COMMONWEALTH OF MASSACHUSETTS
ENERGY FACILITIES SITING BOARD

Petition of New England Power Company d/b/a National Grid for Approval to Construct and Operate a New 345 kV Transmission Line and to Modify an Existing Switching Station Pursuant to G.L. c. 164, § 69J	)	EFSB 12-1
Petition of New England Power Company d/b/a National Grid Pursuant to G.L. c. 40A, § 3 for Exemptions from the Zoning Bylaws of the Towns of Millbury, Sutton, Northbridge, Uxbridge and Millville in Connection with the Proposed Construction and Operation of a New 345 kV Overhead Transmission Line and Related Facility Improvements	)	D.P.U. 12-46
Petition of New England Power Company d/b/a National Grid for Approval to Construct and Operate a New 345 kV Overhead Transmission Line Pursuant to G.L. c. 164, § 72	)	D.P.U. 12-47

FINAL DECISION

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May 16, 2014

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ABBREVIATIONS

AAL	annual average loading
ACEC	Area of Critical Environmental Concern
ACOE	U.S. Army Corps of Engineers
APL	annual peak loading
ASAPP	Archaeological Site Avoidance and Protection Plan
Berkshire Power	Berkshire Power Development, Inc., D.P.U. 96-104 (1997)
Boston Gas	Boston Gas Company, D.T.E. 00-24 (2001)
Cape Wind	Cape Wind Associates LLC, 15 DOMSB 1 (2005)
CELT	Capacity, Energy, Loads, and Transmission
CLL	critical load level
CMP	Conservation and Management Permit
Company	New England Power Company d/b/a National Grid
CVP	Certified Vernal Pool
DAR	Department of Agricultural Resources
dBA	A-weighted decibels
DCR	Massachusetts Department of Conservation and Recreation
Department	Massachusetts Department of Public Utilities
DG	distributed generation
DOMSB	Decisions and Orders of Massachusetts Energy Facilities Siting Board
DOMSC	Decisions and Orders of Massachusetts Energy Facilities Siting Council
DR	demand response
EE	energy efficiency

EFSB	Energy Facilities Siting Board
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
GHG	Greenhouse Gas
G.L. c.	Massachusetts General Laws chapter
GSRP	Western Massachusetts Electric Company, EFSB 08-2/D.P.U. 08-105/08-106
Hampden County	New England Power, EFSB 10-1/D.P.U. 10-107/10-108
HQ Phase II	Hydro-Quebec Phase II direct-current transmission line
Hybrid Alternative	115 kV upgrades in Massachusetts for IRP in lieu of a new 345 kV line in Massachusetts
IRP	Interstate Reliability Project
ISO-NE	ISO New England
kV	kilovolts
kW	kilowatt
Lower SEMA	NSTAR Electric Company, EFSB 10-2/D.P.U. 10-131/10-132 (2012)
MassDEP	Massachusetts Department of Environmental Protection
MECo/Westford	Massachusetts Electric Company, D.T.E. 01-77 (2002)
MESA	Massachusetts Endangered Species Act
mG	Milligauss
MHC	Massachusetts Historical Commission
MODF	Mineral Oil Dielectric Fluid
Modified Project	Connecticut and Rhode Island portions of IRP without upgrades in Massachusetts
MW	Megawatts

MWh	megawatt-hours
NEEWS	New England East–West Solution
NEP	New England Power Company
NERC	North American Electric Reliability Corporation
NHESP	National Heritage and Endangered Species Program
NPCC	Northeast Power Coordinating Council
NY Central Railroad	New York Central Railroad v. Department of Public Utilities, 347 Mass. 586 (1964)
O&M	Operation and Maintenance
OOS	out of service
Project	Massachusetts portion of Interstate Reliability Project
PSC	Public Service Corporation
PVP	Potential Vernal Pools
QC	Qualifying Capacity
Queue	ISO-NE Interconnection Queue
RISE	Rhode Island State Energy Generation Station
ROW	right-of-way
Russell	Russell Biomass, LLC, 17 DOMSB 1 (2009)
Save the Bay	Save the Bay v. Department of Public Utilities, 366 Mass. 667 (1975)
Section 72 Petition	NEP petition pursuant
SF_6	sulfur hexafluoride
SHPO	Massachusetts State Historic Preservation Officer
Siting Board	Massachusetts Energy Facilities Siting Board
Siting Board Petition	NEP petition pursuant to c. 164 § 69 J

Study Area	Massachusetts, Rhode Island, and Connecticut
USEPA	United States Environmental Protection Agency
VMP	Vegetative Management Plan
YOP	Yearly Operational Plan
Zoning Petition	NEP petition pursuant to c. 40A § 3

Pursuant to G.L. c. 164, § 69J, the Massachusetts Energy Facilities Siting Board ("Siting Board") hereby approves, subject to the conditions set forth below, the Petition of New England Power Company d/b/a National Grid ("NEP", "Company", or "Petitioner") to construct a new 15.4-mile overhead 345 kilovolt ("kV") transmission line along existing right-of-way ("ROW") between the existing Millbury No. 3 Switching Station and the Rhode Island border with Massachusetts. Pursuant to G.L. c. 164, § 72, the Siting Board hereby approves, subject to the conditions set forth below, the Petition of NEP for a determination that the proposed 345 kV transmission line is necessary, serves the public convenience, and is consistent with the public interest. Pursuant to G.L. c. 40A, § 3, the Siting Board hereby approves, subject to the conditions set forth below, the Petition of NEP for individual and comprehensive exemptions from the zoning bylaws of the towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville, in connection with the proposed transmission facilities, as described herein.

