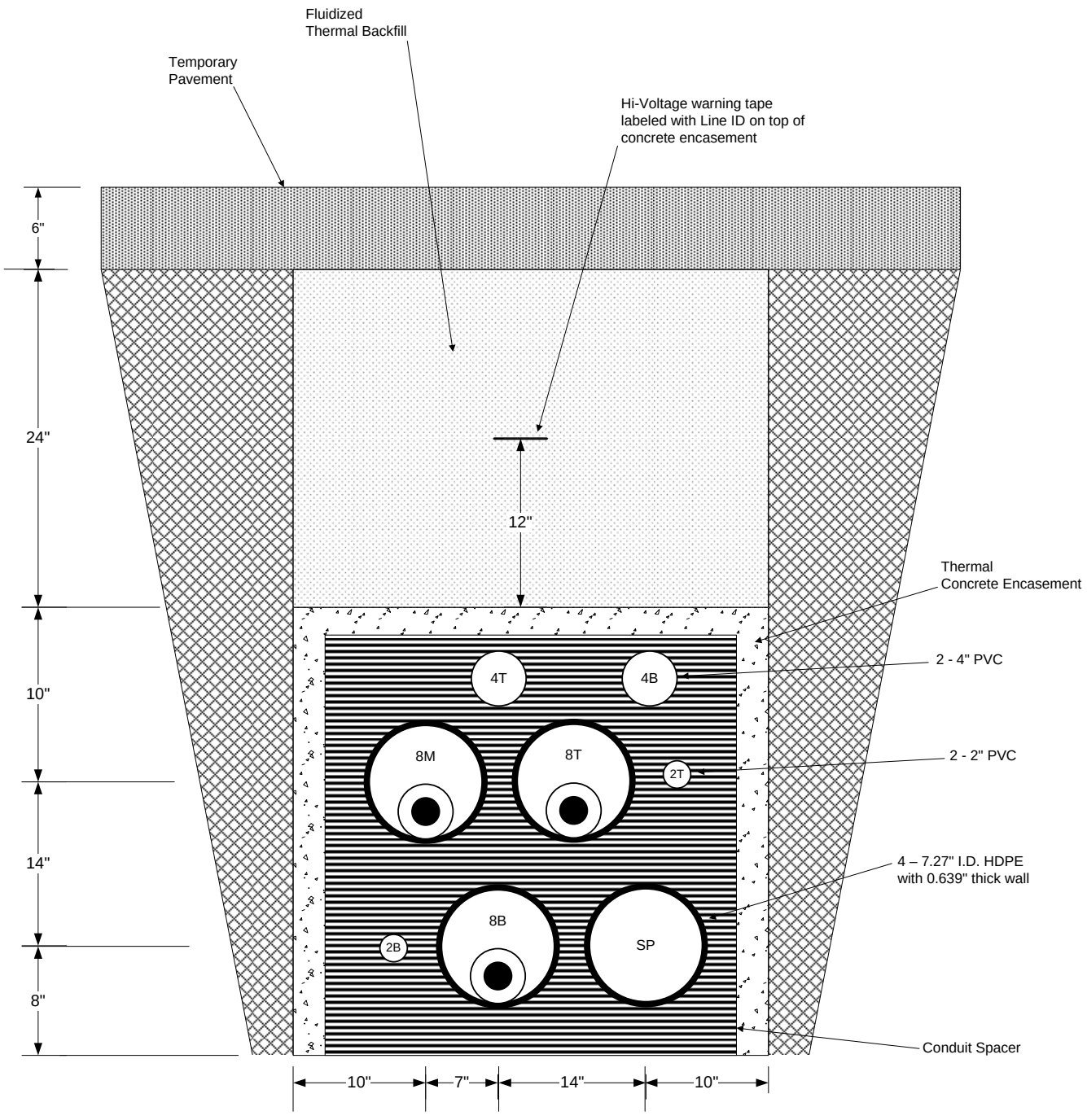
- Option 1A/1B
- Option 2A/2B
- Option 3A/3B

Sudbury Groundwater Map

Source:
Orthoimagery by MassGIS (2015)
H20 - Groundwater contours digitized by VHB from H20 Engineering (1990/1992)
MassGIS - Massachusetts Office of Geographic Information
VHB (Digitized 2016)

\\VtSBdata\dept\EV\Clients\Eversource\Temp VT Files\GIS\SudburytoHudson_SudburyGroundwaterMap.mxd

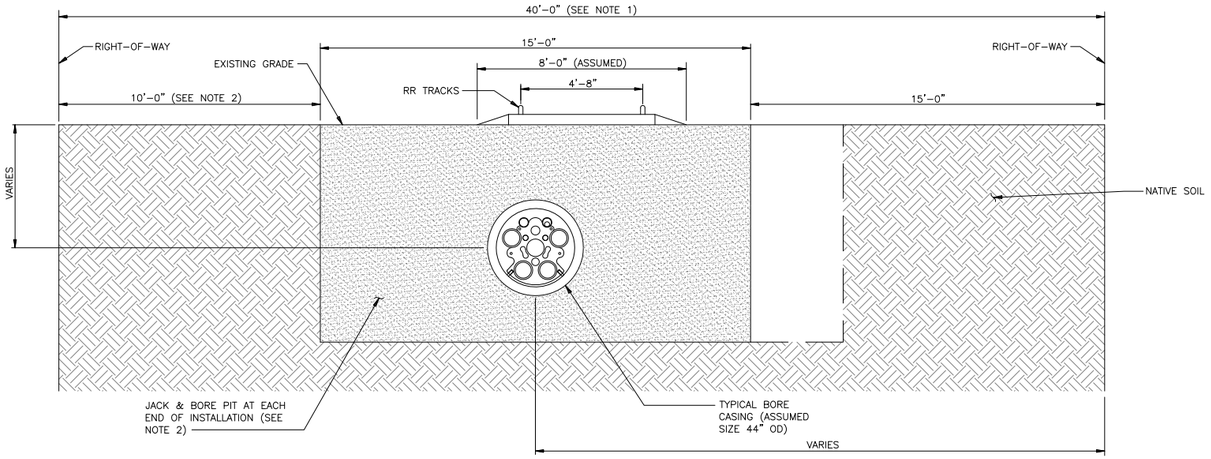

Profile: Sudbury Water District WHPA Crossing
West edge of Wellhead Protection Area at Dudley Brook
East edge of Wellhead Protection Area at Hop Brook
Approximate Base of Aquifer
Elevation (ft msl)
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
790+00
800+00
810+00
820+00
830+00
840+00
850+00
860+00
870+00
880+00
890+00
Distance Along Project Stationing (ft)
Existing Ground Surface
Groundwater
Max. Project Depth



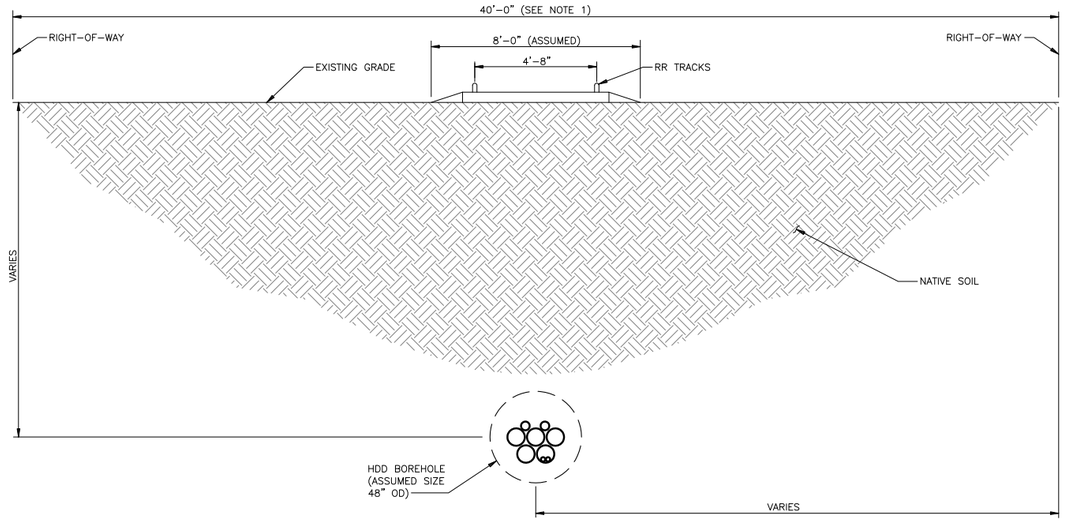
NOTE: Not to Scale

0	XX/XX/XX	Issued
Rev.	Date	Description

NSTAR ELECTRIC	115 KV / 345 KV XLPE Cross Section	Appendix XX Rev 0 Sheet X of X



TYPICAL JACK & BORE CROSS-SECTION
NOT TO SCALE



TYPICAL HDD LAYDOWN CROSS-SECTION
NOT TO SCALE

NOTES

1. WIDTH OF ROW IS AN AVERAGE ACROSS THE ROUTE AND CAN VARY UP TO 80' WIDE ON AVERAGE.
2. JACK & BORE PIT LOCATION WILL VARY AT EVERY BORE LOCATION. 10' SPACING TO EDGE OF ROW NEEDED FOR CONSTRUCTION PURPOSES.

NO.	DESCRIPTION	BY	DATE	APPR.
A	ISSUED FOR CLIENT REVIEW	KDM	09/30/15	ASM

REVISION

EVERSOURCE

115 kV LINE

SUDBURY TO HUDSON 115kV UNDERGROUND LINE

HUDSON, GEASONDALE, & SUDBURY

TYPICAL CROSS SECTIONS – HDD AND JACK & BORE

SCALE: unless noted	DATE	DRAWN	CH'K D.	APPR.	DRAWING NO.	REV.
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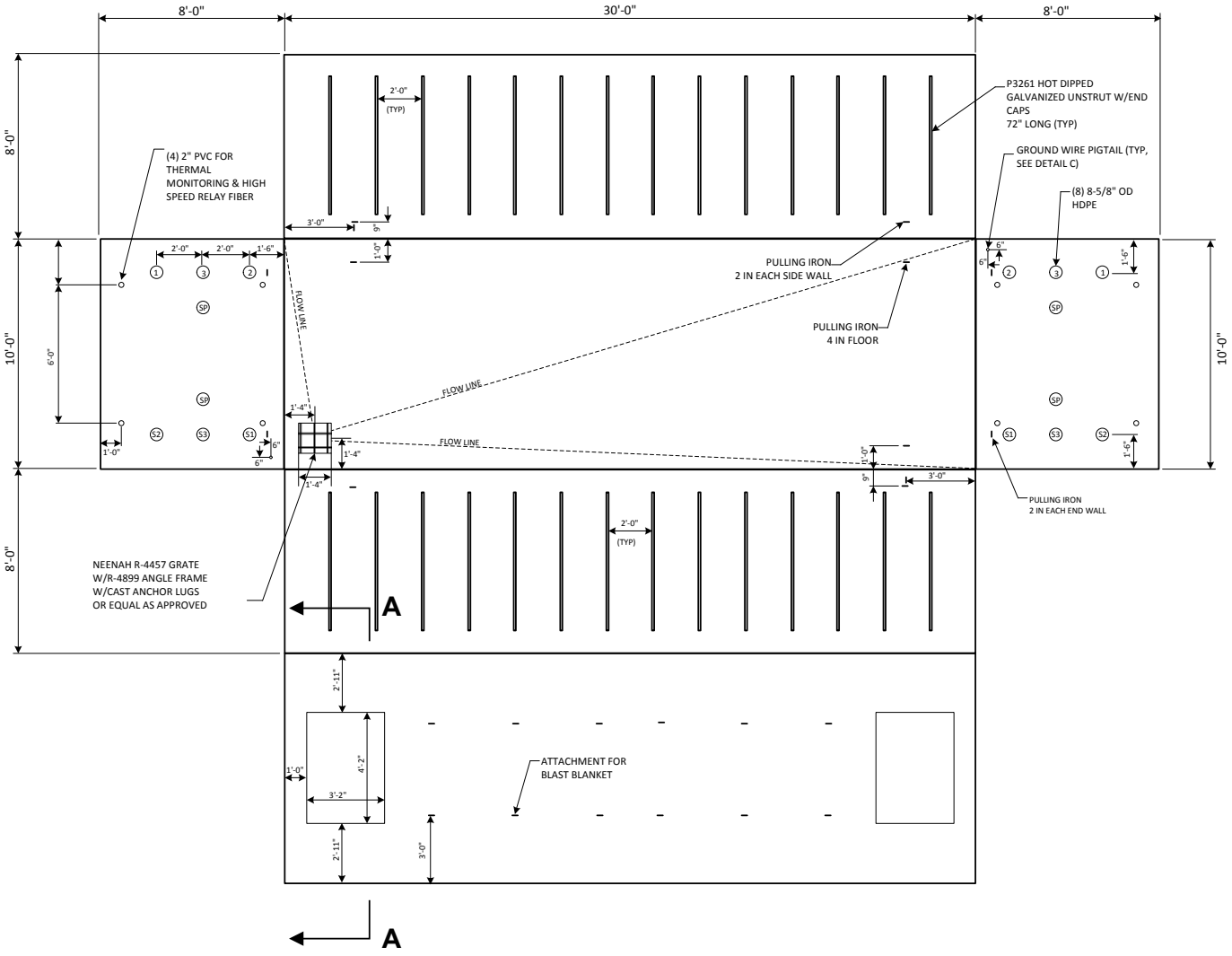


Figure 2
Typical XLPE 30' Manhole
Plan

Note – Manhole dimensions shown are inside dimensions. Manhole wall thickness is typically 12"

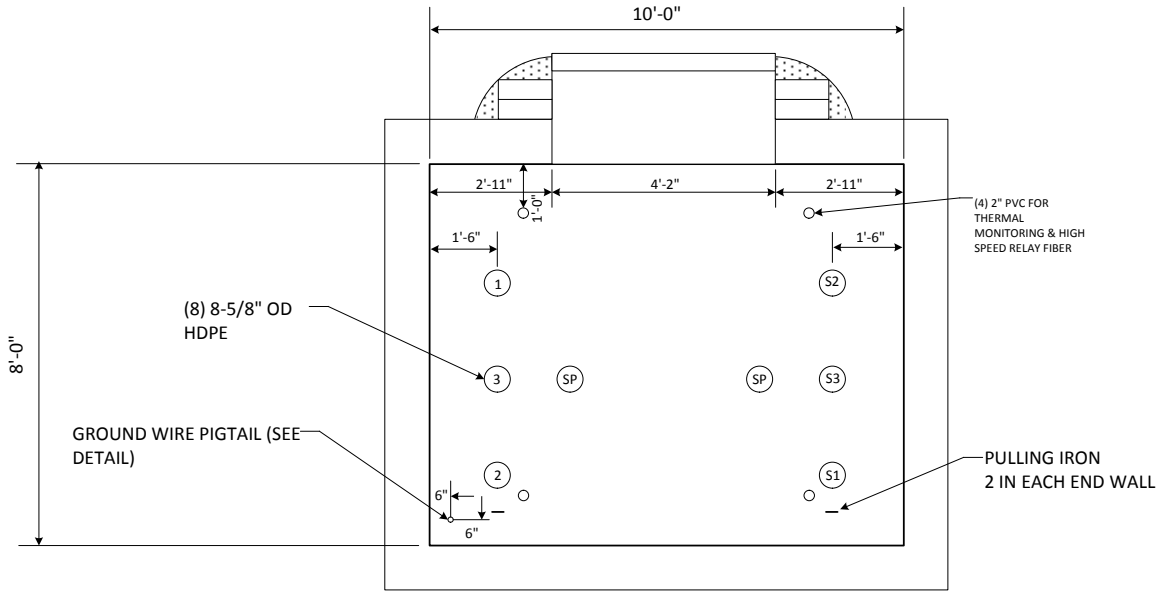


Figure 3
Section A-A
End View

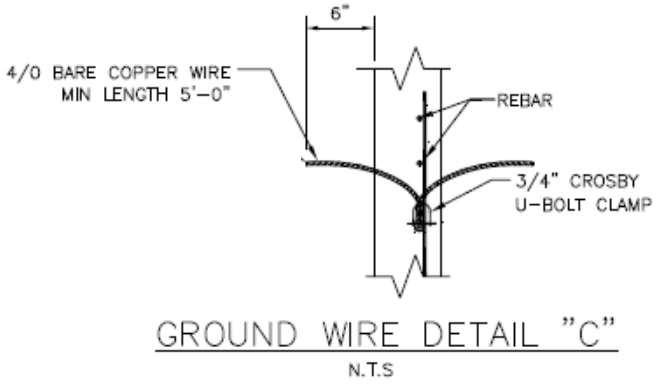
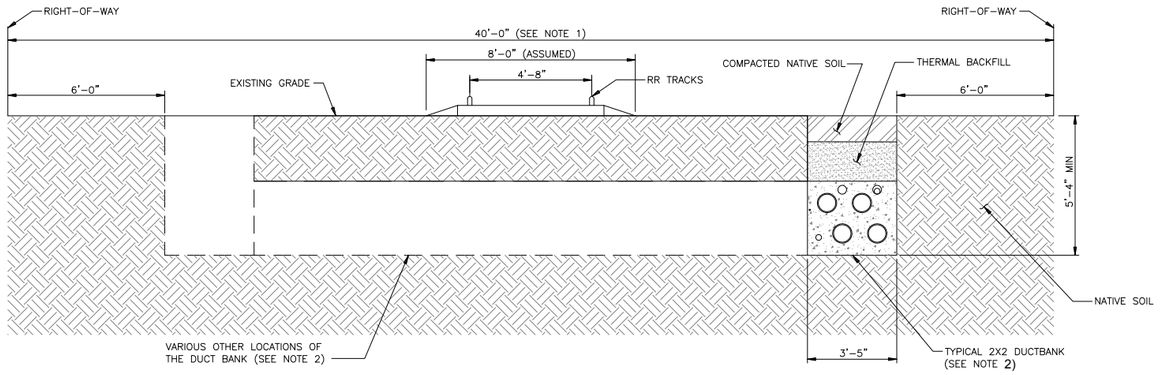
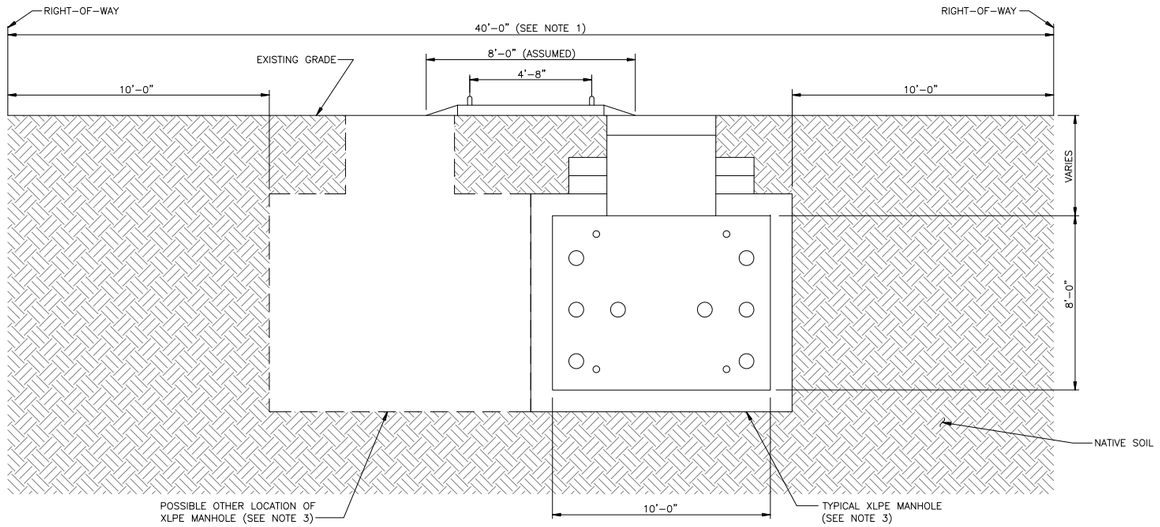


Figure 4
Detail “C”

Note – Manhole dimensions shown are inside dimensions. Manhole wall thickness is typically 12"



TYPICAL DUCTBANK LAYDOWN
CROSS-SECTION
NOT TO SCALE



TYPICAL MANHOLE LAYDOWN
CROSS-SECTION
NOT TO SCALE

NOTES

1. WIDTH OF ROW IS AN AVERAGE ACROSS THE ROUTE AND CAN VARY UP TO 80' WIDE ON AVERAGE.
2. DUCT BANK INSTALLATION LOCATION WILL VARY ACROSS THE ENTIRE ROUTE. CROSS-SECTION SHOWS EXTENTS TO WHICH IT CAN VARY. 6' SPACING TO EDGE OF ROW NEEDED FOR CONSTRUCTION PURPOSES.
3. MANHOLE LOCATION WILL VARY ACROSS THE ENTIRE ROUTE. CROSS-SECTION SHOWS THE POTENTIAL LOCATION OF EITHER SIDE OF RR TRACKS. 10' SPACING TO EDGE OF ROW NEEDED FOR CONSTRUCTION PURPOSES.

NO.	DESCRIPTION	BY	DATE	APPR.
A	ISSUED FOR CLIENT REVIEW	KDM	09/30/15	ASM

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EVERSOURCE

115 kV LINE

SUDBURY TO HUDSON 115kV UNDERGROUND LINE

HUDSON, GEASONDALE, & SUDBURY

TYPICAL CROSS SECTIONS – DUCT BANK AND MANHOLE

SCALE: unless noted	DATE	DRAWN	CH'K D.	APPR.	DRAWING NO.	REV.
NOT TO SCALE	09/18/15	SLH	KDM	ASM	014	A

Visual Impact Assessment

Sudbury-Hudson Transmission Reliability Project

Prepared for:

EVERSOURCE

Eversource Energy
247 Station Drive
Westwood, MA 02090

Prepared by:

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March 2017

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1.0 INTRODUCTION

NSTAR Electric Company d/b/a Eversource Energy ("Eversource") engaged TRC to address the potential visual impacts of the Sudbury-Hudson Transmission Reliability Project (the "Project"). This report examines the visual, aesthetic and recreational resources within a visual study area extending out to 0.5 miles from the Project centerline and the potential impact on these resources. In order to support the assessment, an inventory of visual resources in the study area is provided along with computerized analyses that include a viewshed analysis, artist renderings, and photosimulations.

Eversource is proposing to construct, operate, and maintain an approximately 9-mile 115-kilovolt ("kV") underground transmission line along an unused railroad right-of-way ("ROW") owned by the Massachusetts Bay Transient Authority ("MBTA"). The New Line, which passes through the municipalities of Sudbury, Hudson, Stowe and Marlborough, will connect Eversource's Sudbury Substation to Hudson Light and Power Department's ("HLPD") substation and, together with the substation modifications at Sudbury Substation, comprise the Project.

For the MBTA ROW portion of the route, Eversource considered and evaluated an overhead transmission line design, referred to as the Noticed Variation. In addition, Eversource analyzed a Noticed Alternative Route, which is approximately 10.3 miles long and is a geographically distinct route that travels underground within public roadways for its entire length.

Due to the expected visual impacts from the proposed aboveground transmission option, this visual assessment was conducted with a focus on the overhead portion of the Noticed Variation.

2.0 ROUTE DESCRIPTIONS

The Project entails the construction of a new 115-kV underground transmission line between the existing Eversource Sudbury Substation on Boston Post Road in Sudbury and the existing HLPD Substation on Forest Avenue in Hudson (Figure 1).

2.1 PREFERRED PROJECT

The Preferred Project begins at the Sudbury Substation, located off Route 20, and travels in a northwesterly direction within the existing MBTA ROW for approximately 7.64 miles. Of these 7.64 miles, 4.29 miles are in Sudbury, 0.07 miles are in Stow, 0.01 miles are in Marlborough, and 3.27 miles are in Hudson. At the intersection of the MBTA ROW and Wilkins Street in Hudson, the route leaves the MBTA ROW and proceeds in a southwesterly direction within Wilkins Street (Route 62) and Forest Avenue for a distance of approximately 1.37 miles to the Intel access road before terminating at the Hudson Substation.

The Preferred Project consists of an entirely underground transmission line from the Sudbury Substation along the MBTA ROW, proceeding into Wilkins Street and terminating at the Hudson Substation. Although there are no aboveground structures, approximately 30 feet of tree clearing will be required to maintain the line.

2.2 NOTICED VARIATION

The Noticed Variation consists of an entirely overhead transmission line from Sudbury Substation along the MBTA ROW, and then transitions to an underground transmission line at the ROW intersection with Wilkins Street and proceeds underground within public roadways to its termination at the Hudson Substation. Under the Noticed Variation, the MBTA ROW will be cleared out to its 80 foot width to accommodate the transmission structures and their clearance requirements.

2.3 NOTICED ALTERNATIVE

The Noticed Alternative Route would originate at the Sudbury Substation and travel within public roadways for 10.3 miles. This route would leave the Sudbury Substation and travel west along Boston Post Road/Route 20, then turn north onto Green Hill Road. The route would then travel west on Old Lancaster Road to the intersection with Hudson Road, where it would turn west and continue along State Road in Stow and Main Street in Hudson. At the intersection with Forest Avenue, the route would turn southwest to reach the Intel access road before terminating at the Hudson Substation.

2.4 SUDBURY SUBSTATION FACILITIES

This Section discusses the proposed modifications at Sudbury Substation necessary to accommodate the new transmission line.

Eversource's Sudbury Substation property is located at 163 and 183 Boston Post Road and consists of two adjacent Eversource-owned parcels totaling approximately 14.8 acres, which are bisected by the MBTA ROW. The Sudbury Substation is set back approximately 600 feet to the south from Boston Post Road. The station is bordered by open land to the west, forested land associated with the Great Meadows National Wildlife Refuge to the east and south, and the MBTA ROW to the north.

All necessary work to accommodate the New Line at the Sudbury Substation will occur within the existing substation fence line and utilize existing access driveways. To accommodate the Preferred Project, the following equipment would be installed at the existing Sudbury Substation:

- 115-kV breaker with associated disconnect switch
- 115-kV surge arresters
- 115-kV cable disconnect and termination structure(s)
- 115-kV air core shunt reactor surrounded by a wall on three sides with associated foundations
- 115-kV breaker with associated disconnects and foundations to switch the shunt reactor
- Shielding mast (approximately 100 feet tall)
- 115-kV bus support structures for 115-kV conductors
- Control, protection, and communication equipment
- Conduits and cable trench for controls

To accommodate the Noticed Variation, the following equipment would be installed at the existing Sudbury Substation:

- 115-kV breaker (#7) with associated disconnect switch

- 115-kV surge arresters
- 115-kV cable disconnect and termination structure(s)
- Control, protection and, communication equipment

For both the Preferred Project and the Noticed Variation, a duct bank would be installed to route the underground portion of the New Line from Sudbury Substation to the MBTA ROW. An existing trailer mounted capacitor bank will be removed from its trailer and installed on permanent foundations to free space within the existing fenced area.

3.0 VISIBILITY STUDIES

3.1 PROJECT CONDITIONS

3.1.1 Preferred Project

The Preferred Project would require an average clearing of 30 feet of vegetation for construction and operation of the underground transmission line. Additional clearing would be required at splice vault locations to facilitate construction; however, once construction is completed these areas would be allowed to grow back to maintain a 30-foot-wide corridor. The installation of the underground line would result in an additional 11 feet of clearing compared with the 19 feet of clearing required for a multi-use trail currently being proposed by the Massachusetts Department of Conservation and Recreation. No visible aboveground structures would be installed, thus no comparative viewshed analysis was performed. In most locations, the existing vegetation would provide a visual buffer from abutting land uses, though the cleared portion of the MBTA ROW would be visible at road crossings.

3.1.2 Noticed Variation

The Noticed Variation would result in clearing of an approximately 80-foot width of the MBTA ROW and the installation of transmission structures. The MBTA ROW would be cleared to a larger width than for the Preferred Project. The Company completed a viewshed analysis for the Noticed Variation to assess potential visual impacts to abutting land uses. The visual resource locations and viewshed analysis combined with the visual resource locations are displayed in Figure 2. The extent of the 0.5 mile study area encompasses the towns of Hudson, Marlborough, Stow, Sudbury, and Wayland

3.1.3 Sudbury Substation

At the Sudbury Substation, if the line is installed underground, a new shunt reactor would need to be added to accommodate an underground route associated with the Preferred Project and the Noticed Alternative. Although the addition of this equipment would not require any expansion of the fence line of the substation, it could result in an altered view of the substation that is different from current conditions. However, this substation is largely surrounded by vacant land. The nearest building is an indoor sports dome with no windows and is approximately 325 feet away to the northeast.

3.2 ANALYSIS

This assessment examines the visual, aesthetic and recreational resources within a visual study area extending out to a 0.5 mile radius from the ROW centerline that follows the Preferred Project/Noticed Variation route between Sudbury Substation and and the HLPD Substation.

Potential visibility for the Noticed Variation was evaluated using three methodologies: 1) viewshed analysis, 2) artist renderings, and 3) realistic photosimulations. A viewshed analysis is a Geographic Information System ("GIS") analytical technique that can determine if and where an object, such as a transmission line structure, might geographically be seen over a larger regional area. The results of the viewshed analysis were combined with other sensitive location information such as historic places, state forests and parks, designated scenic areas and other potentially publicly accessible sensitive receptor locations. This assisted in understanding the potential for visibility (of the overhead design) at receptors located in the landscape. Artist renderings for the Preferred Project and Noticed Variation and photosimulations for the Noticed Variation were used to simulate the look and expected change from single discrete locations.

3.3 VISUAL RESOURCES INVENTORY

Prior to assessment of any operational and visual impacts to the landscape, TRC identified areas susceptible to potential impacts. Visual resources found within the 0.5-mile study area include such areas as open space parcels, potential water-based recreation, trails, and historic resources.

The Massachusetts Scenic Landscape Inventory, a datalayer maintained by the Department of Conservation and Recreation and obtained at the Office of Geographic Information (MassGIS) was also consulted. Within the Scenic Landscape Inventory datalayer are geographic locations that have been classified (by the former Department of Environmental Management) into three visual quality categories: Distinctive, Noteworthy, and Distinctive/Noteworthy. Distinctive landscape areas are of the highest visual quality. These areas are characterized by openness, low population density, high relative relief, historical structures and land uses, agriculture, surface water, significant vegetation, important geological features, and lack of contemporary development. Noteworthy is described as areas of lesser, but nevertheless important, visual quality. They typically contain the same factors as Distinctive landscapes but in lesser amounts or in lower quality. Distinctive/Noteworthy are landscapes that may be either Distinctive or Noteworthy. All other areas in MA are considered Common.

A full list of the resource inventory findings within the study area for the Preferred Project and Noticed Variation is provided in Table 1. Source information for the development of the inventory included GIS data available on federal, state, or agency websites, and information from other non-GIS based websites that provided information such as regulatory listings or hardcopy maps. The data included in Table 1 is derived primarily from GIS files obtained from MassGIS.

Table 1 General Listing of Visual Resource by Town within Study Area*		
Study Area Limit (miles)	**Resource**	**Town**
Open Space		
0.25	Assabet River National Wildlife Refuge	Hudson
0.25	Assabet River National Wildlife Refuge	Sudbury
0.25	Charter Oak Country Club	Hudson
0.25	Cherry St. Playground	Hudson
0.25	Chestnut Well	Hudson
0.25	Chestnut Well	Stow
0.25	Cranberry Well	Hudson
0.25	Cutler Gift - Landham Road	Sudbury
0.25	Deerfoot Park	Hudson
0.25	Deerfoot Park	Marlborough
0.25	Desert Conservation Area	Hudson
0.25	Desert Conservation Area	Marlborough
0.25	Forest Ave School	Hudson
0.25	Frank G Feeley Field	Sudbury
0.25	Gillis Land	Hudson
0.25	Great Meadows National Wildlife Refuge	Sudbury
0.25	Hopbrook Marsh Conservation Land	Sudbury
0.25	Hudson Rod And Gun Club	Hudson
0.25	Kane Well	Hudson
0.25	Lyons Cutler Reservation	Sudbury
0.25	Maple Meadows Cr	Sudbury
0.25	Marlborough-Sudbury State Forest	Hudson
0.25	Memorial Forest	Marlborough
0.25	Memorial Forest	Sudbury
0.25	Paris Trust Cr	Sudbury
0.25	Stone	Sudbury
0.25	Sudbury Water District Land	Sudbury
0.25	Walker CR	Sudbury
0.25	Wash Brook Parcel	Sudbury
0.25	Water Department Land	Hudson
0.25	White Pond Rd Watershed	Hudson
0.5	White Pond Rd Watershed	Sudbury
0.5	Assabet River National Wildlife Refuge	Hudson
0.5	Assabet River National Wildlife Refuge	Stow
0.5	Assabet River National Wildlife Refuge	Sudbury
0.5	Borden Hill Cr	Sudbury
0.5	Charter Oak Country Club	Hudson
0.5	Cherry St. Playground	Hudson

Table 1 General Listing of Visual Resource by Town within Study Area*		
Study Area Limit (miles)	**Resource**	**Town**
0.5	Chestnut Water Supply Area	Hudson
0.5	Chestnut Well	Hudson
0.5	Chestnut Well	Stow
0.5	Cranberry Well	Hudson
0.5	Cutler Farm	Sudbury
0.5	Deerfoot Park	Hudson
0.5	Deerfoot Park	Marlborough
0.5	Desert Conservation Area	Marlborough
0.5	Dutton Road Cr	Sudbury
0.5	Forest Street Parcel	Sudbury
0.5	Frank G Feeley Field	Sudbury
0.5	Great Meadows National Wildlife Refuge	Sudbury
0.5	Great Meadows National Wildlife Refuge	Wayland
0.5	Hopbrook Marsh Conservation Land	Sudbury
0.5	Hubert School	Hudson
0.5	Hudson Rod And Gun Club	Hudson
0.5	Kane Land	Stow
0.5	Kane Well	Hudson
0.5	Lyons Cutler Reservation	Sudbury
0.5	Maple Meadows Cr	Sudbury
0.5	Marlborough-Sudbury State Forest	Hudson
0.5	Marlborough-Sudbury State Forest	Marlborough
0.5	Memorial Forest	Marlborough
0.5	Memorial Forest	Sudbury
0.5	N.E. Forestry Land	Hudson
0.5	Neelon Gift	Sudbury
0.5	Paris Trust Cr	Sudbury
0.5	Railroad R-O-W	Sudbury
0.5	Railroad R-O-W	Wayland
0.5	Raymond Reservation	Sudbury
0.5	Sauta Property	Hudson
0.5	Stone	Sudbury
0.5	Sudbury Water District	Sudbury
0.5	Sudbury Water District Land	Sudbury
0.5	Washington Drive Parcel	Sudbury
0.5	Water Department Land	Hudson
0.5	White Pond Rd Watershed	Hudson
Canoe Trips**		
0.25	Assabet River	Hudson
0.5	Assabet River	Hudson

Table 1 General Listing of Visual Resource by Town within Study Area*		
Study Area Limit (miles)	**Resource**	**Town**
0.5	Assabet River	Stow
Long Distance Trails		
0.25	Bay Circuit Trail	Sudbury
0.5	Bay Circuit Trail	Sudbury
Rail Trails		
0.25	Assabet River Rail Trail (Underway)	Hudson
0.25	Assabet River Rail Trail (Underway)	Stow
0.5	Assabet River Rail Trail (Underway)	Hudson
0.5	Assabet River Rail Trail (Underway)	Stow
Massachusetts Scenic Landscape Inventory		
0.25	Concord Sudbury River Unit (Noteworthy)	Sudbury
0.5	Concord Sudbury River Unit (Noteworthy)	Sudbury
0.5	Concord Sudbury River Unit (Noteworthy)	Wayland
Historic* **		
0.25	7 Maple Ave; Cutler, Christopher G. House (LHD)	Sudbury
0.25	10 Concord Rd; Townes, Archer H. House (LHD)	Sudbury
0.25	35 Concord Rd; Brown, H. House (LHD)	Sudbury
0.25	36 Concord Rd; Bowen, Arthur House (LHD)	Sudbury
0.25	11 Massasoit Ave; Lanham Elementary School (LHD)	Sudbury
0.25	33 King Philip Rd; (LHD)	Sudbury
0.25	29 King Philip Rd; Woodbury, Robert C. House (LHD)	Sudbury
0.25	25 King Philip Rd; Woodbury, Miriam L. House (LHD)	Sudbury
0.25	45 Singletary Rd; (LHD)	Sudbury
0.25	306 Boston Post Rd; Richardson, Clifford W. House (LHD)	Sudbury
0.25	320-324 Boston Post Rd; Morse Barn (LHD)	Sudbury
0.25	Boston Post Rd; Boston And Maine Railroad Section Tool House (LHD)	Sudbury
0.25	10 Maple Ave; Cole, B. S. - Bradshaw, Forrest D. House (LHD)	Sudbury
0.25	22 Maple Ave; (LHD)	Sudbury
0.25	28 Maple Ave; (LHD)	Sudbury
0.25	356 Boston Post Rd; Taylor Real Estate Office (LHD)	Sudbury
0.25	365 Boston Post Rd; (LHD)	Sudbury
0.25	8 Concord Rd; (LHD)	Sudbury
0.25	18 Concord Rd; (LHD)	Sudbury
0.25	361 Boston Post Rd; Kidder, Enoch Shoe Shop (LHD)	Sudbury
0.25	370-372 Boston Post Rd; Goodnow, Martin House (LHD)	Sudbury
0.25	21 Concord Rd; Civil War - Union Soldier Monument (NRHP) LHD)	Sudbury
0.25	25 Concord Rd; Arnold, Edwin House (LHD)	Sudbury

Table 1 General Listing of Visual Resource by Town within Study Area*		
Study Area Limit (miles)	**Resource**	**Town**
0.25	62 King Philip Rd; Richardson, Benjamin House (LHD)	Sudbury
0.25	54 King Philip Rd; Goulding, Henry E. House (LHD)	Sudbury
0.25	23 Massasoit Ave; South School Annex (LHD)	Sudbury
0.25	22 King Philip Rd; Morse, R. D. House (LHD)	Sudbury
0.25	10 Pokonoket Rd; (LHD)	Sudbury
0.25	17 King Philip Rd; Hall, John C. House (LHD)	Sudbury
0.25	4 King Philip Rd; Goodnow, John House (LHD)	Sudbury
0.25	46 Singletary Rd; (LHD)	Sudbury
0.25	353 Boston Post Rd; Richardson House (LHD)	Sudbury
0.25	346 Boston Post Rd; Hunt, Emory House (LHD)	Sudbury
0.25	11 Maple Ave; (LHD)	Sudbury
0.25	32 Concord Rd; (LHD)	Sudbury
0.25	290 Dutton Rd; (LHD)	Sudbury
0.25	20 Concord Rd; Parmenter, George House (LHD)	Sudbury
0.25	68 King Philip Rd; Richardson, Josiah House (LHD)	Sudbury
0.25	9 Church St; Burr, Clifford House (LHD)	Sudbury
0.25	61 King Philip Rd; Cutter - Dakin House (LHD)	Sudbury
0.25	48 King Philip Rd; Bogle Sisters House (LHD)	Sudbury
0.25	14 Massasoit Ave; (LHD)	Sudbury
0.25	14 King Philip Rd; (LHD)	Sudbury
0.25	12 King Philip Rd; (LHD)	Sudbury
0.25	57 Singletary Rd; (LHD)	Sudbury
0.25	357 Boston Post Rd; Richardson, Abel House (LHD)	Sudbury
0.25	Boston Post Rd; Milestone, 1767 (NRHP)	Sudbury
0.25	19 Maple Ave; Hobson, Emma A. - Shedd, Jean A. House (LHD)	Sudbury
0.25	365 Boston Post Rd; (LHD)	Sudbury
0.25	4 Maple Ave; (LHD)	Sudbury
0.25	15 Maple Ave; (LHD)	Sudbury
0.25	31 Maple Ave; (LHD)	Sudbury
0.25	354 Boston Post Rd; (LHD)	Sudbury
0.25	5-15 Concord Rd; Citibank (LHD)	Sudbury
0.25	17 Concord Rd; Hill Jewelers (LHD)	Sudbury
0.25	19 Concord Rd; Bank Building (LHD)	Sudbury
0.25	4 King Philip Rd; Goodnow, John Barn (LHD)	Sudbury
0.25	276 Dutton Rd; (LHD)	Sudbury
0.25	232 Peakham Rd; (LHD)	Sudbury
0.25	Boston Post Rd; Milestone, 1767 (NRHP)	Sudbury
0.25	16 Concord Rd; Burr, Hiram G. House (LHD)	Sudbury
0.25	26 Concord Rd; Memorial Congregational Church (LHD)	Sudbury

Table 1 General Listing of Visual Resource by Town within Study Area*		
Study Area Limit (miles)	**Resource**	**Town**
0.25	38 King Philip Rd; Richardson, Gideon House (LHD)	Sudbury
0.25	20 King Philip Rd; Morse, R. D. Milk House (LHD)	Sudbury
0.25	0 King Philip Rd; Smith, E. - Hall, Seneca W. Barn (LHD)	Sudbury
0.25	348 Boston Post Rd; Allen, John - Woods, Abraham House (LHD)	Sudbury
0.25	316 Boston Post Rd; (LHD)	Sudbury
0.25	344 Boston Post Rd; Hunt, George Washington House (LHD)	Sudbury
0.25	14 Maple Ave; Bradshaw, Forrest D. Garage (LHD)	Sudbury
0.25	25 Maple Ave; (LHD)	Sudbury
0.25	34-36 Maple Ave; (LHD)	Sudbury
0.25	359 Boston Post Rd; (LHD)	Sudbury
0.5	Concord Rd; Mount Wadsworth Cemetery (LHD)	Sudbury
0.5	52 Concord Rd; Parmenter, Charles O. House (LHD)	Sudbury
0.5	71 Concord Rd; Brown, Israel How House (LHD)	Sudbury
0.5	83 Concord Rd; Howe, Frank House (LHD)	Sudbury
0.5	62 Concord Rd; (LHD)	Sudbury
0.5	192 Dutton Rd; (LHD)	Sudbury
0.5	118 Peakham Rd; Noyes, Daniel - Warren, William S. House (LHD)	Sudbury
0.5	199 Dutton Rd; Dutton Lodge Wing (LHD)	Sudbury
0.5	Boston Post Rd; Milestone, 1767 (NRHP)	Sudbury
0.5	41 Concord Rd; Puffer, Dexter R. House (LHD)	Sudbury
0.5	67 Concord Rd; Garfield, Francis House (LHD)	Sudbury
0.5	9 Pokonoket Rd; (LHD)	Sudbury
0.5	68 Concord Rd; (LHD)	Sudbury
0.5	95 Concord Rd; (LHD)	Sudbury
0.5	181 Dutton Rd; Dutton Lodge (LHD)	Sudbury
0.5	258 Dutton Rd; (LHD)	Sudbury
0.5	53 Concord Rd; (LHD)	Sudbury
0.5	201 Dutton Rd; (LHD)	Sudbury
0.5	232 Dutton Rd; (LHD)	Sudbury
0.5	47 Concord Rd; Horr, Richard Rush House (LHD)	Sudbury
0.5	40 Concord Rd; Allen, J. P. House (LHD)	Sudbury
0.5	44 Concord Rd; McClaren, James House (LHD)	Sudbury
0.5	58 Concord Rd; Jones, William P. House (LHD)	Sudbury
0.5	55-62 Goodmans Hill Rd; Bogle - Walker House (NRHP)	Sudbury
0.5	61 Concord Rd; (LHD)	Sudbury
0.5	84 Concord Rd; (LHD)	Sudbury
0.5	89 Concord Rd; (LHD)	Sudbury
0.5	15 Broad St; Jefts, L. T. Shoe Company (LHD)	Hudson

* *Table data generated from GIS files obtained from MassGIS.*

*** Canoe trips were obtained as a datalayer from MassGIS and were originally derived from the Appalachian Mountain Club's River Guide for Massachusetts.*
**** Historic information includes MassGIS data National Register Historic Places ("NRHP") and Local Historic District ("LHD") categories.*

3.4 VIEWER/USER GROUPS

Three categories of viewer/user groups were identified within the visual study area:

Local residents included those who live, work, and travel for their daily business or recreation within the visual study area. They would generally view the landscape from their yards, homes, local roads, places of employment, and open space parcels. Residents were concentrated throughout the study area. Except when involved in local travel, residents are likely to be stationary, and have frequent or prolonged views of the landscape. Residents' sensitivity to visual quality is variable, and may be tempered by the aesthetic character/setting of their neighborhood or work place. Those living in densely settled areas with views focused on their neighborhood street or built facilities may be less sensitive to landscape changes than those with a view of open farmland or undeveloped forest. It was assumed that residents were familiar with the surrounding landscape and may be very sensitive to changes, especially with respect to views that are important to them.