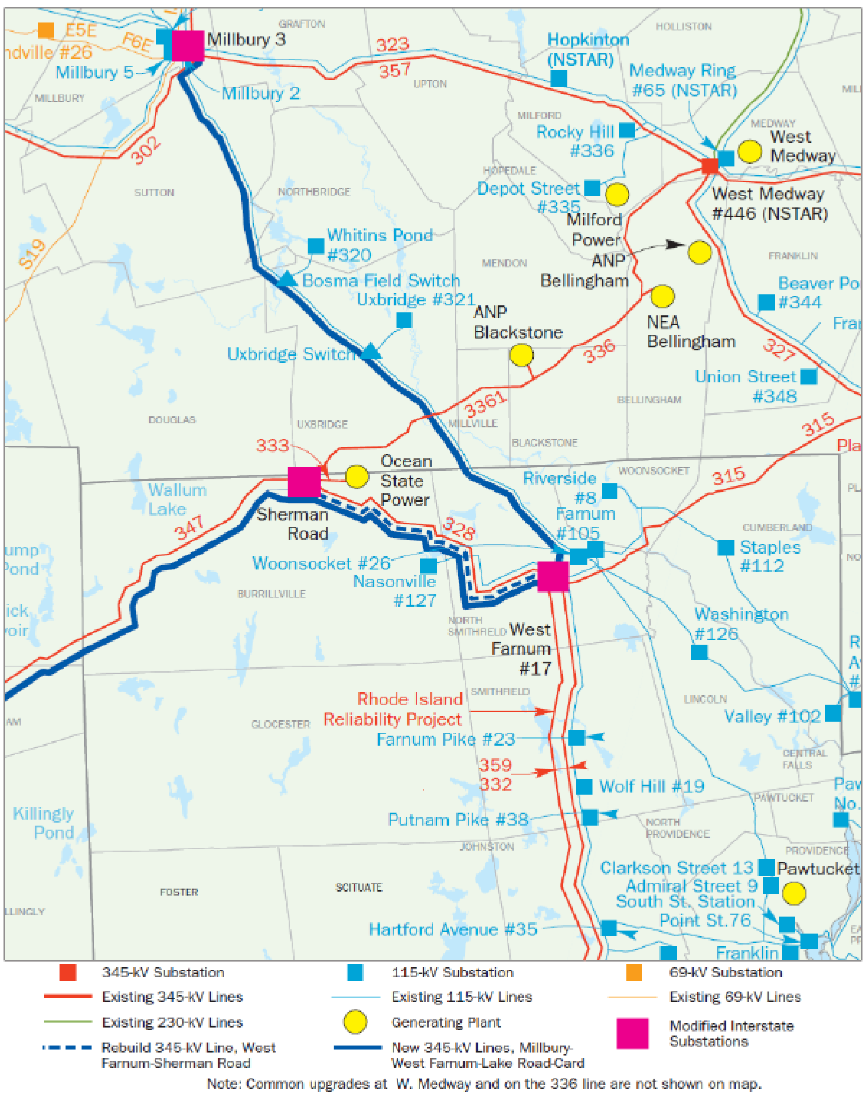
I. INTRODUCTION

A. Summary of the Proposed Transmission Project

The proposed project in Massachusetts is part of a larger three-state transmission proposal, known as the Interstate Reliability Project ("IRP"), which is designed to address reliability needs in southern New England (Exh. NEP-1, at 1-1). The Massachusetts portion of IRP is a proposed overhead 345 kV transmission line along existing ROW, extending approximately 15.4 miles from a terminus at the Millbury No. 3 Switching Station in Massachusetts through the towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville to the Rhode Island border where it continues for 4.8 miles to the West Farnum Substation; an additional 54.5-mile 345 kV segment of IRP connects the West Farnum Substation in Rhode Island with the Card Street Substation in Lebanon, Connecticut. IRP also includes additions to existing 345 kV and 115 kV facilities, and improvements to the Millbury No. 3 Switching Station and other stations in Rhode Island and Connecticut. The project's ROW in Massachusetts is presently occupied for most of its length by two 115 kV transmission lines and by the remaining structures of a double-circuit 69 kV transmission line that was taken out of service in the 1990s.

The estimated cost of the Massachusetts portion of IRP ("Project") is $100.1 million (2011$); the estimated cost of the entire IRP is $542 million (Exh. NEP-1, at 5-73 and app. 1-5, at 11). Figure 1 below shows the location of the Massachusetts and Rhode Island portions of IRP. Siting agencies in Connecticut and Rhode Island have already approved their jurisdictional segments of IRP. The Company is required by G.L. c. 164, § 69J to present both a Primary Route and an Alternative Route for its Project. A description of the Alternative Route and its comparison to the Primary Route is in Section V.B. The Company estimates that construction of IRP would be completed by the end of 2015 (<u>id.</u> at 1-4).

Figure 1. The Interstate Reliability Project (MA and RI portions only)



B. Procedural History

On June 21, 2012, NEP filed three petitions with the Siting Board and the Massachusetts Department of Public Utilities ("Department") relating to the IRP. In the first petition, the Company requests approval of the Project, pursuant to G.L. c. 164, § 69J ("Siting Board Petition"). A second petition seeks individual and comprehensive exemptions from the zoning bylaws of the communities along the preferred route for the Project pursuant to G.L. c. 40A, § 3 ("Zoning Petition"). The third petition requests approval for IRP pursuant to G.L. c. 164, § 72 ("Section 72 Petition").

The Siting Board Petition was docketed as EFSB 12-1, the Zoning Petition as D.P.U. 12-46, and the Section 72 Petition as D.P.U. 12-47. Pursuant to the Company's motion, on June 27, 2012, the Chair of the Department issued a Consolidation Order, referring the Section 72 and Zoning Petitions for review and approval or rejection to the Siting Board pursuant to G.L. c. 164, § 69H(2). The consolidated proceeding was docketed as EFSB 12-1/D.P.U. 12-46/12-47. The Siting Board conducted a single adjudicatory proceeding and developed a single evidentiary record for the consolidated petitions ("Petitions").

The Siting Board held two public hearings, one in Uxbridge and one in Milford, to receive comments on the Project. The Presiding Officer's ruling of September 25, 2012 granted intervenor status to the Attorney General, ISO New England ("ISO-NE"), Louis C. Tusino, trustee of the Pembroke Realty Trust, and Matthew Buskill.

The Petitioner presented the testimony of the following eleven witnesses in support of the Petitions: David Beron, Diedre Matthews, Gabriel Gabremichael, Mark Stevens, Judah Rose, Daniel McIntyre, Erin Whoriskey, James Durand, John Bleyer, Dr. William Bailey, and Robert Longden, Esq. ISO-NE presented the testimony of Stephen Rourke, Brent Oberlin, Steven Judd, and Pradip Vijayan.

The Siting Board held eight days of evidentiary hearings during the period of February 28, 2013 to August 29, 2013. The hearing period was delayed by several months because of the lengthy time required for responses to numerous information requests issued by Siting Board staff. The Company, the Attorney General, and ISO-NE filed briefs on November 1, 2013. The Issues Memorandum, prepared by Siting Board staff, was issued on January 23, 2014; on

January 30, 2014, the Siting Board held a public meeting directing the staff to prepare a tentative decision approving the Company's Petitions with conditions.

II. JURISDICTION AND STANDARD OF REVIEW UNDER G.L. c. 164, § 69J

The Company filed the Siting Board Petition pursuant to G.L. c. 164, § 69J, which requires a project applicant to obtain Siting Board approval for the construction of a proposed energy facility before a construction permit may be issued by another state agency. G.L. c. 164, § 69G defines a "facility" to include "a new electric transmission line having a design rating of 115 kilovolts or more which is ten miles or more in length on an existing transmission corridor, except [for] reconductoring or rebuilding of transmission lines at the same voltage." The proposed 345 kV transmission line is clearly a "facility" with respect to Section 69J. In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct, the Siting Board requires an applicant to justify its proposal in four phases. First, the Siting Board requires the applicant to show that additional energy resources are needed (see Section III, below).

Second, the Siting Board requires the applicant to establish that, on balance, its proposed project is superior to alternative approaches in terms of reliability, cost, and environmental impact, and in its ability to address the identified need (see Section IV, below). Third, the Siting Board requires the applicant to show that it has considered a reasonable range of practical siting alternatives and that the proposed site for the project is superior to a noticed alternative site in terms of cost, environmental impact, and reliability of supply (see Section V, below). Finally, the applicant must show that its plans for construction of its new facilities are consistent with the current health, environmental protection and resource use and development policies as developed by the Commonwealth (see Section V.C, below).

III. NEED FOR THE PROPOSED FACILITIES

A. Standard of Review

G.L. c. 164, § 69J provides that the Siting Board should approve a petition to construct if the Board determines that the petition meets certain requirements, including that the plans for the construction of the applicant's facilities are consistent with the policies stated in G.L. c. 164, § 69H to provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. To accomplish this, the Siting Board must, among other matters, review the need for the facilities to meet reliability, economic efficiency, or environmental objectives. G.L. c. 164, § 69H. Consistent therewith, G.L. c. 164, § 69J requires an applicant to include in its petition an analysis of need for the proposed facility. Here, the Petitioner asserts that the Project is needed for reliability purposes (Exh. NEP-1, at 1-11).[1]

To ensure reliability, each transmission and distribution company establishes planning criteria for construction, operation, and maintenance of its transmission and distribution system. Compliance with the applicable planning criteria can demonstrate a "reliable" system. See e.g., New England Power Company d/b/a National Grid/Hampden County Reliability Project, EFSB 10-1/D.P.U. 10-107/10-108, at 5 (2012) ("Hampden County"); New England Power Company, 7 DOMSB 333, at 346-348 (1998).