Commuters/through travelers passing through the area would view the landscape from motor vehicles on their way to other destinations. Commuters and other through travelers are typically moving, have a relatively narrow field of view oriented along the axis of the roadway, and are destination oriented. Drivers on major roads in the area (e.g., Main Street, Boston Post Road, Union Avenue, Landham Road) would generally be focused on the road and traffic conditions, but would have the opportunity to observe roadside scenery. Passengers in moving vehicles would have greater opportunities for prolonged off-road views than would drivers, and therefore could be more aware of the quality of surrounding scenery. However, through travelers who are not residents of the area are unlikely to be particularly sensitive to visual change along the route of their travel.

Out-of-town visitors come to the area to visit family or friends, or participate in cultural and recreational activities or shopping. Members of this group may view the landscape from high use travel corridors while on the way to their destinations, or from the sites themselves. Outdoor recreational users will often have continuous views of landscape features over relatively long periods of time, but visual quality may or may not be an important part of their visit to the area. However, in almost all cases, scenery can serve to enhance the quality of their visit.

3.5 VIEWSHED ANALYSIS

The Preferred Project would result in 30 feet of tree clearing and no aboveground structures. The Noticed Variation would result in clearing of an approximately 80-foot width of the ROW and the installation of transmission structures. Subsequent to the visual resources inventory as listed in Table 1, a GIS based viewshed analysis for the Noticed Variation aboveground structures was performed to predictively identify those resource areas that may potentially see all or some portion of a transmission line structure. The results of the viewshed analysis combined with the results of the visual resources inventory are displayed in Figure 2.

3.5.1 Methodology

The viewshed analyses used the 2010 Federal Emergency Management Agency ("FEMA") Topographic Lidar data consisting of Concord River Watershed, Massachusetts files published by the National Oceanic and Atmospheric Administration. LiDAR data is the best available elevation data for this analysis as it includes high resolution ground elevations in addition to building heights and individual tree heights that offer realistic physical visual impediments in the landscape. ESRI Spatial and 3D Analyst GIS software was used to develop the viewshed model.

For all analyses, data were controlled within the model to ensure that the vertical offsets of the transmission structures were embedded properly against the LiDAR surface elevation and existing trees. Trees and buildings in the landscape are included in the analyses, as they are inherent in the LiDAR data. The analysis accounted for the clearing of trees within the entire ROW.

The viewshed model was further developed by establishing an observer height of 5.5 feet, and with the assumption that the overhead structures of the Noticed Variation would not be visible to a viewer who is standing amongst trees in a forested area or in buildings themselves. The final resulting output grid identified those areas from which viewers would potentially see all or some part of the proposed vertical elements (Figure 2).

3.5.2 Assumptions and Limitations of the Viewshed Model

The viewshed analysis identifies cells (image pixels) that contain elevation information and computes the differences along the terrain surface between an observer at any point within the study area and a target (e.g. transmission line structure). The analysis is a clear line of sight and therefore certain factors in the interpretation of results need to be considered:

1. The model, because of its computerized aspect, assumes the observer to have perfect vision at all distances. Therefore, a certain amount of reasonable interpretation needs to be considered because of the limitations of human vision at greater distances or those atmospheric/meteorological conditions that may cause imperfect vision, such as haze or inclement weather. Additionally, an object is naturally smaller and shows much less detail at distances and will have less visual impact. These aspects cannot be conveyed with this analysis.

2. Because an area may show visibility, it does not mean the entirety of aboveground structures will be seen. The viewshed analysis depicts areas of visibility over a regional area. It can only predict geographically on a map areas where some part of a transmission pole might be seen. It does not and cannot determine if it is seeing a full on view or a partial view of just an upper portion of a structure. Additionally, if visibility is occurring in an area, it may sometimes only be a result of glimpsing a portion of the structures over undulating treetops or between gaps of trees and not a full-on view. Likewise, there may be understory tree gaps not depicted by the LiDAR where there may be visibility of structures, especially from backyards of adjacent abutters.

3. The viewshed model assumes that any vegetation is opaque and therefore represents a leaf-on condition. By nature of the software model and available parameters, the trees are treated as an opaque object and therefore leaf-on conditions are assumed. Transparency predictions through something similar to bare-branched trees under leaf off conditions cannot be made.

4. The model was developed with the assumption that a viewer would not see the structures if standing amongst trees in forested areas.

For all of these reasons, the accuracy of a viewshed model is limited. It has been used in combination with site visits, artist renderings, and photosimulations to guide the analysis.

3.5.3 Viewshed Results and Discussion

Landform and elevation in addition to vegetative features in the landscape are a key influence on the visibility and sightline of a project.

Within the 0.5 mile study area, the result of the viewshed analysis is depicted as an overlay in relation to sensitive receptors identified from GIS data such as open space lands, historic sites, canoe access points, long distance trails, and Massachusetts Scenic Landscape Scenic Inventory parcels. The predictive viewshed map identifies areas where structures may potentially be visible (Figure 2).

When brought into the field and ground-truthed, the viewshed analysis results offered representation for predictive visibility due to the LiDAR data available for this area. In addition to larger stands of trees, there were many areas where LiDAR was able to capture shorter or isolated groups of trees that serve as a less extreme or sometimes lower profile visual impediment. The building footprints and corresponding building elevations available in the LiDAR data were particularly helpful in some of the denser residential areas of the study area and enhanced the accuracy of the visibility results. However as noted in Assumptions and Limitations there also may be understory tree gaps above low vegetation but below the upper canopy, that allow visibility of overhead structures, especially from adjacent abutters.

The extents of the 0.5 mile study area encompass the towns of Hudson, Marlborough, Stow, Sudbury, and Wayland. Along ROW, viewshed mapping in Figure 2 shows the greatest amount of visibility occurring in adjacent open fields, parking lots and commercial areas, as well as in some neighborhood areas. It is difficult to ground-truth the analysis for every area within 0.5 miles. It is not expected that significant full on views of structures will be seen from many of these areas, and that generally the upper portions of the structures are expected to be visible. This is frequently due to intervening trees and buildings in the area that act as a visual impediment.

The following discusses the predictive visibility of the aboveground structures solely as a result of the viewshed analysis. As noted in Figure 2, viewshed results are classed by the number of structures that may potentially be visible. The discussion below references general levels of visibility (i.e. low: < 6 structures, moderate: 6 to 8 structures; or high: > 8 structures).

Visibility in Hudson

Hudson comprises approximately 46% of the study area. Discussion of the viewshed analysis in Hudson is broken down into four geographic areas to facilitate discussion of each area.

Parmenter Street to Hudson/Sudbury Town Line

Several open space lands occur in this section of the Hudson study area and include the Marlborough-Sudbury State Forest, White Pond Watershed, Cranberry Well, and a small portion of the Assabet River National Wildlife Refuge. These recreational lands are not expected to have much visibility due to the abundance of tree cover. Discrete areas of low to moderate visibility occur in fields to the east near the town line, however a low number of viewers would be assumed. Commercial buildings south of the ROW along Parmenter Street may also experience views of structures. There are some houses closer to the ROW that may have low visibility north of the Noticed Variation route along Parmenter Street.

Main Street/MBTA Crossing to Parmenter Street

The section between Parmenter Street and where Main Street crosses the MBTA ROW consists of several commercial complexes that lie primarily along and in the vicinity of Main Street, Brent Drive, and Kane Industrial Drive. These areas are expected to see structures, as they consist of more expansive open parking lots and vacant land. Portions of the Charter Oak Country Club where it closely abuts the Noticed Variation route will likely have views as well.

Chestnut Street to Main Street/MBTA Crossing

Between the Main Street/MBTA crossing and Chestnut Street, the viewshed maps show significant amounts of visibility. This is in part due to high visibility areas that are predicted in the treeless marshy areas within Chestnut and Kane Wells open space properties. Access may be difficult and therefore the general public is not expected to be present. Open commercial areas exist proximal to the ROW in the vicinity of Main Street and also show the potential for moderate to high visibility of structures. Several residences on the east side of Chestnut Street are predicted to have high visibility of structures due to the open character of the properties.

Broad Street to Chestnut Street

One area of high visibility as noted by the viewshed maps may occur on the west side of Chestnut Street at Ferjulian's Farm in a large field adjacent to the ROW. Other low visibility areas in this section occur intermittently in other open fields. Some low intensity visibility is anticipated in select areas along Orchard Drive and Wilkins Street. Minor visibility also may occur in limited open areas of the Hudson Rod and Gun Club.

Although the study area continues west to Broad Street, the actual overhead transmission structures terminate at the ROW intersection with Wilkins Street. As one proceeds west of Wilkins and Orchard Streets, views are expected to be minimal to none.

Visibility in Marlborough

Marlborough comprises about 2% of the study area. Nearly all of the Marlborough portion of the study area consists of conservation-recreation area, but there would be limited visibility of the Noticed Variation as these areas are forested. Minor visibility could occur in open areas adjacent to the ROW within Desert Conservation Area and Deerfoot Park. The visibility fell within open treeless swamps that were assumed

to have difficult or limited public access. No neighborhoods were present within the Marlborough study area.

Visibility in Stow

Stow comprises approximately 4% of the study area. The most predominant resource occurring in Stow is the Assabet River National Wildlife Refuge. Most of this resource is outside of 0.25 miles. Viewshed mapping shows low to medium-high visibility generally located intermittently on the river and within adjacent open marshes along the river corridor. The marshes are expected to have limited and difficult public access; however, transient views of upper parts of structures could be expected from canoe river travel as one passes through the study area. The section of Assabet River that passes through the study area is a designated canoe trip route (as derived from the Appalachian Mountain Club's River Guide for Massachusetts).

There are discrete sections of residential area that could have low intensity views of the upper portions of structures in the vicinity of Marlborough and High Streets. There may be higher intensity visibility if viewed from upper floors.

Visibility in Sudbury

Sudbury comprises about 48% of the study area. Discussion of the viewshed analysis in Sudbury is broken down into four geographic areas to facilitate discussion of each area.

East of Boston Post Road to Wayland: East of the Boston Post Road and ROW crossing but north of the transmission ROW the land use is commercial interspersed with residential housing. Viewshed results show low intensity visibility in commercial lots along Boston Post Road. Farther north in this eastern section, more formal neighborhood development exists where visibility diminished.

South of the ROW corridor in the Raymond and Lanham Road areas, nearly the entire study area is comprised of conservation land such as Raymond and Lyons Cutler Reservation lands, Wash Brook, Maple Meadows as well as Great Meadows Wildlife Refuge, Frank G Feeley Field, and a Massachusetts Scenic Landscape Inventory parcel (Concord Sudbury River Unit). The Concord Sudbury River Scenic Landscape Inventory parcel is classed as Noteworthy. There are several discrete areas of high visibility in open land, mainly associated with treeless marshes in the open wetland areas where the public is not expected to be present. Some areas of low intensity visibility could occur at the Frank G. Feeley Field and in open residential areas along Landham Road.

Between Horse Pond Road and Boston Post Road: Most of the land use in this section of the Sudbury study area is commercial. Greatest visibility may occur in these commercial areas due to associated open parking areas. One neighborhood in the vicinity of Bridle Path Lane could have small discrete areas of low intensity visibility. One open space parcel named Stone Farm is expected to have views from open fields.

Dutton Road to Horse Pond Road: This section of the Sudbury study area is mostly wooded interspersed with residential houses. Viewshed results show intermittent low intensity visibility from some neighborhood locations such as Amanda and Bulkley Roads as well as the Colburn Circle, Robert Best Road and Jarman Road areas.

Hudson/Marlborough Town Line to Dutton Road: This area is comprised almost entirely of conservation type lands that include the Assabet River National Wildlife Refuge, Memorial Forest, and Hopbrook Marsh Conservation Land. These open space lands are heavily forested and are not expected to have visibility of the Noticed Variation except for open wetland areas along and adjacent to the Hop Brook stream corridor. There are a few residential houses in this section where little to no visibility is expected.

Visibility in Wayland

Wayland comprises approximately 0.6% of the study area and is on the far eastern side of the study area. Viewshed results show low intensity visibility in existing developed commercial areas along Boston Post Road. Low intensity visibility also occurs at the Great Meadows National Wildlife Refuge and a Massachusetts Scenic Landscape Inventory parcel, (Concord Sudbury River Unit) that lies within the outer study area in Wayland. Visible areas at these resources generally occur in open treeless marshes. There appears to be few if any residential housing in the Wayland section of the study area.

3.6 ARTIST RENDERINGS

3.6.1 Methodology

Artist renderings were prepared by Beals and Thomas, Inc. ("B+T"). Photos for the artist renderings were taken on November 3, 2015 and November 16, 2015, at select intersections chosen by Eversource. Structure locations had already been staked in the field by another consultant. Where possible and appropriate, photos were taken to include any visible stakes. B+T was provided a preliminary construction mapping plan and Plan and Profile documents from Eversource which were used to reference when taking the photos and preparing the renderings. B+T was also provided a staking table with each proposed structure height. Known existing conditions information from the provided plans such as locations and dimensions of utility poles, houses, driveways, hydrants, light poles, structure stakes, etc. were compared to those same items in the photographs. The proposed right-of-way clearing, multi-use trail, and transmission line structures were then rendered in an artistic manner to match the perspective and proportions of the photograph and relative to existing conditions.

3.6.2 Discussion of Artist Renderings

The photographs for the artist renderings were taken in close proximity to the Noticed Variation and focus on intersections of roads and ROW. Aside from Figure A1a which shows the Preferred Project, the renderings depict the size and scale of the Noticed Variation option in relation to anticipated recreational activities as well as the look of the ROW after tree clearing. In all cases at these viewpoint locations for the Noticed Variation renderings, the overhead structures would result in visual impacts that would distinctly alter the existing view. Representative artist renderings depict the following locations:

Figure A1a - Boston Post Road & Station Ave, Preferred Project
Figure A1b - Boston Post Road & Station Ave, Noticed Variation
Figure A1c - Boston Post Road & Station Ave, Noticed Variation, 5 Years Following Construction
Figure A2 - Union Avenue & Station Ave, Noticed Variation
Figure A3- Wilkins Street & Orchard Drive, Noticed Variation
Figure A4 - Landham Road, Noticed Variation
Figure A5 - Horse Pond Road, Noticed Variation

Figure A6 - Chestnut Street and Marlboro Road, Noticed Variation

The rendering at Boston Post Road and Station Avenue contrasts the Preferred Project and the Noticed Variation. The Preferred Project rendering (Figure A1a) shows the absence of overhead structures and limited clearing associated with this option. The Noticed Variation (Figures A1b, A1c) shows the transmission line installed adjacent to the multi-use trail where the ROW would be cleared to its full width for construction, but the peripheral zones of the ROW will become revegetated with shrubs five years following construction. The renderings for Union Avenue and Horse Pond Road depict the Noticed Variation at at-grade road crossings, while the renderings for Landham Road and Chestnut Street depict this variation in areas where the road is elevated above the rail. All three viewer groups are represented by the renderings (refer to Section 3.4 for viewer group description). Viewpoints for Figures A1, A2, and A4 fall within urban development and more heavily traveled roadways, where the viewer group would generally consist of commuters, through travelers, and out of town visitors that may be less sensitive to visual impacts.

3.7 PHOTOGRAPHIC SIMULATIONS

Supplemental analysis is provided as photosimulations in additional areas not shown in the artist renderings. A field survey was conducted in April 2016 in order to acquire photographs for simulations during leaf-off conditions. Three photographs are presented as simulations. Attempts were made to position photographs that provided the most unobstructed views to the Noticed Variation ROW. The photo locations were chosen to provide non-road crossing views in areas where there were clear views and/or if high visibility areas appeared on the viewshed maps.

3.7.1 Methodology

Photographs were taken with a full frame Canon 5D Mark II digital camera equipped with a 50 millimeter lens. Fifty millimeters was used as it most closely resembles human vision. Coordinates of camera locations intended for simulations were recorded through the use of a sub-meter Global Positioning System unit ("GPS"), as well as other reference points within the view. These reference locations were later used to refine the placement of the transmission line structures within the simulation photographs. Heights of select high reference points were measured with a Nikon Forestry 550 digital rangefinder.

To create visual simulations, 3DS MAX 2016 software was used to correctly dimension a model of the Noticed Variation into the digital photographic image from each viewpoint location. The 3d model of the overhead line was created by TRC by using engineering specifications provided by Eversource. The simulation model was further developed to position the viewer at the selected vantage point. For a given vantage point, the visualization software is capable of providing and adjusting a camera view that matches that of the actual photograph. From the field effort, the documented camera coordinate (x, y, z) positions were entered into the model. Reference locations, which are existing visible objects in the photograph such as light posts, building corners, trees, gate posts or utility poles were obtained by GPS to assist with refined placement of the proposed structures within the photograph. In some instances, GIS terrain modeling and analysis helped in locking in the 3d facility model within the photograph. Ground point elevations of the camera location and other referenced objects were pulled from the 2010 FEMA Topographic Lidar for the Concord River Watershed.

The day and time of the photographs were also recorded and typically exists as electronic information embedded in the digital photograph file. This information was used to adjust for sun angle in the simulation software in order to represent lighting conditions for the time of day and year.

3.7.2 Discussion of Simulations

While the artist renderings focused on road crossings, the photosimulations represent areas farther out at oblique angles to the Noticed Variation ROW. In all of the simulations, the new structures are visible and create a change in the visual character of the existing landscape.

Figure VP1a,b – Chestnut Street, Hudson. This photo was taken to represent a nearby neighborhood in Hudson with open views towards the ROW near the western end of the route. The photo, taken approximately 974 feet from the ROW, shows the character of this area in addition to potential views from Chestnut Street residences. Upper portions of structures are visible above trees and in some instances there are views to cleared portions of the ROW. The viewer group most affected at this location would be local residents.

Figure VP2a,b – Amanda Road, Sudbury. This photo was taken to represent a view from a neighborhood adjacent to the ROW in Sudbury within the central portion of the route. The photo was taken to represent a typical neighborhood development in this vicinity of the study area. The simulation shows a street side view of the Noticed Variation from an abutter and the effects of tree clearing when there is no intervening vegetation between the ROW and landowner property boundary. The viewer group most affected at this location would be local residents.

Figure VP3a,b – Landham Road, Sudbury. This photo shows a distant view of the structures looking across the Wash Brook open space parcel adjacent to Landham Road in Sudbury. This location, approximately 0.3 miles from the structures appearing in the simulation, offers one of the most open views towards the Noticed Variation from Landham Road. From this vantage point, partial views of several proposed structures and respective conduit would be visible, adding new vertical elements to the existing landscape. Commuters, through travelers, and out of town visitors would be the viewer groups affected, as well as local residents.

4.0 SUMMARY

Viewshed analysis, artist renderings, and photosimulations have been prepared to illustrate where and how visibility from the Project and Noticed Variation will alter changes in the visual environment.

A wide range of factors, including the types of viewer groups, duration of the view, degree of discernable detail, number of viewers, degree of natural buffering, and the scenic value of a location, are considered when assessing visual impacts.

Viewer groups are described in Section 3.4. TRC has made conclusions on visual impacts by describing viewer groups that include other characteristics such as frequency and duration of exposure to views, viewer activity and presumed sensitivity to changes in the visual landscape. All three viewer groups are represented in this assessment; local residents, commuters/through travelers, and out of town visitors and all would be affected in various locations. Within the artist rendering and photosimulation discussion (Section 3.6.2 and 3.7.2, respectively), the viewer groups most affected have been noted.

Degree of discernable detail is determined by distance. This is illustrated by the artist renderings (and Figure VP2 photosimulation), where the photo viewpoint locations are very proximal to the ROW and show a high degree of detail. Figure VP1 and VP3 photosimulations show at least two viewpoints at a distance where visual detail of the Noticed Variation is diminished.

Degree of natural buffering and the trees or buildings in the landscape that provide visual screening are apparent in the viewshed analysis results as well as the photosimulations. There are many commercial buildings, houses, acreages of forested tree groups, and trees lining neighborhood streets that block views to the Noticed Variation.

The Project area can be generally described as suburban to urban with a few semi-rural locations. Despite the high population density, there are many sensitive resource receptors in the study area. Areas of open space and recreational lands, historic sites, canoe access points and recreational river activity, trails, and Massachusetts Scenic Landscape Inventory locations are all considered important and thereby listed in the visual resources inventory Table 1 as well as being depicted on the viewshed maps in Figure 2. The viewshed results overlay the inventoried resources where the visually affected resources can be ascertained. Many of the receptors may have some visibility of some portion of the Noticed Variation, however a number of them are in areas where public access is difficult to obtain, such as open swampland.

Based on the site visits and the subsequent results of artist renderings and photosimulations, in general, it is not expected that significant full on views of structures will be seen unless one is within the ROW itself or is extremely proximal. If visibility is predicted for an area, it may only be a result of glimpsing a portion of the Noticed Variation over undulating treetops or between gaps in forested areas and not a full-on view. Likewise, there may be understory tree gaps not depicted by the LiDAR where there may be visibility of structures, especially from backyards of adjacent abutters. In many locations for the Noticed Variation, the existing vegetation in the regional area is expected to provide a visual impediment for all but the upper portions of some structures or is enough to block all views.

4.1 PREFERRED PROJECT

The Preferred Project would require an average clearing of 30 feet of vegetation for construction and operation of the underground transmission line. Figure A1a provides an example of what 30 feet of ROW tree clearing would look like. No visible aboveground structures would be installed. In most locations, the existing vegetation would provide a visual buffer from abutting land uses, though the cleared portion of the ROW would be more apparent in some locations (mainly at road crossings). In conclusion, the underground design of the Preferred Project would have minimal visual impact.

4.2 NOTICED VARIATION

The Noticed Variation would require an average clearing of 80 feet of vegetation and the installation of an overhead transmission line within the MBTA ROW. The Noticed Variation would result in a permanent visual impact to users of the proposed multi-use trail and abutting land uses that could have a clear line of sight to the ROW due to tree clearing and new vertical aboveground transmission structures. Visual impact and the quality of the new views are depicted in Figures A2-A6 and Figures VP1 - VP3. A viewshed analysis to assess the effects of new vertical elements introduced in the visual environment was performed for this option, since the proposed aboveground structures are often higher than the

surrounding trees. The installation of a transmission line along public roadways in Hudson is not anticipated to result in any permanent visual impacts.

4.3 NOTICED ALTERNATIVE

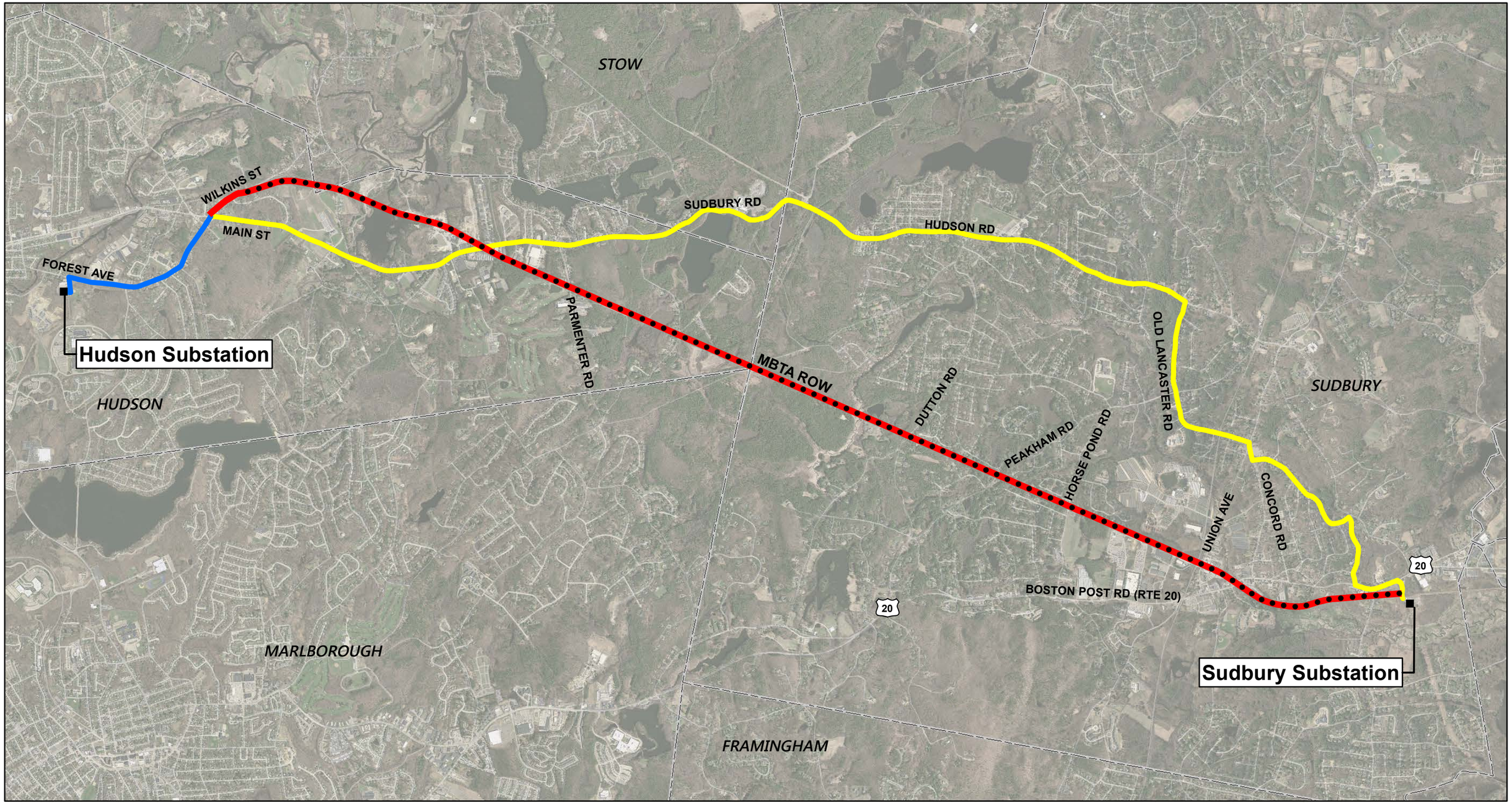
There would be minimal visual impacts to an underground route within roads if the Noticed Alternative is installed within the existing limits of pavement. In some locations (at splice boxes, for example) it could be necessary to trim branches to facilitate construction; however, upon construction completion, the road would be restored to pre-existing conditions and the vegetation would be allowed to grow back.

4.4 COMPARISON OF VISUAL IMPACTS ALONG PREFERRED PROJECT, NOTICED VARIATION, AND NOTICED ALTERNATIVE

The Preferred Project would result in less visual impact along the MBTA ROW, with no aboveground structures and less vegetation removal than the Noticed Variation. The visual impact would primarily be some increased visibility of the proposed multi-use path from abutting uses due to the removal of vegetation. The Noticed Variation would result in the highest potential for visual impacts due to new proposed vertical elements in the landscape and greater vegetative clearing, as demonstrated in the viewshed analysis, artist renderings, and photosimulations.

Along the Noticed Alternative Route, there would be no aboveground structures nor any permanent vegetation removal, so there would be no permanent visual impacts from this route.

While Eversource would work with landowners to mitigate for visual impacts along the Preferred Project and Noticed Variation as much as possible, vegetation removal along the MBTA ROW would still result in a higher potential for visual impacts than there would be for the Noticed Alternative.



Common Underground Segment

Preferred Project (UG)

Noticed Variation (OH in MBTA ROW)

Noticed Alternative Route

Source:
MassGIS, VHB

NOTE: Not to scale. Alignments shown are for graphical purposes only. Lines that appear immediately adjacent to each other should be assumed to follow the same alignment.

0 3,000 6,000 Feet

TRC

FIGURE 1
AERIAL PHOTOGRAPH LOCUS MAP
SUDBURY-HUDSON TRANSMISSION RELIABILITY PROJECT

Model Assumptions
1. The model, because of its computerized aspect, assumes the observer to have perfect vision at all distances. Therefore, a certain amount of reasonable interpretation needs to be considered because of the limitations of human vision at greater distances or those atmospheric/meteorological conditions that may cause imperfect vision, such as haze or inclement weather. Additionally, an object is naturally smaller and shows much less detail at distances and will have less visual impact.
2. Because an area may show visibility, it does not mean the entirety of a structure will be seen.
3. The viewshed model assumes that vegetation is opaque and therefore represents a leaf-on condition.
4. The model was developed with the assumption that a viewer would not see structures if standing amongst trees.

Forest Street Parcel
Neelon Gift
Borden Hill Cr
Railroad R-o-w
Stone
Paris Trust Cr
Walker Cr
Wash Brook Parcel
Cutler Gift - Landham Road
Great Meadows National Wildlife Refuge
Maple Meadows Cr
Lyons Cutler Reservation
Frank G Feeley Field
Sudbury Water District Land
Sc L:Concord Sudbury River Unit
Raymond Reservation
Sudbury Water District
Cutler Farm
Bay Circuit Trail
A1
A2
A4
VP3
CODJER LANE
WALKUP ROAD
CLARK LANE
OLD LANCASTER ROAD
WALKER FARM ROAD
GOODMANS HILL ROAD
OLD COUNTY ROAD
RIVER ROAD
UNION AVENUE
CONFIDENCE WAY
FRANKLIN PLACE
INDIAN RIDGE ROAD
HILLSIDE PLACE
ALLEN PLACE
METACOMET WAY
GREEN HILL ROAD
WINSOR ROAD
MASSASOIT AVENUE
BRADLEY PLACE
POKONOKET AVENUE
CHURCH STREET
KING PHILIP ROAD
SINGLETARY LANE
STATION ROAD
BOSTON POST ROAD
MAPLE AVENUE
RAYMOND ROAD
COOLIDGE LANE
STAGECOACH DRIVE
BROOKSIDE FARM LANE
HAWTHORNE DRIVE
BECKWITH STREET
GRISCOM ROAD
GUZZLEBROOK DRIVE
PELHAM ISLAND ROAD
LANDHAM ROAD
BLACKMER ROAD
VICTORIA ROAD
CUTLER FARM ROAD
READ ROAD
ANSELM WAY
WOODSIDE ROAD
WRIGHT ROAD
WOODLAND ROAD
HIGHLAND AVENUE
NOBSCOT ROAD
SPRING HOUSE POND
DUDLEY ROAD
Wayland
Sudbury

0.25 Mile Radius
0.50 Mile Radius
Proposed Transmission Structure
Underground Segment
RENDERING LOCATIONS
Artist Render (A)
Photosimulation (VP)

Open Space
Canoe Access Points
Canoe Trips
DCR Roads and Trails
LONG DISTANCE TRAILS
Bay Circuit Trail
THE SCENIC LANDSCAPE INVENTORY
Noteworthy

MHC HISTORIC INVENTORY POINTS
Nat'l Register of Historic Places
Local Historic District
NRHP and LHD
BIKETRAILS
Underway (Assabet River Rail Trail)

VISIBILITY
Number of Visible Structures
1 - 3
4 - 5
6 - 8
9 - 15
16 - 89

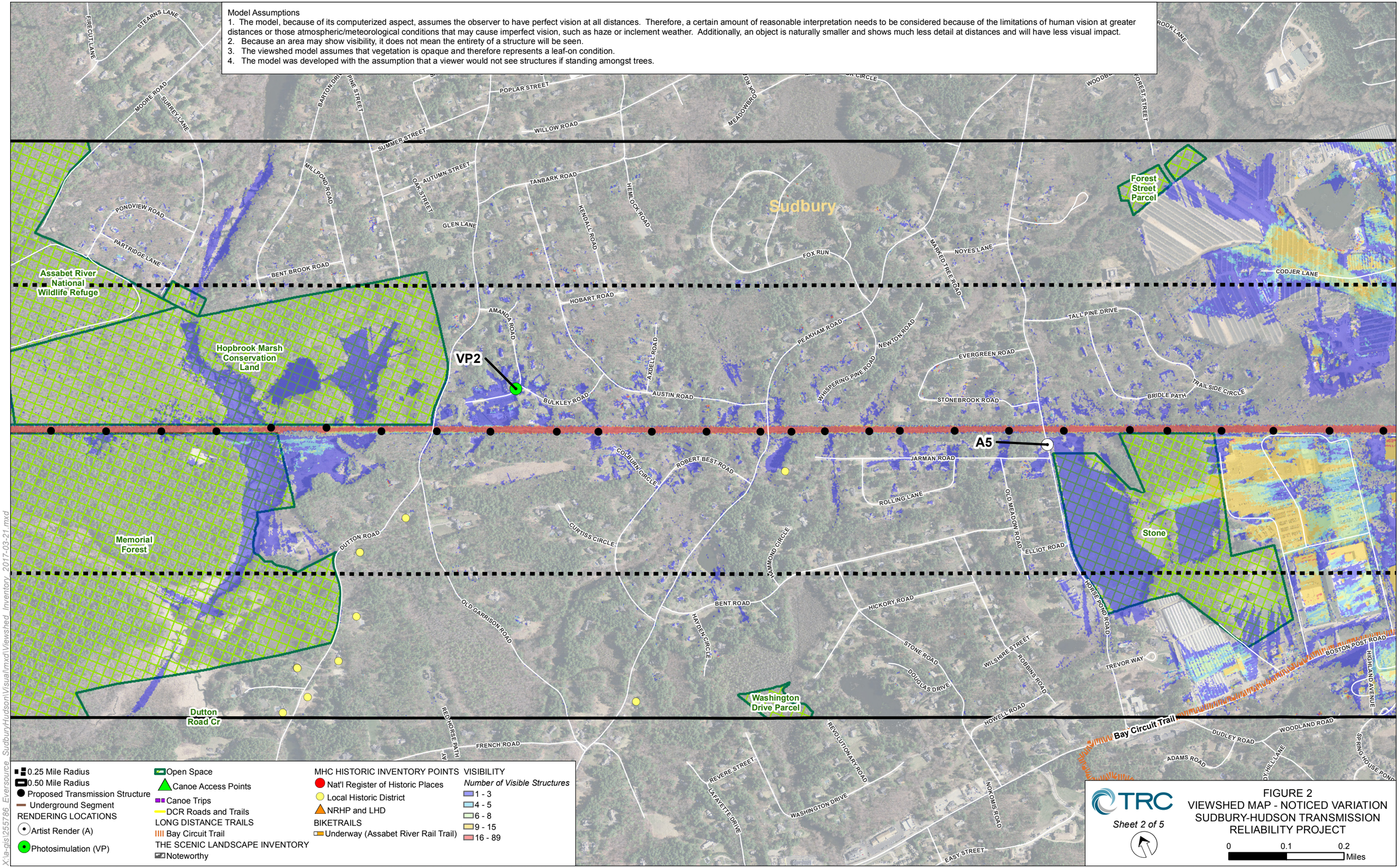
TRC
Sheet 1 of 5

FIGURE 2
VIEWSHED MAP - NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION RELIABILITY PROJECT

0 0.1 0.2 Miles

X:\a-gis\265786_Eversource_SudburyHudson\Visual\mxd\Viewshed_Inventory_2017-03-21.mxd

Model Assumptions
1. The model, because of its computerized aspect, assumes the observer to have perfect vision at all distances. Therefore, a certain amount of reasonable interpretation needs to be considered because of the limitations of human vision at greater distances or those atmospheric/meteorological conditions that may cause imperfect vision, such as haze or inclement weather. Additionally, an object is naturally smaller and shows much less detail at distances and will have less visual impact.
2. Because an area may show visibility, it does not mean the entirety of a structure will be seen.
3. The viewshed model assumes that vegetation is opaque and therefore represents a leaf-on condition.
4. The model was developed with the assumption that a viewer would not see structures if standing amongst trees.



0.25 Mile Radius
0.50 Mile Radius
Proposed Transmission Structure
Underground Segment
RENDERING LOCATIONS
Artist Render (A)
Photosimulation (VP)

Open Space
Canoe Access Points
Canoe Trips
DCR Roads and Trails
LONG DISTANCE TRAILS
Bay Circuit Trail
THE SCENIC LANDSCAPE INVENTORY
Noteworthy

MHC HISTORIC INVENTORY POINTS
Nat'l Register of Historic Places
Local Historic District
NRHP and LHD
BIKETRAILS
Underway (Assabet River Rail Trail)

VISIBILITY
Number of Visible Structures
1 - 3
4 - 5
6 - 8
9 - 15
16 - 89

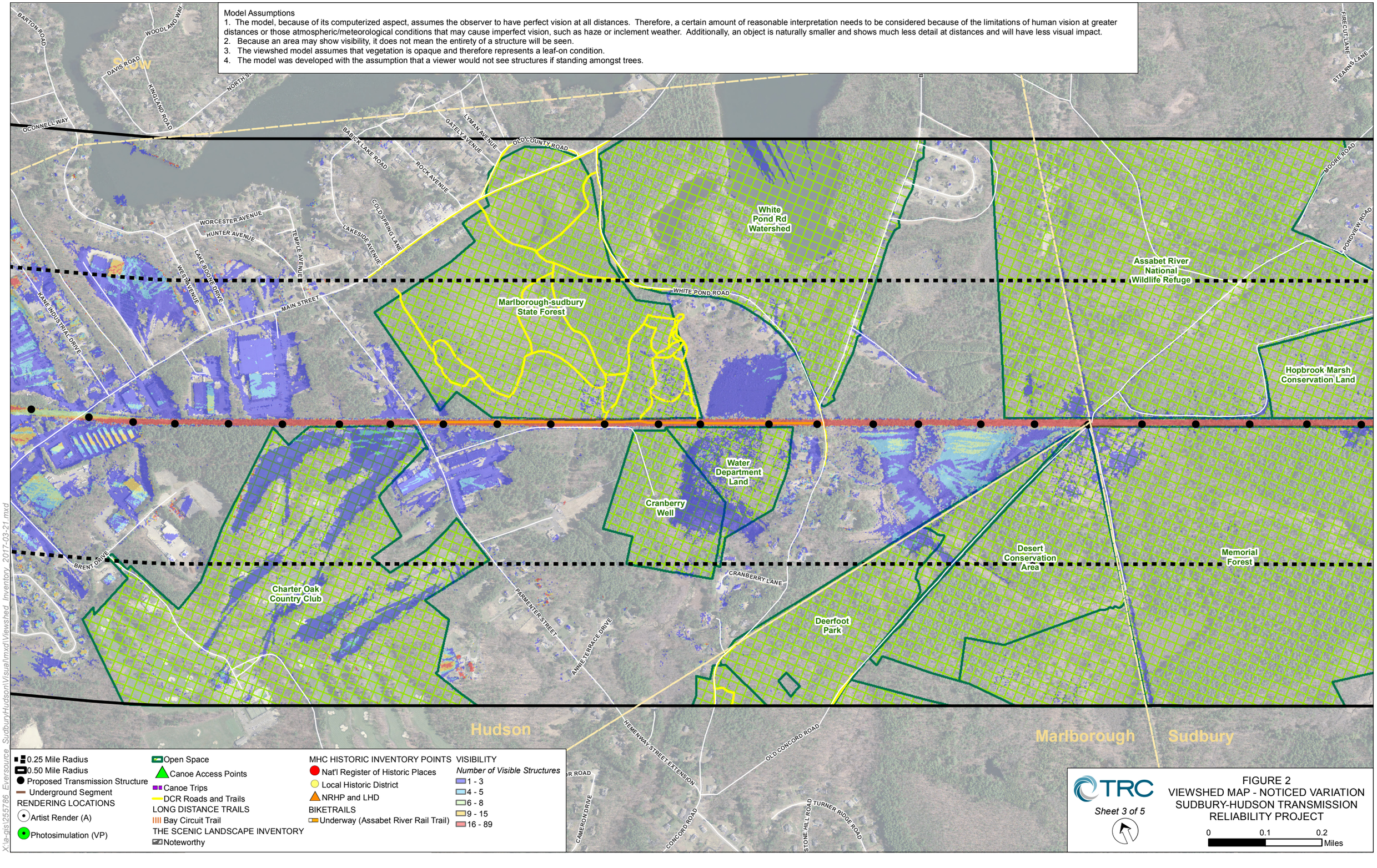
TRC
Sheet 2 of 5

FIGURE 2
VIEWSHED MAP - NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION RELIABILITY PROJECT

0 0.1 0.2 Miles

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16 - 89

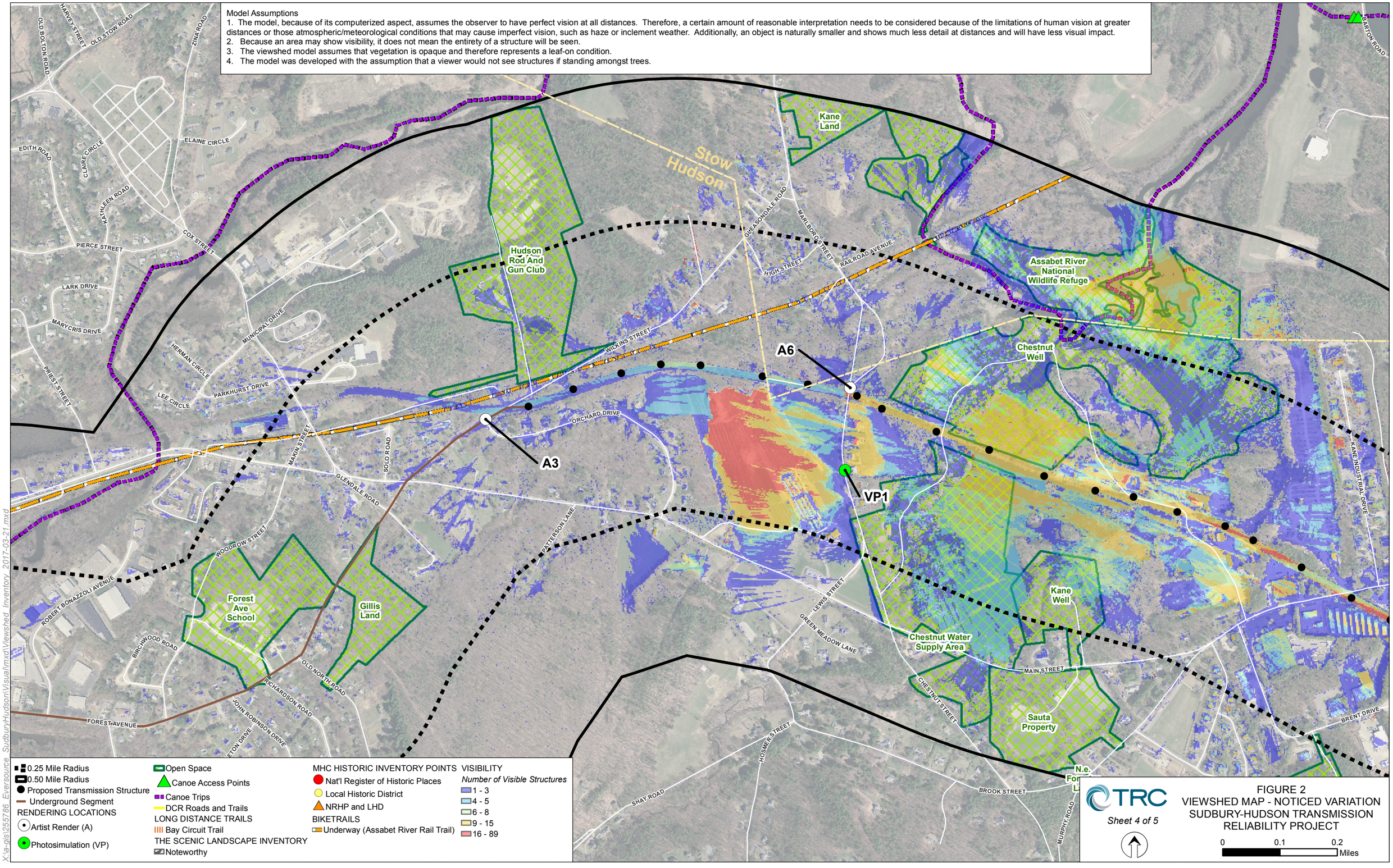
TRC
Sheet 3 of 5

FIGURE 2
VIEWSHED MAP - NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

0 0.1 0.2 Miles

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0.50 Mile Radius
Proposed Transmission Structure
Underground Segment
RENDERING LOCATIONS
Artist Render (A)
Photosimulation (VP)

Open Space
Canoe Access Points
Canoe Trips
DCR Roads and Trails
LONG DISTANCE TRAILS
Bay Circuit Trail
THE SCENIC LANDSCAPE INVENTORY
Noteworthy

MHC HISTORIC INVENTORY POINTS
Nat'l Register of Historic Places
Local Historic District
NRHP and LHD
BIKETRAILS
Underway (Assabet River Rail Trail)

VISIBILITY
Number of Visible Structures
1 - 3
4 - 5
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9 - 15
16 - 89

TRC

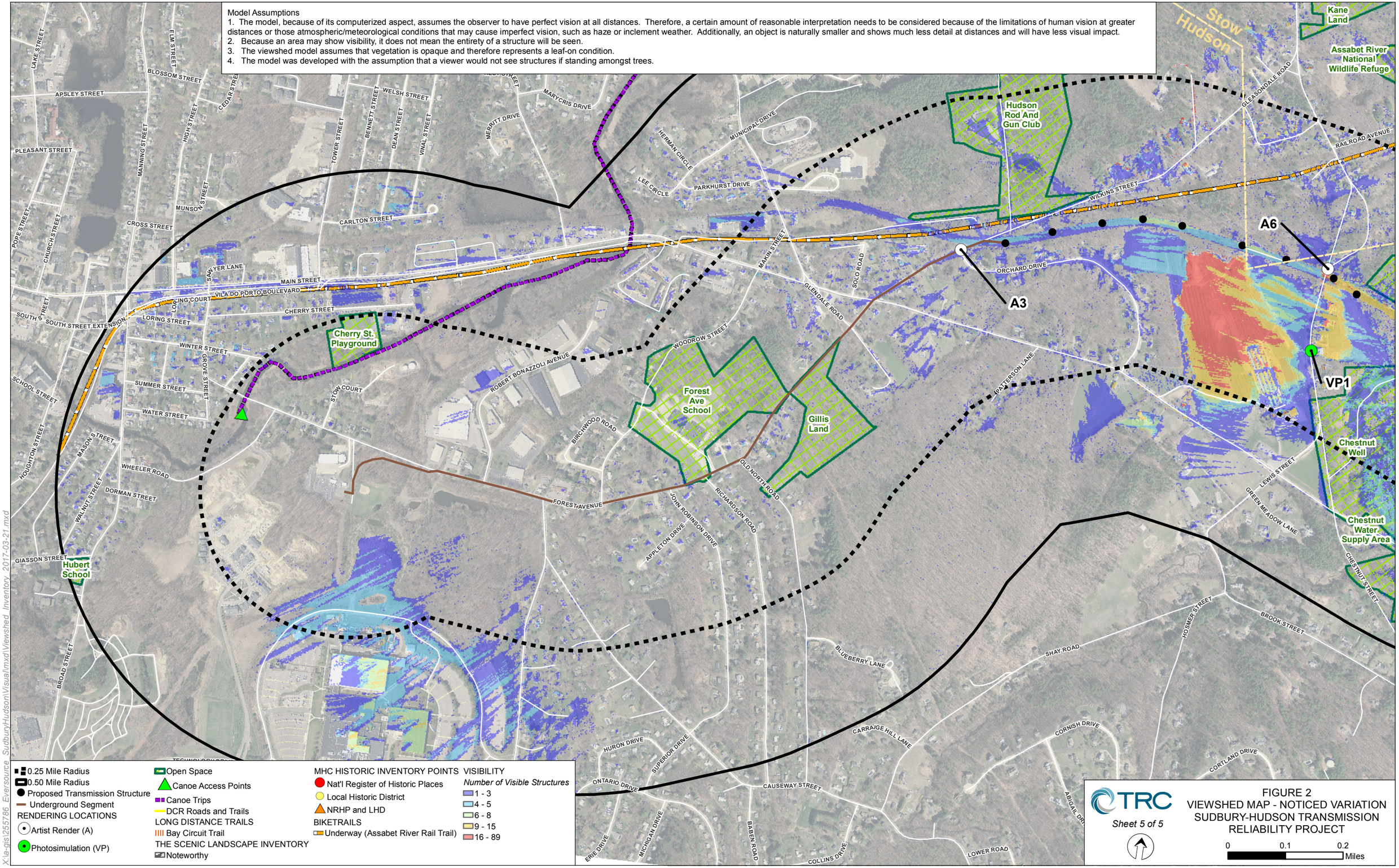
Sheet 4 of 5

FIGURE 2
VIEWSHED MAP - NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

0 0.1 0.2 Miles

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Model Assumptions
1. The model, because of its computerized aspect, assumes the observer to have perfect vision at all distances. Therefore, a certain amount of reasonable interpretation needs to be considered because of the limitations of human vision at greater distances or those atmospheric/meteorological conditions that may cause imperfect vision, such as haze or inclement weather. Additionally, an object is naturally smaller and shows much less detail at distances and will have less visual impact.
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TRC

Sheet 5 of 5

FIGURE 2
VIEWSHED MAP - NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

0 0.1 0.2 Miles

X:\a-gis\255786_Eversource_SudburyHudsonVisual\mxd\Viewshed_Inventory_2017-03-21.mxd

Boston Post Road & Station Road, Sudbury *(Facing East)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



BEALS+THOMAS

DATE: 02/09/2016
BTI FILE NO: 240901P002B-001

FIGURE A1a
BOSTON POST ROAD & STATION AVE
PREFERRED PROJECT
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Boston Post Road & Station Road, Sudbury *(Facing East)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



BEALS+THOMAS

DATE: 03/08/2016
BTI FILE NO: 240901P002C-001

FIGURE A1b
BOSTON POST ROAD & STATION AVE
NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Boston Post Road & Station Road, Sudbury *(Facing East)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



BEALS+THOMAS

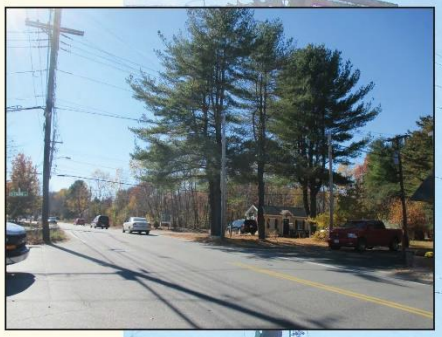
DATE: 03/08/2016
BTI FILE NO: 240901P002D-001

FIGURE A1c
BOSTON POST ROAD & STATION AVE
NOTICED VARIATION – 5 YRS AFTER CONSTRUCTION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Union Ave & Station Road, Sudbury *(Facing South)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail





BEALS+THOMAS

DATE: 02/01/2016
BTI FILE NO: 240901P003A-001

FIGURE A2
UNION AVENUE & STATION ROAD
NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Wilkins Street & Orchard Drive, Hudson *(Facing North)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



BEALS+THOMAS

DATE: 11/12/2015
BTI FILE NO: 240901P004A-001

FIGURE A3
WILKINS STREET & ORCHARD DRIVE
NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Landham Road, Sudbury *(Facing North)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



BEALS+THOMAS

DATE: 11/16/2015
BTI FILE NO: 240901P005A-001

FIGURE A4
LANDHAM ROAD
NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Horse Pond Road, Sudbury *(Facing North)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



BEALS+THOMAS

DATE: 11/17/2015
BTI FILE NO: 240901P006A-001

FIGURE A5
HORSE POND ROAD
NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT

Chestnut Street and Marlboro Road, Hudson *(Facing South)*

EVERSOURCE

Sudbury-Hudson Line and Proposed Rail Trail



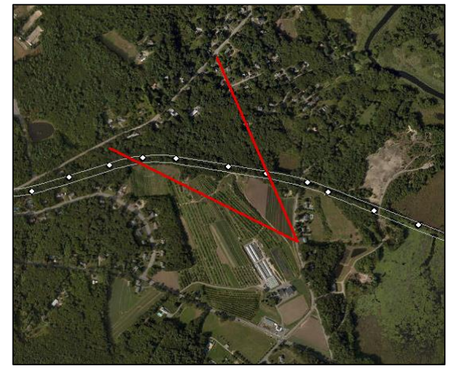
BEALS+THOMAS

DATE: 11/17/2015
BTI FILE NO: 240901P007A-001

FIGURE A6
CHESTNUT STREET & MARLBORO ROAD
NOTICED VARIATION
SUDBURY-HUDSON TRANSMISSION
RELIABILITY PROJECT



VIEWPOINT LOCATION MAP



PROPOSED CONDITIONS



TECHNICAL INFORMATION

Viewpoint Coordinates in	649627.8 E
Mass State Plane feet	2968675.2 N
Viewpoint Location	Chestnut St Hudson
Viewer Elevation	220 ft msl
Distance to Project	974 ft
Camera Model	Canon 5D Full Frame
Lens Setting	50 mm
Date/Time	4.20.16/10:43 am

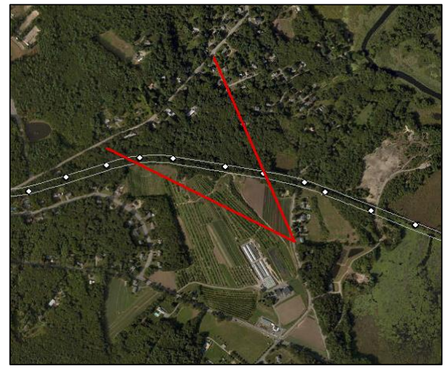
SUDBURY- HUDSON TRANSMISSION RELIABILITY PROJECT

FIGURE VP1a: CHESTNUT STREET, HUDSON– EXISTING CONDITIONS

EVERSOURCE



VIEWPOINT LOCATION MAP



EXISTING CONDITIONS



TECHNICAL INFORMATION

Viewpoint Coordinates in	649627.8 E
Mass State Plane feet	2968675.2 N
Viewpoint Location	Chestnut St Hudson
Viewer Elevation	220 ft msl
Distance to Project	974 ft
Camera Model	Canon 5D Full Frame
Lens Setting	50 mm
Date/Time	4.20.16/10:43 am

SUDBURY- HUDSON TRANSMISSION RELIABILITY PROJECT

FIGURE VP1b: CHESTNUT STREET, HUDSON– PROPOSED CONDITIONS

EVERSOURCE



VIEWPOINT LOCATION MAP



PROPOSED CONDITIONS



TECHNICAL INFORMATION

Viewpoint Coordinates in	668703.1 E
Mass State Plane feet	2961535.0 N
Viewpoint Location	Amanda Rd Sudbury
Viewer Elevation	190 ft msl
Distance to Project	472 ft
Camera Model	Canon 5D Full Frame
Lens Setting	50 mm
Date/Time	4.20.16/12:55 pm

SUDBURY- HUDSON TRANSMISSION RELIABILITY PROJECT

FIGURE VP2a: AMANDA ROAD, SUDBURY– EXISTING CONDITIONS

EVERSOURCE

VIEWPOINT LOCATION MAP



EXISTING CONDITIONS





TECHNICAL INFORMATION

Viewpoint Coordinates in	668703.1 E
Mass State Plane feet	2961535.0 N
Viewpoint Location	Amanda Rd Sudbury
Viewer Elevation	190 ft msl
Distance to Project	472 ft
Camera Model	Canon 5D Full Frame
Lens Setting	50 mm
Date/Time	4.20.16/12:55 pm

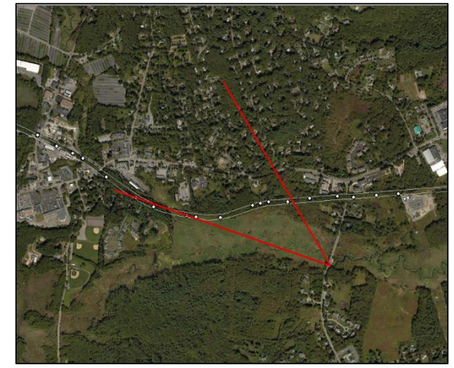
SUDBURY- HUDSON TRANSMISSION RELIABILITY PROJECT

FIGURE VP2b: AMANDA ROAD, SUDBURY– PROPOSED CONDITIONS

EVERSOURCE



VIEWPOINT LOCATION MAP



PROPOSED CONDITIONS



TECHNICAL INFORMATION

Viewpoint Coordinates in	682406.1 E
Mass State Plane feet	2955195.6 N
Viewpoint Location	Landham Rd Sudbury
Viewer Elevation	117 ft msl
Distance to Project	0.33 miles
Camera Model	Canon 5D Full Frame
Lens Setting	50 mm
Date/Time	4.20.16/2:25 pm

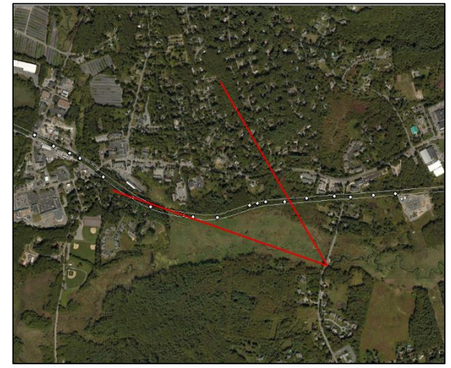
SUDBURY- HUDSON TRANSMISSION RELIABILITY PROJECT

FIGURE VP3a: LANDHAM ROAD, SUDBURY– EXISTING CONDITIONS

EVERSOURCE



VIEWPOINT LOCATION MAP



EXISTING CONDITIONS



TECHNICAL INFORMATION

Viewpoint Coordinates in	682406.1 E
Mass State Plane feet	2955195.6 N
Viewpoint Location	Landham Rd Sudbury
Viewer Elevation	117 ft msl
Distance to Project	0.33 miles
Camera Model	Canon 5D Full Frame
Lens Setting	50 mm
Date/Time	4.20.16/2:25 pm

SUDBURY- HUDSON TRANSMISSION RELIABILITY PROJECT

FIGURE VP3b: LANDHAM ROAD, SUDBURY – PROPOSED CONDITIONS

EVERSOURCE

Appendix 5-9

Health Sciences Practice

Exponent®

Research on Extremely Low Frequency Electric and Magnetic Fields and Health

August 1, 2012 – August 31, 2016

Research on Extremely Low Frequency Electric and Magnetic Fields and Health

August 1, 2012 – August 31, 2016

Submitted to:

Massachusetts Energy Facilities Siting Board
One South Station, Fifth Floor
Boston, MA 02110

Prepared by:

Exponent
149 Commonwealth Drive
Menlo Park, California 94025

December 19, 2016

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Acronyms and Abbreviations

AC	Alternating current
ALL	Acute lymphoblastic leukemia
ALS	Amyotrophic lateral sclerosis
AMI	Acute myocardial infarction
BMP	Best Management Practices
CI	Confidence interval
CSC	Connecticut Siting Council
CVD	Cardiovascular disease
DMBA	dimethylbenz[a]anthracene
EFSB	Energy Facilities Siting Board
ELF	Extremely low frequency
EMF	Electric and magnetic fields (or electromagnetic fields)
EPA	Environmental Protection Agency
F344	Fischer 344
G	Gauss
GD	Gestational day
GHz	Gigahertz
Hz	Hertz
IARC	International Agency for Research on Cancer
ICES	International Committee for Electromagnetic Safety
ICNIRP	International Commission on Non-Ionizing Radiation Protection
kV	Kilovolt
kV/m	Kilovolts per meter
mG	Milligauss
NIEHS	National Institute for Environmental and Health Sciences
NRPB	National Radiation Protection Board of Great Britain
OR	Odds ratio
ROW	Right of way
RR	Relative risk
SCENIHR	Scientific Committee on Emerging and Newly Identified Health Risks

TWA	Time weighted average
V/m	Volts per meter
WHO	World Health Organization

Limitations

At the request of Eversource Energy, Exponent prepared this summary report on the status of research related to extremely low-frequency electric- and magnetic-fields and health. The findings presented herein are made to a reasonable degree of scientific certainty. Exponent reserves the right to supplement this report and to expand or modify opinions based on review of additional material as it becomes available, through any additional work, or review of additional work performed by others.

The scope of services performed during this investigation may not adequately address the needs of other users of this report for purposes other than project permitting, and any re-use of this report or its findings, conclusions, or recommendations presented herein is at the sole risk of the user. The opinions and comments formulated during this assessment are based on observations and information available at the time of the investigation. No guarantee or warranty as to future life or performance of any reviewed condition is expressed or implied.

The following Executive Summary provides only an outline of the material discussed in this report. Exponent's technical evaluations, analyses, conclusions, and recommendations are included in the main body of this report, which at all times is the controlling document.

Executive Summary

This report was prepared to update the Massachusetts Energy Facilities Siting Board (EFSB) on current health research relating to extremely low frequency (ELF) electric and magnetic fields (EMF) at the request of Eversource Energy. This will assist the EFSB and the public to consider evidence from scientific research addressing magnetic fields and public health and the scientific consensus of health and scientific agencies regarding magnetic fields.

ELF EMF are invisible fields surrounding all objects that generate, use, or transmit electricity. People living in developed countries are almost constantly exposed to ELF EMF in their environments, because the electricity network is an essential infrastructure of technologically-advanced societies. Sources of man-made ELF EMF include, for example, appliances, wiring in homes, and electric motors, as well as distribution and transmission lines. Section 2 of this report provides information on the nature and sources of ELF EMF, and typical exposure levels.

Research on EMF and health began with the goal of finding therapeutic applications and understanding biological electricity (i.e., the role of electrical potentials across cell membranes and current flows between cells in our bodies). Since the late 1970s, researchers have examined whether EMF from man-made sources can cause short- or long-term health effects in humans using a variety of study designs and techniques. Research on ELF EMF and long-term human health effects was prompted by an epidemiologic study conducted in 1979 of children in Denver, Colorado, which reported that children with cancer were more likely to live near distribution and transmission lines that appeared to be capable of producing higher magnetic-field levels. The results of that study prompted further research on childhood leukemia and other cancers. Childhood leukemia has remained the focus of ELF EMF and health research, although many other diseases have been studied, including other cancers in children and adults, neurodegenerative diseases, reproductive and developmental effects, cardiovascular diseases, and psychological and behavioral effects such as depression or suicide.

Guidance on the possible health risks of all types of exposures comes from health risk assessments (i.e., systematic weight-of-evidence evaluations of the cumulative literature) on a particular topic conducted by expert panels organized by national and international scientific organizations.

The World Health Organization (WHO) published one of the most comprehensive health risk assessments of EMF in the ELF range in 2007 that critically reviewed the cumulative epidemiologic and laboratory research through 2005, taking into account the strength and quality of individual research studies. The public and policy makers should look to the conclusions of reviews such as this, because they are conducted by scientists representing the various disciplines required to understand the topic at hand applying validated scientific methods in a systematic assessment. The scientific literature published following the publication of the WHO report and

up to 2012 was subsequently considered in systematic reviews submitted by Eversource with previous applications to the Connecticut Siting Council (CSC).[1]

In a health risk assessment of any exposure, it is essential to consider the type and strength of research studies available for evaluation. Human health studies vary in methodological rigor and, therefore, in their capacity to extrapolate findings to the population at large. Furthermore, all studies in three areas of research—epidemiologic, *in vivo* (experimental whole animal), and *in vitro* (experimental in cells and tissues)—must be evaluated to understand possible health risks. Epidemiologic and *in vivo* studies provide the primary basis for a human health risk assessment, with *in vitro* studies contributing supplementary, secondary information on potential biological mechanisms.

Section 3 of this report provides a summary of the methods used to conduct a health risk assessment. Section 4 provides a summary of the WHO's conclusions with regard to various health outcomes (childhood leukemia and brain cancer, adult breast cancer, brain cancer, leukemia/lymphoma; reproductive and developmental effects; neurodegenerative disease; and cardiovascular disease). Section 5 of this report contains a systematic literature review and a critical evaluation of all relevant epidemiologic studies in these areas of research and *in vivo* animal studies of cancer published between August 1, 2012 and August 31, 2016. Finally, the report also provides a brief overview of reviews conducted on EMF health research by scientific organizations since the WHO evaluation (Section 6).

[1] CSC Docket No. 424, "Current Status of Research on Extremely Low Frequency Electric and Magnetic Fields and Health: Interstate Reliability Project, June 10, 2011"; CSC Docket No. 435, "Update of Research on Extremely Low Frequency Electric and Magnetic Fields and Health May 1, 2011 – July 31, 2012, Stamford Reliability Cable Project, August 30, 2012."

1 Introduction

Questions about electric and magnetic fields (EMF) and health are commonly raised during the permitting of transmission lines. Numerous national and international scientific and health agencies have reviewed the research and evaluated potential health risks of exposure to extremely low frequency (ELF) EMF. The most comprehensive of these reviews of ELF EMF research was published by the World Health Organization (WHO) in 2007. The WHO's Task Group critically reviewed the cumulative epidemiologic and laboratory research through 2005, taking into account the strength and quality of the individual research studies.

The WHO report provided the following overall conclusions:

> New human, animal, and in vitro studies published since the 2002 IARC Monograph, 2002 [*sic*] do not change the overall classification of ELF as a possible human carcinogen (WHO, 2007, p. 347).
>
> Acute biological effects [i.e., short-term, transient health effects such as a small shock] have been established for exposure to ELF electric and magnetic fields in the frequency range up to 100 kHz that may have adverse consequences on health. Therefore, exposure limits are needed. International guidelines exist that have addressed this issue. Compliance with these guidelines provides adequate protection. Consistent epidemiological evidence suggests that chronic low-intensity ELF magnetic field exposure is associated with an increased risk of childhood leukaemia. However, the evidence for a causal relationship is limited, therefore exposure limits based upon epidemiological evidence are not recommended, but some precautionary measures are warranted (WHO, 2007, p. 355).

The above WHO conclusions are consistent with conclusions of earlier reviews published by the National Institute for Environmental and Health Sciences (NIEHS) in 1999, the International Agency for Research on Cancer (IARC) in 2002, the Australian Radiation Protection and Nuclear Safety Agency in 2003, the National Radiological Protection Board of Great Britain (NRPB) in 2004, and the Health Council of the Netherlands in 2005.

The scientific literature up to 2012 has been considered in systematic reviews submitted by Eversource as part of previous applications to the CSC.[2]

This Exponent report contains a systematic review and a critical evaluation of the literature, including all relevant epidemiologic studies for various outcomes and *in vivo* studies of carcinogenicity published between August 1, 2012 and August 31, 2016, which were identified

[2] CSC Docket No. 424. "Current Status of Research on Extremely Low Frequency Electric and Magnetic Fields and Health: Interstate Reliability Project, June 10, 2011"; CSC Docket No. 435. "Update of Research on Extremely Low Frequency Electric and Magnetic Fields and Health May 1, 2011 – July 31, 2012 Stamford Reliability Cable Project, August 30, 2012."

in our literature searches. This new report, along with the two previous summaries referenced above, provides an analysis of the status of research on ELF EMF inclusive of 2006 through August 31, 2016.

The studies evaluated in the current and the previous two reports do not provide sufficient evidence to alter the basic conclusion of the WHO: the research does not support the conclusion that ELF EMF at the levels we encounter in our everyday environment, including those near electric power lines, are a cause of cancer or any other disease.

There are no national guidelines or standards in the United States to regulate ELF EMF. The WHO recommends adherence to the International Commission on Non-Ionizing Radiation Protection's (ICNIRP) standards or those developed by the IEEE's International Committee for Electromagnetic Safety (ICES) for the prevention of acute, short-term health effects at high exposure levels (ICES, 2002; ICNIRP, 2010). In light of the epidemiologic data on childhood leukemia, these scientific organizations are still in agreement that only no-cost or low-cost interventions to reduce ELF EMF exposure are appropriate.

This policy approach is consistent with the recommendation of the EFSB for the use of effective no-cost and low-cost technologies to reduce the public's magnetic-field exposure. While the large body of existing research does not indicate any harm associated with long-term ELF EMF exposure, research on this topic will continue to reduce remaining scientific uncertainty.

2 Extremely Low Frequency Electric and Magnetic Fields: Nature, Sources, Exposure, and Known Effects

Nature of ELF EMF

Electricity is transmitted as current from generating sources to high-voltage transmission lines, substations, distribution lines, and then finally to our homes and workplaces for consumption. The vast majority of electricity is transmitted as alternating current (AC), completing full cycles of direction changes 60 times per second (i.e., a frequency of 60 Hertz [Hz]) in North America. ELF EMF from these AC sources is often referred to as power-frequency EMF.

Everything that is connected to our electrical system (i.e., power lines, appliances, and wiring) produces ELF EMF (Figure 1). Electric fields and magnetic fields are both properties of the space near these electrical sources. Forces are experienced by objects capable of interacting with these fields; electric charges are subject to a force in an electric field, and moving charges experience a force in a magnetic field.

- **Electric fields** are the result of voltages applied to electrical conductors and equipment. The electric field is expressed in measurement units of volts per meter (V/m) or kilovolts per meter (kV/m), where 1 kV/m = 1,000 V/m. Conducting objects including fences, buildings, and our own skin and muscle easily block electric fields. Therefore, certain appliances within homes and workplaces are the major source of electric fields indoors, while power lines are the major source of electric fields outdoors.

- **Magnetic fields** are produced by the flow of electric currents. Unlike electric fields, however, most materials (including the earth) do not readily block magnetic fields. The strength of a magnetic field is expressed as magnetic flux density in units of gauss (G) or mG, where 1 G = 1,000 mG.[3] The strength of the magnetic field at any point depends on characteristics of the source, including (in the case of power lines) the arrangement of conductors, the amount of current flow, and distance from the conductors.

Sources and exposure

The intensity of both electric fields and magnetic fields diminishes with increasing distance from the source. For example, higher EMF levels are measured close to the conductors of distribution and transmission lines and decrease rapidly with increasing distance from the conductors. Transmission line EMF generally decreases with distance from the conductors in proportion to the square of the distance, creating a bell-shaped curve of field strength to either side of the line.

Since electricity is such an integral part of our infrastructure (e.g., transportation systems) and our homes and businesses, people living in modern communities are surrounded by these fields (Figure 1). While EMF levels decrease with distance from the source, any home, school, or

[3] Scientists also refer to magnetic flux density at these levels in units of microtesla. Magnetic flux density in mG units can be converted to microtesla by dividing by 10 (i.e., 1 mG = 0.1 microtesla).

office tends to have a background EMF level as a result of the combined effect of the numerous EMF sources present in these locations.

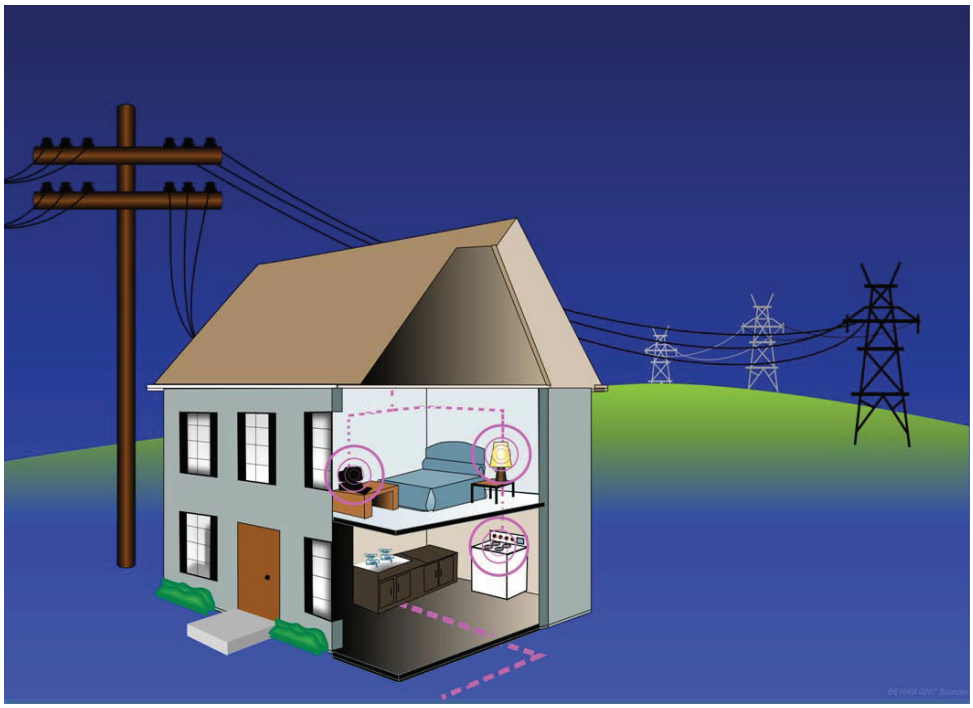


Figure 1. Common sources of ELF EMF in the home (appliances, wiring, currents running on water pipes, and nearby distribution and transmission lines).

Figure 2 outlines typical EMF levels measured in residential settings and occupational environments (all of which contribute to a person's background EMF level) compared to typical EMF levels measured at a typical transmission line's right-of-way (ROW).[4] In general, the background magnetic-field level as estimated from the average of measurements throughout a house away from appliances may range up to approximately 5 mG, while levels can be hundreds of mG in close proximity to appliances. Background levels of electric fields range from 10-20 V/m, while appliances produce levels up to several tens of V/m (WHO, 1984).

Experiments have yet to show which aspect of long-term ELF EMF exposure, if any, may be relevant to biological systems. The most commonly used metric of EMF exposure for health research is long-term, average personal exposure, which is the average of all exposures to the varied electrical sources encountered in the many places we spend our days and nights. As expected, this exposure is different for every person and is difficult to approximate. Exposure assessment is a source of uncertainty in epidemiologic studies of ELF EMF and health (WHO, 2007). Some basic conclusions drawn from surveys of the general public's exposure to magnetic fields are:

[4] The fields from underground transmission lines are not included in this figure because they are a rare source of EMF exposure. The magnetic field over buried conductors can be as high, or even higher, than an overhead line, but the magnetic field will diminish more quickly with distance. No electric field will be produced above ground by underground cables.

- *Residential sources of magnetic-field exposure:*
    - Residential magnetic-field levels are caused by currents carried by nearby transmission and distribution systems, pipes or other conductive paths, and electrical appliances (Zaffanella, 1993).
    - The highest magnetic-field levels are typically found directly next to appliances (Zaffanella, 1993). NIEHS (2002) identified field levels at various distances from a number of common appliances in the home—the highest reported measured values at 6-inches from selected appliances were as follow: can opener, 1,500 mG; dishwasher; 200 mG; electric range, 200 mG; and washing machine, 100 mG; to name a few.
    - Several parameters affect personal magnetic-field exposures at home: residence type, residence size, type of water line, and proximity to overhead power lines. Persons living in small homes, apartments, homes with metallic piping, and homes close to three-phase electric power distribution and transmission lines tended to have higher at-home magnetic-field levels (Zaffanella and Kalton, 1998).
- *Personal magnetic-field exposure:*
    - A survey of approximately 1,000 randomly selected persons in the United States who wore a magnetic field meter that recorded the magnetic field twice each second reports that the average of all measurements taken over 24-hours, i.e., their time-weighted average (TWA) exposure, is less than 2 mG for the vast majority of persons (Zaffanella and Kalton, 1998).[5]
    - In general, personal magnetic-field exposure is greatest at work and when traveling (Zaffanella and Kalton, 1998).
- *Workplace magnetic-field exposure*
    - Some occupations (e.g., electric utility workers, sewing machine operators, telecommunication workers, industrial welders) have higher exposures due to work near equipment with high ELF EMF levels (NIEHS, 2002).
- *Power-line magnetic-field exposure*
    - The EMF levels associated with power lines vary substantially depending on their configuration and current load, among other factors. At a distance of 300 feet and during average electricity demand, however, the magnetic-field levels from many transmission lines are often similar to the background levels found in most homes (Figure 2).

[5] TWA exposure is the average exposure over a given specified time period (i.e., an 8-hour workday or a 24-hour day) of a person's exposure to a chemical or physical agent. The average is determined by sampling the exposure of interest throughout the time period.