To determine whether system improvements are needed, the Siting Board: (1) examines the reasonableness of the petitioner's system reliability planning criteria; (2) determines whether the petitioner uses reviewable and appropriate methods for assessing system reliability over time based on system modeling analyses or other valid reliability indicators; and (3) determines whether the relevant transmission and distribution system meets these reliability criteria over time under normal conditions and under certain contingencies, given existing and projected loads. NSTAR Electric Company, EFSB 10-2/D.P.U. 10-131/10-132, at 5 (2012) ("Lower SEMA"); Hampden County at 5.

When a petitioner's assessment of system reliability and facility requirements are, in whole or in part, driven by load projections, the Siting Board reviews the underlying load forecast. The Siting Board requires that forecasts be based on substantially accurate historical

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1 The Siting Board's review of proposed transmission facilities is conducted pursuant to G.L. c. 164, § 69J. This section states, in part, that "[n]o applicant shall commence construction of a facility at a site unless . . . in the case of an electric or gas company which is required to file a long-range forecast pursuant to section sixty-nine I, that facility is consistent with the most recently approved long-range forecast for that company." The Siting Board notes that, pursuant to Notice of Inquiry and Rulemaking, D.T.E.98-84/EFSB 98-5 (2003), Massachusetts electric companies, including NEP, are now exempt from the requirements of G.L. c. 164, § 69I. Thus, the Siting Board need not consider whether the proposed transmission facilities are consistent with a recently approved long-range forecast.

information and reasonable statistical projection methods that include an adequate consideration of conservation and load management. G.L. c. 164, § 69J. To ensure that this standard has been met, the Siting Board requires that forecasts be reviewable, appropriate and reliable. Hampden County at 5-6. A forecast is reviewable if it contains enough information to allow a full understanding of the forecast method. A forecast is appropriate if the method used to produce the forecast is technically suitable to the size and nature of the company to which it applies. A forecast is considered reliable if its data, assumptions and judgments provide a measure of confidence in what is most likely to occur. Lower SEMA at 5; Hampden County at 6.

B. Understanding the Existing Transmission System in the Study Area

The adequacy of transmission in New England is evaluated, in part, by studying the ability of the transmission system to serve load in certain subregions after the the loss of significant generation in the subregion as well as two additional unplanned contingencies (either transmission- or generation-related). In this case, the study area used by ISO-NE and the Company in their assessment of need consists of the three southern New England states of Massachusetts, Rhode Island, and Connecticut (Exh. NEP-1, app. 2-5, at 1).[2] Within the study area, ISO-NE analyzed the extent to which transmission that serves subregions is capable of sustaining loads when significant generation (one or more units) is assumed to be out of service ("OOS") followed by the unplanned loss of two significant additional resources (generation and/or transmission).

Figure 2 provides a geographical representation of the eastern and western New England subregions, which ISO-NE studied as part of an overall assessment of the need for new transmission in southern New England. The major high voltage transmission lines that serve as bridges between subregions are known as "interfaces" (Exh. NEP-1, at 2-3). The West-to-East interface divides New England approximately in half, separating the major load centers of eastern Massachusetts from those in Connecticut and western Massachusetts (id. at 2-3). When net power flows in southern New England go towards load centers in Connecticut and western

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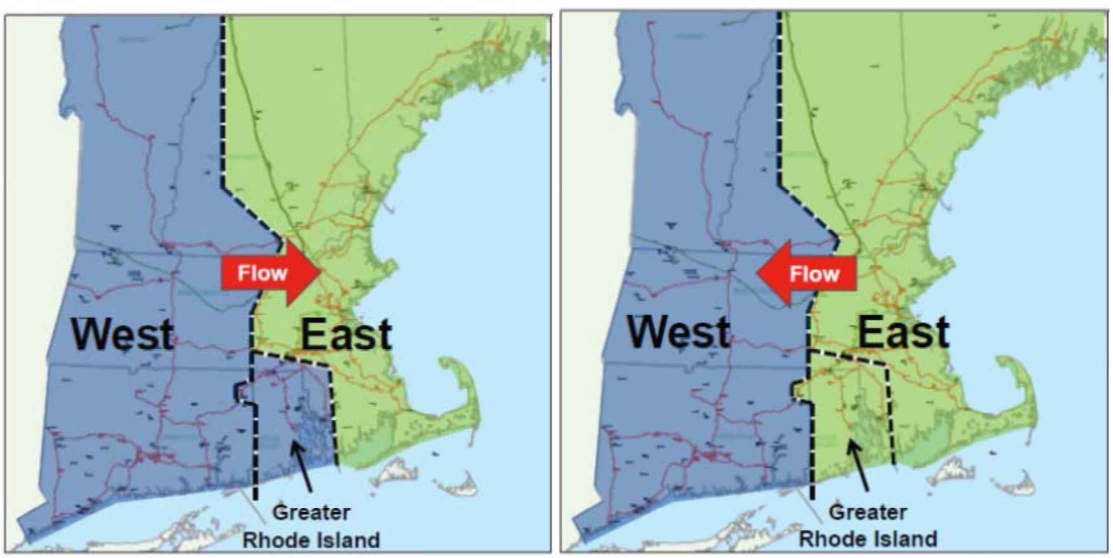
2 ISO-NE plays a central regional role in performing detailed transmission planning studies for the region, and in supporting petitions for approval of new transmission resources before the Siting Board (see Exh. ISO-1, at 8-9).

Massachusetts, generation located in Rhode Island may be constrained from also flowing to the west due to loading limitations on the existing transmission lines (id. app. 2-5, at 7). Similarly, when net power flows go towards eastern Massachusetts, generation in Rhode Island may be constrained from also flowing to the east. As a result, Greater Rhode Island is assumed to be in the east when studying east-to-west flows, and is assumed to be in the west when studying west-to-east flows (id.).

There are three 345 kV transmission lines that cross the East-to-West Interface, two of which are shown in Figure 3 below (the third one is in southern New Hampshire).[3] Two 230 kV transmission lines and a small number of 115 kV transmission lines also cross the interface; however, these smaller transmission lines add only marginally to the transfer capability across the interface (Exh. NEP-1, at 2-4).

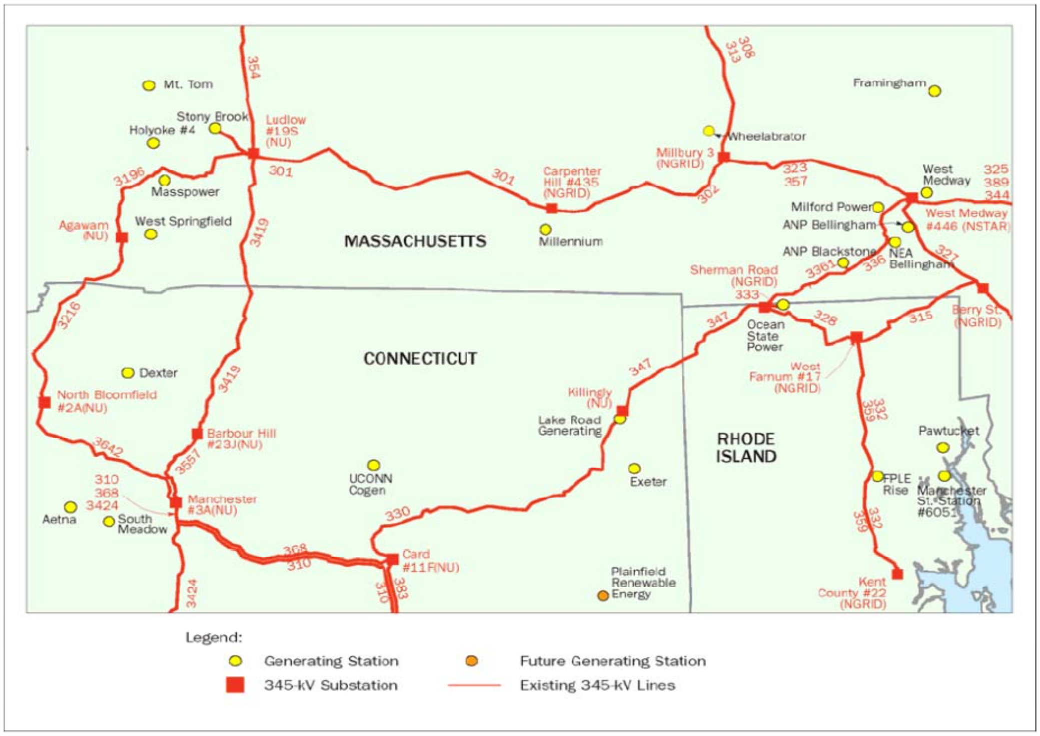
Figure 2. New England West-to-East and East-to-West Interfaces



Source: Exh. NEP-1, app. 2-5, at 8.