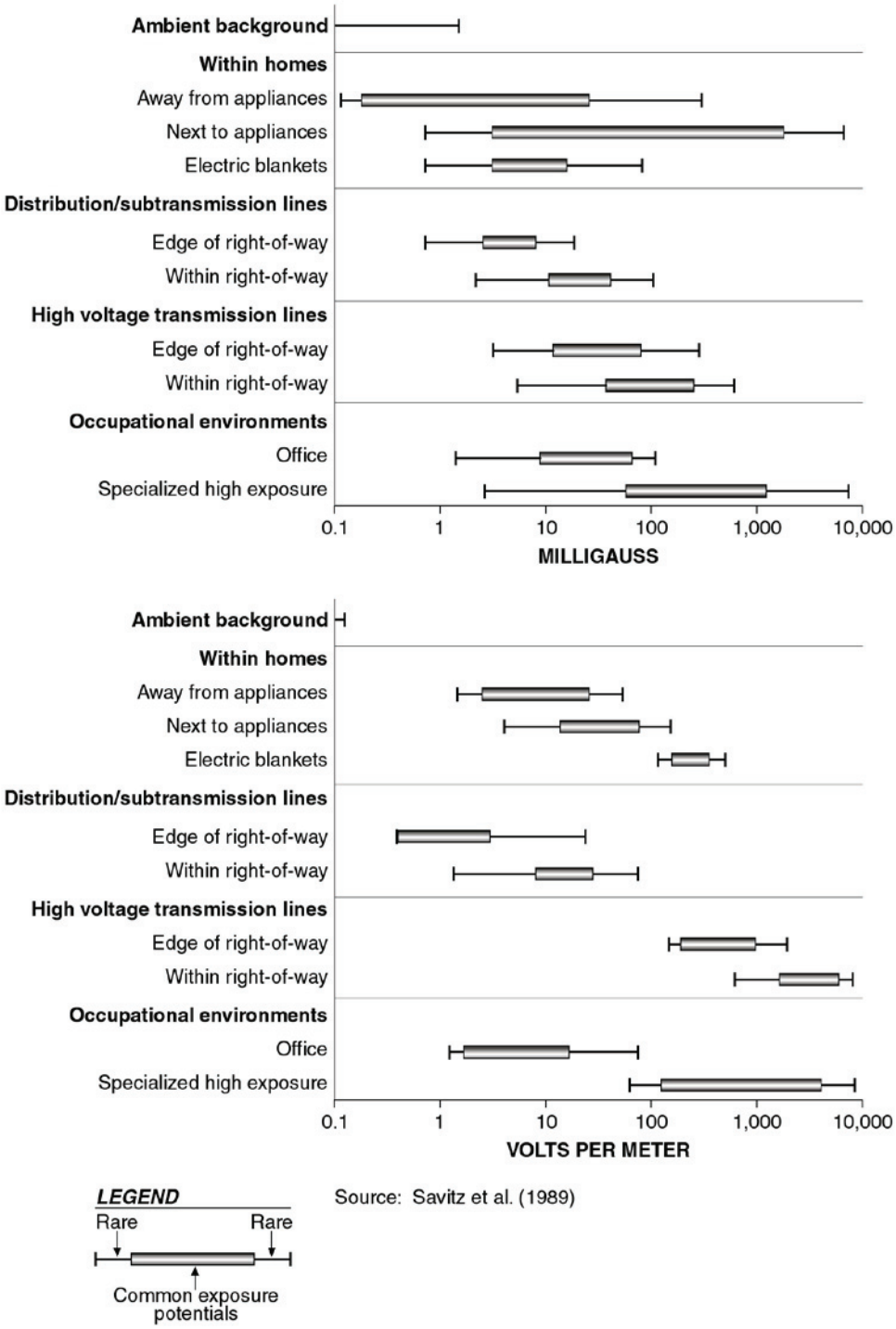


Figure 2. ELF magnetic field (upper panel) and electric field (lower panel) levels in various environments.

Known effects

There is a greater opportunity for long-term exposure to magnetic fields since electric fields are effectively blocked by common conductive objects. For this reason, among others, research on long-term health effects has focused on magnetic fields rather than electric fields.

Like virtually any exposure, adverse effects can be expected from exposure to very high levels of ELF EMF. If the current density or electric field induced by an extremely strong magnetic field exceeds a certain threshold, excitation of muscles and nerves is possible. Also, strong electric fields can induce charges on the surface of the body or ungrounded objects that can lead to small shocks (i.e., micro shocks) when discharged. These effects have no long-term damage or health consequences. Limits for the general public and workplace have been set to prevent these effects, but there are no real-life situations where these levels are exceeded on a regular basis.

Two international scientific organizations, ICNIRP and ICES, have published guidelines for limiting public exposure to ELF EMF to protect against these acute effects (ICES, 2002; ICNIRP, 1998, 2010). These guidelines were developed following weight-of-evidence reviews of the literature, including epidemiologic and experimental evidence related to both short-term and long-term exposure. Both reviews concluded that the stimulation of nerves and the central nervous system could occur at very high exposure levels immediately upon exposure, but that the research did not suggest any long-term health effects.

The ICNIRP guideline states that exposure to magnetic fields should be below 2,000 mG for the general public and 10,000 mG for workers "[to] provide protection against all established adverse health effects" (ICNIRP, 2010). The ICES recommends a maximum permissible magnetic-field exposure of 9,040 mG for the general public (ICES, 2002). For reference, in a survey by Zaffanella and Kalton (1998), only about 1.6% of the general public experienced exposure to magnetic fields of at least 1,000 mG during a 24-hour period.

The ICNIRP's screening value for exposure to 60-Hz electric fields for the general public is 4.2 kV/m and the ICES screening value is 5 kV/m. Both organizations allow higher exposures if it can be demonstrated that exposures do not produce electric fields within tissues that exceed basic restrictions on internal electric fields.

Table 1. Reference levels for whole body exposure to 60-Hz fields: general public

Organization recommending limit	Magnetic fields	Electric fields
ICNIRP restriction level	2,000 mG	4.2 kV/m
ICES maximum permissible exposure	9,040 mG	5 kV/m 10 kV/m[a]

[a] This is an exception within transmission line ROWs because people do not spend a substantial amount of time at these locations and very specific conditions are needed before a response is likely to occur (i.e., a person must be well insulated from ground and must contact a grounded conductor) (ICES, 2002, p. 27).

The literature over the past few years includes a number of studies of workers with the potential for high field exposures that characterize occupational exposure and evaluate compliance with standards. They include a study of spot measurements of EMF during work tasks at 110-kilovots (kV) switching and transforming stations in Finland to evaluate compliance with ICNIRP reference levels (Korpinen et al., 2011a) and a study of occupational electric field exposure at the same 110-kV switching station that evaluated compliance with the European Union's Directive 2004/40/EC (Korpinen et al., 2012); 3-hour TWA magnetic-field measurements of dentists and spot measurements near dental equipment in Taiwan (Huang et al., 2011); spot measurements and personal monitoring of magnetic fields in hospital personnel in Spain (Ubeda et al., 2011); spot measurements and personal monitoring of magnetic fields in railway workers in Italy (Contessa et al., 2010); and a study of electric fields, current densities, and contact currents at a 400-kV substation in Finland (Korpinen et al., 2011b). More recent publications reported measured magnetic-field values inside 110-kV substations in Finland (Korpinen and Pääkkönen, 2015, 2016) and the Ukraine (Okun et al., 2014), and in four power plants in Greece (Christopoulou et al., 2015). The highest measured field levels were 2,500 mG in the first Finnish study, 510 mG in the second Finnish study, 4,200 mG in the Ukranian study, and 4,700 mG in the Greek study in the immediate vicinity of busbars and cables. In general, the measured magnetic fields in these studies were below the occupational reference values of ICNIRP. At some locations within substations, worker exposure to electric fields could exceed the reference level (Korpinen et al., 2011b, 2012), but the calculated induced current density in the central nervous system did not exceed the ICNIRP's 1998 basic restriction value.

3 Methods for Evaluating Scientific Research

Science is more than a collection of facts. It is a method of obtaining information and of reasoning to ensure that the information and conclusions are accurate and correctly describe physical and biological phenomena. Many misconceptions in human reasoning occur when people casually interpret their observations and experience. Therefore, scientists use systematic methods to conduct and evaluate scientific research and assess the potential impact of a specific agent on human health. This process is designed to ensure that more weight is given to those studies of better quality and studies with a given result are not selected out from all of the studies available to advocate or suppress a preconceived idea of an adverse effect. Scientists and scientific agencies and organizations use these standard methods to draw conclusions about the many exposures in our environment.

Weight-of-evidence reviews

The scientific process entails looking at *all* the evidence on a particular issue in a systematic and thorough manner to evaluate if the overall data present a logically coherent and consistent picture. This is often referred to as a weight-of-evidence review, in which all relevant studies are considered together, giving more weight to studies of higher quality and using an established analytic framework to arrive at a conclusion about a possible causal relationship. Weight-of-evidence reviews are typically conducted within the larger framework of health risk assessments or evaluations of particular exposures or exposure circumstances that qualitatively and quantitatively define health risks. Weight-of-evidence and health risk assessment methods have been described by several agencies, including the IARC, which routinely evaluates substances such as drugs, chemicals, and physical agents for their ability to cause cancer; the WHO International Programme for Chemical Safety; and the US Environmental Protection Agency (EPA), which set guidance for public exposures (USEPA, 1993; WHO, 1994; USEPA, 1996; Rooney et al., 2014; OHAT, 2015). Two steps precede a weight-of-evidence evaluation: a systematic review to identify the relevant literature and an evaluation of each study to determine its strengths and weaknesses.

The following sections discuss important considerations in the evaluation of human health studies of ELF EMF in a weight-of-evidence review, including exposure considerations, study design, methods for estimating risk, bias, and the process of causal inference. The purpose of discussing these considerations here is to provide context for the later weight-of-evidence evaluations.

EMF exposure considerations

Exposure assessment methods range widely in studies of EMF. These methods include the classification of residences based on the relative capacity of nearby power lines to produce magnetic fields (i.e., wire code categories); occupational titles; calculated magnetic-field levels based on job histories (e.g., a job-exposure matrix); residential distance from nearby power lines; spot measurements of magnetic-field levels inside or outside residences; 24-hour and 48-hour measurements of magnetic fields in a particular location in the house (e.g., a child's bedroom);

calculated magnetic-field levels based on the characteristics of nearby power installations; and, finally, personal 24-hour and 48-hour magnetic-field measurements.

Each of these methods has strengths and limitations (Kheifets and Oksuzyan, 2008). Since magnetic-field exposures are ubiquitous and vary over a lifetime as the places we frequent and the sources of EMF in those places change, determining valid estimates of personal magnetic-field exposure is challenging. Furthermore, without a biological basis to define a relevant exposure metric (e.g., average or peak exposure) and a defined critical period for exposure (e.g., *in utero* or shortly before diagnosis), relevant and valid assessments of exposure are problematic. Exposure misclassification is one of the most significant concerns in epidemiologic studies of ELF EMF.

In general, long-term personal exposure measurements are the metric recommended by most epidemiologists to estimate exposure in their studies. Changes in the study subjects' behavior or environment that may be related to the disease under investigation, however, could potentially result in misclassification of the exposure when personal measurements are conducted following disease development. Other methods are also subject to exposure misclassification because they may not be strong predictors of long-term exposure and do not take into account all magnetic-field sources.

EMF can be estimated indirectly by assigning an estimated amount of EMF exposure to an individual based on calculations considering nearby power installations or a person's job title. For example, a relative estimate of exposure could be assigned to all machine operators based on historical information on the magnitude of the magnetic field produced by the machine. Indirect measurements are not as accurate as direct measurements because they do not contain information specific to that person or the exposure situation. In the example of machine operators, the indirect measurement may not account for how much time any one individual spends working at that machine or any potential variability in magnetic fields produced by the machines over time, and occupational measurements do not take into account the worker's residential magnetic-field exposures.

While an advance over earlier methods, job-exposure matrices still have some important limitations, as highlighted in a review by Kheifets et al. (2009) summarizing an expert panel's findings.[6] A person's occupation provides some relative indication of the overall magnitude of his or her occupational magnetic-field exposure, but it does not take into account the possible variation in exposure due to different job tasks within occupational titles, the frequency and intensity of contact to relevant exposure sources, or variation by calendar time. This was highlighted in a study of 48-hour magnetic-field measurements of 543 workers in Italy in a variety of occupational settings, including: ceramics, mechanical engineering, textiles, graphics, retail, food, wood, and biomedical industries (Gobba et al., 2011). There was significant variation in this study among the measured TWA magnetic-field levels for workers in many of the International Standard Classification of Occupations' job categories, which the authors attributed to variation in industry within the task-defined categories.

[6] Kheifets et al. (2009) reports on the conclusions of an independent panel organized by the Energy Networks Association in the United Kingdom in 2006 to review the current status of the science on occupational EMF exposure and identify the highest priority research needs.

Types of health research studies

Research studies can be broadly classified into two groups: 1) epidemiologic observations of people and 2) experimental studies conducted on humans, animals (*in vivo*), and cells and tissues (*in vitro*) in laboratory settings.

Epidemiologic studies investigate how disease is distributed in populations and what factors influence or determine this disease distribution (Gordis, 2000). Epidemiologic studies attempt to establish causes for human disease while observing people as they go about their normal, daily lives. Such studies are designed to quantify and evaluate the associations between disease and reported exposures to environmental factors.

The most common types of epidemiologic studies in the EMF literature are case-control and cohort studies. In case-control studies, the exposures of people with and without the disease of interest are compared. Often, people are interviewed or their personal records (e.g., medical records or employment records) are reviewed in order to establish the exposure history for each individual. The exposure histories of the diseased (case) and non-diseased (control) populations are compared to determine whether any statistically significant differences in exposure histories exist. A difference in the exposure of the case and control populations may suggest an association between the exposure and the disease. In cohort studies, on the other hand, individuals within a defined cohort of people (e.g., all persons working at a utility company) are classified as exposed or non-exposed and followed over time for the incidence of disease. Researchers then compare disease incidence in the exposed and non-exposed groups and so can directly estimate exposure related risks.

Experimental studies are designed to test specific hypotheses under controlled conditions and are vital to assessing cause-and-effect relationships. An example of a human experimental study relevant to this area of research would be a study that measures the impact of magnetic-field exposure on acute biological responses in humans, such as hormone levels. These studies are conducted in laboratories under controlled conditions.

In vivo and *in vitro* experimental studies are also conducted under controlled conditions in laboratories. *In vivo* studies expose laboratory animals to very high levels of a chemical or physical agent to determine whether exposed animals develop cancer or other diseases at higher rates than unexposed animals, while attempting to control other factors that could possibly affect disease rates (e.g., diet and genetics). *In vitro* studies of isolated cells and tissues are also important because they can help scientists understand biological mechanisms as they relate to the same exposure in intact humans and animals.

The results of experimental studies of animals, and particularly those of isolated tissues or cells, however, may not always be directly extrapolated to human populations. In the case of *in vitro* studies, the responses of cells and tissues outside the body may not reflect the response of those same cells if maintained in a living system, so their relevance cannot be assumed. Therefore, it is both necessary and desirable to explore agents that could present a potential health threat in epidemiologic studies as well.

Both of these approaches—epidemiologic and experimental laboratory studies—have been used to evaluate whether exposure to EMF has any adverse effects on human health. Epidemiologic studies are valuable because they are conducted in human populations, but they are limited by their non-experimental design and typical retrospective nature. In epidemiologic studies of EMF, for example, researchers cannot control the amount of individual exposure to EMF, the contribution from different field sources, how exposure occurs over time, or individual behaviors that could affect disease risk, such as diet or smoking. In valid risk assessments of EMF, epidemiologic studies are considered alongside experimental studies of laboratory animals, while studies of isolated cells and tissues are generally acknowledged as being supplementary.

Estimating risk

Epidemiologists measure the statistical association between exposures and disease in order to estimate risk. In this context, risk simply refers to an exposure that is associated with a health event and does not imply that a causal relationship has been established.[7] This brief summary of risk is included to provide a foundation for understanding and interpreting statistical associations in epidemiologic studies as risk estimates.

Two common types of risk estimates are absolute risk and relative risk (RR). Absolute risk, also known as incidence, is the amount of new disease that occurs in a given period of time. For example, the absolute risk of invasive childhood cancer in children ages 0-19 years for 2004 was 14.8 per 100,000 children (Ries et al., 2007). RR estimates are calculated to evaluate whether a particular exposure or inherent quality (e.g., EMF, diet, genetics, race) is associated with a disease outcome. This is calculated by looking at the absolute risk in one group relative to that in a comparison group. For example, white children in the 0-19 year age range had an estimated absolute risk of childhood cancer of 15.4 per 100,000 in 2004, and African American children had an estimated absolute risk of 13.3 per 100,000 in the same year. By dividing the absolute risk of white children by the absolute risk of African American children, we obtain a RR estimate of 1.16. This RR estimate can be interpreted to mean that white children have a risk of childhood cancer that is 16% greater than the risk of African American children. Additional statistical analysis is needed to evaluate whether this association is statistically significant, as defined in the following sub-section.

It is important to understand that risk is estimated differently in cohort and case-control studies because of the way the studies are designed. Traditional cohort studies can provide a direct estimate of RR, while case-control studies can only provide indirect estimates of RR, called odds ratios (OR). For this reason, among others, cohort studies usually provide more reliable estimates of the risk associated with particular exposures. Case-control studies are more common than cohort studies, however, because they are less costly and more time efficient.

[7] The following definition is provided of a risk factor in a dictionary of epidemiology terms: "…an aspect of personal behavior or lifestyle, an environmental exposure, or an inborn or inherited characteristic, that, on the basis of epidemiological evidence, is known to be associated with health-related condition(s) considered important to prevent" (Last, 2001, p. 160).

Thus, the association between a particular disease and exposure is measured quantitatively in an epidemiologic study as either the RR estimate (cohort studies) or OR (case-control studies). The general interpretation of a RR estimate equal to 1.0 is that the exposure is not associated with the occurrence of the disease. If the RR estimate is greater than 1.0, the inference is that the exposure is associated with an increased incidence of the disease. On the other hand, if the RR estimate is less than 1.0, the inference is that the exposure is associated with a reduced incidence of the disease. The magnitude of the RR estimate is often referred to as its strength (i.e., strong vs. weak). Stronger associations are given more weight because they are less susceptible to the effects of bias.

Statistical significance

Statistical significance testing provides an idea of whether or not a statistical association is caused by chance alone, i.e., whether the association is likely to be observed upon repeated testing or whether it is simply a chance occurrence. The terms "statistically significant" or "statistically significant association" are used in epidemiologic studies to describe the tendency of the level of exposure and the occurrence of disease to be linked, with chance alone as an unlikely explanation. Statistically significant associations, however, are not automatically an indication of cause-and-effect, because the interpretation of statistically significant associations depends on many other factors associated with the design and conduct of the study, including, how the data were collected and the size of the study. Statistical significance testing in itself does not provide any information on potential sources of systematic error or bias in the study.

Confidence intervals (CI) are typically reported along with RR and OR values. A CI is a range of values for an estimate of effect that has a specified probability (e.g., 95%) of including the true estimate of effect; CIs evaluate statistical significance, but do not address the role of bias, as described further below. A 95% CI indicates that, if the study were conducted a very large number of times, 95% of the measured estimates would be within the upper and lower confidence limits.

The range of the CI is also important for interpreting estimated associations, including the precision and statistical significance of the association. A very wide CI indicates great uncertainty in the value of the true risk estimate. This is usually due to a small number of observations. A narrow CI provides more certainty about where the true RR estimate lies (assuming no bias in the study). Another way of interpreting the CI is if the 95% CI does not include 1.0, the probability of an association being due to chance alone is 5% or lower and the result is considered statistically significant, as discussed above. Statistical variation, however, while easily estimated, is just one of the sources of uncertainty in the characterization of epidemiological associations. Additional uncertainties may result from bias (e.g., participation, selection, or recall biases) and confounding by alternative exposures. These additional uncertainties are not quantified by statistical testing and the assessment of their influence on the overall interpretation requires expert evaluation of information from outside the studies themselves.

Meta-analysis and pooled analysis

In epidemiologic research, the results of studies with a smaller number of participants may be difficult to distinguish from normal, random variation. This is also the case for sub-group analyses where few cases are estimated to have high exposure levels (e.g., in case-control studies of childhood leukemia and TWA magnetic-field exposure greater than 3-4 mG). Meta-analysis is an analytic technique that combines the published results from a group of studies into one summary result. A pooled analysis, on the other hand, combines the raw, individual-level data from the original studies and analyzes all of the data from the studies together. These methods are valuable because they increase the number of individuals in the analysis, which allows for a more robust and stable estimate of association. Meta- and pooled analyses also are an important tool for quantitatively synthesizing the results of a large group of studies.

The disadvantage of meta- and pooled analyses is that they can convey a false sense of consistency across studies if *only* the combined estimate of effect is considered (Rothman and Greenland, 1998). These analyses typically combine data from studies with different study populations, methods for measuring and defining exposure, and disease definitions. This is particularly true for analyses that combine data from case-control studies, which often use very different methods for the selection of cases and controls and exposure assessment. Therefore, in addition to the synthesis or combining of data, meta- and pooled analyses should be used to understand what factors cause the results of the studies to vary (e.g., publication date, study design, possibility of selection bias), and how these factors affect the associations calculated from the data of all the studies combined (Rothman and Greenland, 1998).

Meta- and pooled analyses are a valuable technique in epidemiology; however, in addition to calculating a summary RR, they should follow standard techniques (Stroup et al., 2001) and analyze the factors that contribute to any heterogeneity between the studies. It is also important to note that potential biases present in the original individual studies will also impact the results of the meta- and pooled analyses.

Bias in epidemiologic studies

One key reason that results of non-experimental epidemiologic studies cannot directly provide evidence for cause-and-effect is the potential presence of bias. Bias is defined as “any systematic error in the design, conduct or analysis of a study that results in a mistaken estimate of an exposure’s effect on the risk of disease” (Gordis, 2000, p. 204). In other words, sources of bias are factors or research situations that can mask a true association or cause an apparent association in the study that does not truly exist. As a result, the extent of bias, as well as its types and sources, is one of the most important considerations in the interpretation of epidemiologic studies. Since it is not possible to fully control human populations, perfectly measure their exposures, or control for the effects of all other risk factors, bias will exist in some form in all epidemiologic studies of human health. Experimental studies, on the other hand, more effectively manage bias because of the tight control the researchers have over most study variables.

One important source of bias occurs when a third variable confuses the relationship between the exposure and disease of interest because of its relationship to both. Consider an example of a

researcher whose study finds that people who exercise have a lower risk of diabetes compared to people who do not exercise. It is known that people who exercise more also tend to consume healthier diets and healthier diets may lower the risk of diabetes. If the researcher does not control for the impact of diet, it is not possible to say with certainty that the lower risk of diabetes is due to exercise and not to a healthier diet. In this example, diet is the confounding variable.

Cause vs. association and evaluating evidence regarding causal associations

Epidemiologic studies can help suggest factors that may contribute to the risk of disease, but they are not used as the sole basis for drawing inferences about cause-and-effect relationships. Since epidemiologists do not have control over the many other factors to which people are exposed in their studies (e.g., chemicals, pollution, infections) and diseases can be caused by a complex interaction of many factors, the results of epidemiologic studies must be interpreted with caution. A single epidemiologic study is rarely unequivocally supportive or non-supportive of causation; rather, a weight is assigned to the study based on the validity of its methods and all studies (epidemiologic, *in vivo*, and *in vitro*) must be considered together in a weight-of-evidence review to arrive at a conclusion about possible causality between an exposure and disease.

Scientific guidance for assessing the overall epidemiologic evidence for causality was formally proposed by Sir Austin Bradford Hill (Hill, 1965). Hill put forth nine criteria for use in an evaluation of causality for associations observed in epidemiologic studies. These criteria included strength of association, consistency, specificity, temporality, biological gradient, plausibility, coherence, experiment, and analogy. Hill cautioned that, while none of these criteria are *sine qua non* of causality, the more the epidemiologic evidence meets these guidelines, the more convincing the evidence is for a potential causal interpretation. The use of these guidelines is recommended after chance is ruled out with reasonable certainty as a potential explanation for the observed epidemiologic association.

In 1964, the Surgeon General of the United States published a landmark report on smoking-related diseases (HEW, 1964). As part of this report, nine criteria, similar to those proposed by Hill for evaluating epidemiologic studies (along with experimental data) for causality, were outlined. In a more recent version of this report, these criteria have been reorganized into seven criteria. In the earlier version, coherence, plausibility, and analogy were considered as distinct items, but are now summarized together because they have been treated in practice as essentially reflecting one concept (HHS, 2004). Table 2 provides a listing of the criteria and a brief description of each.

Table 2. Criteria for evaluating whether an association is causal

Criteria	Description
Consistency	Repeated observation of an association between exposure and disease in multiple studies of adequate statistical power, in different populations, and at different times.
Strength of the association	The larger (stronger) the magnitude and statistical strength of an association is between exposure and disease, the less likely such an effect is the result of chance or unmeasured confounding.
Specificity	The exposure is the single (or one of a few) cause of disease.
Temporality	The exposure occurs prior to the onset of disease.
Coherence, plausibility, and analogy	The association cannot violate known scientific principles and the association must be consistent with experimentally demonstrated biologic mechanisms.
Biologic gradient	This is also known as a dose-response relationship, i.e., the observation that the stronger or greater the exposure is, the stronger or greater the effect.
Experiment	Observations that result from situations in which natural conditions imitate experimental conditions. Also stated as a change in disease outcome in response to a non-experimental change in exposure patterns in population.

Source: Department of Health and Human Services, 2004

The criteria were meant to be applied to statistically significant associations that have been observed in the cumulative epidemiologic literature, i.e., if no statistically significant association has been observed for an exposure then the criteria are not relevant. It is important to note that these criteria were not intended to serve as a checklist; rather, they were intended to serve as a guide in evaluating associations for causal inference. Theoretically, it is possible for an exposure to meet all seven criteria, but still not be deemed a causal factor. Also, no one criterion can provide indisputable evidence for causation, nor can any single criterion, aside from temporality, rule out causation.

In summary, the judicious consideration of these criteria is useful in evaluating epidemiologic studies, but they cannot be used as the sole basis for drawing inferences about cause-and-effect relationships. In line with the criteria of "coherence, plausibility, and analogy," epidemiologic studies are considered along with *in vivo* and *in vitro* studies in a comprehensive weight-of-evidence review. Epidemiologic support for causality is usually based on high-quality studies reporting consistent results across many different populations and study designs that are supported by the experimental data collected from *in vivo* and *in vitro* studies.

Biological response vs. disease in human health

When interpreting research studies, it is important to distinguish between a reported biological response and an indicator of disease. This is relevant because exposure to EMF may elicit a biological response that is simply a normal response to environmental conditions. This response, however, might not be a disease, cause a disease, or be otherwise harmful. There are many exposures or factors encountered in day-to-day life that elicit a biological response, but the response is neither harmful nor does it cause disease. For example, when an individual walks

from a dark room indoors to a sunny day outdoors, the pupils of the eye naturally constrict to limit the amount of light passing into the eye. This constriction of the pupil is a biological response to the change in light conditions. Pupil constriction, however, is neither a disease itself, nor is it known to cause disease.

4 The WHO 2007 Report: Methods and Conclusions

The WHO is a scientific organization within the United Nations system whose mandate includes providing leadership on global health matters, shaping health research agendas, and setting norms and standards. The WHO established the International EMF Project in 1996, in response to public concerns about exposure to EMF and possible adverse health outcomes. The project's membership includes 8 international organizations, 8 collaborating institutions, and over 54 national authorities. The overall purpose of the Project is to assess health and environmental effects of exposure to static and time-varying fields in the frequency range 0-300 Gigahertz (GHz). A key objective of the EMF Project was to evaluate the scientific literature and make a status report on health effects to be used as the basis for a coherent international response, including the identification of important research gaps and the development of internationally acceptable standards for EMF exposure.

Methods

As part of their Environmental Health Criteria Programme, the WHO published a Monograph in June 2007 summarizing health research on EMF exposure in the ELF range. The Monograph used standard scientific procedures, as outlined in its Preamble and described above in Section 3, to conduct the review. The Task Group responsible for the report's overall conclusions consisted of 21 scientists from around the world with expertise in a wide range of disciplines. The Task Group relied on the conclusions of previous weight-of-evidence reviews,[8] where possible, and mainly focused on evaluating studies published after an IARC review of ELF EMF (with regard to cancer) in 2002 .

The WHO Task Group and IARC use specific terms to describe the strength of the evidence in support of causality between specific agents and cancer. These categories are described here because, while they are meaningful to scientists who are familiar with the IARC process, they can be confusing and can create an undue level of concern with the general public.

Sufficient evidence of carcinogenicity is assigned to a body of epidemiologic research if a positive association has been observed in studies in which chance, bias, and confounding can be ruled out with reasonable confidence. *Limited evidence of carcinogenicity* describes a body of epidemiologic research where chance, bias, or confounding cannot be ruled out as an explanation for the observed epidemiologic association; the findings are inconsistent or there are outstanding questions about study design or other methodological issues that preclude making a conclusion. *Inadequate evidence of carcinogenicity* describes a body of epidemiologic research where it is unclear whether the data are supportive or unsupportive of causation because there is a lack of data or there are major quantitative or qualitative issues. A similar classification system is used for evaluating *in vivo* studies and mechanistic data for carcinogenicity.

[8] The term weight-of-evidence review is used in this report to denote a systematic review process by a multidisciplinary, scientific panel involving experimental and epidemiologic research to arrive at conclusions about possible health risks. The WHO Monograph on EMF does not specifically describe their report as a weight-of-evidence review. Rather, they describe conducting a health risk assessment. A health risk assessment differs from a weight-of-evidence review in that it also incorporates an exposure and exposure-response assessment.

Summary categories are assigned by considering the conclusions of epidemiologic and *in vivo* evidence together (Figure 3).[9] Categories include (from highest to lowest risk): known carcinogen; probable carcinogen; possible carcinogen; not classifiable; and probably not a carcinogen. These categories are intentionally meant to err on the side of caution, giving more weight to the possibility that the exposure is truly carcinogenic and less weight to the possibility that the exposure is not carcinogenic. In the IARC classification system, possible carcinogen denotes exposures for which there is limited evidence of carcinogenicity in epidemiologic studies and less than sufficient evidence of carcinogenicity in studies of experimental animals.

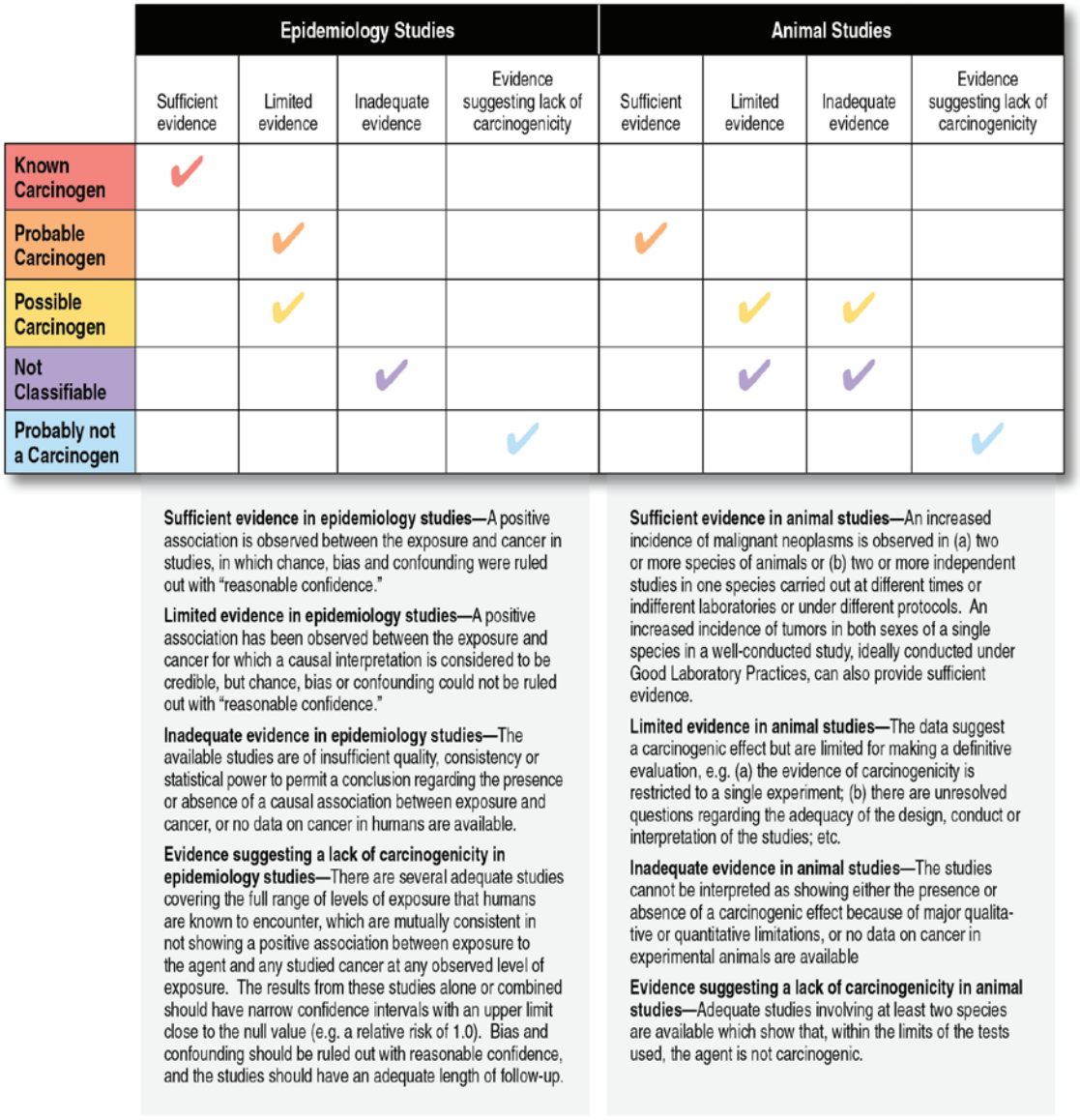


Figure 3. Basic IARC method for classifying exposures based on potential carcinogenicity.

[9] *In vitro* research is not described in Figure 3 because it provides ancillary information and, therefore, is used to a lesser degree in evaluating carcinogenicity. *In vitro* studies are classified simply as strong, moderate, or weak.

As of September 2016, the IARC has reviewed close to 1,000 substances and exposure circumstances to evaluate their potential carcinogenicity. About 80% of exposures fall in the categories of possible carcinogen (29%) or not classifiable (51%). This occurs because it is nearly impossible to prove that something is completely safe and few exposures show a clear-cut or probable risk, so most agents will end up in either of these two categories. Throughout the history of the IARC, only one agent has been classified as probably not a carcinogen, which illustrates the conservatism of the evaluations and the difficulty in proving the absence of an effect beyond all doubt.

Conclusions

The WHO report provided the following overall conclusions with regard to ELF EMF:

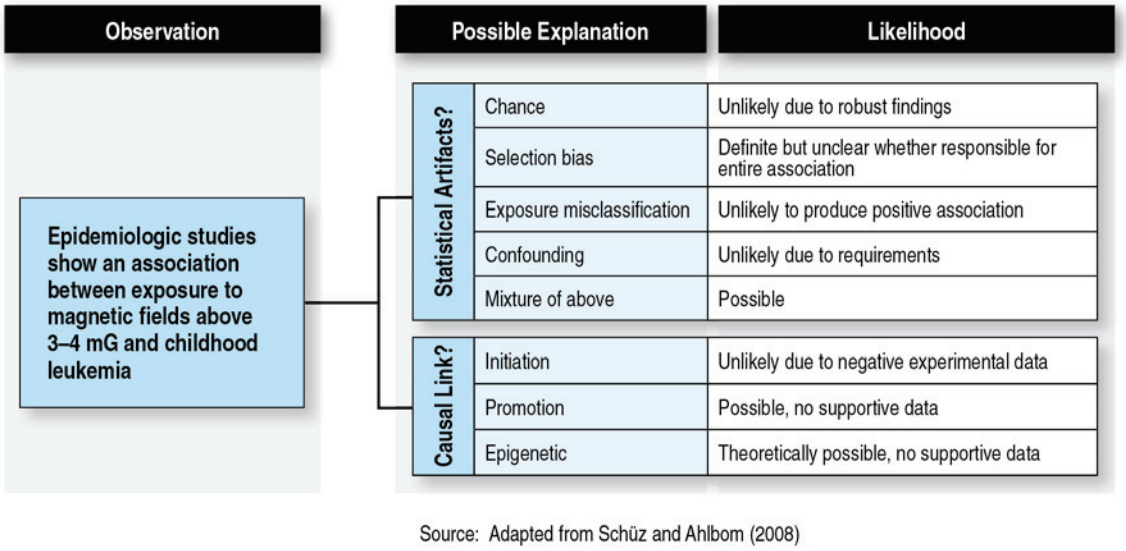
> New human, animal, and *in vitro* studies published since the 2002 IARC Monograph, 2002 [*sic*] do not change the overall classification of ELF as a possible human carcinogen (WHO, 2007, p. 347).
>
> Acute biological effects [i.e., short-term, transient health effects such as a small shock] have been established for exposure to ELF electric and magnetic fields in the frequency range up to 100 kHz [kilohertz] that may have adverse consequences on health. Therefore, exposure limits are needed. International guidelines exist that have addressed this issue. Compliance with these guidelines provides adequate protection. Consistent epidemiological evidence suggests that chronic low-intensity ELF magnetic field exposure is associated with an increased risk of childhood leukaemia. However, the evidence for a causal relationship is limited, therefore exposure limits based upon epidemiological evidence are not recommended, but some precautionary measures are warranted (WHO, 2007, p. 355).

With regard to specific diseases, the WHO concluded the following:

Childhood cancers. The WHO report paid particular attention to childhood leukemia because the most consistent epidemiologic association in the area of ELF EMF and health research has been reported between this disease and estimates of TWA exposure to relatively high average magnetic-field levels. Two pooled analyses reported an association between childhood leukemia and TWA magnetic-field exposure greater than 3-4 mG (Ahlbom et al., 2000; Greenland et al., 2000); these data, categorized as limited epidemiologic evidence, resulted in the classification of ELF magnetic fields as a possible carcinogen by the IARC in 2002.

The WHO report systematically evaluated several factors that might be partially, or fully, responsible for the consistent association, including: chance; misclassification of magnetic-field exposure; confounding from hypothesized or unknown risk factors; and selection bias (Figure 4). The authors concluded that chance is an unlikely explanation since the pooled analyses had a large sample size and decreased variability. Control selection bias probably occurs to some extent in these studies and would result in an overestimate of the true association, but would likely not entirely explain the observed association. It is less likely that confounding occurs, although the possibility that some yet-to-be identified confounder is responsible for the

association cannot be fully excluded. Finally, exposure misclassification would likely result in an underestimate of the true association, although that may not always be the case. The WHO concluded that reconciling the apparent discrepancy between epidemiologic data on childhood leukemia and the negative experimental findings (i.e., no hazard or risk observed) through innovative research is currently the highest priority in the field of ELF EMF research. It is worth noting here that a recommendation for further research is not an indication of the likelihood of causality, rather further research is recommended to reduce scientific uncertainty and to make sure that even small potential effects are not missed. Given that few children are expected to have average magnetic-field exposures greater than 3-4 mG, however, the WHO stated that the public health impact of magnetic fields on childhood leukemia would likely be minimal, even if the association was determined to be causal.



Source: Adapted from Schüz and Ahlbom (2008)

Figure 4. Possible explanations for the observed association between magnetic fields and childhood leukemia.

Fewer studies have been published on magnetic fields and childhood brain cancer compared to studies of childhood leukemia. The WHO Task Group described the results of these studies as inconsistent and limited by small sample sizes. They recommended a meta-analysis to clarify the research findings.

Breast cancer. The WHO concluded that the more recent published studies on breast cancer and ELF EMF exposure were higher in quality compared with earlier studies, and for that reason, they provided strong support to previous consensus statements that magnetic-field exposure does not influence the risk of breast cancer. In summary, the WHO stated "[w]ith these [recent] studies, the evidence for an association between ELF magnetic-field exposure and the risk of female breast cancer is weakened considerably and does not support an association of this kind" (WHO, 2007, p. 9). The WHO recommended no further research with respect to breast cancer and magnetic-field exposure.

Adult leukemia and brain cancer. The WHO concluded, "In the case of adult brain cancer and leukaemia [*sic*], the new studies published after the IARC monograph do not change the conclusion that the overall evidence for an association between ELF [EMF] and the risk of these diseases remains inadequate" (WHO, 2007, p. 307). The WHO panel recommended updating the existing European cohorts of occupationally-exposed individuals and pooling the epidemiologic data on brain cancer and adult leukemia to confirm the absence of an association.

In vivo research on carcinogenesis. The WHO concluded the following with respect to *in vivo* research, "[t]here is no evidence that ELF exposure alone causes tumours. The evidence that ELF field exposure can enhance tumour [*sic*] development in combination with carcinogens is inadequate" (WHO, 2007, p. 10). Recommendations for future research included the development of a rodent model for childhood acute lymphoblastic leukemia (ALL) and the continued investigation of whether magnetic fields can act as a co-carcinogen.

In vitro research on carcinogenesis. The WHO concluded that magnetic-field exposure below 50,000 mG was not associated with genotoxicity *in vitro*. There was some evidence, however, to suggest that magnetic fields above these levels might interact with other genotoxic agents to induce damage. Evidence for an association between magnetic fields and altered apoptosis or expression of genes controlling cell cycle progression was considered inadequate.

Reproductive and developmental effects. The WHO concluded that, overall, the body of research does not suggest that maternal or paternal exposures to ELF EMF cause adverse reproductive or developmental outcomes. The evidence from epidemiologic studies on miscarriage was described as inadequate and further research on this possible association was recommended, although it was designated as low priority.

In vivo research on reproductive and developmental effects. The WHO Task Group concluded that the available *in vivo* studies were inadequate for drawing conclusions regarding the potential effects of magnetic fields on the reproductive system. Furthermore, the Task Group concluded that studies conducted in mammalian models showed no adverse developmental effects associated with magnetic-field exposure.