3 By comparison, the West-to-East Interface includes one additional 345 kV transmission line, Line 315 from Rhode Island to Massachusetts (see Figures 2 and 3).

Figure 3. Existing 345 kV System in the Central Part of Southern New England



Source: Exh. NEP-1, at 2-5.

C. Description of the Company's Demonstration of Need

1. Regional/National Context for Company Reliability Planning

The Company described key aspects of the regional and national reliability-planning regime and the resulting standards and procedures applicable to the Company's transmission system (Exh. NEP-1, at 2-2). As a transmission provider, NEP must maintain its system consistent with the reliability standards and criteria developed by the Northeast Power Coordinating Council ("NPCC") and ISO-NE (id.). These criteria are established under the purview of the North American Electric Reliability Council ("NERC"), which sets the standards for electric power transmission for all of North America. The Company is generally required to plan for system upgrades that would keep the transmission system in compliance with the applicable criteria (id.).

An N-1 contingency, as specified by NERC, NPCC, and ISO-NE standards and criteria, is characterized as an unplanned single event causing the loss of one or more system elements, such as a generator, a transmission line, or a bus section (Exh. NEP-1, at 2-1, n.1). The occurrence of two unplanned and unrelated outages within a short period of time is referred to as an "N-1-1" contingency event (id.). ISO-NE plans the bulk power transmission system to be able to withstand unplanned N-1 and N-1-1 events by modeling system impacts of unplanned contingencies.[4] The modeling results demonstrate whether contingencies could cause certain elements of the transmission system to become loaded beyond their temperature-based capability ratings (i.e., thermal violations) or system voltages to fall outside the range of acceptable limits (i.e., voltage violations) (id. at 2-9).

Currently, NERC transmission planning standards are prescriptive concerning what specific N-1 and N-1-1 contingencies should be studied in a transmission planning study. However, NERC standards do not provide similar prescriptive detail about the "base case" conditions (e.g., generator availability) that should be used in planning studies before N-1 and N-1-1 contingencies are applied. ISO-NE has suggested that NERC provide greater specificity concerning the critical conditions that are properly included or excluded in a base case (Tr. 5, at 840).[5] In the absence of such NERC standards, ISO-NE asserts that it is not required by NERC to develop or evaluate sensitivity cases for use in a planning model that would alter the levels of stress incorporated in a base case (id. at 840-842). Instead, ISO-NE maintains that it is appropriate for ISO-NE to develop a base case that includes as much stress as can reasonably be expected to occur and use it to identify the relevant system impacts (id. at 841-842).

2. Load Forecasting Methodology

The load forecast used in the Company's Petitions relies upon a ten-year planning horizon based on ISO-NE's 2012 Capacity, Energy, Loads, and Transmission ("CELT") Report (Exh. NEP-1, app. 2-5, at 2). During the course of the proceeding the Company updated its

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4 The bulk electric system broadly includes all transmission facilities that are necessary for operating the interconnected transmission network. See North American Electric Reliability Corporation, 146 FERC ¶ 61,199, at ¶ 4 (2014).

5 FERC has also expressed its concern that allowing complete discretion to the transmission modeler over base case conditions "does not provide any parameters or criteria for such an entity to define the base case in a rational and consistent manner" Mandatory Reliability Standards for the Bulk-Power System, 117 FERC ¶ 61,084 at ¶ 1046 (2006).

power flow analysis for certain base cases to reflect the results of the 2013 CELT Report (RR-EFSB-64).

The ISO-NE load forecast used for transmission planning studies is a 90/10 forecast (i.e., where the summer peak temperature has a ten percent chance of being exceeded) that focuses on peak demand load levels during the ten-year horizon from 2013 to 2022 (Exh. NEP-1, app. 2-5, at 19). ISO-NE develops a 10-year econometric forecast for New England and for each of the six New England states. Western Massachusetts Electric Company, EFSB 08-2/D.P.U. 08-105/08-106 at 31 ("GSRP"). ISO-NE's load forecast relies upon regression analyses, which relate historical electricity use to historical demographic and economic measures such as average income per household, the total number of households, real income and gross state product (id.). The forecast then uses individual forecasts of the same economic measures to determine expected future electricity use and demand levels (id.).

ISO-NE's forecast accounted for demand response ("DR") resources, which are split into two categories: passive DR and active DR (Exh. NEP-1, app 2-5, at 20). Active DR is dispatchable peak load reduction used when a forecasted or real-time capacity shortage occurs on the system (id.). Passive DR is the reduction of demand resulting from energy efficiency ("EE") programs (id.). ISO-NE modeled demand reductions due to DR and EE at the levels of the most recent forward capacity auction ("FCA") at the time of the study (FCA-6) (id.).[6]

The Company has provided sufficient information to permit a general understanding of its forecasting method and has provided evidence that it uses appropriate historical data, independent variables, and quantitative methods. Therefore, the Siting Board finds that NEP's load forecast is reviewable, appropriate, and reliable.

3. The Company's Base Case Assumptions

ISO-NE developed three individual base cases that reflect stressed conditions for net power flows into eastern New England, western New England, and Rhode Island. ISO-NE then modeled the effects of N-1 and N-1-1 transmission contingencies in each of these stressed

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6 ISO-NE now forecasts EE over a ten-year forecast period, as compared to its historical approach that incorporated EE into its forecast using the results of the most recent FCA exclusively (Exh. NEP-1, app. 2-5, at 20).

subregions to determine whether forecasted loads under summer 90/10 peak conditions could reliably be served through 2022 (Exh. NEP-1, app. 2-5, at 2).[7] ISO-NE also modeled two sensitivity cases for the study year 2022 (id.).

ISO-NE typically uses a generic approach to establishing the level of stress to apply to a study area prior to modeling N-1 and N-1-1 transmission contingencies. Since 2006, this generic approach has assumed that the two generation units that would have the greatest impact on the modeling results would be assumed out of service (Exhs. EFSB-19; EFSB-41, at 14; NEP-1, app. 2-4, at 28).[8] In this case, in addition to the "two generator out" assumption, ISO-NE developed its base case for resource availability using a host of generator and transmission assumptions shown below in Table 1.

Table 1. ISO-NE Base Case Common Resource Availability Assumptions

Base Case Assumption	ISO-NE Reason for Assumption
Hydro-Quebec Phase II, New Brunswick and New York ties assumed out of service.	Reflects absence of long-term contracts that ISO-NE maintains are necessary to assume the availability of power flowing over the ties (Exh. EFSB-ISO-141, at 4).
Quick start units de-rated by 20 percent (specific units assumed out of service to reflect the 20 percent de-rating).	Due to the infrequent use of the units, they have historically not always responded when dispatched (Exh. NEP-1, app. 2-5, at 26).
Wind power output de-rated by 95 percent of nameplate capacity for onshore locations, and the lesser of the Qualifying Capacity or 80 percent of wind capacity for offshore locations.	Based on forecasted level of output on a hot summer day (Exh. EFSB-41, at 14).
Run-of-the-river hydro de-rated by approximately 90 percent of nameplate capacity.	Low hydro assumptions were adopted to represent dry summer conditions and limited flow (Exh. EFSB-41, at 14; see also Exh. EFSB-ISO-141).
Pumped storage facilities de-rated by 50 percent of capacity.	Reflects potential output limitations caused by inability to complete pumping operations during off-peak hours (Exh. EFSB-ISO-41, at 15).
Resources that have dynamically de-listed in multiple (more than one) auctions assumed out of service.	This approach is intended to represent potential generation retirements (Exh. EFSB-ISO-41, at 15).
DR de-rated by 25 percent; real-time emergency generation de-rated by 100 percent.	DR based on actual performance data in 2009 (Exh. EFSB-ISO-9). Real-time emergency generation excluded because it is outside of normal system planning (Exh. EFSB-ISO-90).

7 ISO-NE conducted multiple need assessments over the last several years, with the most recent study entitled "Follow-Up Analysis to the 2011 New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment," dated September 2012 (Exh. NEP-1, app. 2-5).

8 The Company maintains that having *at least* two generators out is a reasonable assumption for purposes of the IRP study because of the large amount of generation and load requirements in eastern and western New England (Exh. EFSB-N-21).

a. Eastern New England Base Case

To model stress on transmission lines bringing power into the eastern New England load zone, ISO-NE assumed certain generation out of service in the load zone, thereby requiring the transmission system to deliver power from outside eastern New England. In its base case evaluation of this scenario, ISO-NE assumed the two largest resources serving the eastern New England load zone were out of service – the Hydro-Quebec Phase II direct-current transmission line ("HQ Phase II") and Seabrook Nuclear Station (Exh. NEP-1, app. 2-5, at 26). ISO-NE also justified its decision to assume HQ Phase II as out of service because ISO-NE interprets its tariff as requiring that all imports from outside its control area be modeled at zero megawatts in the absence of long-term contracts (Exhs. EFSB-N-141, at 4; EFSB-ISO-185). In addition, ISO-NE assumed a third resource as out of service – New Brunswick Power – as it too lacks a long-term contract for capacity with transmission or distribution companies in eastern New England. ISO-NE therefore assumed that imports from New Brunswick Power were unavailable in its base case (Exh. EFSB-ISO-141, at 4). Table 2 below sets forth the primary sources of unavailable generation and transmission.

Table 2. Base Case Conditions in Eastern New England

Out-of-Service Resources Assumed by ISO-NE	Capacity
Seabrook Nuclear Station out-of-service	1,245 MW
HQ Phase II out-of-service	1,400 MW
New Brunswick Power imports unavailable[9]	700 MW
Quick start generation out of service (represents 20 percent of 643 MW total quick start capability located in eastern New England)	129 MW
90 percent of run of river hydro not available	365 MW
Salem Harbor assumed retired	749 MW
Total resources assumed out of service	**4,588 MW**
Total resources in eastern New England assumed for 2023 (including New Brunswick Power (700 MW) and HQ Phase II (1400 MW))	**16,423 MW**

Sources: Exhs. NEP-1, app. 2-5, at 26; EFSB-ISO-90; RR-EFSB-64, at 3.

9 A single sensitivity case was also run in which the only change to the assumptions shown in Table 2 was the availability of an additional 700 MW from New Brunswick Power, which is its typical operational limit (Exh. NEP-1, app. 2-5, at 2).

b. Western New England Base Case

To stress the East-to-West interface, generation was modeled as reduced in western New England. ISO-NE modeled four primary generating units as out of service, including the two largest generating units, Millstone Nuclear Station Units 2 and 3, together with Vermont Yankee and Berkshire Power (Exh. NEP-1, app. 2-5, at 26). ISO-NE assumed the Berkshire Power as being out of service "to reflect the equivalent demand forced outage rate for western Massachusetts generation" and it also assumed Vermont Yankee as being out of service because of the significant uncertainty surrounding its continued operation (id. at 24, 26-27).[10] Table 3 summarizes the base case conditions assumed for western New England.[11]

Table 3. Base Case Conditions in Western New England

Out-of-Service Resources Assumed by ISO-NE	Capacity
Millstone Nuclear Station Unit 3 assumed out of service	1,225 MW
Millstone Nuclear Station Unit 2 assumed out of service	877 MW
Berkshire Power assumed out of service[12]	229 MW
Vermont Yankee assumed out of service	604 MW
Quick start generation out of service (represents 20 percent of 1,640 MW total quick start capability in western New England)	328 MW
Western New England run-of-river hydro unavailable (based on assumed low flow conditions at summer peak)	347 MW
Pumped storage from Bear Swamp and Northfield Mountain de-rated by 50 percent, due to an inability to complete pumping operations during off-peak hours in the midst of a long outage	874 MW
Zero imports from New York to New England were assumed because of the absence of multi-year contracts (tie is capable of approximately 1400 MW)	1,400 MW (AC ties only)
Total resources assumed out of service	5,884 MW
Total resources available to western New England assumed for 2023 (including 1,400 MW from New York AC ties)	9,850 MW

Sources: Exhs. NEP-1, app. 2-5, at 27; EFSB-ISO-190; RR-EFSB-64, at 3.

10 While the hearings in this case were underway, Vermont Yankee separately announced its intention to retire in late 2014.

11 As a subset of ISO-NE's study of the East-to-West base case, ISO-NE studied the ability to import power into Connecticut (Exh. NEP-1, app. 2-5, at 27).

12 A single sensitivity case was run, in which the only change to the assumptions shown in Table 3 was that Berkshire Power was available but West Springfield Unit No. 3 was not available (Exh. NEP-1, app. 2-5, at 27).

4. Rhode Island Base Case

To evaluate stress on the Rhode Island interface, ISO-NE modeled a reduced amount of generation that would otherwise be available in Rhode Island by assuming the two largest generating units in Rhode Island as out of service (Exh. NEP-1, app. 2-5, at 27-28). As shown in Table 4 below, the two largest units, which are the Rhode Island State Energy Generation Station ("RISE") and Franklin Square/Manchester Station Unit No. 9, represent virtually all of the resources that were assumed to be unavailable in Rhode Island.

Table 4. Base Case Conditions in Rhode Island

Out-of-Service Resources Assumed by ISO-NE	Capacity
RISE Generation Station assumed out of service	548 MW
Franklin Square/Manchester Unit No. 9 assumed out of service	149 MW
Rhode Island Quick Starts de-rated by 20 percent	2 MW
Total resources assumed out of service	699 MW
Total resources for Rhode Island assumed for 2023	1,143 MW

Sources: Exhs. NEP-1, app. 2-5, at 28; EFSB-ISO-190.

5. Summary of Year of Need for the Base Cases

ISO-NE ran its transmission performance model separately for each of the base and sensitivity cases identified above, and determined that thermal violations would occur under certain N-1-1 contingencies that would require new transmission: (1) for eastern New England before 2012; (2) for western New England and Connecticut by 2016-2017; and (3) for Rhode Island before 2012 (Exh. NEP-1, app. 2-5, at 46-48). In the case of Rhode Island, certain N-1-1 contingencies modeled for the year 2022 also led to a voltage collapse of the Rhode Island transmission network (id. at 43). The results indicate that Rhode Island would need additional energy resources before 2012 to resolve its thermal violations, although this shortfall is relatively small – 27 MW in 2012, 19 MW in 2013, 39 MW in 2014 and 27 MW in 2015 (Exh. EFSB-ISO-141(1) at 4).[13] Eastern New England is the only one of the four subregions studied where the power flow analysis also indicated potential N-1 violations, in addition to

13 The Rhode Island legislature mandated a distributed generation ("DG") contract program requiring 40 MW of newly installed DG by 2014 (Exh. EFSB-21). Implementation of this program should further reduce the Rhode Island shortfalls.