Neurodegenerative disease. The WHO reported that the majority of epidemiologic studies have reported associations between occupational magnetic-field exposure and mortality from Alzheimer's disease and amyotrophic lateral sclerosis (ALS), although the design and methods of these studies were relatively weak (e.g., disease status was based on death certificate data; exposure was based on incomplete occupational information from census data; and there was no control for confounding factors). The WHO concluded that there is inadequate data in support of an association between magnetic fields and Alzheimer's disease or ALS. The panel highly recommended that further studies be conducted in this area, particularly studies where the association between magnetic fields and ALS is estimated while controlling for the possible confounding effect of electric shocks.

In vivo research on neurological effects. The WHO stated that various animal models were used to investigate possible field-induced effects on brain function and behavior. Few brief, transient responses had been identified.

Cardiovascular disease. It has been hypothesized that magnetic-field exposure reduces heart rate variability, which in turn increases the risk for acute myocardial infarction (AMI). With one exception (Savitz et al., 1999), however, none of the studies of cardiovascular disease morbidity and mortality has shown an association with exposure. Whether a specific association exists between exposure and altered autonomic control of the heart remains speculative and the overall evidence does not support an association. Experimental studies of both short- and long-term exposure indicate that, while electric shock is an obvious health hazard, other hazardous cardiovascular effects associated with ELF EMF are unlikely to occur at exposure levels commonly encountered environmentally or occupationally.

5 Current Scientific Consensus

The following sections identify and describe epidemiologic studies and *in vivo* studies of carcinogenesis related to ELF EMF exposure published from August 1, 2012 through August 31, 2016. The purpose of this section is to evaluate whether the findings of these recent studies alter the conclusions published by the WHO in their 2007 report, as described in Section 4.

A structured literature search was conducted using PubMed, a search engine provided by the National Library of Medicine and the National Institutes of Health that includes over 26 million up-to-date citations from MEDLINE and other life science journals for biomedical articles (http://www.pubmed.gov). A well-defined search strategy was used to identify literature indexed August 1, 2012 through August 31, 2016.[10] While PubMed contains an extensive database of publications, some studies are indexed well after their publication date. For that reason, there may be studies included in this report that were actually published prior to August 1, 2012, but indexed after that date.

All fields (title, abstract, keywords, among others) were searched with various search strings that referenced the exposure[11] and diseases of interest.[12] A scientist with experience in this area reviewed the titles and abstracts of these publications for inclusion in this evaluation. Only peer-reviewed, epidemiologic studies and pooled- or meta-analyses of 50-Hz or 60-Hz AC ELF EMF and recognized disease entities are included. *In vivo* animal and human studies of 50-Hz or 60-Hz AC ELF EMF are also included, but only on the topic of cancer.

In addition to PubMed, EMF-Portal was also searched for relevant articles published during the same timeframe.[13] EMF-Portal is an extensive online database dedicated to scientific research related to potential effects of EMF. EMF-Portal currently includes over 23,000 publications on EMF at all frequencies and close to 6,000 research summaries in a searchable format. EMF-Portal is maintained by Aachen University in Germany.

Methodological research is now being pursued in many areas of ELF EMF research to identify the possible impact of certain aspects of study design or biases on the studies' results. Therefore, articles evaluating the impact of methodological aspects of epidemiologic studies in this field are discussed, where appropriate. Systematic review articles of relevant topics are also noted, where appropriate. Studies published prior to the scope of this update are noted in certain circumstances to provide context.

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[10] While extensive efforts were made to identify relevant studies, it is possible that some studies reporting on the association between a disease and some measure of EMF exposure were missed. Many occupational and environmental case-control studies of cancer are published, some of which examine a large number of possible exposures; if no reference to EMF is made in the abstract, title, or keywords, for example, these studies may not have been identified using our search strategy. The most informative studies in this field, however, will be identified by our search strategy.

[11] EMF, magnetic fields, electric fields, or electromagnetic.

[12] Cancer (cancer, leukemia, lymphoma, carcinogenesis), neurodegenerative disease (neurodegenerative disease, Alzheimer's disease, amyotrophic lateral sclerosis, or Lou Gehrig's disease), cardiovascular effects (cardiovascular or heart rate), or reproductive outcomes (miscarriage, reproduction, or development).

[13] http://www.emf-portal.de

Epidemiologic studies are evaluated below by outcome (childhood cancer; adult cancer; reproductive or developmental effects; neurodegenerative diseases; and cardiovascular effects), followed by an evaluation of *in vivo* research in the field of cancer. Tables 3-11 list the relevant studies in these areas, including the study's first author and the title of the article. No recent epidemiologic studies have assessed exposure to electric fields, thus, all EMF epidemiologic studies discussed below are magnetic field studies.

Childhood leukemia

In 2002, the IARC reviewed research related to ELF EMF to evaluate the strength of the evidence in support of carcinogenicity. The IARC expert panel noted that, when studies with the relevant information were combined in a pooled analysis, a statistically significant, approximately two-fold association was observed between childhood leukemia and estimated exposure to high, average levels of magnetic fields (i.e., greater than 3-4 mG of average 24- and 48-hour exposure). This evidence was classified as limited evidence in support of carcinogenicity, falling short of sufficient evidence because chance, bias, and confounding could not be ruled out with reasonable confidence. Largely as a result of the findings related to childhood leukemia, the IARC classified magnetic fields as a possible carcinogen, a category that describes exposures with limited epidemiologic evidence and inadequate evidence from *in vivo* studies (see Figure 3). The classification of possible carcinogen was confirmed by the WHO in their June 2007 review.

Recent studies (2012 – 2016)

Childhood leukemia continues to be the main focus of ELF EMF epidemiologic research. In recent years, several large case-control studies from France, Denmark, the United Kingdom, and California have assessed the risk of childhood leukemia in relation to residential proximity to high-voltage power lines (Sermage-Faure et al., 2013; Bunch et al., 2014; Bunch et al., 2015, 2016; Pedersen et al., 2014a, 2014b, 2015; Crespi et al., 2016). The French study used geocoded information on residential addresses and power line locations to examine the risk of childhood leukemia in association with distance to power lines between 2002 and 2007. Overall, the study included 2,779 cases of childhood leukemia and 30,000 control children (Sermage-Faure et al., 2013) and reported no statistically significant increase in leukemia risk with distance to power lines. The authors, however, noted a statistically non-significant risk increase in a sub-analysis within 50 meters of 225-kV to 400-kV lines, but this was based on a small number of cases (n=9).

A similar study from Denmark included 1,698 cases of childhood leukemia and 3,396 healthy control children (Pedersen et al., 2014a). The authors reported no risk increases for childhood leukemia with residential distance to power lines. The same authors also evaluated whether consideration of other potential risk factors for childhood leukemia may influence the results for distance to power lines (Pedersen et al., 2014b). No influence of adjustment for socioeconomic status, mother's age, birth order, domestic radon exposure, or traffic-related air pollution was observed in the power-line specific results. While the authors reported a statistical interaction between distance to power lines and radon exposure, they attributed these findings to chance, as these results were based on a small number of cases. In 2015, Pedersen et al., reported results of another case-control study that included all children diagnosed with a first primary leukemia

(n=1536), central nervous system (CNS) tumor (n=1324), or malignant lymphoma (n=417) in Denmark before the age of 15 years between 1968 and 2003. The study population of this paper mostly overlaps with the previously described papers. Cases were identified from the Danish Cancer Registry. Two to five controls (n=9129) for each case were selected randomly from the Danish childhood population. Controls were matched to cases based on their sex and year of birth. For all study subjects, average magnetic-field exposure levels were calculated from overhead 50- to 400- kV power lines based on their residential addresses from 9 months before birth until the diagnosis. The authors reported statistically non-significant associations between cancers combined and three types of cancers separately and estimated exposures ≥0.4 microtesla (μT) compared to <0.1 μT. The large number of cases and controls in the study, the inclusion of residential history and exposure assessment throughout their children's entire lifetime, control for some potential confounders (including radon exposure, traffic related air pollution, socioeconomic status) and the reliance on reliable population-based cancer and population registries in Denmark are among the strengths of the study. Reliance on calculated magnetic-field levels for exposure assessment and lack of details on the accuracy of the input data to these calculations, including historical line loading and distance to residence are among the limitations of the paper.

Bunch et al. (2014) reported on a study that updated and extended the 2005 study conducted by Draper et al. in the United Kingdom. The update extended the study period by 13 years, included Scotland in addition to England and Wales, and included 132-kV lines in addition to 275-kV and 400-kV transmission lines. Bunch et al. is the largest case-control study to date—it included over 53,000 childhood cancer cases, diagnosed between 1962 and 2008, and over 66,000 healthy children as controls. Overall, the authors reported no association with residential proximity to power lines with any of the voltage categories. In the overall analysis of the updated data, the statistical association that was reported in the earlier study (Draper et al., 2005) was no longer apparent. An analysis by calendar time indicated that the association was evident only in the earlier decades (1960s and 1970s) but not present in the later decades starting from the 1980s (Bunch et al., 2014). This weakens the argument that the associations observed earlier are due to magnetic-field effects. Population mixing (with potential infectious etiology) has been proposed to explain the associations observed in the earlier years but no empirical data are available in support of this hypothesis (Jeffers, 2014).

In a separate analysis of the same study population, the investigators also examined residential distance to high-voltage underground cables (mostly AC 275 kV and 400 kV) to case and control residences (Bunch et al., 2015). Over 52,000 cases of childhood cancer occurring between 1962 and 2008 in England and Wales, along with their matched controls, were included in these analyses. The authors reported no statistically significant associations or exposure-response trends between childhood leukemia and distance to power lines or calculated magnetic-field levels from the underground cables. The authors concluded that their results further detract from the hypothesis that exposure to magnetic fields explains the associations observed in earlier studies.

Based on additional analyses of the data, Bunch et al. (2016) reported that the risk increases observed in the earlier years, which were more pronounced among older children (aged 10-14 years), and for myeloid leukemia, were linked to calendar year of birth or year of cancer diagnosis, rather than the age of the power lines. This finding implies that whatever factors

might have resulted in the apparent risk increase in the earlier years of the study are less likely to be linked to the newly built or existing power lines, and more likely to be related to a yet to be identified characteristic of the population (or chance variation) in those years. Analyses by regions of the country did not suggest any clear pattern. The authors concluded that their findings, overall, do not provide support for the etiologic role of magnetic fields in the reported associations.

Crespi et al. (2016) reported results of a large, record-based case-control study of childhood leukemia (n=5,788) and CNS tumors (n= 3,308) diagnosed between 1986 and 2008 and residential proximity to high-voltage overhead power lines (60 kV to 500 kV) in California. Additional details on methods were presented in a previous publication (Kheifets et al., 2015). Cases were identified from the California Cancer Registry and age and sex matched controls were selected from the California Birth Registry. Birth record was also obtained for cases. For all subjects, distance of the address at birth to the nearest power line was estimated using geographic information systems, aerial imaging from Google Earth, and, for a subset of subjects, site visits. The authors reported no consistent overall associations between risk of leukemia or CNS tumor and residential distance to power lines with voltage 200 kV and above. A statistically non-significant increase was reported for childhood leukemia among subjects with addresses closer than 50 meters to 200+ kV power lines. Analyses that also included lower voltage lines revealed no associations for either leukemia or CNS tumors. In a separate publication, details of magnetic-field calculations for the same study populations also were presented (Vergara et al., 2015); thus, it may be anticipated that associations between cases and controls based calculated field levels will be investigated in the future.

The strengths of these studies include their large size and their population-based design that minimized the potential for selection bias. These studies, however, primarily relied on distance to power lines as their main exposure metric, which is known to be a poor predictor of actual residential magnetic-field exposure. The limitations of distance as an exposure proxy also have been discussed by several observers in the scientific literature in the context of the French study (Bonnet-Belfais et al., 2013; Clavel et al., 2013). In addition, Chang et al. (2014) recently provided a detailed discussion of the limitations of exposure assessment methods based on geographical information systems. Swanson et al. (2014a) also concluded, based on their analysis of data from the British study (Bunch et al., 2014), that geocoding information that is not based on exact address but only on post code information is "probably not acceptable for assessing magnetic-field effects" (Swanson et al., 2014a, p. N81).

Epidemiologists from Italy have published two papers that describe the methods and results of a childhood leukemia case-control study and residential exposure to 50-Hz magnetic fields (Magnani et al., 2014; Salvan et al., 2015). In total, 412 leukemia cases under the age of 10 years diagnosed between 1998 and 2001 and 587 controls were included in the study. Exposure to residential ELF magnetic fields was assessed by extended (24 – 48-hr) measurements in the children's bedroom. Conditional logistic regression was used to calculate RR and adjust for potentially confounding variables. In their analyses, the researchers evaluated a number of exposure metrics (measures of central tendency or peak-exposure measures; continuous or categorical exposures based on measurements during nighttime, weekend, or entire measurement periods). The potential role of residential mobility of the subjects in the observed associations was also assessed. No consistent exposure-response patterns were observed in any of the

analyses. The main limitations of the study include the potential for differential participation of controls and cases and differences in participation rates of the study subjects based on their socioeconomic status, which in combination may result in a reference group that is not fully representative of the underlying population at risk. This, in turn, may bias the calculated effect estimates. The low prevalence of highly-exposed subjects (particularly exposure above 3 mG) results in a limitation of the statistical power of the study.

A hospital-based case-control study of EMF and childhood leukemia included 79 cases and 79 matched controls in the Czech Republic (Jirik et al., 2012). Exposure was measured in the participants' homes, in the "vicinity" of the residences, and the participants' schools. No association was reported between the measured magnetic field and leukemia risk. The study was small and provided insufficient information on the methods of case ascertainment, control selection, subject recruitment, and exposure assessment to fully assess its quality.

An even smaller cross-sectional study of 22 cases of childhood ALL and 100 controls from Iran reported a statistically significant association with "prenatal and postnatal childhood exposure to high voltage power lines" (Tabrizi and Bigdoli, 2015, p. 2347). The study, however, would carry very little, if any, weight in an overall evaluation, because of its cross-sectional study design and very small sample size, and due to the complete lack of information on exposure assessment in the study. An apparent duplication of the study with near identical results and limitations was also published (Tabrizi and Hossein, 2015). A letter to the editor that highlighted major flaws in the study also pointed out the apparent duplication and suggested retraction of the second publication (Dechent and Driessen, 2016).

A recent pooled analysis (Schüz et al., 2012) aimed to follow up on two earlier studies that, based on small numbers of cases, reported poorer survival among cases of childhood leukemia with increased average exposure to magnetic fields, suggesting the magnetic fields may play a role in the progression in the disease following diagnosis (Foliart et al., 2006; Svendsen et al., 2007). The pooled analysis included exposure and clinical data on more than 3,000 cases of childhood leukemia from Canada, Denmark, Germany, Japan, the United Kingdom, and the United States. The authors reported no association between magnetic-field exposure and overall survival or relapse of disease in children with leukemia after diagnosis.

Researchers also examined the association between occupational exposures of fathers and the risk of childhood leukemia in their children in the United Kingdom (Keegan et al., 2012). The study included a total of 15,785 cases of childhood leukemia diagnosed between 1962 and 2006 and a similar number of matched controls in the analyses. EMF exposure was among the 33 investigated occupational exposures. Occupational EMF exposure of the fathers did not show a statistically significant relationship to leukemia in their children when all types of leukemia, lymphoid leukemia (the most common type), or myeloid leukemia were considered. The authors reported a statistically significant increase for leukemia classified as "other types," which included but 7% of the leukemia cases.

Several meta-analyses have been published by Chinese researchers in recent years. Zhao et al. (2014a) conducted a meta-analysis of nine case-control studies of EMF exposure and childhood leukemia published between 1997 and 2013. The authors reported a statistically significant association between average exposure above 4 mG and all types of childhood leukemia (OR

1.57; 95% CI 1.03–2.4). The meta-analysis relied on published results from some of the same studies included in previous pooled analyses, thus provided little new insight. Su et al. (2016) conducted a meta-analysis of 11 case-control studies and 1 cohort study that investigated the association between parental exposure to EMF and risk of childhood leukemia in the offspring. Overall, neither maternal nor paternal occupational EMF exposure was associated with childhood leukemia risk. The authors noted, however, that they observed an association when they combined small and low-quality studies, but not when they combined larger and high-quality studies. Zhang et al. (2016) combined epidemiologic studies of all types of cancer in their meta-analyses, including studies of adult and childhood cancers. Since various adult and childhood cancers have very different etiologies and biological mechanisms, it is scientifically not defensible to expect that any specific exposure will have an identical effect on the risk of all types of cancers, which renders the study's main results mostly meaningless, or difficult to interpret at best.

Swanson et al. (2014b) investigated the potential role of corona ions from AC power lines in childhood cancer development in a large British epidemiologic study of childhood cancer (Bunch et al., 2014). This work is a follow up on a hypothesis suggesting that charged aerosol particles generated by corona activity might increase exposure to ambient airborne substances leading to increased risk of certain cancers, including childhood cancers. The authors used an improved model to predict exposure to corona ions using meteorological data on wind conditions, power line characteristics, and proximity to residential address. The authors concluded that their results provided no empirical support for the corona ion hypothesis. While some (Jeffers, 2015) questioned the validity of the employed modeling in the study claiming that corona ions may travel farther than 600 meters from the line, the authors responded that if corona ions were to explain the association reported up to 600 meters by Draper et al. (2005), exposure beyond that distance has no relevance in the context of the study because that would not contribute to the reported association (Swanson et al., 2015).

Several methodological studies have also examined the potential role of causal and alternative, non-causal explanations for the reported epidemiologic associations. Swanson and Kheifets (2012) proposed that if the biological mechanism explaining the epidemiologic association involves free radicals then, due to the small timescale of the reactions, the effects of ELF EMF and the earth's geomagnetic fields would be similar. Thus, to test this hypothesis the authors evaluated whether the magnitude of the earth's geomagnetic field modifies the effects reported by ELF EMF childhood leukemia studies from various parts of the world. The results were not in full support of the hypothesis. Swanson (2013) examined differences in residential mobility among residents who lived at varying distances from power lines in order to assess if these differences in mobility may explain the statistical association of leukemia with residential proximity to power lines. The study reported some variations in residential mobility, "but only small ones, and not such as to support the hypothesis" (Swanson, 2013, p. N9). A third study evaluated whether selection bias may play a role in the association between childhood leukemia and residential magnetic-field exposure (Slusky et al., 2014). The authors used wire code categories to assess exposure among participant and nonparticipant subjects in the Northern California Childhood Leukemia Study. While the authors reported systematic differences between participant and nonparticipant subjects in both wire code categories and socioeconomic status, these differences did not appear to influence the association between childhood leukemia and exposure estimates. The limitations of the study include the use of wire code categories to

assess exposure, which is known to be a poor predictor for actual magnetic-field exposure, and that the study showed no association between magnetic fields and childhood leukemia among the participant subjects.

Recent reviews continue to highlight that the observed epidemiologic association between EMF and childhood leukemia remains unexplained and there are no supportive data from laboratory animal studies or known biophysical mechanisms that could explain a carcinogenic effect (Ziegelberger et al., 2011; Teepen and van Dijck, 2012; Grellier et al., 2014; Schüz et al., 2016). In contrast, Leitgeb (2014, 2015) concluded, based on his combined analysis of 36 childhood leukemia epidemiologic studies, that overall, childhood leukemia is not linked to ELF magnetic field exposure when results from all epidemiologic studies are considered together. He reached his conclusions after plotting ORs as a function of the number of exposed cases and the publication year of the studies. As the analysis is not a conventional meta- or pooled analysis and it does not consider any of the design features and characteristics of the individual studies (e.g., exposure assessment methods, potential sources of bias), no firm conclusion could be drawn based on this analysis.

Grellier et al. (2014) estimated that, if the association was causal, ~1.5% to 2% of childhood leukemia cases in Europe might be attributable to ELF EMF. They conclude that "this contribution is relatively small and is characterised [*sic*] by considerable uncertainty" (Grellier et al., 2014, p. 61). A recent evaluation by a European Union funded research consortium concluded that recent research results have not provided new evidence that would change the overall conclusion reached by IARC in 2001, and the current evidence is consistent with the possibly carcinogenic classification (Schüz et al., 2016). Authors continue to emphasize that further understanding may be gained by studies of improved methodology and reduced potential for bias and by international and interdisciplinary collaborations (Ziegelberger et al., 2011; Teepen and van Dijck, 2012; Mezei et al., 2014).

Assessment of residential exposure to EMF among children also continues to be of interest. While not linked to any specific health outcomes, EMF exposure assessment studies of children have recently been reported from Australia, Italy, Spain, and Switzerland (Karipidis, 2015; Struchen et al., 2015; Liorni et al., 2016; Gallastegi et al., 2016).

Assessment

In summary, while most of the recently published large and methodologically advanced studies showed no statistically significant associations (e.g., Bunch et al., 2014, Pedersen et al., 2014a, 2014b, Pedersen et al., 2015; Crespi et al., 2016), the association between childhood leukemia and magnetic fields observed in some earlier studies remains unexplained. Thus, the results of recent studies do not change the classification of the epidemiologic data as limited, which is also the assessment of the most recent weight-of-evidence review released in 2015 by the Scientific Committee on Emerging and Newly Identified Health Risks (SCENIHR).[14]

[14] On July 8, 2015, SCENIHR was renamed the Scientific Committee on Health, Environment, and Emerging Risks (SCHEER). Since any publications by this body referenced in this report were published before the name was changed, all citations to their publications will note SCENIHR rather than SCHEER.

It should be noted that magnetic fields are just one small area in the large body of research on the possible causes of childhood leukemia. There are many other hypotheses under investigation that point to possible genetic, environmental, and infectious explanations for childhood leukemia, which have similar or stronger support in epidemiologic studies (Ries et al., 1999; McNally and Parker, 2006; Belson et al., 2007; Rossig and Juergens, 2008; Eden, 2010; Rudant et al., 2015).

Table 3. Relevant studies of childhood leukemia

Author	Year	Study Title
Bunch et al.	2014	Residential distance at birth from overhead high-voltage powerlines: childhood cancer risk in Britain 1962-2008.
Bunch et al.	2015	Magnetic fields and childhood cancer: an epidemiological investigation of the effects of high-voltage underground cables
Bunch et al.	2016	Epidemiological study of power lines and childhood cancer in the UK: further analyses
Chang et al.	2014	Validity of geographically modeled environmental exposure estimates
Crespi et al.	2016	Childhood leukaemia and distance from power lines in California: a population-based case-control study
Dechent and Driessen	2016	Re: Role of Electromagnetic Field Exposure in Childhood Acute Lymphoblastic Leukemia and No Impact of Urinary Alpha- Amylase - a Case Control Study in Tehran, Iran
Grellier et al.	2014	Potential health impacts of residential exposures to extremely low frequency magnetic fields in Europe
Jirik et al.	2012	Association between childhood leukaemia and exposure to power-frequency magnetic fields in middle Europe
Keegan et al.	2012	Case–control study of paternal occupation and childhood leukaemia in Great Britain, 1962–2006
Leitgeb	2014	Childhood leukemia not linked with ELF magnetic fields
Leitgeb	2015	Synoptic analysis clarifies childhood leukemia risk from ELF magnetic field exposure
Magnani et al	2014	SETIL: Italian multicentric epidemiological case-control study on risk factors for childhood leukaemia, non hodgkin lymphoma and neuroblastoma: study population and prevalence of risk factors in Italy
Pedersen et al.	2014a	Distance from residence to power line and risk of childhood leukemia: a population-based case-control study in Denmark
Pedersen et al.	2014b	Distance to high-voltage power lines and risk of childhood leukemia - an analysis of confounding by and interaction with other potential risk factors
Pedersen et al.	2015	Residential exposure to extremely low-frequency magnetic fields and risk of childhood leukaemia, CNS tumour and lymphoma in Denmark
Salvan et al.	2015	Childhood leukemia and 50 Hz magnetic fields: findings from the Italian SETIL case-control study
Schüz et al.	2012	Extremely low-frequency magnetic fields and survival from childhood acute lymphoblastic leukemia: an international follow-up study
Schüz et al.	2016	Extremely low-frequency magnetic fields and risk of childhood leukemia: A risk assessment by the ARIMMORA consortium
Sermage-Faure et al.*	2013	Childhood leukaemia close to high-voltage power lines – the Geocap study, 2002–2007
Slusky et al.	2014	Potential role of selection bias in the association between childhood leukemia and residential magnetic fields exposure: a population-based assessment
Su et al.	2016	Associations of parental occupational exposure to extremely low-frequency magnetic fields with childhood leukemia risk

Author	Year	Study Title
Swanson	2013	Residential mobility of populations near UK power lines and implications for childhood leukaemia
Swanson and Kheifets	2012	Could the geomagnetic field be an effect modifier for studies of power-frequency magnetic fields and childhood leukaemia?
Swanson et al.	2014a	Relative accuracy of grid references derived from postcode and address in UK epidemiological studies of overhead power lines.
Swanson et al.†	2014b	Childhood cancer and exposure to corona ions from power lines: an epidemiological test.
Tabrizi and Bidgoli	2015	Increased risk of childhood acute lymphoblastic leukemia (ALL) by prenatal and postnatal exposure to high voltage power lines: a case control study in Isfahan, Iran
Tabrizi and Hosseini	2015	Role of Electromagnetic Field Exposure in Childhood Acute Lymphoblastic Leukemia and No Impact of Urinary Alpha- Amylase--a Case Control Study in Tehran, Iran
Teepen and van Dijck	2012	Impact of high electromagnetic field levels on childhood leukemia incidence
Vergara et al.	2015	Case-control study of occupational exposure to electric shocks and magnetic fields and mortality from amyotrophic lateral sclerosis in the US, 1991-1999
Zhao et al.	2014a	Magnetic fields exposure and childhood leukemia risk: a meta-analysis based on 11,699 cases and 13,194 controls
Zhang et al.	2016	Meta-analysis of extremely low frequency electromagnetic fields and cancer risk: a pooled analysis of epidemiologic studies
Ziegelberger et al.	2011	Review. Childhood leukemia: Risk factors and the need for an interdisciplinary research agenda
*Comments and Replies on Sermage-Faure et al.:		
Bonnet-Belfais et al.	2013	Comment: childhood leukaemia and power lines--the Geocap study: is proximity an appropriate MF exposure surrogate?
Clavel et al.	2013	Reply: comment on 'Childhood leukaemia close to high-voltage power lines--the Geocap study, 2002-2007'--is proximity an appropriate MF exposure surrogate?
†Comments and Replies on Swanson et al. 2014b		
Jeffers	2015	Comment on: Childhood cancer and exposure to corona ions from power lines: an epidemiological study
Swanson et al.	2015	Reply to 'Comment on: Childhood cancer and exposure to corona ions from power lines: an epidemiological study'.

Childhood brain cancer

Compared to the research on magnetic fields and childhood leukemia, there have been fewer studies of childhood brain cancer. The data are less consistent and limited by smaller numbers of exposed cases than studies of childhood leukemia. The WHO review recommended the following:

> As with childhood leukaemia, a pooled analysis of childhood brain cancer studies should be very informative and is therefore recommended. A pooled analysis of this kind can inexpensively provide a greater and improved insight into the existing data, including the possibility of selection bias and, if the studies are sufficiently homogeneous, can offer the best estimate of risk (WHO, 2007, p. 18).

Recent studies (2012 – 2016)

The potential relationship between residential proximity to overhead and underground transmission lines and childhood brain cancer also has been investigated in some of the epidemiologic studies discussed in the childhood leukemia section (Bunch et al., 2014; Bunch et al., 2015; Bunch et al., 2016; Pedersen et al., 2015; Crespi et al., 2016). The previously described case-control epidemiologic study by Bunch et al. (2014) also included cases of brain cancer (n=11,968) and other solid tumors (n=21,985) among children in the United Kingdom between 1962 and 2008 in the analysis of overhead power lines. No statistical association was reported in any of the analyses for childhood brain cancer and proximity to overhead lines. In the follow up analyses that investigated the occurrence of cancer separately among younger and older children (Bunch et al., 2016), no clear pattern was identified. In the analyses of residential proximity to high-voltage underground cables (Bunch et al., 2015) in the same study population, the authors report a statistical association for childhood brain cancer with distance, but only in an intermediate category (20 – 49.9 meters), without clear support for an exposure-response pattern. No statistically significant associations were reported with calculated magnetic fields from underground cables.

As described above in the childhood leukemia section, the childhood cancer epidemiologic studies conducted in Denmark and California also included cases of CNS tumors (Pedersen et al., 2015; Crespi et al., 2016). Neither of the two studies reported any consistent association between residential proximity to power lines and childhood brain cancer risk regardless of investigated time periods and voltage of the included transmission lines.

Assessment

The studies published between 2012 and 2016 did not report any consistent association between estimated magnetic-field exposure and brain tumors among children. This is in line with the previous assessment that the weight of the recent data does not support an association between magnetic-field exposures and the development of childhood brain cancer (Kheifets et al., 2010; SCENIHR, 2015). The recent data do not alter the classification of the epidemiologic data in this field as inadequate.

Table 4. Relevant studies of childhood brain cancer

Authors	Year	Study Title
Bunch et al.	2014	Residential distance at birth from overhead high-voltage powerlines: childhood cancer risk in Britain 1962-2008.
Bunch et al.	2015	Magnetic fields and childhood cancer: an epidemiological investigation of the effects of high-voltage underground cables
Bunch et al.	2016	Epidemiological study of power lines and childhood cancer in the UK: further analyses
Crespi et al.	2016	Childhood leukaemia and distance from power lines in California: a population-based case-control study
Pedersen et al.	2015	Residential exposure to extremely low-frequency magnetic fields and risk of childhood leukaemia, CNS tumour and lymphoma in Denmark

Breast cancer

The WHO reviewed studies of breast cancer and residential magnetic-field exposure, electric blanket usage, and occupational magnetic-field exposure. These studies did not report consistent associations between magnetic-field exposure and breast cancer. The WHO concluded that the more recent body of research they reviewed on this topic was less susceptible to bias compared with previous studies, and, as a result, it provided strong support to previous consensus statements that magnetic-field exposure does not influence the risk of breast cancer. Specifically, the WHO stated:

> Subsequent to the IARC monograph [2002] a number of reports have been published concerning the risk of female breast cancer in adults associated with ELF magnetic field exposure. These studies are larger than the previous ones and less susceptible to bias, and overall are negative. With these studies, the evidence for an association between ELF exposure and the risk of breast cancer is weakened considerably and does not support an association of this kind (WHO, 2007, p. 307).

The WHO did not recommend any specific research with respect to breast cancer and magnetic-field exposure.

Recent studies (2012 – 2016)

Researchers in the United Kingdom published a large case-control study that investigated risk of adult breast cancer, leukemia, brain tumors, and malignant melanoma, in relation to magnetic-field exposure and residential distance to high voltage power lines (Elliott et al., 2013). The study included incident cancer cases, including 29,202 female breast cancer cases, from England and Wales diagnosed between 1974 and 2008, and a total of over 79,000 controls between the age of 15 and 74 years. Location of power lines and residential addresses were identified based on data from geographical information systems. Magnetic-field exposure was calculated for each control address and for each case address for the year of and 5 years prior to diagnosis. Risk of female breast cancer showed no association with distance to power lines or with estimated magnetic fields. Following publication, the study received criticism regarding its exposure assessment, exposure categorization, and the potential for confounding (de Vocht, 2013; Philips et al., 2013; Schüz, 2013).

Sorahan (2012) studied cancer incidence among more than 80,000 electricity generation and transmission workers in the United Kingdom between 1973 and 2008. Standardized registration rates were calculated among the workers compared to rates observed in the general population. No statistically significant increases were reported for breast cancer among either men or women. There was no trend for breast cancer incidence with year of hire, years of being employed, or years since leaving employment. The strengths of the study include its prospective nature and its large size. It is, however, limited in exposure assessment because risk was not calculated by magnetic-field exposure levels, and incidence rates were compared to an external reference group.

Koeman et al. (2014) investigated occupational exposure to ELF magnetic fields and cancer incidence in a cohort of about 120,000 men and women in the Netherlands Cohort study. The

researchers used a case-cohort approach to analyze their data and identified 2,077 breast cancer cases among women and no breast cancer among men in the cohort. Exposure to ELF magnetic fields was assigned based on job title using a job-exposure matrix. Breast cancer showed no association with the level of estimated ELF magnetic-field exposure, or the length of employment, or cumulative exposure in the exposed jobs.

Li et al. (2013) conducted a nested case-cohort analysis of breast cancer incidence among more than 267,000 female textile workers in Shanghai. The researchers identified 1,687 incidence breast cancer cases in the cohort between 1989 and 2000 and compared their estimated exposure to 4,702 non-cases. Exposure was assessed based on complete work history and a job-exposure matrix specifically developed for the cohort. No association was observed between cumulative exposure and risk of breast cancer regardless of age, histological type, and whether a lag period was used or not. An accompanying editorial opined that this well-designed study further adds to the already large pool of data not supporting an association between ELF EMF and breast cancer (Feychting, 2013). The editorial suggests that further studies on breast cancer "have little new knowledge to add," following the considerable improvement in study quality over time in breast cancer epidemiologic studies, and with the evidence being "consistently negative" (Feychting, 2013, pp. 1046).

Gundy et al. (2016) reported results of their population-based case-control study of male breast cancer and occupational exposure to magnetic fields. Cases (n=115) were identified from eight Canadian provinces through the provincial cancer registries between 1994 and 1998. Controls (n=570), matched on age and sex, were selected from provincial health insurance plans or using random digit dialing. Information on demographic characteristics and occupational history was obtained through self-administered questionnaires. Exposure to magnetic fields was assessed by expert review of the jobs held by the study subjects, and classified into three categories (<0.3, 0.3 to <0.6 and ≥0.6 μT). The authors reported statistically non-significant risk increases with highest average exposure ≥0.6 μT compared to exposure <0.3 μT, and with having an exposed job (≥0.3 μT) for at least 30 years compared to never having an exposed job.

Meta-analyses for breast cancer were conducted by Chinese investigators for both female (Chen et al., 2013; Zhao et al., 2014b) and male breast cancers (Sun et al., 2013). The meta-analysis for female breast cancer included 23 case-control studies published between 1991 and 2007. Based on all 23 studies, the authors estimated a slight, but statistically significant association between breast cancer and ELF magnetic-field exposure (OR 1.07; 95% CI 1.02-1.13), which was slightly higher for estrogen receptor positive and premenopausal cancer (OR 1.11) (Chen et al., 2013). The conclusion of the authors that ELF magnetic fields might be related to breast cancer is contrary to the conclusion of the WHO and other risk assessment panels, which may be due to their reliance on earlier and methodologically less advanced studies in the meta-analysis. Zhao et al. (2014b) reported the results of their meta-analysis of 16 case-control epidemiologic studies of ELF EMF and breast cancer published between 2000 and 2007. They reported a weak but statistically significant association, which appeared to be stronger among non-menopausal women. The conclusion of the authors that ELF magnetic fields might be related to breast cancer is contrary to the conclusion of the WHO and other risk assessment panels. Similar to the previous meta-analysis, this may be due to the inclusion of earlier and methodologically less advanced studies in the meta-analysis. Sun et al (2013) conducted a meta-analysis of male breast cancer including 7 case-control and 11 cohort studies. The studies, with one exception that

estimated residential exposure, estimated occupational exposure to ELF magnetic fields. The combined analysis showed a statistically significant association between male breast cancer and exposure to ELF EMF (OR 1.32; 95% CI 1.14-1.52). Methodological limitations, the small number of cases in the individual studies, and the potential for publication bias may contribute to the findings. As mentioned earlier, Zhang et al. (2016) combined epidemiologic studies of all types of cancer in their meta-analysis, including studies of adult and childhood cancers, which renders their main conclusions mostly meaningless, or difficult to interpret at best. Based on a sub-analysis that included 23 epidemiologic studies, the authors reported no statistically significant associations for breast cancer.

Assessment

The recent large case-control and cohort studies, which report no statistically significant associations with female or male breast cancer, add to the growing support against a causal role for magnetic-field exposure, both in residential and occupational settings, in breast cancer development. A recent review by SCENIHR (2015) concluded that, overall, studies on "adult cancers show no consistent associations" (p. 158).

Table 5. Relevant studies of breast cancer

Authors	Year	Study
Chen et al.	2013	A meta-analysis on the relationship between exposure to ELF-EMFs and the risk of female breast cancer.
*Elliott et al.	2013	Adult cancers near high-voltage overhead power lines
Feytching	2013	Invited commentary: extremely low-frequency magnetic fields and breast cancer--now it is enough!
Grudy et al.	2016	Occupational exposure to magnetic fields and breast cancer among Canadian men
Koeman et al.	2014	Occupational extremely low-frequency magnetic field exposure and selected cancer outcomes in a prospective Dutch cohort
Li et al	2013	Occupational exposure to magnetic fields and breast cancer among women textile workers in Shanghai, China
Sorahan et al.	2012	Cancer incidence in UK electricity generation and transmission workers, 1973–2008
Sun et al.	2013	Electromagnetic field exposure and male breast cancer risk: a meta-analysis of 18 studies
Zhang et al.	2016	Meta-analysis of extremely low frequency electromagnetic fields and cancer risk: a pooled analysis of epidemiologic studies
Zhao et al.	2014b	Relationship between exposure to extremely low-frequency electromagnetic fields and breast cancer risk: a meta-analysis
*Comment and Replies on Elliot et al.		
De Vocht	2013	Letter to the Editor: Adult cancers near high-voltage power lines
Philips et al.	2013	Letter to the Editor: Adult cancers near high-voltage power lines
Schüz	2013	Commentary: power lines and cancer in adults: settling a long-standing debate?

Adult brain cancer

Brain cancer was studied in many of the occupational studies of EMF. The findings were inconsistent, and there was no pattern of stronger findings in studies with more advanced

methods, although a small association could not be ruled out. The WHO classified the epidemiologic data on adult brain cancer as inadequate and recommended (1) updating the existing European cohorts of occupationally-exposed individuals and (2) pooling the epidemiologic data on brain cancer and adult leukemia to confirm the absence of an association.

The WHO stated the following:

> In the case of adult brain cancer and leukaemia, the new studies published after the IARC monograph do not change the conclusion that the overall evidence for an association between ELF [EMF] and the risk of these disease remains inadequate (WHO, 2007, p. 307).

Recent studies (2012 – 2016)

The Elliot et al. (2013) study of residential proximity and magnetic-field exposure from power lines, described above, also included 6,781 brain cancer cases. The risk of brain cancer showed no statistically significant increase with either distance or estimated magnetic-field levels in the study.

Sorahan (2012, 2014a) also examined the incidence of brain cancer in his analyses in the cohort of electricity generation and transmission workers in the United Kingdom. He made both internal comparisons (within the cohort of workers) and external comparisons (to the general population of the United Kingdom) and considered cumulative, recent, and distant occupational exposures to occupational ELF EMF. He reported no increased risk for brain cancer among either men or women. No trend was reported for brain cancer with year of hire, years of employment, years since employment in the study, or with estimates of cumulative, recent, or distant exposure to occupational ELF magnetic fields.

Koeman (2014) identified 160 male and 73 female cases of brain cancer in the Netherlands Cohort Study, described above. No statistically significant risk increase or trend was observed for cumulative ELF magnetic-field exposure among either men or women.

Turner et al. (2014) reported results from the INTEROCC study, which is an international case-control study of brain cancer and occupational exposure to ELF EMF. A total of 3,761 cases of brain cancer and 5,404 controls were included from Australia, Canada, France, Germany, Israel, New Zealand, and the United Kingdom between 2000 and 2004. Exposure was assessed based on individual job history and a job-exposure matrix. There was no association with lifetime cumulative exposure, average exposure, or maximum exposure for either glioma or meningioma. The authors, however, reported an association for both brain cancer types with exposure in the 1 to 4 year time-window prior to diagnosis. A statistical decrease in risk for glioma was also reported in the highest maximum exposure category.

Assessment

Recent studies did not report a consistent overall increase of brain cancer risk with either occupational or residential exposure to ELF EMF, and provide no overall support of a relationship between magnetic fields and brain cancer. The data remain inadequate as reported earlier (EFHRAN, 2012). As mentioned above, the most recent SCENIHR report (2015) states that, overall, studies on "adult cancers show no consistent associations" (p. 158).