N-1-1 violations, by 2022 (Exh. NEP-1, app. 2-5, at 36-39). As the reliability issues associated with eastern New England appear to present the most severe challenges at this time, the Siting Board focuses its analysis principally on eastern New England, and to a lesser extent on Rhode Island and western New England.

6. Changes After 2012 ISO-NE Needs Assessment

Following ISO-NE's most recent Needs Assessment in September 2012 upon which the Company's Petitions were based, ISO-NE conducted two subsequent forward capacity auctions – FCA-7 in February 2013 (before evidentiary hearings were held in this case) and FCA-8 in February 2014 (after evidentiary hearings in this case had concluded).[14] Two new generators entered the market in eastern New England through FCA-7: (1) Footprint Power (674 MW); and (2) Cape Wind (74 MW).[15] In addition, ISO-NE issued a more recent CELT Report in May 2013, with an updated energy and demand forecast, as well as an updated EE forecast for New England. Further, as part of the FCA notice requirements, a number of existing generating units have announced their intention to retire, including Brayton Point, Vermont Yankee and Norwalk Harbor (RR-EFSB-64(S2)). Accordingly, Siting Board staff sought to update the record in this case to determine whether additional energy resources, such as the IRP, are needed in light of more recent developments.

7. Alternative Base Case Assumptions Requested by Staff

At the end of evidentiary hearings, staff requested that the Company prepare additional power flow model runs to: (1) update input assumptions based on more recent information; and (2) evaluate how sensitive the model results were to material changes in base case assumptions. The first consideration is discussed in Section III.C.6, above. The second consideration arose because of the reported difficulty by ISO-NE in determining the probability or likelihood of any

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14 NEP submitted a partial revised petition on September 28, 2012 to reflect new information included in ISO-NE's September 2012 updated needs assessment.

15 This value is Cape Wind's Qualifying Capacity ("QC"). Cape Wind has a proposed total nameplate rating of 468 MW (Exh. EFSB-ISO-141, at 2, n.2.

particular base case occurring (Exhs. EFSB-ISO-79; EFSB-ISO-81; EFSB-ISO-82; EFSB-ISO-83; EFSB-ISO-84; EFSB-ISO-87; EFSB-ISO-132; EFSB-ISO-180). In addition, discovery responses raised questions concerning whether the OOS generating units that were chosen for the base case were appropriate based on actual operating experience during peak periods (e.g., HQ Phase II has delivered approximately 1,400 MWs over historical peak periods). To test the robustness of the Company's analysis, staff requested sensitivity cases that emerged from discovery and examination in the case, and were intended to be consistent with established planning standards. Accordingly, as shown in Tables 5A and 5B below, staff proposed that additional base case assumptions be tested using FCA-7 information and the 2013 CELT Report.

Table 5A. Staff Additional Base Case Conditions in Eastern New England

Resource	Case 1-A (2018 and 2023)	Case 1-B (2018 and 2023)	Case 2-A (2018 and 2023)	Case 2-B (2018 and 2023)
Phase II HVDC	1400 MW	1400 MW	1400 MW	1400 MW
New Brunswick	735 MW	124 MW	735 MW	124 MW
Seabrook	OFF	OFF	OFF	OFF
Mystic 9	OFF	OFF	695 MW	695 MW
Pilgrim	702 MW	702 MW	OFF	OFF
Footprint	674 MW	674 MW	674 MW	674 MW
Cape Wind	84 MW	84 MW	84 MW	84 MW

Source: Exh. NEP-12.

Table 5B. Staff Additional Base Case Assumptions in Western New England

Resource	Case 3-A	Case 3-B
Millstone 2	OFF	OFF
Millstone 3	OFF	OFF
Berkshire Power	236 MW	236 MW
Vermont Yankee	OFF	OFF
Mt. Tom	157 MW	157 MW
Norwalk Harbor	OFF	OFF
NY-NE AC ties	0 MW	1400 MW NY to NE

Source: RR-EFSB-64, at 2.

8. Results of the Various Power Flow Modeling Analyses

a. Eastern New England

As shown in Table 6, below, up to three potential thermal overloads are seen under N-1 conditions in 2022, with no voltage performance issues (Exh. N-1, at 2-25). Potential thermal overloads and voltage performance issues under N-1 and N-1-1 contingencies are shown regardless of the amount of imports from New Brunswick (id.). Overall, adding New Brunswick Power as an available resource at 700 MW had some beneficial effect in reducing line loadings and the number of thermal overloads (although it did not completely eliminate them); it had no effect on voltage issues, however. The N-1-1 contingency analysis shows up to 21 overloaded elements in 2022 (assuming New Brunswick imports at 0 MW). There would also be two voltage performance issues by 2022 regardless of the assumed New Brunswick import levels under N-1-1 contingencies (id.).

Table 6. Year 2022 Thermal Overloads and Performance Issues: West-to-East Scenario

	N-1 Contingencies			**N-1-1 Contingencies**		
	Elements Loaded 95-100 percent[16]	**Thermal Overloads**	**Voltage Performance Issues**	**Elements Loaded 95-100 percent**	**Thermal Overloads**	**Voltage Performance Issues**
New Brunswick Power @ 0 MW (Base Case)	2	3	0	4	21	2
New Brunswick Power @700 MW (Company Sensitivity Case)	1	2	0	9	10	2

Source: Exh. NEP-1, at 2-25.

The Company provided additional power flow analyses using sensitivity base case assumptions requested by staff. The Company also provided additional power flow model runs on its own initiative that reflect certain alternative base case assumptions, which the Company offered for a more complete record (RR-EFSB-64; RR-EFSB-64(S1); RR-EFSB-64(S2); RR-

16 Although transmission lines between 95 and 100 percent are not technically overloaded, they are indicative of thermal loading problems that may occur just over the ten-year study horizon if loads continue to grow (Exh. NEP-1, at 2-25).

EFSB-64(S3)).[17] The results are summarized in Table 7 below. According to the Company, the majority of the overloaded transmission elements identified in each scenario is overloaded under multiple contingency pairs that largely involve various breaker failures (RR-EFSB-64(S2) at 10 n.5).

Table 7. Potentially Overloaded Elements in 2023 – Staff Assumptions (West to East)

	Case 1-A	Case 1-B	Case 2-A	Case 2-B
345 kV Overloads	2	5	2	4
115 kV Overloads	8	10	8	11
Type of contingency	N-1-1	N-1-1	N-1-1	N-1-1
Year of first overload	2013-14	Prior to 2013	2014-2015	Prior to 2013

Sources: RR-EFSB-64, at 2; RR-EFSB-64(S1) at 2.

The Company provided the results of its additional power flow analyses to compare the performance of the transmission system, with and without the IRP, in the event of the retirement of either the Brayton Point generating units or the Canal generating units. In conducting this analysis, the Company stated that it used the staff assumptions, including the assumption that 1,400 MW is available over the HQ Phase II interface (RR-EFSB-64, at 3). The results are summarized in Table 8.

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17 ISO-NE also conducted a spreadsheet analysis following the FCA-7 auction that used the FCA-7 results to analyze whether there would be any change in the year of need (Exh. EFSB-ISO-141). However, this spreadsheet analysis was conducted before the 2013 CELT Report was issued, and did not alter the base case assumptions originally relied upon by ISO-NE and the Company in the Petition (id.).

Table 8. Potentially Overloaded Elements in 2023 – Additional Retirements (West to East)

Primary Retirement Assumption	Brayton Point Retirement		Canal Retirement	
	Without IRP			
Additional units assumed out-of-service (OOS)	Seabrook OOS	Seabrook OOS Mystic 9 OOS	Seabrook OOS	Seabrook OOS Mystic 9 OOS
345 kV overloads	1	8	2	7
115 kV overloads	9	13	7	15
	With IRP			
	Brayton Point Retirement		**Canal Retirement**	
345 kV overloads	0	0	0	0
115 kV overloads	0	1	1	2

Source: RR-EFSB-64, at 3.

After evidentiary hearings had concluded, the Company submitted additional information indicating that ISO-NE had received numerous Non-Price Retirement ("NPR") requests commencing with the 2017-18 capacity commitment period for approximately 2,480 MW of electric generation, including the following units: (1) Brayton Point Units 1-4; (2) Brayton Diesel Units 1-4; (3) Bar Harbor Diesels; (4) Medway Diesels; (5) Bridgeport Harbor 2; (6) John Street Units 3, 4, and 5; (7) Ameresco SEMA Demand Response ("DR"); and (8) EnerNOC DR (RR-EFSB-64(S2)). Brayton Point in Somerset, at 1,535 MWs, is the largest of these generating stations.[18] The great majority of the capacity represented by these retirement requests was from resources located in eastern New England (RR-EFSB-64(S2)). These retirements are in addition to Vermont Yankee's recent retirement announcement, which represents an additional 604 MW.

NEP submitted a further update stating that ISO-NE had performed a reliability power flow analysis for Brayton Point's NPR that demonstrated a need for Brayton Point Units 1-4 (RR-EFSB-64(S3)). As a result, ISO-NE rejected Brayton Point's request to retire Units 1-4 (id.). The Company also presented the results of ISO-NE's sensitivity analysis, which modeled the full IRP in service in order to understand the impact of the IRP on the reliability of the system. This sensitivity analysis shows that even with the full IRP in service, there is a

18 Brayton Point consists of the following units: Unit 1 (239.2 MW), Unit 2 (238.9 MW), Unit 3 (612 MW), Unit 4 (435 MW), and four diesel units (9.9 MW) (RR-EFSB-64(S2) at 7).

continuing reliability need for Brayton Point Unit 1 (239 MW), but not for Brayton Point Units 2, 3, and 4 (RR-EFSB-64(S3) at 2).

b. Western New England

As shown in Table 9A, below, there were no thermal overloaded elements or voltage performance issues in western New England under N-1 conditions in 2022, using the modeling assumptions shown in Table 3, above (Exh. NEP-1, at 2-26). Under N-1-1 contingency conditions, thermal overloads could occur on up to seven transmission lines in western New England in 2022 (assuming Berkshire Power is out of service). There were no potential voltage performance issues in 2022 (id.).

Table 9A. Thermal Overloads and Performance Issues in 2022: East to West Scenario

Case	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95-100 percent	Thermal Overloads	Voltage Performance Issues	Elements Loaded 95-100 percent	Thermal Overloads	Voltage Performance Issues
Berkshire Power OOS	0	0	0	2	7	0
W. Springfield Unit 3 OOS	0	0	0	5	3	0

Source: Exh. NEP-1, at 2-26.

The Company also provided results, shown below in Table 9B, from the power flow analysis based on the alternative base case assumptions shown above in Table 5B.

Table 9B. Thermal Overloads in 2023 East to West (using staff's alternative assumptions)

	Case 3-A	Case 3-B
345 kV overloads	3	0
115 kV overloads	5	0

Source: RR-EFSB-64, at 2.

c. Rhode Island

Table 10, below, shows that Rhode Island would experience no thermal or voltage performance issues under N-1 conditions in 2022 (Exh. NEP-1, at 2-27). Under certain N-1-1 contingency conditions, potential voltage collapse may occur. ISO-NE's transmission modeling does not identify the thermal overloads that could also result from these contingencies (id.).

Therefore, according to the Company, Table 10 understates the number of thermal overloads that may result from N-1-1 contingencies (id.).

Table 10. Thermal Overloads and Performance Issues: Rhode Island Scenario

Year	N-1 Contingencies			N-1-1 Contingencies		
	Elements Loaded 95-100 percent	**Thermal Overloads**	**Voltage Performance Issues**	**Elements Loaded 95-100 percent**	**Thermal Overloads**	**Voltage Performance Issues**
2022	0	0	0	one or more	two or more	collapse

Source: Exh. NEP-1, at 2-27.

9. Positions of the Parties

NEP maintains that the base case assumptions used by ISO-NE "impose stress on the system that is severe, but reasonable" and clearly demonstrate the need for IRP (Company Brief at 43). NEP contends that there is a particular need for ISO-NE to assume more units out of service than in some other parts of the country because the New England region is at the far northeastern end of the Eastern Interconnection, with limited ties to the west (Company Brief at 46, *citing* Tr. 4, at 634).

NEP maintains that IRP is the product of repeated planning studies on deficiencies and interrelated needs in southern New England first conducted in 2004 and updated several times (Company Brief at 23). The Company states that ISO-NE's 2012 updated needs analysis shows that the system will be unable to withstand single and multiple contingencies as the system approaches or exceeds expected peak loads over the forecast period (id. at 28). In addition, the Company states that the ISO-NE March 2013 supplemental analysis accounting for FCA-7 results confirmed a continuing need for the IRP (id. at 30).

NEP argues that the large number of recently announced generation retirements reinforces the need for the IRP, and that this is true even with other more optimistic assumptions used in the sensitivity cases requested by staff (Company Brief at 35). The Company argues that analyses using staff's requested assumptions and dispatches, standing alone, "are not an adequate basis for transmission planning analysis and that relying on them without considering the assumptions set forth in ISO-NE's 2012 follow-up needs analysis could put the reliability of the New England transmission system at risk" (id. at 36).

The Company notes that it undertook the following sensitivity analyses using the staff's requested base case assumptions in order to provide the Siting Board with a more complete understanding of the performance of the regional transmission system under contingencies:

- West-to-East stress, based on the staff's base case assumptions, but also assuming the retirement of Canal Station or Brayton Point, and Seabrook modeled out of service or both Seabrook and Mystic 9 modeled out of service ("Retirement Sensitivities");
- East-to-West stress, based on the staff's base case assumptions, but with flows over the New England to New York AC ties set at the average historic scheduled flows and at the maximum flows for peak load days ("NY-NE Interface Sensitivities").

(Company Brief at 36, *citing* RR-EFSB-64(1)).

NEP contends that the Retirement Sensitivities and the NY-NE Interface Sensitivities show overloaded transmission system elements "that would be resolved with IRP in service" (Company Brief at 36-37). According to NEP, "[t]he recently announced retirements, as well as potential future generation retirements, make the need for the robust transmission system that the IRP will provide more acute and immediate" (id. at 38).

NEP maintains that the Siting Board should find that ISO-NE's transmission planning studies, as they were originally submitted in the Company's Petition, used reasonable system planning criteria and reviewable and appropriate methods for determining system reliability (Company Brief at 23). NEP contends that the design of system stress from generator outages, also known as "critical system conditions," is properly left to ISO-NE, the planning authority for the New England region (id. at 43). According to the Company, ISO-NE's base cases impose stress on the system that is severe, but reasonable, and that such testing ensures that the transmission system is designed so that it can be operated reliably under a broad range of reasonably foreseeable conditions (id.). The Attorney General agrees with NEP on this point (Attorney General Brief at 13).

ISO-NE argues that there is a need to increase the eastern New England import capability and to take action to avoid thermal overloads on the central 345 kV East-West path (ISO-NE Brief at 11, *citing* Exh. ISO-NE-1, at 13). According to ISO-NE, recent generation retirements following ISO-NE's September 2012 needs analysis only make the need for the IRP more clear (ISO-NE Brief at 18). ISO-NE states that, even if the staff's alternative base case assumptions were to be relied upon, there are numerous overloads that would occur during the planning horizon, both on the 345 kV and the 115 kV networks (id.).