Table 6. Relevant studies of adult brain cancer

Authors	Year	Study
Elliott et al.	2013	Adult cancers near high-voltage overhead power lines
Koeman et al.	2014	Occupational extremely low-frequency magnetic field exposure and selected cancer outcomes in a prospective Dutch cohort
Sorahan	2012	Cancer incidence in UK electricity generation and transmission workers, 1973–2008
Sorahan	2014a	Magnetic fields and brain tumour risks in UK electricity supply workers
Turner et al	2014	Occupational exposure to extremely low frequency magnetic fields and brain tumour risks in the INTEROCC study

Adult leukemia and lymphoma

There is a vast amount of literature on adult leukemia and EMF, most of which is related to occupational exposures. Overall, the findings of these studies are inconsistent—with some studies reporting a positive association between measures of EMF and leukemia and other studies showing no association. No pattern has been identified whereby studies of higher quality or design are more likely to produce positive or negative associations. The WHO subsequently classified the epidemiologic evidence for adult leukemia as "inadequate." They recommended updating the existing occupationally-exposed cohorts in Europe and updating a meta-analysis on occupational magnetic-field exposure. Kheifets et al. (2008) updated meta-analyses they had published in 1995 and 1997. Their updated meta-analysis indicated that pooled risk estimates from more recent studies were lower than in past meta-analyses, and no consistent pattern was seen by leukemia subtypes. Thus the combined results were not in support of a causal association between occupational EMF exposure and adult leukemia.

Recent studies (2012 – 2016)

Elliott et al (2013) included 7,823 cases of adult leukemia and reported no elevated risk or trend in association with distance or estimated magnetic-field exposure from high-voltage power lines in the United Kingdom. In the cohort of electricity power plant and transmission workers in the United Kingdom, Sorahan (2012) reported no increase in risk for leukemia, when compared to the general population of the United Kingdom, either among men or women, and no increasing trend was observed with length of employment. Sorahan also analyzed leukemia risk in relation to estimated occupational exposure to ELF magnetic fields within the cohort of employees; he reported that RR estimates were "unexceptional," and were close to unity for all exposure categories based on cumulative, recent, and distant exposures (Sorahan, 2014b). Sorahan (2014b) reported a statistical association for ALL in a sub-analysis, but attributed this, in the main, to unusually low risk in the reference category.

Koeman et al. (2014) identified 761 and 467 hematopoietic malignancies among men and women, respectively, in the Netherlands Cohort Study. No increases in risk or trend were observed in association with cumulative exposure to ELF magnetic fields among either men or women.

Rodriguez-Garcia and Ramos (2012) reported inverse correlations between acute myeloid leukemia, ALL, and the distance to thermoelectric power plants and high-density power line networks in their study of hematologic cancers in a region of Spain from 2000 to 2005. This

study, however, has severe limitations due to the use of aggregated data, rudimentary methods of exposure assessment, and the lack of an adequate comparison group.

Talibov et al. (2015) reported on a large case-control study of acute myeloid leukemia and occupational exposure to ELF EMF and electric shocks. The study included 5,409 cases diagnosed between 1961 and 2005 in Finland, Iceland, Norway, and Sweden and 27,045 controls matched on age, sex, and country. Lifetime occupational exposure to ELF EMF and shocks were assessed with job-exposure matrices based on jobs reported on the censuses. Potential confounding variables, such as work-related exposure to benzene and ionizing radiation, were adjusted for in the analyses. No associations between leukemia and exposure to ELF EMF or electric shocks were reported among either men or women.

Assessment

Recent studies did not provide substantial new evidence in support of an association between EMF and leukemia and lymphoma in adults. While some scientific uncertainty remains on a potential relationship between adult lymphohematopoietic malignancies and magnetic-field exposure because of the remaining deficiencies in study methods, the current database of studies provides inadequate evidence for an association (EFHRAN, 2012; SCENIHR, 2015).

Table 7. Relevant studies of adult leukemia/lymphoma

Authors	Year	Study
Elliott et al.	2013	Adult cancers near high-voltage overhead power lines
Koeman et al.	2014	Occupational extremely low-frequency magnetic field exposure and selected cancer outcomes in a prospective Dutch cohort
Rodriguez-Garcia and Ramos	2012	High incidence of acute leukemia in the proximity of some industrial facilities in El Bierzo, northwestern Spain
Sorahan	2012	Cancer incidence in UK electricity generation and transmission workers, 1973–2008
Sorahan	2014b	Magnetic fields and leukaemia risks in UK electricity supply workers
Talibov et al.	2015	Occupational exposure to extremely low-frequency magnetic fields and electrical shocks and acute myeloid leukemia in four Nordic countries

In vivo studies of carcinogenesis

In the field of ELF EMF research, a number of research laboratories have exposed rodents, including those with a particular genetic susceptibility to cancer, to high levels of magnetic fields over the lifetime of the animals and performed tissue evaluations to assess the incidence of cancer in many organs. In these studies, magnetic-field exposure has been administered alone (to test for the ability of magnetic fields to act as a complete carcinogen), in combination with a known carcinogen (to test for a promotional or co-carcinogenetic effect), or in combination with a known carcinogen and a known promoter (to test for a co-promotional effect).

The WHO review described four large-scale, long-term studies of rodents exposed to magnetic fields over the course of their lifetime that did not report increases in any type of cancer related to the intensity of exposure (Mandeville et al., 1997; Yasui et al., 1997; McCormick et al., 1999; Boorman et al., 1999a, 1999b). The highest intensity studied was 50,000 mG (Yasui et al., 1997). At the time of the WHO report, no directly relevant animal model for childhood ALL had

been developed. Some animals, however, develop a type of lymphoma similar to childhood ALL and studies exposing predisposed transgenic mice to ELF magnetic fields did not report an increased incidence of this lymphoma type (Harris et al., 1998; McCormick et al., 1999; Sommer and Lerchl, 2004).

Studies investigating whether exposure to magnetic fields can promote cancer or act as a co-carcinogen used known cancer-causing agents, such as ionizing radiation, ultraviolet radiation, or other chemicals. No effects were observed for studies on chemically-induced preneoplastic liver lesions, leukemia or lymphoma, skin tumors, or brain tumors; however, the incidence of 7,12-dimethylbenz[a]anthracene (DMBA)-induced mammary tumors was increased with magnetic-field exposure in a series of experiments in Germany (Löscher et al., 1993, 1994, 1997; Mevissen et al., 1993a, 1993b, 1996a, 1996b, 1998; Baum et al., 1995; Löscher and Mevissen, 1995; Mandeville et al., 1997), suggesting that magnetic-field exposure increased the proliferation of mammary tumor cells. These results were not replicated in a subsequent series of experiments in a laboratory in the United States (Anderson et al., 1999; Boorman et al., 1999a, 1999b), possibly due to differences in experimental protocol and the species strain. In Fedrowitz et al. (2004), exposure enhanced mammary tumor development in one sub-strain (Fischer 344 [F344] rats), but not in another sub-strain of rats that was obtained from the same breeder, which argues against a promotional effect of magnetic fields.[15]

Two laboratories have reported an increase in genotoxic effects among exposed animals (e.g., DNA strand breaks in the brains of mice at field levels between 100 and 5,000 mG [e.g., Lai and Singh, 2004]). Other investigators have reported no effect of magnetic field exposure and thus did not replicate these results.

In summary, the WHO concluded the following with respect to *in vivo* research on carcinogenesis: "There is no evidence that ELF [EMF] exposure alone causes tumours. The evidence that ELF field exposure can enhance tumour development in combination with carcinogens is inadequate" (WHO, 2007, p. 322). Recommendations for future research included the development of a rodent model for childhood ALL and the continued investigation of whether magnetic fields can act as a promoter or co-carcinogen.

Recent studies (2012 – 2016)

Studies published since Exponent's 2012 update that investigated the potential carcinogenic effects of electric- and magnetic-field exposure in animals are listed in Table 8. As noted above, none of the past large-scale, long-term bioassays of magnetic-field exposures have reported that lifetime exposure to magnetic fields initiate or promote tumor development in rodents. In some other studies, increases of DMBA-initiated mammary tumors in a particular strain of rats exposed to magnetic fields were reported in a single laboratory. To further investigate this phenomenon, Fedrowitz and Löscher (2012) evaluated gene expression in pooled samples of mammary tissue from both F344 rats (magnetic-field susceptible)[16] and Lewis rats (magnetic-

[15] The WHO concluded with respect to the German studies of mammary carcinogenesis, "Inconsistent results were obtained that may be due in whole or in part to differences in experimental protocols, such as the use of specific substrains" (WHO, 2007, p. 321).

field insensitive) following 2 weeks of continuous exposure to 1,000 mG, 50-Hz magnetic fields. Control rats were sham exposed and analyses conducted in a blinded manner. Using a 2.5-fold change as the cut-off for establishing an exposure-related response, only 22 of 31,100 gene transcripts were altered with magnetic-field exposure in the two rat strains combined. Genes with the greatest change in response to magnetic-field exposure in F344 rats (with no change in expression in Lewis rats) were α-amylase (a 832-fold decrease), parotid secretory protein (a 662-fold decrease), and carbonic anhydrase 6 (a 39-fold decrease).

To follow-up on these findings, Fedrowitz et al. (2012) examined α-amylase activity in mammary tissues collected from the two rat strains in previous experiments. In tissues collected in 2005 through 2006, magnetic-field exposure was associated with increased α-amylase activity in cranial, but not caudal, mammary tissues of both F344 and Lewis rats. Thus, the response did not correlate with the observed rat strain susceptibility to magnetic-field exposure. In tissues collected in 2007 through 2008, α-amylase activity in the cranial tissues was unaffected by magnetic-field exposure, but increased in the caudal tissues of F344 rats (and not Lewis rats). Additional experiments looked at α-amylase protein expression and its correlation with tissue differentiation following treatment with diethylstilbestrol. Overall, the findings of this study are contradictory, making interpretation difficult regarding the potential role of α-amylase expression in the observed sensitivity of F344 rats to magnetic-field exposure.

Because of the potential significance of chronic exposure studies, two publications by Soffritti et al. are discussed in detail below. Soffritti et al. (2016a) conducted two experiments at the same time. The first involved exposures of over 5,000 rats to 50-Hz magnetic fields at intensities of 0, 20, 200, 1,000, and 10,000 mG for 19 hours per day starting before birth and continuing over their lifetime. In the second experiment, only 600+ rats were administered a single dose of high-energy x-rays (0.1 Gray), a known cause of cancer, at 6 weeks of age and then exposed to either 0 mG, 200 mG, or a 10,000 mG 50-Hz magnetic field for 19 hours per day starting before birth and continuing over the life span. These authors had included some data from both experiments in a book chapter and reported that among female rats there was no significant effect of either magnetic-field treatment (10,000 mG) alone, 0.1 Gray of high-energy x-rays, or combined exposure to 20 or 10,000 mG + radiation (Soffritti et al., 2010). Soffritti et al. (2016a), however, does not include the results from groups exposed to magnetic fields alone. Although sharing the same room with exposed rats, there was no evidence that the control group for these studies was housed in the same way as the rats exposed to magnetic fields (i.e., a sham exposure). The number of animals per treatment group was >100 per sex per group in the treated groups and ≥500 per sex in the unexposed group; therefore, statistical variation is probably the smallest source of uncertainty in this study compared to that from other factors. The design of the study, however, has severe limitations including: 1) the reported absence of sham controls, which would have had all conditions of housing, light, handling, etc., the same as the exposed groups (with the exception of exposure); 2) the allocation of individual rats to groups was not random and no account of within-litter effects was made in the statistical analysis; and 3) the histologic analyses were not reported to have been performed without *a priori* knowledge of the exposure condition that would to prevent bias in the scoring of the tissues.

Soffritti et al. (2016a) reported no effects of radiation + magnetic field treatment on the body weights or survival rates of male or female rats. The incidence of benign mammary fibroadenomas was statistically increased in the males, but not females, exposed to 10,000 mG + radiation compared to the unexposed control group. Atypical hyperplasia within the glands was reported to be increased in females in groups exposed to 200 and 10,000 mG + radiation (although not in a dose-related manner) and males only at 10,000 mG + radiation. The percent of animals with actual cancers of the gland was greater in female rats exposed to radiation alone (7.6 %) than radiation + 20 mG (7.5%), but was less than in females exposed to radiation + 10,000 mG (16.1%).[17] In contrast, male rats exposed to radiation + 20 mG had a higher incidence of cancers (2.9 %) than rats exposed to radiation + 10,000 mG (0.9%) or unexposed controls/radiation only groups (0% and 0.2%, respectively). Additionally, males exhibited a statistically significant increased incidence of malignant schwannomas in the heart at both magnetic-field strengths and greater at 10,000 mG than 20 mG, but fewer than three rats in any group developed such tumors; thus, a larger study would be needed to resolve the relation to treatment for this finding. Finally, hemolymphoreticular neoplasms (lymphomas and leukemias) were grouped altogether for the analysis and an increased incidence in males was reported for the radiation +10,000 mG. These data are difficult to interpret because of the differences between the housing of the controls and the animals exposed to magnetic fields. Additionally, some tumor types were grouped for analysis, the time to tumors was not reported, the study was carried out for the lifetime of the animals rather than the standard two years more commonly used in cancer studies, and at least some of the increased tumor types were associated with the extreme end of life at which the size of the study groups is diminished and subject to greater variability.

Additional serious concerns have been raised about the quality of the chronic exposure implemented in this and other studies performed at the Ramazzini Institute where Dr. Soffritti has served as Scientific Director. Based on concerns about the ability of Ramazzini scientists to properly distinguish between leukemias and lymphomas in certain tissues, the U.S. Environmental Protection Agency (EPA) has "decided not to rely on RI [Ramazzini Institute] data on lymphomas and leukemias in IRIS [Integrated Risk Information System] assessments" (EPA, 2013). Furthermore, scientists from EPA and the National Institute for Environmental Health Sciences have taken an unprecedented step to warn risk assessors about problems with cancer bioassays conducted by the Ramazzini Institute, including: the accuracy of cancer diagnoses; the categorization of tumors; errors in identifying cellular changes as leukemia/lymphoma in certain tissues that appear to be due to infections (lung) and tissue inflammation; a unexplained significant rise in the incidence of leukemia/lymphomas over time in control groups unrelated to the exposure under study; lack of complete reporting of analytical specifications and documentation; failure to control or analyze for potential genetic similarities associated with the breeding litters; and the use of common controls for multiple studies (Gift et al., 2013). Such factors probably account for the more than two-fold difference in the incidence of mammary cancers in unexposed controls in the Soffritti et al. (2016a) and Sofritti et al. (2014) studies and a similar difference in the incidence of mammary cancers upon exposure to 0.1 Gray of high-energy X-ray radiation between these studies.

[17] The exact same results for female rats exposed to radiation + 10,000 mG are reported in Soffritti et al (2010) and Soffritti et al. (2016a). However, only in the latter published paper is the difference from controls identified as statistically significant.

The investigators from the Ramazzini Institute used the same exposure apparatus and general methods to examine the effects of 10,000 mG, 50-Hz exposure in rats alone or in combination with oral exposure to 50 mg/L formaldehyde, a known cause of cancer, in drinking water for two years (Soffritti et al., 2016b). Controls were either unexposed (the same control group as reported in the previous study) or treated with formaldehyde in drinking water only. Again, sham exposures and blinded analyses were not described. The numbers of animals per treatment group were larger (≥200 per sex per group in the treated groups) than in the previously discussed study. Groups exposed or not exposed to magnetic fields did not differ in body weight or survival. Exposure to either magnetic fields alone or formaldehyde alone did not increase the incidence of total benign or malignant tumor above that observed in the control group but the contribution of different tissues, including the mammary gland, to this total was not disclosed. Malignant tumors, including C-cell carcinomas of the thyroid, and lymphatic tumors, were increased in the males exposed to both magnetic fields and formaldehyde compared to the unexposed control but the reported incidences were not significantly different than those seen with formaldehyde treatment alone. No effects were seen in females, except for an increase in thyroid adenomas and carcinomas with formaldehyde alone. These results were confounded by the substantially reduced water intake levels over the first year of the study in males receiving formaldehyde in the drinking water with or without magnetic-field exposure. Again, some of the reported increases were based on limited numbers of affected animals, time to tumor development was not reported, and the study was carried out for the lifetime of the animals. Unfortunately, the consistency of the background incidence rates in the two studies cannot be compared as each one reports on different tissues. Further, these results conflict with those of the investigators' other study in that they do not support a co-carcinogenic effect of magnetic-field exposure.

Another recent study (Qi et al., 2015) examined the effects of exposure to 500 mG, 50-Hz magnetic fields on tumor development in mice. The exposures were begun *in utero* with 1 week (12 hours per day) exposure of pregnant females and continued for 15.5 months after birth. Controls were not sham-exposed (i.e., in the same exposure apparatus, but with the system turned off) and analyses were not reported to have been conducted in a blinded manner. Further, the exposure apparatus and control for potential confounding variables (e.g., light, vibration, noise) were not described. Exposed offspring exhibited significantly reduced body weights compared to controls. Tumors were not increased in males, but chronic myeloid leukemias were significantly higher in exposed females compared to controls. Interpretation of these data is difficult because of the limited experimental detail reported and because overall survival data and the expected background incidence for tumors in these mice were not reported. Further, these data are contradictory to the largely negative large-scale rodent carcinogenesis studies, as reviewed by the WHO (2007).

Other studies investigated the therapeutic potential of high magnetic-field exposures in the treatment of tumors. El-Bialy and Rageh (2013) injected female mice with Ehrlich ascites carcinoma cells, then treated them with 3 mg/kg cisplatin on days 1, 4, and 7, or exposed them to 100,000 mG, 50-Hz magnetic fields for 14 days (1 hour per day), or both. A control group was saline-treated, but not sham exposed to magnetic fields, and blinded analyses were not reported. Both magnetic-field exposure and cisplatin treatment, alone or in combination, were associated with reduced tumor volume; the strongest response was observed with combination treatment. In another study (Mahna et al., 2014), female mice were injected with mouse mammary tumor cells,

then exposed to 150,000 mG, 50-Hz magnetic fields (10 minutes per day for 12 days). Other animal groups were exposed to magnetic fields and electrochemotherapy (a combination of chemotherapy with pulsed electric current applied to the skin in an attempt to increase permeability of cancers cells to the drugs). A sham-exposed control group was included, but analyses were not conducted in a blinded manner. Magnetic-field exposure alone or in combination with the other treatments was reported to reduce tumor volume. Although these studies suffer from various limitations, the results suggest that magnetic-field exposure may have therapeutic applications in the treatment of tumors. Field strengths, however, were relatively high, and it is possible that the observed responses were due to an induced electric field.

Several recent studies examined the genotoxic potential of magnetic-field exposure. Miyakoshi et al. (2012) continuously exposed 3-day old rats to 100,000 mG, 50-Hz magnetic fields for 72 hours, treated them with 5 or 10 mg/kg bleomycin, or both; control animals were sham exposed. Brain astrocytes were then examined in culture for the presence of micronuclei (i.e., small nucleus-like structures containing DNA indicative of a chromosomal break). In other experiments, the animals were treated as described, but also administered tempol, an antioxidant. Magnetic-field exposure alone or in combination with 5 mg/kg bleomycin had no effect on micronuclei formation, but increased the frequency of micronuclei resulting from co-treatment with 10 mg/kg bleomycin. Tempol co-exposure was reported to reduce micronuclei formation, suggesting a role for activated oxygen species in their formation. In a study by Villarini et al. (2013), male mice were exposed to 1,000 to 20,000 mG, 50-Hz magnetic fields for 7 days (15 hours per day), then sacrificed immediately or 24 hours later. The striatum, hippocampus, and cerebellum were evaluated in a blinded manner for DNA damage using the Comet assay. Control mice were sham-exposed and X-irradiated mice served as DNA-damage positive controls. Mice exposed to 10,000 or 20,000 mG, but not lower strength magnetic fields, showed evidence of DNA fragmentation in the brain tissues when sacrificed immediately following exposure. By 24 hours post-exposure, however, the levels of DNA fragmentation were back to baseline, indicating either that any associated DNA damage was reversible or that the fragmentation was an indicator of apoptosis, which disappeared as the apoptotic cells were removed during the 24-hour recovery period. Male mice were exposed to 2,000 mG, 50-Hz magnetic fields for 7 to 28 days in a study by Alcaraz et al. (2014). No sham-exposed controls were included. Mice exposed to 50 centi-Gray of X-rays served as positive controls and analyses were conducted blind. The authors reported an increase in micronuclei in bone marrow erythrocytes 24 hours after magnetic-field exposure. The increase was not duration-dependent, however, and was substantially lower than that induced by X-irradiation.

Wilson et al. (2015) examined the effect of exposure to 100 to 3,000 mG, 50-Hz magnetic fields for 2 or 15 hours on the gene mutation frequency in the sperm and blood cells of mice. Sham-exposed mice were included as negative controls; X-irradiated mice served as positive controls. Mutation frequencies in blood cells of magnetic-field exposed mice were similar to those of the negative controls at 12 weeks after exposure. Mutation frequencies in sperm cells were slightly, but significantly, increased among magnetic-field exposed mice, although not in a dose-response-related pattern. In contrast, X-irradiation significantly increased the mutation frequency in both cell types.

Saha et al. (2014) studied DNA double-strand breaks in mouse embryonic neuronal stem cells with in vivo exposure to 1,000 mG, 50-Hz magnetic fields for 2 hours or with continuous or

intermittent exposure (5 minutes on, 10 minutes off) to a 3,000 mG magnetic field for 15 hours. The study included sham-exposed controls, multiple positive control groups exposed to X-irradiation, and appropriate statistical methods to account for litter effects. No increase in double-strand breaks was seen in groups exposed to magnetic fields. In a follow-on study (Woodbine et al., 2015), the same group of researchers using the same experimental system assessed whether concomitant exposure to magnetic fields and X-rays would have an effect. The mouse embryos were exposed to 3,000 mG, 50-Hz for 3 hours before and up to 9 hours after X-irradiation. Controls were X-irradiated and sham-exposed to magnetic fields. Additional controls were unexposed, sham-exposed, X-irradiated only (with or without sham-exposure), or magnetic-field exposed only. X-irradiation significantly increased DNA double-strand breaks at 1 hour post-exposure; levels decreased to control by 6 to 11 hours post-exposure with DNA repair. Magnetic-field exposure had no effect on the response to X-irradiation, indicating that magnetic fields did not affect the DNA repair process. One weakness of these studies is that the number of maternal animals per group was relatively small (n=1-4/group).

Korr et al. (2014) continuously exposed mice for 8 weeks to 1,000 mG or 10,000 mG, 50-Hz magnetic fields. At the end of the exposure period, the animals were injected with radiolabeled thymidine to look for DNA single-strand breaks and unscheduled DNA synthesis in the liver, kidneys, and brain. A slight reduction in mitochondrial DNA synthesis was observed in the kidney collecting ducts at 1,000 mG, but no increase in DNA single-strand breaks was observed. At 10,000 mG, a slight reduction in unscheduled DNA synthesis (likely related to reduced mitochondrial DNA synthesis) was observed in the brain choroid plexus and the kidney collecting duct, but again, there was no effect on DNA single-strand breaks. Although controls were not sham exposed, the analyses were conducted in a blinded manner.

Three recent studies examined DNA damage in human subjects exposed to EMF. Tiwari et al. (2015) investigated DNA damage in peripheral blood lymphocytes among 293 subjects in a cross-sectional analysis. (In a cross-sectional study, the investigators determine the study subjects' exposure and outcome status at the same time, thus, these types of studies are not suitable to draw any conclusion on a potential causal association.) The authors considered 142 subjects as "exposed to EMFs emitted from high-voltage (132-kV) substations for more than 2 years of occupational exposure." No further details were provided on how exposure status was determined. The exposed subjects were compared to 151 non-exposed individuals of similar socioeconomic status. How these control subjects were selected was not reported in the paper. The analyses did not consider or control for the potential confounding effect of other occupational exposures. DNA damage was assessed using the alkaline Comet assay and coded examination of slides; other parameters related to plasma epinephrine concentrations, lipid peroxidation, and nitric oxide expression levels were also assessed. Although the Comet tail length exhibited a slightly larger range in the exposed group, there was no significant difference between the two groups in the degree of DNA damage observed.

In another cross-sectional study of human subjects (Villarini et al., 2015), DNA damage was assessed using the alkaline Comet assay in 21 electric arc welders exposed to EMF as well as various metal fumes as a result of their occupation. The control group included 21 non-exposed individuals (healthy blood donors) of similar age, residence, and smoking status. Magnetic-field exposure was measured in exposed individuals using personal dosimeters worn for a single work shift and found to average 78 mG; magnetic-field exposure was not assessed in the non-exposed

controls. Comet tail lengths were similar in both groups; however, the welders exhibited significantly lower tail intensity and tail moment values than did controls, suggesting that they had a lower degree of DNA damage. The authors suggested that this unexpected finding may be related to the type of DNA damage that might occur with exposure to various metal fumes, including chromium and nickel; both may induce DNA-protein cross-links that would migrate to a lesser degree than non-cross-linked DNA in the assay.

A well-designed double-blind study (Kirschenlohr et al., 2012) examined gene expression in the white blood cells of 17 pairs of human subjects following exposure to a 620 mG, 50-Hz magnetic field on four different days (2 hours per day) over 2 weeks. On each exposure day, one member of each pair was exposed to the magnetic field; the other was either sham-exposed (with the current passing through the two coils of the exposure apparatus in opposing directions so that the magnetic field was cancelled, but the total current remained the same) or unexposed. On the next day, the exposures were reversed for the pair of subjects. Blood samples were collected just prior to and following exposures, as well as at multiple times throughout the exposure period. Gene expression in one set of the collected blood samples (collected in week 1) was determined via microarray analysis with an emphasis on immediate early genes involved in stress, inflammatory, and proliferative and apoptotic responses. Samples collected just prior to exposure were used as reference samples. Any positive findings were verified using the second set of collected blood samples. No genes showed a consistent response to magnetic-field exposure.

In a similarly well-conducted study, Kabacik et al. (2013) looked for changes in gene expression in the bone marrow of juvenile mice exposed to a 1,000 mG, 50-Hz magnetic field for 2 hours. The premise for conducting this research was that many leukemias are derived from cells in the bone marrow; thus, changes in bone marrow gene expression may be related to this process. Control mice were sham-exposed, the experiment was repeated in multiple groups of exposed and unexposed mice, and replicate samples were analyzed in a blinded manner using multiple methods and in different laboratories. Again, no consistent changes in gene expression in response to magnetic-field exposure were found.

Assessment

A single new animal bioassay of long-term magnetic-field exposure as a possible carcinogen has been conducted since the last update (Qi et al., 2015). This study reported increased chronic myeloid leukemia in female, but not male mice, exposed to magnetic fields from prior to birth through 15.5 months of age—a finding that conflicts with those of the other large-scale rodent bioassays reviewed by the WHO in 2007. Further, the new bioassay suffers from substantial methodological and reporting flaws which affect its weight in the overall assessment.

Two additional studies by a single research group examined the possible co-carcinogenic effects of lifetime magnetic-field exposure, with conflicting findings. These studies also suffer from substantial methodological and reporting flaws. At least some of the reported findings from Soffritti et al. (2016a, 2016b) are based on a limited number of affected animals and the occurrence of tumors that typically occur only at the extreme end of life. Additionally, serious concerns have been raised by others in the scientific community regarding tumor findings reported by this research group. Further investigations to assess the source of the species differences in susceptibility for mammary tumors generally have been unfruitful.

In addition to these studies, various shorter-term studies have been conducted to investigate the potential genotoxicity of magnetic-field exposure and its possible effects on gene expression in cells associated with cancer in humans. Many of these studies suffer from various methodological deficiencies, including small samples sizes, the absence of sham-exposure treatment groups, and analyses that were not conducted in a blinded manner. Further, consistency across the body of studies is commonly lacking in terms of the exposures applied, the cell types assessed, and the specific parameters evaluated. These studies do not change the WHO's conclusion that the overall evidence from *in vivo* studies does not support a role of EMF exposures in direct genotoxic effects.

Two particularly well-conducted studies evaluated potential differences in gene expression resulting from magnetic-field exposure. These studies employed sham exposures, replicate samples, and blinded analyses using multiple experimental methods of measuring gene expression in multiple laboratories; they also took into consideration the potential statistical power of the studies. Neither of these studies reported consistent changes in gene expression due to magnetic-field exposure.

Two studies looked at the possible anti-carcinogenic therapeutic potential associated with high magnetic-field strengths, an area for which more research is still warranted to address the influence of potential confounding variables on observed outcomes.

Overall, the *in vivo* studies published since the last update do not alter the previous conclusion that there is inadequate evidence of carcinogenicity due to ELF EMF exposure. The research on whether magnetic-field exposure can enhance tumor development in combination with known carcinogens remains inadequate.

Table 8. Relevant *in vivo* studies related to carcinogenesis

Authors	Year	Study
Alcaraz et al.	2014	Effect of long-term 50 Hz magnetic field exposure on the micronucleated polychromatic erythrocytes of mice.
El-Bialy and Rageh	2013	Extremely low-frequency magnetic field enhances the therapeutic efficacy of low-dose cisplatin in the treatment of Ehrlich carcinoma
Fedrowitz and Löscher	2012	Gene expression in the mammary gland tissue of female Fischer 344 and Lewis rats after magnetic field exposure (50 Hz, 100 µT) for 2 weeks
Fedrowitz et al.	2012	Effects of 50 Hz magnetic field exposure on the stress marker α-amylase in the rat mammary gland
Kabacik et al.	2013	Investigation of transcriptional responses of juvenile mouse bone marrow to power frequency magnetic fields
Korr et al.	2014	No evidence of persisting unrepaired nuclear DNA single strand breaks in distinct types of cells in the brain, kidney, and liver of adult mice after continuous eight-week 50 Hz magnetic field exposure with flux density of 0.1 mT or 1.0 mT
Mahna et al.	2014	The effect of ELF magnetic field on tumor growth after electrochemotherapy.
Miyakoshi et al.	2012	Tempol suppresses micronuclei formation in astrocytes of newborn rats exposed to 50-Hz, 10-mT electromagnetic fields under bleomycin administration
Qi et al.	2015	Effects of extremely low-frequency electromagnetic fields (ELF-EMF) exposure on B6C3F1 mice

Saha et al.	2014	Increased apoptosis and DNA double-strand breaks in the embryonic mouse brain in response to very low-dose X-rays but not 50 Hz magnetic fields.
Soffritti et al.	2014	Life-span carcinogenicity studies on Sprague-Dawley rats exposed to γ-radiation: design of the project and report on the tumor occurrence after post-natal radiation exposure (6 weeks of age) delivered in a single acute exposure
Soffritti et al.	2016a	Life-span exposure to sinusoidal-50 Hz magnetic field and acute low-dose γ radiation induce gacinogenic effects in Spargue-Dawley rats
Soffritti et al.	2016b	Synergism between sinusoidal-50 Hz magnetic field and formaldehyde in triggering carcinogenic effects in male Sprague-Dawley Rats
Tiwari et al.	2015	Epinephrine, DNA integrity and oxidative stress in workers exposed to extremely low-frequency electromagnetic fields (ELF-EMFs) at 132 kV substations
Villarini et al.	2013	Brain hsp70 expression and DNA damage in mice exposed to extremely low frequency magnetic fields: Adose-response study
Villarini et al.	2015	Primary DNA damage in welders occupational exposed to extremely-low-frequency magnetic fields (ELF-MF)
Wilson et al.	2015	The effects of extremely low frequency magnetic fields on mutation induction in mice.
Woodbine et al.	2015	The rate of X-ray-induced DNA double-strand break repair in the embryonic mouse brain is unaffected by exposure to 50 Hz magnetic fields

Reproductive/developmental effects

Over a decade ago, two studies received considerable attention because of a reported association between peak magnetic-field exposure greater than approximately 16 mG and miscarriage: a prospective cohort study of women in early pregnancy (Li et al., 2002) and a nested case-control study of women who miscarried compared to their late-pregnancy counterparts (Lee et al., 2002).

These two studies improved on the existing body of literature because average exposure was assessed using 24-hour personal magnetic-field measurements (earlier studies on miscarriage were limited because they used surrogate measures of exposure, including visual display terminal use, electric blanket use, or wire code data). The Li et al. study was criticized by the NRPB *inter alia* because of the potential for selection bias, a low compliance rate, measurement of exposure after miscarriages, and apparent selection of exposure categories after inspection of the data (NRPB, 2002).

Following the publication of these two studies, however, a hypothesis was put forth that the observed association may be the result of behavioral differences between women with healthy pregnancies that went to term (i.e., less physically active) and women who miscarried (i.e., more physically active) (Savitz, 2002). It was proposed that physical activity is associated with an increased opportunity for peak magnetic-field exposure, and the nausea experienced in early, healthy pregnancies and the cumbersomeness of late, healthy pregnancies would reduce physical activity levels, thereby decreasing the opportunity for exposure to peak magnetic fields. This hypothesis received empirical support from studies that reported consistent associations between activity (mobility during the day) and various metrics of measures of peak magnetic-field exposure (Mezei et al., 2006; Savitz et al., 2006; Lewis et al., 2015). These findings suggest that the association between maximum magnetic-field exposure and miscarriage is due to differing activity patterns of the cases and controls, not to an effect of the magnetic field on embryonic

development and viability. Furthermore, nearly half of women who had miscarriages reported in the cohort by Li et al. (2002) had magnetic-field measurements taken after miscarriage occurred, when changes in physical activity may have already occurred, and all measurements in Lee et al. (2002) occurred post-miscarriage.

The scientific panels that have considered these two studies concluded that the possibility of this bias precludes making any conclusions about the effect of magnetic fields on miscarriage (NRPB, 2004; FPTRPC, 2005; WHO, 2007). The WHO concluded, "There is some evidence for increased risk of miscarriage associated with measured maternal magnetic-field exposure, but this evidence is inadequate" (WHO, 2007, p. 254) and recommended further epidemiologic research.

Recent studies (2012-2016)

Three epidemiologic studies investigated the relationship between ELF magnetic-field exposure and miscarriage or stillbirth. A study in China (Wang et al., 2013), identified 413 pregnant women at 8 weeks of gestation between 2010 and 2012. The researchers measured magnetic-field levels at the front door and the alley in front of the participants' homes. No statistically significant association was seen with average exposure at the front door, but the authors reported an association with maximum magnetic-field values measured in the alleys in front of the homes. Magnetic-field levels measured at the front door are very poor predictors of home and personal exposure, thus the study provides only a limited contribution, if any, to current knowledge.

A study from Iran (Shamsi Mahmoudabadi et al., 2013) reported results of a hospital-based case-control study that included 58 women with spontaneous abortion and 58 pregnant women. The study reported a statistically significant increase in measured magnetic-field levels among the cases compared to controls. The study provides little weight to an overall assessment, however, due to limited information provided on subject recruitment, exposure assessment, type of metric used and potential confounders, and the small number of subjects.

A Canadian study (Auger et al., 2012) investigated the association between stillbirth and residential proximity to power lines. The authors identified over 500,000 births and 2,033 stillbirths in Québec and determined distance between postal code at birth address and the closest power line. No consistent association or trend was reported between stillbirth and residential distance. Reliance on distance to power lines and using the postal code for address information is a major limitation of the study's exposure assessment.

Three studies examined various birth outcomes in relation to ELF EMF exposure. A study from the United Kingdom investigated birth outcomes in relation to residential proximity to power lines during pregnancy between 2004 and 2008 in Northwest England (de Vocht et al., 2014). The researchers examined hospital records of over 140,000 births and distance to the nearest power lines were determined using geographical information systems. The authors reported moderately lower birth weight within 50 meters of power lines, but observed no statistically significant increase in risk of any adverse clinical birth outcomes (such as preterm birth, small for gestational age, or low birth weight). The limitations of the study include its reliance on distance for exposure assessment and the potential for confounding by socioeconomic status as also discussed by the authors. A follow-up analysis of the same data suggested that the observed

association in the de Vocht et al. (2014) study, at least partially, could be due to confounding and missing data (de Vocht and Lee, 2014).

A study from Iran reported no association between ELF EMF and pregnancy and developmental outcomes, such as duration of pregnancy, birth weight and length, head circumference, and congenital malformations (Mahram and Ghazavi, 2013). The study, however, provided little information on subject selection and recruitment, thus it is difficult to assess its quality.

Finnish scientists examined the potential association between residential exposure to magnetic fields and time to pregnancy, low birth weight, and being small for gestational age (SGA) among 373 mothers who gave birth between 1990 and 1994 in Kuopio University Hospital (Eskelinen et al., 2016). The study group was selected from the birth register of the hospital. To increase the prevalence of high exposure to EMF and the exposure contrast in the study, the scientists selected mothers with residences in close proximity to nearby sources (e.g., transmission lines, transformers). Exposure to magnetic fields was assessed through spot measurements in the home and using a questionnaire that requested information on occupational and residential sources of EMF (e.g., electrical appliances and equipment). None of the exposure metrics used to assess EMF exposure was statistically associated with measures of fetal growth or time to pregnancy in the study. Consideration of various metrics, including residential measurements, and availability of personal level information on potential confounders were among the strengths of the study, while the relatively low number of highly-exposed subjects limited the study's statistical precision.

An Italian study reported that blood melatonin levels showed a statistically significant increase among 28 newborns 48 hours after being taken from incubators with assumed elevated ELF EMF exposure, but not among 28 control newborns who were not in incubators (Bellieni et al., 2012). Neither the before nor the after values were statistically different from each other in the two groups (incubator vs. control), however, thus the clinical significance of the findings, if any, is unclear.

A cross-sectional study conducted in China examined correlations between magnetic-field exposure and embryonic development (Su et al., 2014). The study population was comprised of 149 pregnant women who were seeking induced termination of pregnancy during the first trimester. Exposure to EMF was assessed using personal 24-hour measurements within four weeks of the termination. Embryonic bud and sac lengths were determined by ultrasound prior to the termination. Since exposure to magnetic fields was measured following the termination of the pregnancy, the examiner completing the ultrasound examination could not be aware of the measured field levels. An association between maternal daily magnetic-field exposure and embryonic bud length was reported. The study provides little, if any weight in a weight-of-evidence assessment due to its severe limitations, the most important of which are the cross-sectional design of the study and the lack of consideration of gestational age, which is a major determinant of embryonic bud length.

An assessment of the scientific literature on ELF EMF exposure and measures of infertility and adverse pregnancy outcomes reviewed the strength and limitations of recently published studies and concluded that design limitations in most studies may explain their inconsistent findings (Lewis et al., 2016). The authors' recommendations for future studies included, among others,

the selection of appropriate study populations, the assessment and control for potential confounding by the mothers' physical activity, the careful characterization of exposure, and the analysis of various exposure metrics in the study.

Assessment

The recent epidemiologic studies on pregnancy and reproductive outcomes provided little new insight in this research area and do not change the classification of the data from earlier assessments as inadequate. The recent review by (SCENIHR, 2015) concluded that "recent results do not show an effect of ELF MF [magnetic field] exposure on reproductive function in humans."

Table 9. Relevant studies of reproductive and developmental effects

Authors	Year	Study
Auger et al.	2012	Stillbirth and residential proximity to extremely low frequency power transmission lines: a retrospective cohort study
Bellieni et al.	2012	Is newborn melatonin production influenced by magnetic fields produced by incubators?
de Vocht and Lee	2014	Residential proximity to electromagnetic field sources and birth weight: Minimizing residual confounding using multiple imputation and propensity score matching
de Vocht et al.	2014	Maternal residential proximity to sources of extremely low frequency electromagnetic fields and adverse birth outcomes in a UK cohort
Eskelinen et al.	2016	Maternal exposure to extremely low frequency magnetic fields: Association with time to pregnancy and foetal growth
Lewis et al.	2016	Exposure to Power-Frequency Magnetic Fields and the Risk of Infertility and Adverse Pregnancy Outcomes: Update on the Human Evidence and Recommendations for Future Study Designs
Mahram and Ghazavi	2013	The effect of extremely low frequency electromagnetic fields on pregnancy and fetal growth, and development
Shamsi Mahmoudabadi et al.	2013	Exposure to Extremely Low Frequency Electromagnetic Fields during Pregnancy and the Risk of Spontaneous Abortion: A Case-Control Study
Su et al.	2014	Correlation between exposure to magnetic fields and embryonic development in the first trimester
Wang et al.	2013	Residential exposure to 50 Hz magnetic fields and the association with miscarriage risk: a 2-year prospective cohort study

Neurodegenerative diseases

The WHO panel concluded that there is inadequate data in support of an association between magnetic fields and Alzheimer's disease or ALS. The panel recommended more research in this area using better methods; in particular, studies that enrolled incident Alzheimer's disease cases (rather than ascertaining cases from death certificates) and studies that estimated electrical shock history in ALS cases were recommended. Specifically, the WHO concluded, "When evaluated across all the studies, there is only very limited evidence of an association between estimated ELF exposure and [Alzheimer's] disease risk" (WHO, 2007, p. 194) and "overall, the evidence for an association between ELF exposure and ALS is considered inadequate" (WHO, 2007, p.

206).

Recent studies (2012 – 2016)

A population-based case-control study (Frei et al., 2013) examined the relationship between residential distance to power lines and neurodegenerative diseases covering the entire population of Denmark between 1994 and 2010. Distance from the nearest power line to the residential address for all newly-reported cases and matched controls were determined using geographical information systems. Overall, none of the investigated diseases, including Alzheimer disease and other types of dementia, ALS, Parkinson's disease, or multiple sclerosis was related to residential proximity to power lines. The inclusion of newly-diagnosed cases from hospital discharge records represents a significant methodological improvement over mortality studies. The study, however, was limited by the methods used for the exposure assessment.

Seelen et al. (2014) conducted a population-based case-control study including 1,139 ALS cases diagnosed in the Netherlands between 2006 and 2013 and 2,864 frequency-matched controls. Case and control addresses were geocoded and the shortest distance to the nearest high-voltage power line (50 – 380 kV) was determined. No statistically significant associations were reported for ALS with residential proximity to power lines with any of the included voltages. A combined analysis of the current results with two previously published studies (Marcilio et al., 2011; Frei et al., 2013) resulted in an overall OR of 0.9 (95% CI 0.7-1.1) for living within 200 meters of a high-voltage power line. Reconstruction of lifetime residential history represents a methodological improvement of the current study. The main limitation, similarly to previous power-line studies, is the use of distance to power lines as a surrogate for magnetic-field exposure.

Data from the Swiss National Cohort study was used to examine the relationship between occupational exposure to EMF and electric shocks and ALS mortality from 2000 to 2008 (Huss et al., 2014). Occupations reported at the 1990 and 2000 censuses along with job-exposure matrices were used to estimate exposure. A total of 2.2 million subjects were included in the analyses with available data from both censuses. Among these, 278 cases of ALS were identified. The authors reported an association with medium and high estimates of ELF EMF exposure, but not with estimates of exposure to electric shocks. Yu et al. (2014) reported results of a small case-control study of ALS, including 66 cases and 66 controls, examining various lifestyle, environmental, and work-related variables as potential risk factors. Their results on occupational exposure to EMF, however, cannot be interpreted because of a severe error of combining estimates of ionizing and non-ionizing radiation exposures in their analysis.

In a study of 3,050 Mexican Americans, aged 65+, enrolled in Phase I of the Hispanic Established Population for the Epidemiologic Study of the Elderly study, the association between severe cognitive dysfunction and occupational ELF magnetic-field exposure was examined (Davanipour et al., 2014). Information on occupational history, and socio-demographic variables were obtained by in-person interviews. Occupational exposure to magnetic fields was classified as low, medium, and high. The mini-mental state exam was used to evaluate cognitive function. Cognitive dysfunction was defined as an exam score below 10. The study is a cross-sectional survey, even though the authors describe it as a population-based case-control study. The authors report a statistically significant association between estimated occupational magnetic-field exposure and severe cognitive dysfunction. The reported

association is, however, difficult to interpret due to the number of severe limitations of the study, which include the cross-sectional study design, the lack of clear clinical diagnosis for case-definition, and the rudimentary assessment of exposure to occupational EMF.

Koeman et al. (2015) analyzed data from the Netherlands Cohort Study, a longitudinal follow-up study of approximately 120,000 men and women enrolled in 1986, to study the relationship between various occupational exposures and non-vascular dementia. Between 1986 and 2003, 798 male and 1,171 female cases were identified. Lifetime occupational history was obtained by questionnaire. Based on occupational titles and with the use of various job-exposure matrices, occupational exposures to solvents, pesticides, metals, ELF magnetic fields, electric shocks, and diesel exhaust were assessed. No association was reported for exposure to electric shocks. The authors reported moderate, but statistically non-significant, associations for the highest estimates of exposures to metals, chlorinated solvents, and ELF magnetic fields. The association for ELF fields, however, showed no exposure-response relationship based on cumulative exposure and the authors concluded that the association observed for ELF magnetic fields and solvents might be attributable to confounding by exposure to metals.

Brouwer et al. (2015) identified cases of Parkinson's disease between 1986 and 2003 in a cohort of approximately 120,000 adults (i.e., the Netherlands Cohort Study, noted above). They assessed occupational exposure to EMF and electric shocks among the study subjects using job-exposure matrices. Based on a total of 609 cases of Parkinson's disease, the authors concluded that their results generally do not provide strong support for an association with EMF or electric shocks. A hospital-based case-control study in the Netherlands included 444 cases of Parkinson's disease and 876 matched controls (van der Mark et al., 2014). Occupational exposure to EMF and electric shocks was assessed using work history and a job-exposure matrix. No associations were reported between any of the exposure metrics and Parkinson's disease.

Vergara et al. (2015) conducted a mortality case-control study of occupational exposure to electric shock and magnetic fields and ALS in the United States. A total of 5,886 deaths due to ALS were identified between 1991 and 1999. For each ALS death, 10 controls, matched on sex, age, year of death, and region, were selected from among other deaths. The occupation reported on the death certificates were linked to job exposure matrices for electric shocks and magnetic fields, and classified as high, medium, and low. Occupations classified as "electric occupations" were moderately associated with ALS (OR 1.23, 95% CI, 1.04-1.47). ALS, however, was inversely associated with electric shocks (OR 0.73, 95% CI, 0.67-0.79 in high exposure, and OR 0.90, 95% CI, 0.84-0.97 in medium exposure compared to low exposure) and not statistically associated with EMF (OR 1.09, 95% CI, 1.00-1.19 in high exposure, and OR 1.09, 95% CI, 0.96-1.23 in medium exposure compared to low exposure). The authors conclude that their findings do not support that either electric shock or magnetic fields explain the observed association of ALS with "electric occupations."

Fischer et al. (2015) conducted a population-based case-control study of occupational exposure to electric shocks and magnetic fields and ALS in Sweden. The base population of the study included all individuals born in Sweden between 1901 and 1970 who were enumerated during the 1990 Swedish Census. All cases of ALS in the study population, newly diagnosed between 1990 and 2010, were identified by record linkages to the Swedish patient and death registries. Five controls, individually matched to cases on birth year and sex, were selected for each case

from the study base. Census-based information on occupations was linked to multiple previously developed job-exposure matrices to classify exposure to EMF and electric shocks for cases and controls. A total of 4,709 cases and 23,335 controls were included in the study. Overall, neither EMF nor electric shocks were related to ALS. Among subjects aged < 65 years, statistically significant increases in ALS risk were reported with exposure to electric shocks. A statistically non-significant decrease, however, was also observed among subjects 65 years and older. The study has a number of strengths, which include its large sample size, population-based design, inclusion of incidence cases, and the reliance on multiple job-exposure matrices (three for EMF and two for electric shocks) for exposure assessment.

Weak to no evidence of an association was presented in recent meta-analyses of occupational exposure to ELF magnetic fields and neurodegenerative disease (Zhou et al., 2012; Vergara et al., 2013; Capozzella et al., 2014; Huss et al., 2015); hence, the authors concluded that potential within-study biases, evidence of publication bias, and uncertainties in the various exposure assessments greatly limit the ability to infer an association, if any, between occupational exposure to magnetic fields and neurodegenerative disease. In sum, these recent meta-analyses provide no convincing evidence of a relationship between ELF magnetic fields and neurodegenerative disease.

It has been previously suggested that the weak and inconsistent association between ELF EMF and ALS might be explained by electric shocks in occupational environments. Several recent studies, however, addressed the issue of the potential role of electric shocks in the development of neurodegenerative and neurological diseases, but none of them presented convincing evidence for an association (Das et al., 2012; Grell et al., 2012; van der Mark et al., 2014; Vergara et al., 2015; Fischer et al., 2015).

Assessment

In recent years, a number of studies have been published that examined the potential relationship between EMF, electric shocks, and neurodegenerative diseases. Many of these studies represented methodological improvements (e.g., increased sample size, improved exposure assessment, inclusion of incidence cases) compared to previous studies. In spite of these methodological improvements, the overall evidence from these studies provided no further support for a causal association. The most recent SCENIHR report (2015) concluded that newly published studies "do not provide convincing evidence of an increased risk of neurodegenerative diseases, including dementia, related to ELF MF [magnetic field] exposure" (SCENIHR, 2015, p. 186).

Table 10. Relevant studies of neurodegenerative disease

Authors	Year	Study
Brouwer et al	2015	Occupational exposures and Parkinson's disease mortality in a prospective Dutch cohort
Capozella et al.	2014	Work related etiology of amyotrophic lateral sclerosis (ALS): a meta-analysis
Das et al.	2012	Familial, environmental, and occupational risk factors in development of amyotrophic lateral sclerosis

Authors	Year	Study
Davanipour	2014	Severe cognitive dysfunction and occupational extremely low frequency magnetic field exposure among elderly Mexican Americans
Fischer et al.	2015	Occupational Exposure to Electric Shocks and Magnetic Fields and Amyotrophic Lateral Sclerosis in Sweden
Frei et al.	2013	Residential distance to high-voltage power lines and risk of neurodegenerative diseases: a Danish population-based case-control study
Huss et al.	2014	Occupational exposure to magnetic fields and electric shocks and risk of ALS: The Swiss National Cohort
Huss et al.	2015	Extremely Low Frequency Magnetic Field Exposure and Parkinson's Disease--A Systematic Review and Meta-Analysis of the Data
Grell et al.	2012	Risk of neurological diseases among survivors of electric shocks: a nationwide cohort study, Denmark, 1968-2008
Koeman et al.	2015	Occupational exposures and risk of dementia-related mortality in the prospective Netherlands Cohort Study
Seelen et al.	2014	Residential exposure to extremely low frequency electromagnetic fields and the risk of ALS
Van der Mark et al.	2014	Extremely low-frequency magnetic field exposure, electrical shocks and risk of Parkinson's disease
Vergara et al.	2013	Occupational exposure to extremely low-frequency magnetic fields and neurodegenerative disease: A meta-analysis
Vergara et al.	2015	Case-control study of occupational exposure to electric shocks and magnetic fields and mortality from amyotrophic lateral sclerosis in the US, 1991-1999
Yu et al.	2014	Environmental risk factors and amyotrophic lateral sclerosis (ALS): a case-control study of ALS in Michigan
Zhou et al.	2012	Association between extremely low-frequency electromagnetic fields occupations and amyotrophic lateral sclerosis: A meta-analysis

Cardiovascular disease

It has been hypothesized that magnetic-field exposure reduces heart rate variability, which in turn is a marker of increased susceptibility for AMI. In a large cohort of utility workers, Savitz et al. (1999) reported an increased risk of arrhythmia-related deaths and deaths due to AMI. Previous and subsequent studies did not report a statistically significant increase in cardiovascular disease mortality or incidence related to occupational magnetic-field exposure (WHO, 2007). The WHO concluded, “Overall, the evidence does not support an association between ELF exposure and cardiovascular disease” (WHO, 2007, p. 220).

Recent studies (2012 – 2016)

One study from the Netherlands evaluated the relationship between occupational exposure to ELF EMF and cardiovascular disease mortality (Koeman et al., 2013). The study identified more than 8,000 cardiovascular deaths among the more than 120,000 men and women in the Netherlands Cohort Study during a 10-year period. Occupational exposure was determined by linking occupational histories to an ELF-magnetic-field job-exposure matrix. The authors reported no association between cumulative occupational ELF-magnetic-field exposure and cardiovascular mortality or death due to any of the subtypes of cardiovascular disease. The

authors concluded that their results add "to the combined evidence that exposure to ELF-MF [magnetic fields] does not increase the risk of death from CVD [cardiovascular disease]" (Koeman et al., 2013, p. 402).

Assessment

The recent study reported no association between ELF magnetic fields and cardiovascular disease, thus confirming earlier conclusions about the lack of an association between magnetic fields and cardiovascular disease.

Table 11. Relevant studies of cardiovascular disease

Authors	Year	Study Title
Koeman et al.	2013	Occupational exposure to extremely low-frequency magnetic fields and cardiovascular disease mortality in a prospective cohort study

6 Reviews by Scientific Organizations

Several reports with regard to the possible health effects of ELF EMF have been published by national and international scientific organizations since 2012 (NZMH, 2015; Hall et al., 2015; SCENIHR, 2015; SSM, 2013, 2014, 2015). Although none of these documents represents a cumulative weight-of-evidence review of the depth of the WHO review published in June 2007, their conclusions are of relevance. In general, the conclusions of these reviews are consistent with the scientific consensus articulated in Sections 4 and 5. The most comprehensive recent scientific review was published by SCENIHR in 2015, which updated the previous report on potential health effects of EMF issued by the same committee in 2009 (SCENIHR, 2009). The conclusions of the 2015 SCENIHR review are consistent with earlier comprehensive reviews, most notably the WHO review discussed in detail above. SCENIHR (2015) did not conclude that the available scientific evidence confirms a causal link between any adverse health effects (including both cancer and non-cancer health outcomes) and EMF exposure. With respect to epidemiologic results of childhood leukemia, the review concludes that: "… no mechanisms have been identified and no support is existing [*sic*] from experimental studies that could explain these findings, which, together with shortcomings of the epidemiological studies prevent a causal interpretation" (SCENIHR, 2015, p. 7).

The WHO and other scientific organizations have not found any *consistent* associations with regard to ELF EMF exposure and any type of cancer or disease, except childhood leukemia, nor have they concluded that there is a cause-and-effect link with any health effect, including childhood leukemia (WHO, 2007; SCENIHR, 2009, 2015; EFHRAN, 2010, 2012; ICNIRP, 2010; SSM, 2010; NZMH, 2015; Hall et al., 2015).

In summary, over the past decades, reviews published by scientific organizations using weight-of-evidence methods have concluded that the cumulative body of research to date does not support the hypothesis that ELF EMF causes any long-term adverse health effects at the levels we encounter in our everyday environments. An evaluation of current research does not point to better quality or stronger evidence that is sufficient to change the conclusions of these assessments.

7 Summary

A number of epidemiologic and *in vivo* studies have been published on EMF and health since Exponent's 2012 update to the WHO report. The weak statistical association between high, average magnetic fields and childhood leukemia remains largely unexplained and unsupported by the experimental studies. The recent *in vivo* studies confirm the lack of experimental data supporting a leukemogenic risk associated with magnetic-field exposure or other effects on health.

Overall, the current body of research supports the conclusion that there is no association between magnetic fields and adult cancer or cardiovascular disease, although future research is needed to improve methods to estimate exposure. Recent literature does not confirm an association between magnetic fields and neurodegenerative diseases, including Alzheimer's disease and ALS.

In conclusion, no recent studies provide evidence to alter the conclusion that the scientific evidence does not confirm that ELF EMF exposure is the cause of cancer or any other disease process at the levels we encounter in our everyday environment.

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Appendix 5-10

Electrical Engineering and Computer Science Practice

Exponent®

Sudbury to Hudson Transmission Line Reliability Project

Electric Field and Magnetic Field Assessment

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Sudbury to Hudson Transmission Line Reliability Project

Electric Field and Magnetic Field Assessment

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Acronyms and Abbreviations

A	Ampere
AC	Alternating current
EMF	Electric and magnetic fields
G	Gauss
Hz	Hertz
ICES	International Committee on Electromagnetic Safety
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IEEE	Institute of Electrical and Electronics Engineers
kV/m	Kilovolts per meter
mG	Milligauss
ROW	Right of way
V/m	Volts per meter

Executive Summary

The proposed Sudbury to Hudson Transmission Line Reliability Project (Project) involves the construction of a new 115-kilovolt (kV) transmission line between Eversource's Sudbury Substation in Sudbury, Massachusetts, and the Hudson Light and Power Substation in Hudson, Massachusetts. The Project is approximately 9 miles of underground line including approximately 7. 6 miles constructed within an existing Massachusetts Bay Transportation Authority (MBTA) right-of-way (ROW) and 1.4 miles within city streets. The Noticed Variation would be constructed entirely overhead on the MBTA ROW and underground in streets over the remainder of the Project route to the Hudson Substation. A Noticed Alternative Route also has been identified, which would be somewhat longer (10.3 miles), and the line along this route would be constructed entirely underground beneath city streets.

For the Project, Noticed Variation and Noticed Alternative, the proposed transmission line will be a source of 60-Hertz magnetic fields and, where constructed overhead, also a source of electric fields above ground. To characterize the levels of electric and magnetic fields (EMF) associated with each route and design, Exponent modeled the different configurations of the line corresponding to overhead, underground, and manhole portions of the Project. Each of these configurations was modeled for two loading scenarios appropriate for calculating expected annual average and annual peak magnetic field levels.

The proposed Project is consistent with World Health Organization (WHO) and Energy Facility Siting Board (EFSB) guidance in that the line would be largely constructed on an existing ROW bordered by fewer residents, as compared to the longer in-street Noticed Alternative. In addition, the Project would be constructed underground on the MBTA ROW and in the road to minimize environmental impacts. These Project design choices are methods recognized by the EFSB and WHO for reducing EMF levels. Construction of the Project entirely underground on the Noticed Alternative Route would pass more residences, and at annual average loading the magnetic fields from the underground line would be greater because of higher expected loading for this all-underground line.

Levels of EMF were compared to health-based international standards and guidelines developed by the International Commission on Non-Ionizing Radiation Protection and the International Committee for Electromagnetic Safety and were found to be far below these standards, even directly beneath the overhead portion or above the underground portion of the transmission line.

Introduction

The proposed Sudbury to Hudson Transmission Line Reliability Project (Project) involves the construction of a new 115-kilovolt (kV) underground transmission line between Eversource's Sudbury Substation, located on Boston Post Road (Route 20) in Sudbury, Massachusetts, and the Hudson Light and Power substation located on Forest Avenue in Hudson, Massachusetts. Approximately 4.3 miles of the proposed line will be in Sudbury, Massachusetts, while approximately 3.3 miles will be in Hudson, Massachusetts.[1]

The Project is designed to improve the future reliability of the electric system by providing a new transmission path to supplement the existing system and address identified thermal and voltage problems in the area, which are goals common to several other projects serving the Greater Boston/Metro West area. In addition, the aggregate suite of projects is expected to reduce transmission congestion costs by enabling reliable delivery of more lower-cost electricity generated outside the area to serve the power demands within the area.

The proposed transmission line will be a source of 60-Hertz (Hz) magnetic fields above ground and, where constructed overhead, also a source of electric fields. Eversource has requested that Exponent evaluate the electric and magnetic fields (EMF) associated with the Project. To characterize the Project's EMF levels, Exponent modeled the transmission line in one overhead configuration and one predominant underground configuration. Exponent also modeled the magnetic field associated with the portions of the route (each approximately 30 feet in length) where the underground cables are spliced together in a manhole vault.

Transmission Line Route

Eversource has identified a preferred route for the new 115-kV transmission line (the Project) as well as a Noticed Variation, and a Noticed Alternative Route. The Project (red line in Figure 1) exits the Sudbury Substation and travels approximately 7.6 miles in an existing Massachusetts Bay Transportation Authority (MBTA) right-of-way (ROW) to Wilkins Street in Hudson,

[1] Smaller portions of the line also are proposed to pass through both Marlborough and Stow, Massachusetts.

Massachusetts. From Wilkins Street, the line will continue approximately 0.2 miles to Main Street, where the line will follow Forest Avenue for approximately 1.2 miles to the Hudson Substation as shown by the blue line in Figure 1. The entire Project between substations is proposed to be constructed underground. For the Noticed Variation, the line would be constructed overhead along the MBTA ROW (dotted line), then transition underground at Wilkins Street and continue from Wilkins Street to Main Street underground in the street *en route* to the Hudson Substation (blue line).

If constructed on the Noticed Alternative Route, the proposed transmission line would be underground beneath city streets for the entire distance (approximately 10.3 miles) between the Sudbury and Hudson Substations as shown by the yellow line in Figure 1. Note that the Project, Noticed Variation and the Noticed Alternative Route all share the same proposed underground portion of the line along Forest Avenue from Main Street to the Hudson Substation.

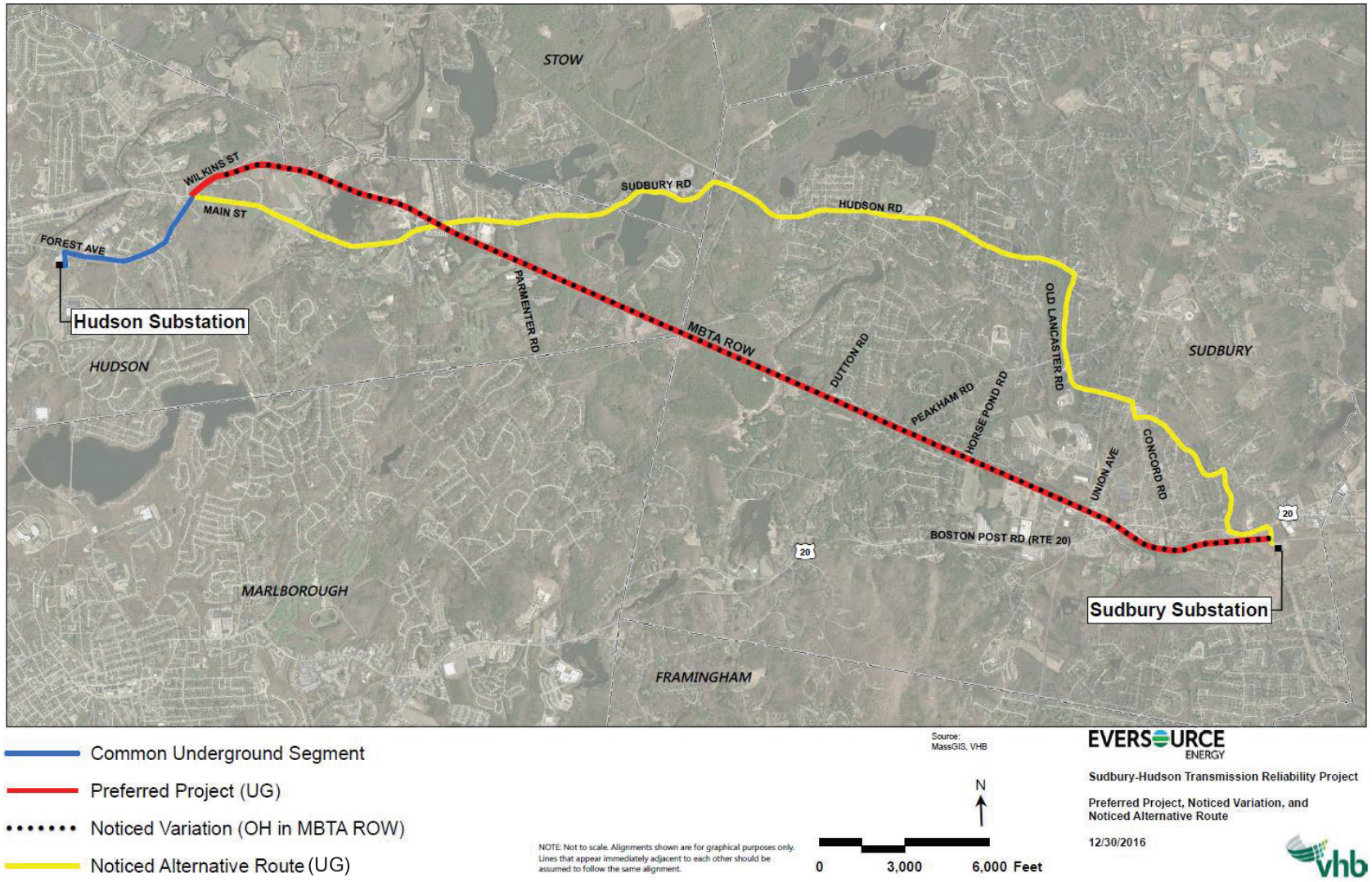


Figure 1. Underground Project route, with indicated overhead Noticed Variation, and the underground Noticed Alternative Route of the proposed 115-kV transmission line between the Sudbury and Hudson Substations.

Proposed Configuration

Along the Project, the Noticed Variation and the Noticed Alternative Route, the new transmission line is proposed to be constructed in locations without existing parallel transmission lines so EMF levels were calculated assuming the proposed line is operating in isolation from all other sources. As a result calculated EMF levels will depend only on the physical configuration of the line and the loading of the line. Three line configurations are evaluated: a) overhead on monopole structures with a vertical conductor configuration, b) underground with cables in an inverted delta configuration, and c) underground manholes where the cables are spliced together and installed in a vertical configuration. The proposed configurations are shown below in Figure 2.

For almost the entire underground portion of the line, the power cables are proposed to be installed in an inverted delta (∇) configuration (Figure 2b) with a ground continuity conductor (GCC) installed to provide a path to divert current from the cable sheaths in the event of a cable fault. In order to connect consecutive portions of the underground transmission line together, the cables must be brought into a manhole for splicing. In the manhole (splice vault) the cables will be installed in a vertical configuration (as shown in Figure 2c). In the overhead line configuration (Figure 2a), the center of the transmission line structures is proposed to be 23 feet from one edge of the 82.5-foot-wide MBTA ROW.[2]

[2] In some portions of the MBTA ROW, the structures will be 23 feet from the southern ROW edge, in other portions they will be 23 feet from the northern ROW edge.

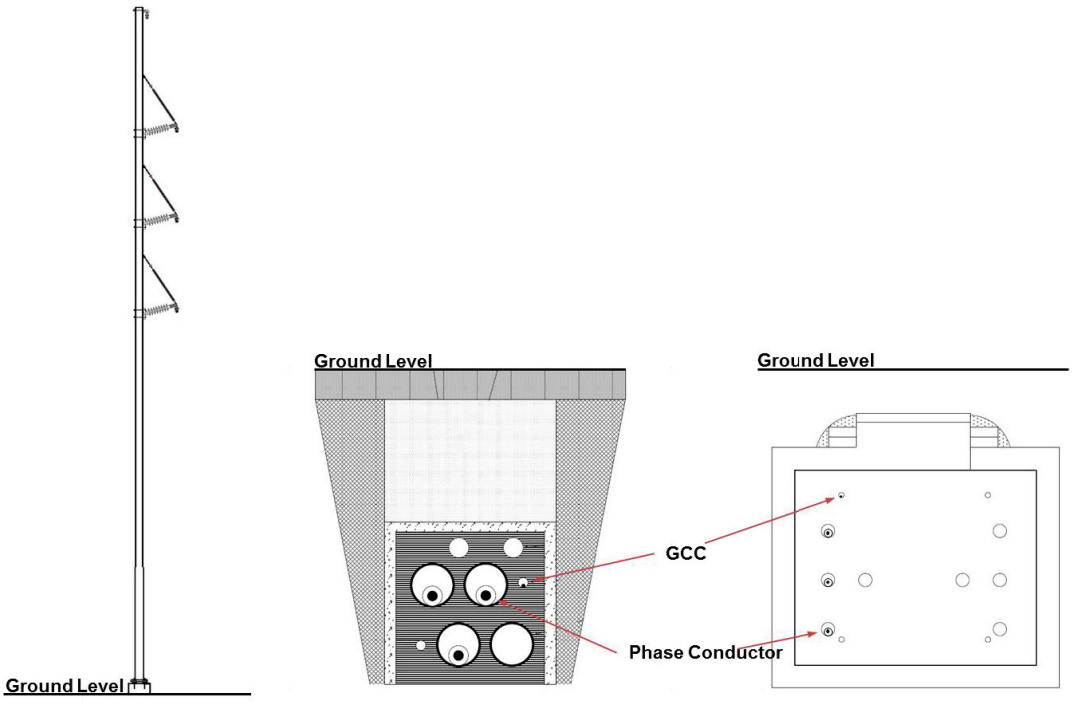


Figure 2. Configurations of the proposed transmission line used for EMF modeling.

a) Overhead on monopole structures with a vertical conductor configuration, b) underground in an inverted delta configuration, and c) underground at manholes where cables are spliced together (drawings not to scale).

Electrical Environment

All objects contain both positive and negative charges. When the numbers of positive and negative charges in an object are equal, the object is described as electrically neutral. When the object contains more of one charge or the other, however, the resulting net charge gives rise to an electric field. Magnetic fields result from the movement of electric charges or from the patterns of electron movement in certain materials such as permanent magnets.

Electricity is the movement of electric charges. Consequently, both electric fields and magnetic fields are properties of the space surrounding anything that generates, transmits, or uses electricity. Most electricity in North America is transmitted as alternating current (AC) at a frequency of 60 Hz (i.e., it changes direction and magnitude in a continuous cycle that repeats 60 times per second). The fields from these AC sources are commonly referred to as power-frequency or extremely low frequency (ELF) EMF.[3] The proposed transmission line is a source of 60-Hz magnetic fields and, where constructed overhead, also a source of 60-Hz electric fields.

Electric Fields

Electric fields from transmission lines result from the voltage on the conductors. Electric fields are measured in units of volts per meter (V/m) and for higher fields, in kilovolts per meter (kV/m), where 1,000 V/m is equal to 1 kV/m. In general, the level of an electric field diminishes with increasing distance from the source. In the case of transmission lines that decrease is typically in proportion to the square of the distance from the lines, so the electric-field level decreases rapidly with distance. The electric-field level increases as the voltage increases, and even if an appliance or electrical device is turned off, if the voltage is still present on the conductors, an electric field will also be present. The major sources of electric fields outdoors are transmission lines and distribution lines. Electric companies maintain voltage on the components of the electric system within tight limits so that the electric field from these

[3] The electric and magnetic fields described in this report are quasi-static ELF (non-propagating) fields, not to be confused with propagating electromagnetic fields produced by systems such as AM or FM radio or cellular phones.

conductors at the source is quite constant. Conducting objects such as walls, fences, and trees easily block electric fields from outdoor sources so these outdoor sources contribute very little to electric fields indoors where the major sources are appliances, equipment, and machines within homes, offices, and factories.

Magnetic Fields

Magnetic fields are created by current that flows in transmission line conductors. The level of magnetic fields is often reported as magnetic flux density in units of milligauss (mG), and for higher fields in Gauss (G) where 1,000 mG = 1 G. Unlike electric fields, magnetic fields are not blocked by conductive objects; however, similar to electric fields, the level of magnetic fields diminishes with increasing distance from the source.

Magnetic fields differ from electric fields in that they depend on the current flowing through a conductor, rather than voltage, so if an appliance or electrical device is turned off, magnetic fields are not present even if it is still connected to the power source. Since current—expressed in units of amperes (A)—generates magnetic fields around transmission-line conductors, measurements or calculations of the magnetic field present only a snapshot at one moment of time because the current flow varies depending upon the patterns of power demand on the bulk transmission system. Power demand on a given day, throughout a week, or over the course of months and years can vary, so the magnetic field of a transmission line can also vary. Therefore, current flow is often expressed at an annual average load, which is a good predictor of the magnetic field on any randomly selected day of the year, and also as annual peak load (which occurs on only a few days during a year).

Sources of EMF

Electricity plays such an integral role in modern society that we are surrounded by the resulting EMF. Sources of EMF include not only electrical infrastructure such as transmission and distribution lines but also everyday electrical items such as household appliances, equipment, and wiring in our schools and workplaces. Figure 3 illustrates levels of EMF measured in typical residential and occupational environments. These measured EMF levels are also

compared to levels measured on or at the edge of typical transmission-line ROW. While EMF levels decrease with distance from the source, any home, school, or office will have an ambient background level that is not attributable to a specific source as a result of the contribution of numerous EMF sources.

The World Health Organization (WHO) found that AC magnetic-field exposure in the home does not vary greatly throughout the developed world. The AC magnetic-field level away from appliances is typically between 1 and 2 milligauss (mG) whereas close to appliances levels can be hundreds of mG. Background levels of AC electric fields are generally below 0.1 kilovolts per meter (kV/m), even near appliances (NIEHS, 2002; WHO, 2007).

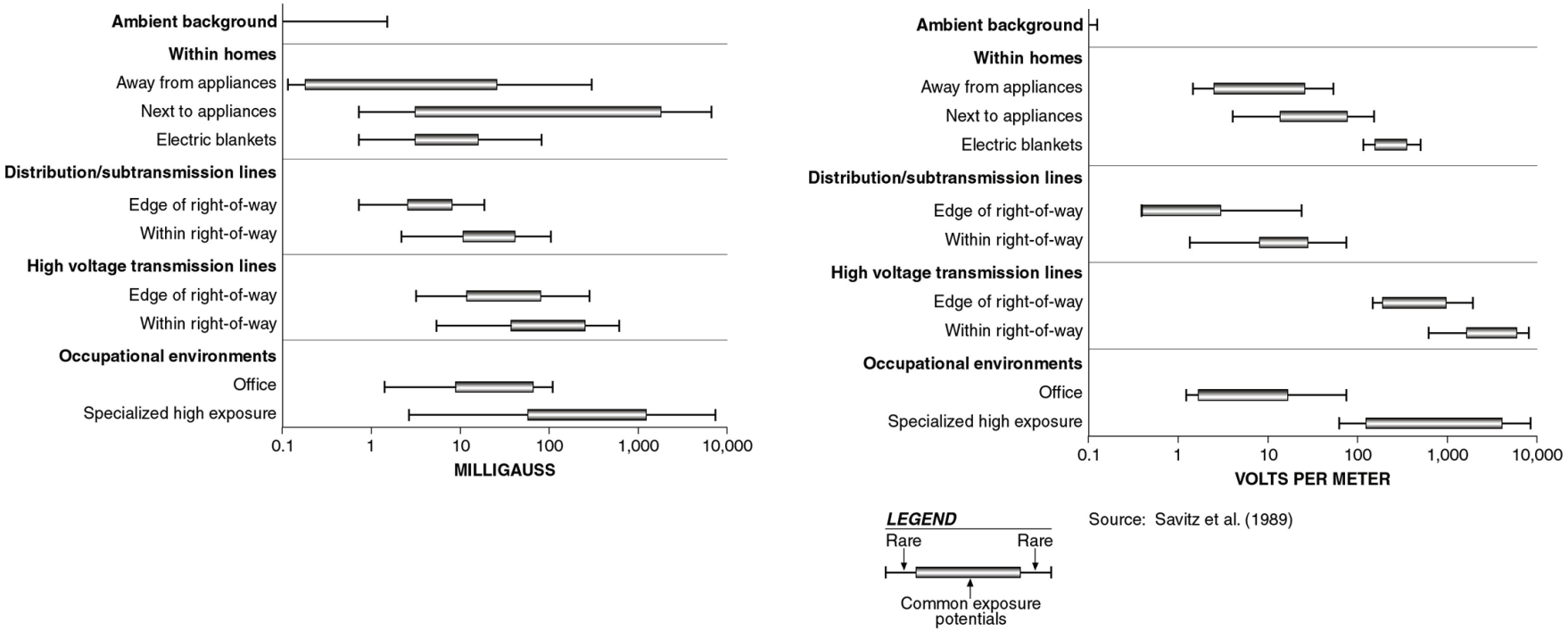


Figure 3. Levels of electric fields (right) and magnetic fields (left) in the environment (Savitz, 1989).

Methods

Based upon information provided by Eversource, Exponent calculated EMF using computer algorithms developed for AC transmission lines by the Bonneville Power Administration (BPA), an agency of the U.S. Department of Energy (BPA, 1991). The inputs to the program include the voltage, current flow, phasing, and conductor configurations, as well as the locations of GCCs for the underground portions of the route.

In the model, simplifying assumptions are made in order to make the calculations more tractable and to yield conservative values to ensure that the model will tend to overestimate, not underestimate, EMF levels. Each conductor is modeled as infinite in length at a fixed height above a flat earth or a fixed burial depth below ground and is assumed to be parallel to all other conductors. For EMF calculations of the overhead line, the conductor height above ground is taken at a midspan height representative of typical load conditions and terrain. Although these assumptions simplify the calculations, they do not decrease the accuracy of the model and have been shown to accurately predict electric-field and magnetic-field levels measured near transmission lines (Chartier and Dickson, 1990; Perrin et al., 1991). Both electric fields and magnetic fields are calculated at a height of 1 meter (3.28 feet) above ground and are reported as the root mean square value of the field in accordance with IEEE Std. C95.3.1-2010 and IEEE Std. 644-1994 (R2008).

Conductor Specifications and Modeling Configuration

When constructed underground, the power cables are proposed to be installed in an inverted delta (∇) configuration. In this configuration the centers of the top-most phase conductors are modeled to be 39 inches below grade with a horizontal phase spacing of 14 inches. The lower power cable is 14 inches below the two upper power cables and centered horizontally between them. The insulation on the power cables is proposed to be cross-linked polyethylene (XLPE), and each cable will have an outer diameter of approximately 4.5 inches and an inner conductor area of 3,500 kcmil. The GCC will be a 500-kcmil copper conductor. For the manhole configuration, the center of the top-most cable has been modeled at a burial depth of 5.5 feet

with phase spacing of 2 feet using the same 3,500-kcmil XLPE phase cables and 500-kcmil GCC.

On the overhead portion of the line the bare conductors (954-kcmil ACSS, 54/7 Cardinal) are 1.196 inches in diameter and modeled with a minimum midspan ground clearance of 30 feet for the bottom conductor, based upon Eversource design criteria. Each phase conductor is supported on braced insulators at a distance of 7 feet from the pole centerline, and with a vertical spacing of 11.5 feet between phase conductors is 11.5 feet. The 0.512-inch lightning shield wire is an optical ground wire (OPGW) with an attachment height of 13.5 feet above the top-most phase conductor.

Induced Current on GCC

The close proximity of the GCC to the phase conductors in the underground configuration results in an induced current flowing on the GCC which will, in turn, also result in a magnetic field from the GCC. The induced current on the GCC was calculated using COMSOL Multiphysics v5.2a. The results of this calculation include both a magnitude and phase of the induced current on the GCC, which then are included with the currents on the phase conductors as input to the BPA computer algorithms. This GCC current will result in a slight asymmetry to the magnetic field calculations which would not otherwise be expected.

Loading

Transmission line currents, and therefore magnetic fields from such lines, vary with hourly, daily and seasonal changes in the demand for electricity. The two loadings considered for this assessment are annual average load, which is a good predictor of the magnetic field on any randomly selected day of the year, and annual peak load (the highest magnetic-field level that might occur for a few hours on a few days during the year).

Table 1 summarizes the projected 2023 annual average and annual peak loading of the proposed line for each of the three project options. Note that loads for the all-underground options (Project and the Noticed Alternative) are higher than in the predominantly overhead option

(Noticed Variation). Constructing a line underground and for longer distances underground (such as in the Project or the Noticed Alternative Route) will result in higher line loadings than for the primarily overhead Noticed Variation, because of the lower impedance/foot of the underground cables. Magnetic field levels therefore are calculated for loadings representative for each of these options.

Table 1. Summary of 2023 loadings for all Route Alternatives

Route Alternative	Annual Average Loading (A)	Annual Peak Loading (A)
Project (Underground)*	128	461
Noticed Variation (Overhead)	68	350
Noticed Alternative (Underground)*	136	448

* Note that the average loading of Project is less than that of the Noticed Alternative, but the peak loading of Project is greater than that for the Noticed Alternative. This occurs because of differences in the charging current and the line impedance, factors that have opposite effects on loading level and both of which vary with the length of the line.

Assessment Criteria

While the federal government has no regulations regarding EMF, including levels from transmission lines, the Massachusetts Energy Facilities Siting Board (EFSB) assesses EMF levels from transmission lines on a case-by-case basis with a focus on practical options to reduce magnetic fields along transmission ROWs. This practice is also consistent with the recommendations of the WHO (WHO, 2007).

Levels of EMF can also be assessed in reference to standards and guidelines developed by scientific and health agencies. Two international agencies that have published limits of exposure to EMF include the International Committee on Electromagnetic Safety (ICES) and the International Commission on Non-Ionizing Radiation Protection (ICNIRP). The assessment levels (reference levels) set by these organizations are summarized Table 2 below.

The reference values listed in Table 2 were used as criteria for the evaluation of potential line designs and their potential effects on the electrical environment around transmission lines. These are not exposure limits, and exposures to higher EMF levels are allowed if the underlying basic restrictions on fields in the body are not exceeded.

Table 2. Reference levels for whole body exposure to 60-Hz fields: general public.

Organization	Magnetic Fields	Electric Fields
ICNIRP	2,000 mG	4.2 kV/m
ICES	9,040 mG	5 kV/m 10 kV/m*

* This is an exception within transmission line ROWs.

Modeling Results and Discussion

Results

The calculated field levels are highest immediately beneath overhead line portions and above underground line portions of the route, but decrease rapidly with distance from the transmission line. Magnetic field levels are slightly higher over the manhole configuration than for the inverted delta configuration, but the manholes represent only a very small portion of the route (each manhole is approximately 30 feet long). The electric field from the underground transmission line is shielded by a metallic sheath around each cable and by the earth itself, so the underground portion of the transmission line is not a source of electric fields above ground.

Tables 3 and 4 summarize the predicted magnetic and electric field levels for each of the route configurations for comparison to the ICNIRP and ICES reference levels. In Table 4, the calculated magnetic field levels at 25 feet on each side of the cable are not quite the same so the highest calculated value at this distance (on either side) is shown. Calculated magnetic field values at additional distances from the conductors for each modeling scenario (including each physical configuration and loading) are summarized in tables in Appendix A. Graphical profiles of the predicted magnetic field one meter above ground at annual average loading are shown in Appendix B. Electric fields from the project will only occur along the MBTA ROW in the Noticed Variation.[4] There will be no project-related electric field above ground for any underground configuration. The calculated electric-field levels are summarized in Appendix A and shown graphically in Appendix B.

[4] Electric fields depend only on the conductor heights above ground, their relative positions, and the voltage on the line. The value of electric fields is not expected to change significantly under peak line loading.

Table 3. Comparison of calculated magnetic field levels from underground portions of the line to ICNIRP (2,000 mG) and ICES (9,040 mG) reference levels.

Route Alternative	Configuration	Average Loading		Peak Loading	
		Highest at ±25 ft	Above cables	Highest at ±25 ft	Above cables
Project	Inverted Delta	3.4	24	12	88
	Manhole	4.4	28	16	99
Noticed Variation	Inverted Delta	1.8	13	9.3	67
	Manhole	2.4	15	12	75
Noticed Alternative	Inverted Delta	3.6	26	12	86
	Manhole	4.7	29	15	97

Note all distances shown are referenced to the centerlines of the underground cables

Table 4. Comparison of calculated electric and magnetic field levels from overhead portion of the line (Noticed Variation) to EMF reference levels.

Calculated Field	Location		Reference Levels	
	Nearest ROW edge	Below conductors	ICNIRP (2010)	ICES (2002)
Magnetic Field (annual average loading)	3.8	6.8	2,000 mG	9,040 mG
Magnetic Field (annual peak loading)	20	35		
Electric Field (kV/m)	0.3	1.2	4.2 kV/m	5 kV/m

Magnetic field levels for underground lines in the Project and the Noticed Alternative configurations at their respective annual average loadings are higher for both the inverted delta and manhole configurations than for the similar underground line portions of Noticed Variation due to higher expected line loading (see Table 1). The magnetic field directly above the underground transmission line for the Project at annual average loading is approximately 24 mG for the inverted delta configuration and 28 mG for the manhole configuration. At a distance of 25 feet from the centerline of the conductors in the inverted delta configuration, calculated magnetic field levels are 1.8 mG on one side of the ductbank and 3.4 mG on the other side. For the manhole configuration, at a distance of 25 feet from the center of the conductors, the magnetic field level is 4.4 mG on both sides of the manhole.

Similarly, for the Noticed Alternative the magnetic field level directly above the underground transmission line at annual average loading is approximately 26 mG for the inverted delta configuration and 29 mG for the manhole configuration. At a distance of 25 feet from the

centerline of the conductors in the inverted delta configuration, calculated magnetic field levels are 1.9 mG on one side of the ductbank and 3.6 mG on the other side. For the manhole configuration at a distance of 25 feet from the center of the conductors the magnetic field level is 4.7 mG on both sides of the manhole.

The magnetic field directly above the underground transmission line for the Noticed Variation is approximately 13 mG for the inverted delta configuration and 15 mG for the limited area represented by the manhole configuration at annual average loading but falls off more quickly with distance than in the overhead portion. The underground transmission line on city streets is not proposed to be installed in a specific ROW, therefore calculated magnetic field values are reported herein at a lateral distance of ±25 feet from the transmission centerline. At this distance, the magnetic-field level for the inverted delta configuration falls to 1.0 mG on one side of the ductbank and 1.8 mG on the other. For the manhole configuration at a distance of 25 feet from the center of the conductors the magnetic-field level is 2.3 mG on one side of the manhole and 2.4 mG on the other.

The magnetic field on the overhead portion of the ROW for the Noticed Variation at annual average loading is calculated to be approximately 6.8 mG directly beneath the line conductors and to decrease to 2.1 mG at one ROW edge and 3.8 mG at the other ROW edge.

For the short periods of time in which annual peak loading occurs, magnetic field levels are higher for all configurations and Project alternatives. At projected annual peak loading, the magnetic field levels at the edge of the ROW (or 25 feet from the duct bank centerline) for all Project alternatives increase over annual average loading by approximately 4 to 16 mG depending on the Project alternatives and configuration (see Appendix A).

The highest predicted electric field value on the ROW of the overhead portion of the transmission line is 1.2 kV/m, decreasing to 0.3 kV/m or less at the edge of the ROW.

Discussion

The EFSB objective to provide a “reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost” led to the Project alternatives

presented. The Project design incorporates many of the methods recognized by the EFSB and WHO for reducing magnetic field exposure such as constructing the line underground with small distance between conductors and constructing the overhead transmission line in a vertical configuration and with conductor heights which exceed National Electrical Safety Code® (NESC, 2012) standards.

The magnetic field from the underground transmission line (in the Project or Noticed Alternative) is higher directly over the conductors than directly below the conductors of the overhead line (in the Noticed Variation). However, the magnetic field from the underground line decreases more rapidly with increasing distance from the conductors than from the overhead line. In addition, the routing of the transmission line on an existing MBTA ROW reduces the length of the route and also minimizes the number of residences adjacent to the Project route compared to the Noticed Alternative.

The calculated EMF levels for all Project alternatives are far below both ICNIRP (2,000 mG and 4.2 kV/m) and ICES (9,040 mG and 5 kV/m) guidelines at all publically accessible locations.

Summary

This report summarizes calculations of EMF associated with the proposed transmission line between the Hudson Substation in Hudson, Massachusetts, and the Sudbury Substation in Sudbury, Massachusetts. These calculations have been performed using methods that are accepted within the scientific, engineering, and regulatory communities and which previously have been found to match well with measurements. These calculations have been compared to applicable guidelines and found to be below levels used to assess potential adverse impacts to public health.

The predicted EMF levels for the Project, Noticed Variation and the Noticed Alternative at average and peak line loadings are far below recommended guidelines for public exposure of ICNIRP (2,000 mG and 4.2 kV/m) and ICES (9,040 mG and 5 kV/m), even at public locations closest to the line. The Project alternatives presented are consistent with the methods recognized by the EFSB and WHO for reducing exposure to magnetic fields. Magnetic field levels decrease quickly with distance such that away from the line (e.g., at 25 feet from the underground cables or at the ROW edge) magnetic field levels for the Project, Noticed Variation and the Noticed Alternative are similar and low.

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Notice

At the request of Eversource Energy, Exponent modeled the levels of EMF associated with the proposed 115-kV transmission line between the Sudbury and Hudson Substations. This report summarizes work performed to date and presents the findings resulting from that work. In the analysis, we have relied on geometry, material data, usage conditions, specifications, and various other types of information provided by Eversource. Eversource has confirmed to Exponent that the data provided to Exponent, and summary contained herein, are not subject to Critical Energy Infrastructure Information restrictions. We cannot verify the correctness of this data, and rely on the clients for the data's accuracy. Although Exponent has exercised usual and customary care in the conduct of this analysis, the responsibility for the design and operation of the Project remains fully with the clients.

The findings presented herein are made to a reasonable degree of engineering and scientific certainty. Exponent reserves the right to supplement this report and to expand or modify opinions based on review of additional material as it becomes available, through any additional work, or review of additional work performed by others.

The scope of services performed during this investigation may not adequately address the needs of other users of this report outside of the EFSB permitting process, and any re-use of this report or its findings, conclusions, or recommendations presented herein are at the sole risk of the user. The opinions and comments formulated during this assessment are based on observations and information available at the time of the investigation. No guarantee or warranty as to future life or performance of any reviewed condition is expressed or implied.

Appendix A

Summary Tables of Calculated EMF

Table A-1. Electric (kV/m) and magnetic (mG) field levels for the proposed overhead portion of the Noticed Variation

Field	Location				
	100 ft beyond –ROW edge	−ROW edge	Max on ROW	+ROW edge	100 ft beyond +ROW edge
Magnetic Field (annual average loading)	0.5	3.8	6.8	2.1	0.4
Magnetic Field (annual peak loading)	2.5	20	35	11	1.8
Electric Field (kV/m)	<0.1	0.3	1.2	<0.1	<0.1

Table A-2. Magnetic-field levels (mG) at annual average loading for underground portions of Project, Noticed Variation, and Noticed Alternative†

Route alternative	Configuration	Location‡				
		–125 ft	−25 ft	Above cables	+25 ft	+125 ft.
Project	Inverted Delta	0.5	3.4	24	1.8	0.4
	Manhole	0.5	4.4	28	4.4	0.5
Noticed Variation	Inverted Delta	0.3	1.8	13	1.0	0.2
	Manhole	0.3	2.3	15	2.4	0.3
Noticed Alternative	Inverted Delta	0.5	3.6	26	1.9	0.4
	Manhole	0.5	4.7	29	4.7	0.5

† The current induced on the GCC is calculated to be small, approximately 7% of the phase current, and the resulting change in calculated magnetic-field levels above ground is also small—approximately 1-2 mG or less at annual average loading. This GCC current, however, also results in a small asymmetry in the calculated magnetic-field levels above ground, which would not otherwise occur.

‡ All distances shown are referenced to the centerlines of the underground cables.

Table A-3. Magnetic-field levels (mG) at annual peak loading for underground portions of Project, Noticed Variation, and Noticed Alternative

Route Alternative	Configuration	Location‡				
		–125 ft	−25 ft	Above cables	+25 ft	+125 ft
Project	Inverted Delta	1.8	12	88	6.5	1.5
	Manhole	1.8	16	99	16	1.8
Noticed Variation	Inverted Delta	1.4	9.3	67	4.9	1.2
	Manhole	1.3	12	75	12	1.4
Noticed Alternative	Inverted Delta	1.8	12	86	6.3	1.5
	Manhole	1.7	15	97	15	1.7

‡ All distances shown are referenced to the centerlines of the underground cables.

Appendix B

Graphical Profiles of Calculated EMF

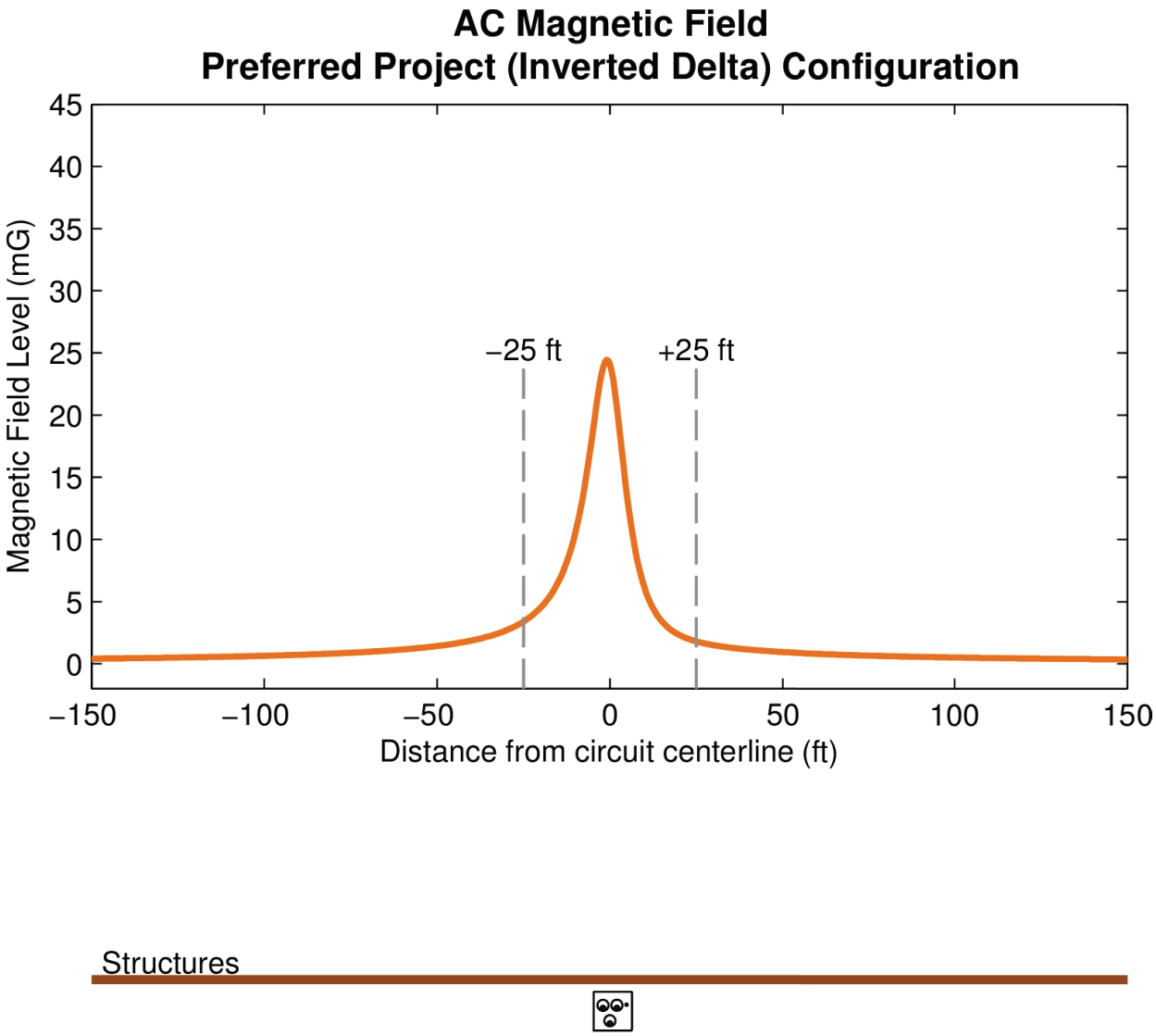


Figure B-1. Calculated magnetic-field level for the Inverted Delta Configuration of the Project under annual average loading conditions.

Duct bank not to scale.

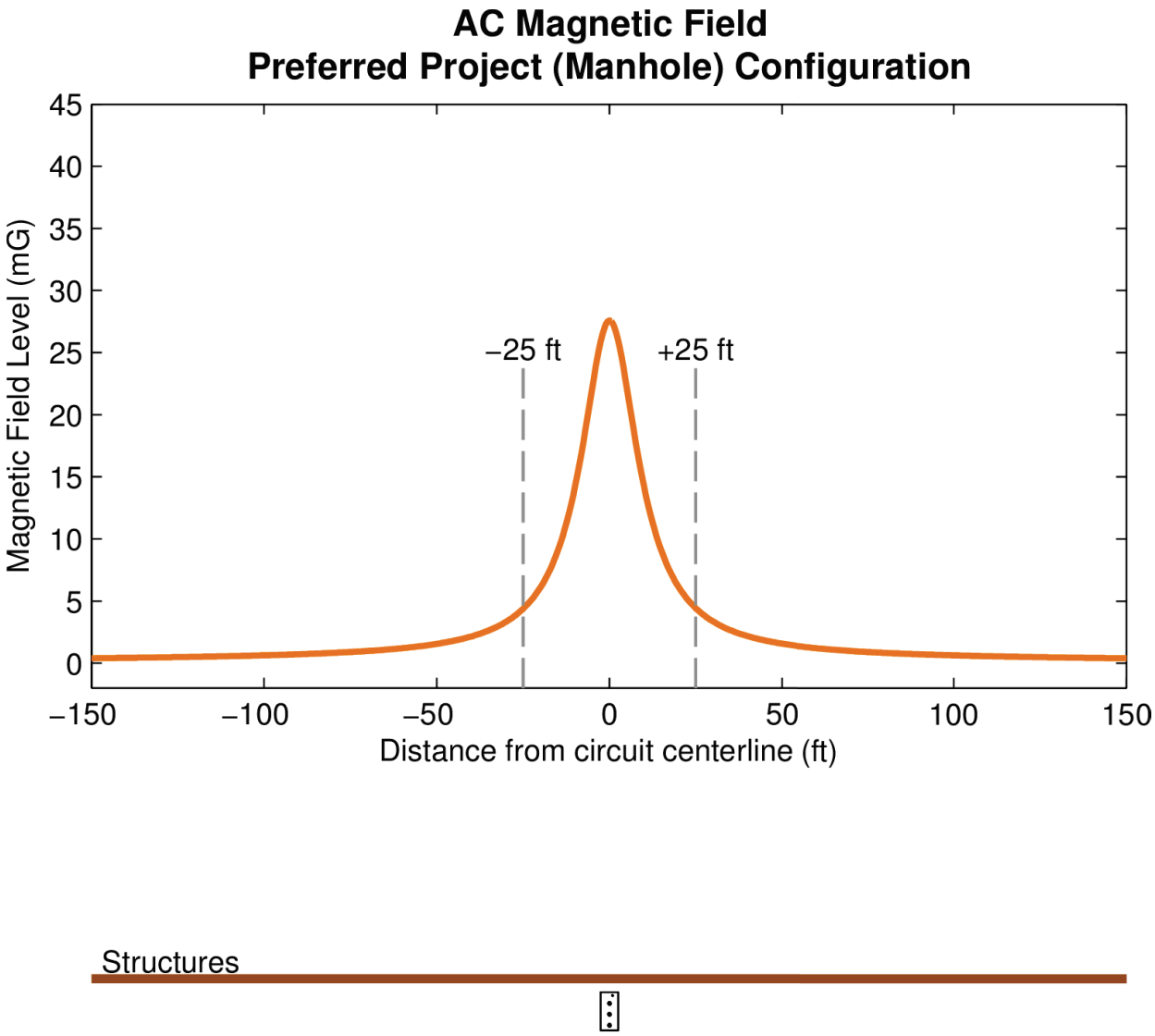


Figure B-2. Calculated magnetic-field level for the Manhole Configuration of the Project under annual average loading conditions.

Manhole not to scale and showing only the relevant half of manhole.

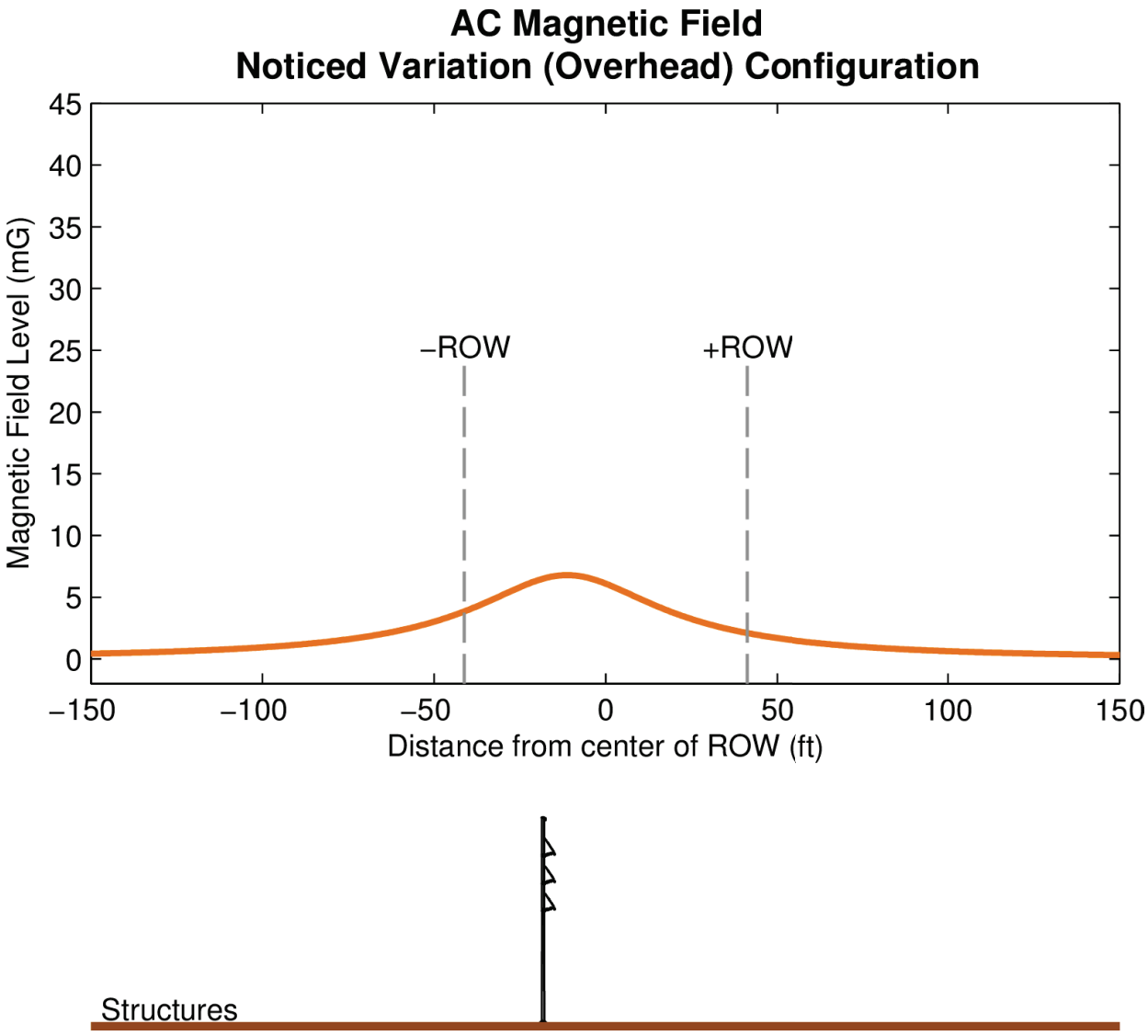


Figure B-3. Calculated magnetic-field level for the Overhead Configuration of the Noticed Variation under annual average loading conditions.

Structure not to scale.

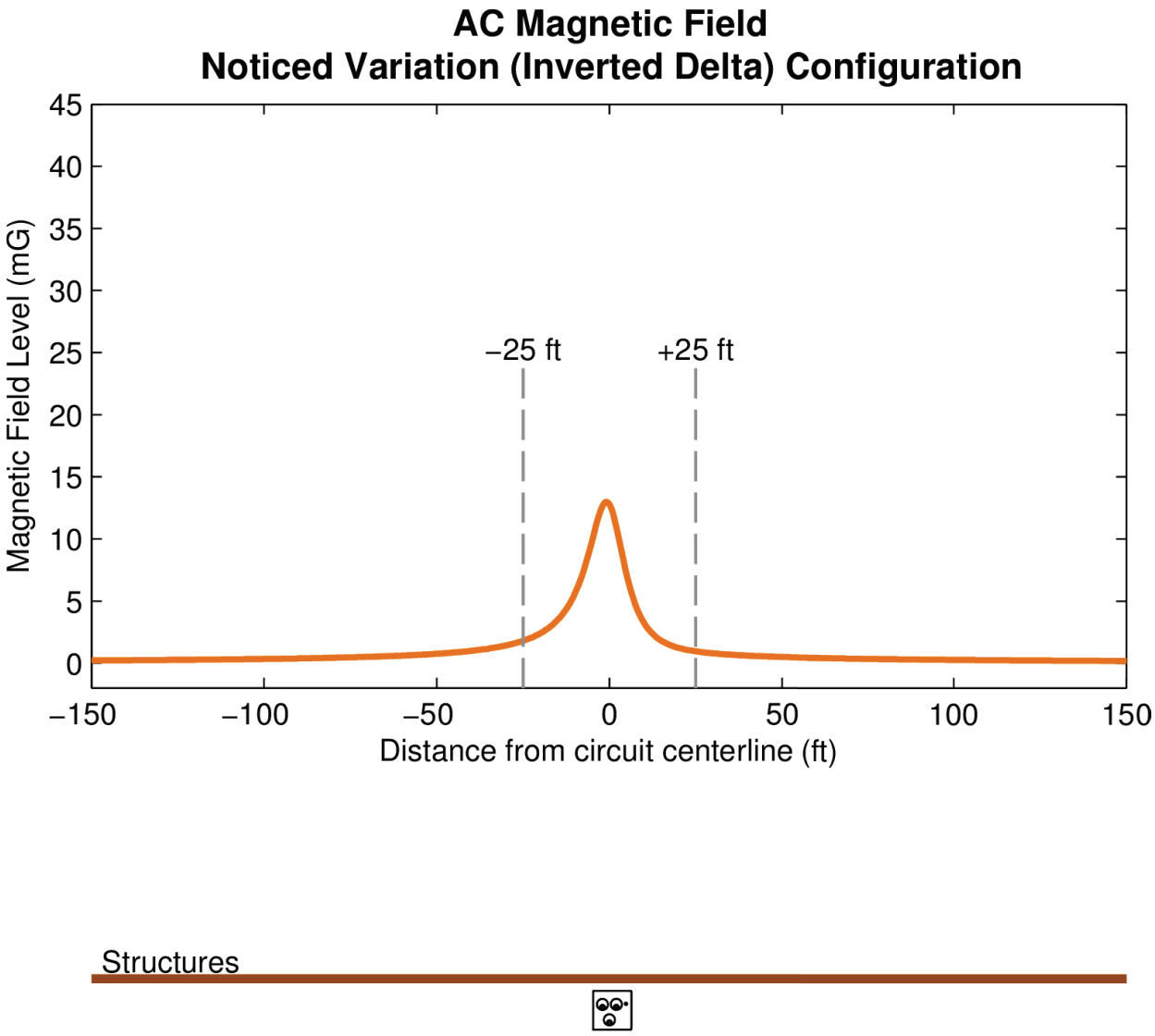


Figure B-4. Calculated magnetic-field level for the Inverted Delta Configuration of the Noticed Variation under annual average loading conditions.

Duct bank not to scale.

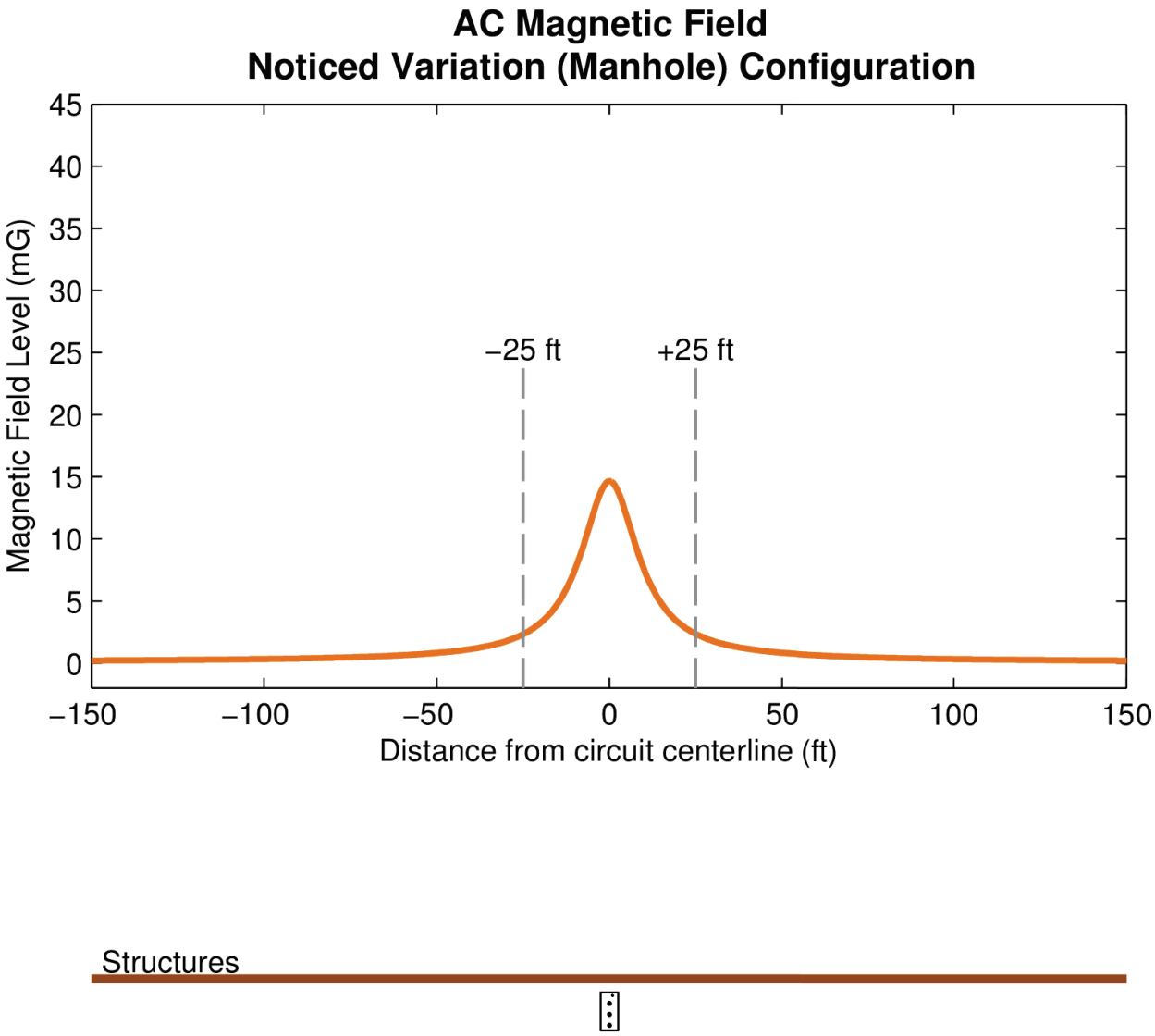


Figure B-5. Calculated magnetic-field level for the Manhole Configuration of the Noticed Variation under annual average loading conditions.

Manhole not to scale and showing only the relevant half of manhole.

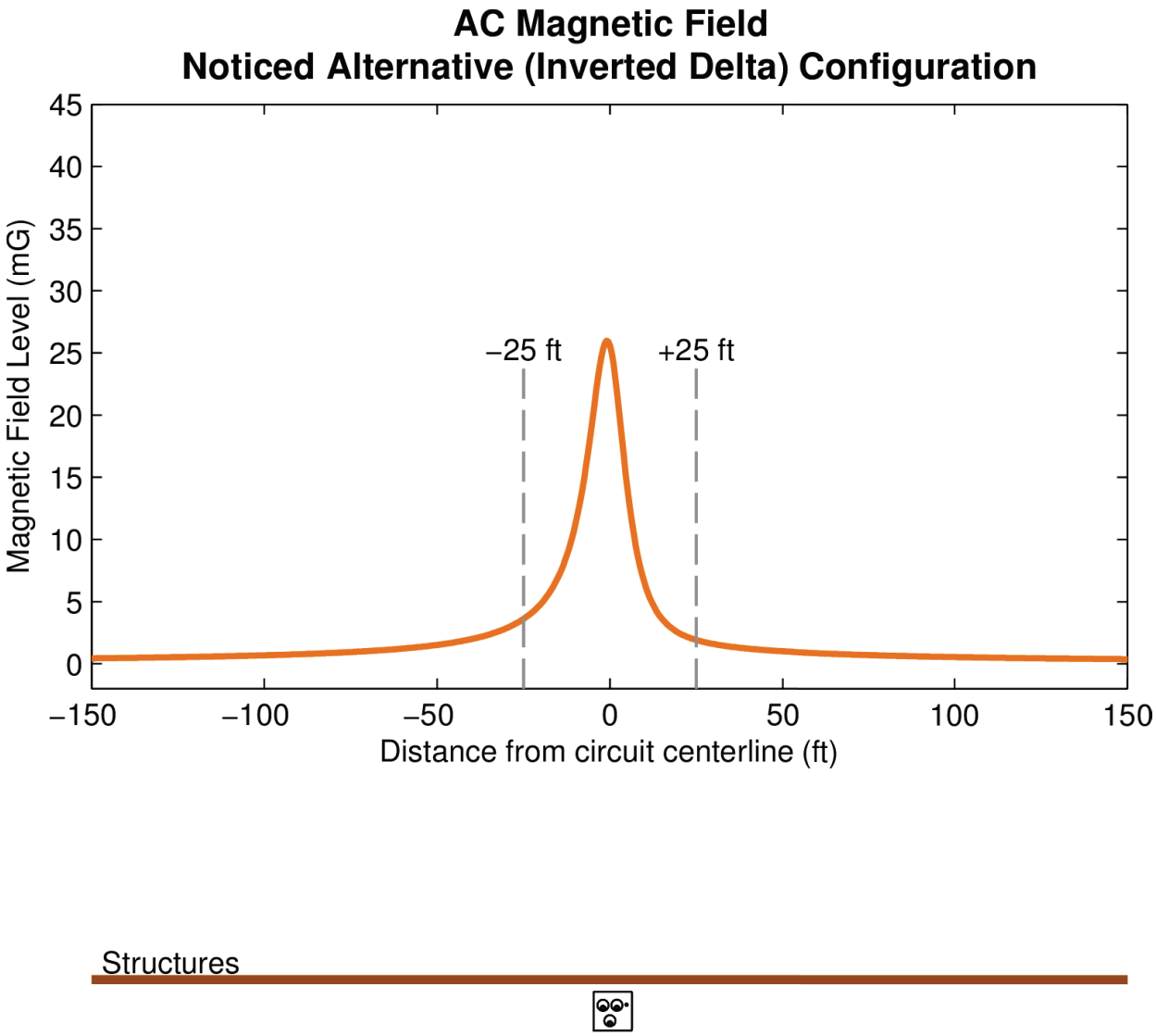


Figure B-6. Calculated magnetic-field level for the Inverted Delta Configuration of the Noticed Alternative under annual average loading conditions.

Duct bank not to scale.

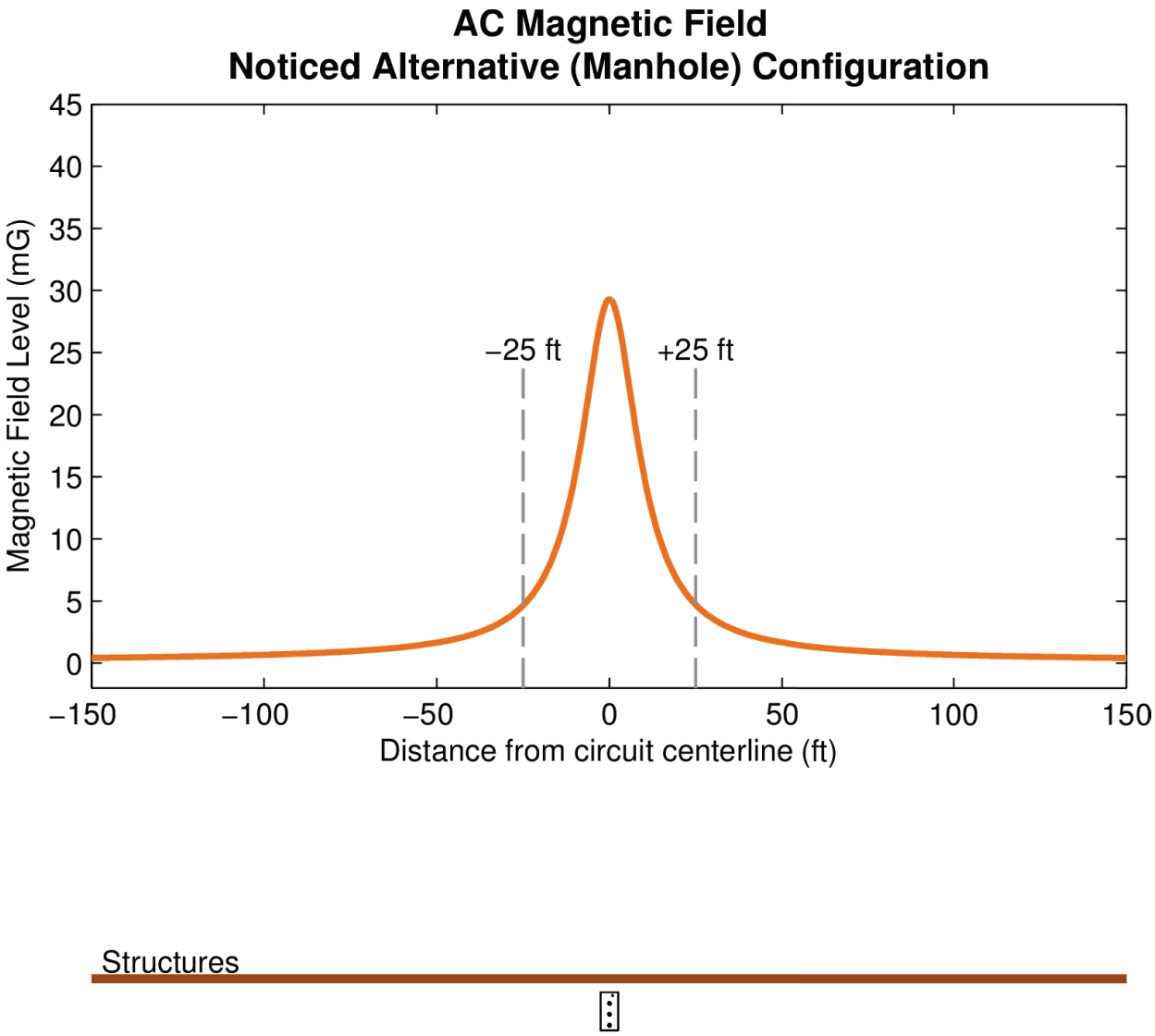


Figure B-7. Calculated magnetic-field level for the Manhole Configuration of the Noticed Alternative under annual average loading conditions.

Manhole not to scale and showing only the relevant half of manhole.

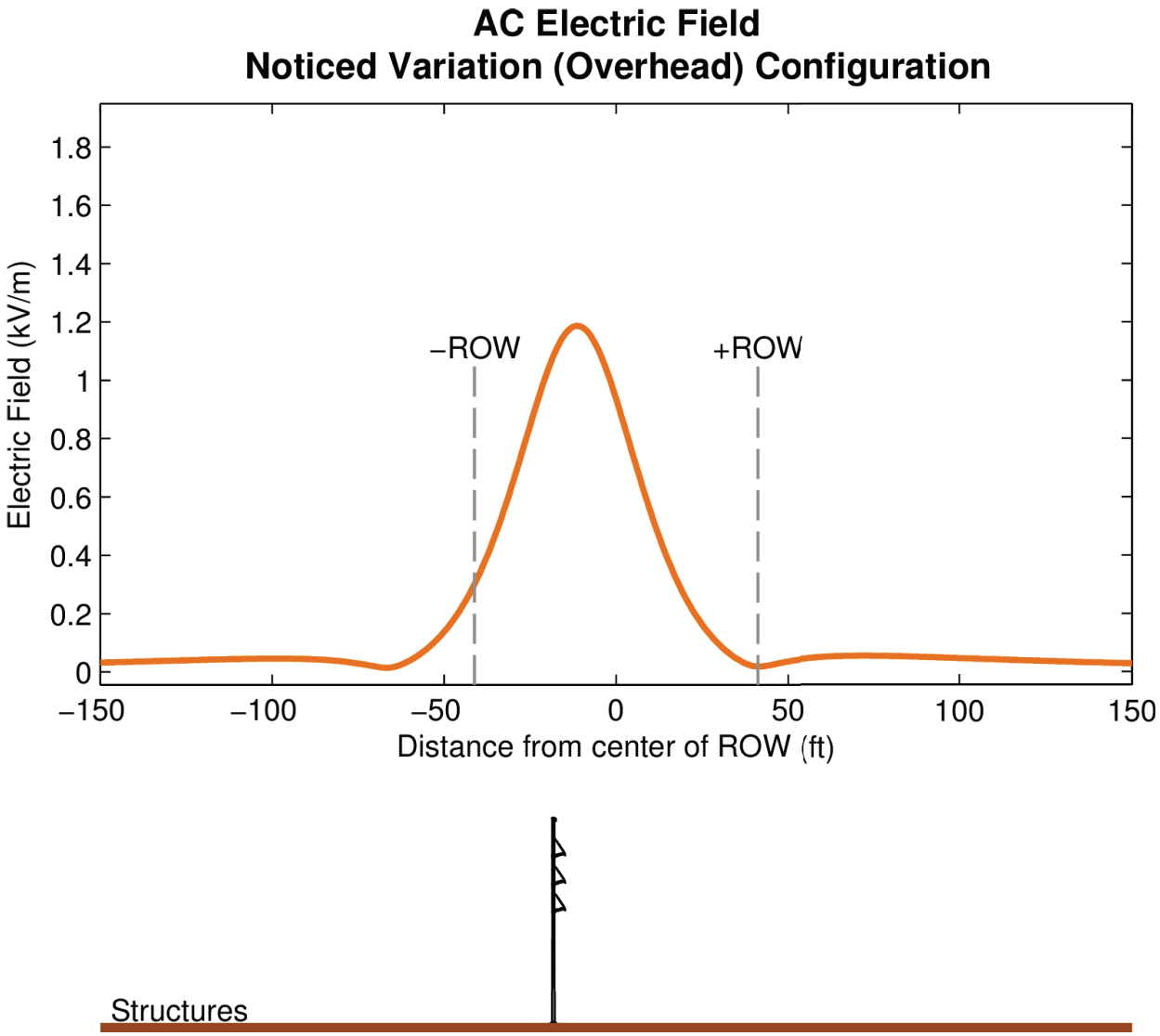


Figure B-8. Calculated electric-field level for the overhead configuration of the Noticed Variation.

Structure not to scale.