ISO-NE states that the base case conditions were reasonably stressed, "because in many cases those stressed conditions have been seen in some form in actual operating experience" (ISO-NE Brief at 20). ISO-NE also maintains that the particular resource outages represented in the base case should "be viewed as a proxy for other conditions that could have a similar effect on the transmission system" (id., *citing* Tr. 5, at 825).

ISO-NE maintains that it is reasonable to take "something of a conservative approach" to base case assumptions given the serious adverse safety and economic consequences of potential electric supply disruptions (ISO-NE Brief at 24). In addition, although the probability of the base case conditions actually occurring may seem low, ISO-NE contends that there are numerous examples of low-probability events actually occurring on the New England grid (id.).

The Attorney General maintains that the evidence and testimony demonstrate that there is a need for the Project (Attorney General Brief at 12). According to the Attorney General, the Company used reviewable and appropriate methods for assessing system reliability based on load-flow analyses (id. at 13).

D. Analysis and Findings on Need

The Siting Board has reviewed the various power flow modeling results presented in this proceeding, which include individual reviews of the modeling results from: (1) ISO-NE's power flow studies relying on ISO-NE's original base case assumptions; (2) NEP's power flow studies using Siting Board staff's alternative base case assumptions; (3) NEP's power flow studies based on its alternative retirement scenario analysis; and (4) ISO-NE's most recent Brayton Point power flow studies that were conducted to understand the implications of Brayton Point's retirement for the overall ISO-NE system.

ISO-NE's base case modeling shows that there is the potential for as many as 21 separate transmission elements experiencing thermal overloads in 2022, with each element overloading under one or more combinations of N-1-1 contingencies, when using ISO-NE's base case assumption that neither HQ Phase II nor New Brunswick Power is available to serve eastern New England (see Table 6 above). This modeling analysis is quite conservative, however, as it assumes a base case scenario where the two largest resources (HQ Phase II and Seabrook) that serve eastern New England are assumed out of service, and New Brunswick Power is also assumed to be out of service – even before studying the effects on the system of two additional contingencies (i.e., N-1-1) (see Table 2 above).

These modeling results can be put in clearer perspective, however, when reviewing the results of Siting Board staff's requested alternative base case, which assumes, among other things, that HQ Phase II and New Brunswick Power are available to serve eastern New England, but that Seabrook and Mystic 9 are the two unavailable units (see Table 5A, Case 1-A). In that scenario, up to ten separate transmission elements could overload in 2023, with each element overloading under one or more combinations of N-1-1 contingencies. Under these assumptions, the earliest modeled transmission element overload would occur during the 2013-2014 period (see Table 7).

To provide further context for these results, the Company modeled a scenario in which it assumed staff's base case conditions (e.g., HQ Phase II and New Brunswick Power are both available to serve), but that Brayton Point generating station is assumed retired (see Table 8). NEP's Brayton Point retirement scenario analysis proved quite timely in that only weeks after the Company conducted it, Brayton Point's owners requested that the entire generating station be permitted to retire in 2017. Under this set of base case assumptions, there is the modeled potential for up to 21 separate transmission elements experiencing thermal overloads by 2023, including eight 345 kV lines and 13 115 kV lines.

During the course of this proceeding, staff requested that the Company conduct a number of additional model runs based on alternative base cases for the purpose of understanding the breadth of potential conditions under which the existing transmission system might be inadequate in the next ten to 20 years. The additional model runs were useful for this purpose, and support the conclusion that additional transmission is needed to facilitate transfer of power among regions of southern New England. Considering the full range of these separate power flow study results, the need for the Project is clear. The Siting Board finds that there is a need for additional energy resources in Massachusetts and, more broadly, across the southern New England region.

We note that in this case the Company did not provide in its Siting Board Petition an evaluation of need supported by a wide range of base cases. A broader range was developed during the course of the proceeding. A decision concerning whether additional resources are needed should be based on sufficient modeling to provide a broader understanding of need than is provided by only one set – or even a few sets – of base case assumptions. This case illustrates how modeling results can vary greatly depending upon which base case assumptions are adopted. Consideration of multiple base cases is especially valuable where proponents are unable to ascribe statistical probabilities to the likelihood of specific resources being unavailable individually or in combination, which was the case here.

Rather than relying on a single set of base case assumptions for modeling purposes, the Siting Board shall require future applicants to evaluate and submit multiple model runs, consistent with the facts and circumstances of each case, to demonstrate the sensitivity of the results to material changes in base case assumptions. This directive is also consistent with FERC's finding that "it would be appropriate for planning entities to conduct sensitivity studies to 'bracket' the range of probable outcomes. Thus, without having to anticipate 'every conceivable critical operating condition,' planning entities will have a means to identify an appropriate range of critical operating conditions." Mandatory Reliability Standards for the Bulk-Power System (NOPR), 117 FERC ¶ 61,084 at ¶ 1047 (2006). Moreover, the Siting Board encourages future applicants to more fully describe project need through the use of probabilistic planning methodologies, including statistical measures of resource unavailability.

IV. ALTERNATIVE APPROACHES FOR MEETING IDENTIFIED NEED

A. Standard of Review

G.L. c. 164, § 69J requires a project proponent to present alternatives to the proposed facility, which may include: (1) other methods of transmitting or storing energy; (2) other sources of electrical power; or (3) a reduction of requirements through load management.[19] In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on

[19] G.L. c. 164, § 69J also requires an applicant to present "other site locations." This requirement is discussed in Section V.A, below.

balance, its proposed project is superior to such alternative approaches in terms of cost, environmental impact, and ability to meet the identified need. In addition, the Siting Board requires a petitioner to consider reliability of supply as part of its showing that the proposed project is superior to alternative project approaches. Lower SEMA at 53; New England Power Company, EFSB 09-1/D.P.U. 9-52/9-53, at 19 (2011) ("Worcester Decision"); GSRP at 41.

B. Identification of Project Approaches for Analysis

IRP is one of four major transmission projects that together make up the New England East-West Solution ("NEEWS"), which also includes: (1) GSRP (completed in 2013); (2) the Rhode Island Reliability Project (completed in 2013); and (3) the Central Connecticut Reliability Project (Revised Need Study completed in 2013; Revised Solution Study to be completed in 2014) (Exh. NEP-1, app. 3-1, at 1-1). ISO-NE selected these four NEEWS projects, in combination, as its preferred approach to address reliability concerns identified for southern New England.[20] Each of the NEEWS projects includes the installation of a new 345 kV line, improvements to the existing 115 kV system, and substation upgrades (among other components); collectively they are designed to increase bi-directional power flows across the southern New England East-West interface and also increase power transfer capabilities between Massachusetts, Connecticut, and Rhode Island (id.).

In developing the IRP portion of NEEWS, ISO-NE and the study participants conducted an initial Need Assessment in April 2011 (followed by a related Solutions Study Report in February 2012) (Exh. NEP-1, app. 1-4 and 1-5). The Solution Study assessed how numerous possible solution options would perform under stressed conditions with projected peak load and a series of transmission outage scenarios in order to determine whether those options would be able to reliably support a range of transmission requirements (id.). Over the course of these successive studies, ISO-NE and the study group consistently selected IRP as one of its proposed four NEEWS projects (id.). ISO-NE noted that IRP not only resolved all the needs identified in the needs analysis, but also stood out as the best option after a comparison of electrical

20 The need for the four components of NEEWS came out of studies done over the 2004-2008 timeframe by the Southern New England Regional Working Group (consisting of ISO-NE, National Grid USA, and Northeast Utilities) (Exh. NEP-1, app. 1-5, at p. 2).

performance factors, costs, and natural/human environmental impact factors (Exh. NEP-1, app. 3-3 at 8).

As a potential alternative to the Project, the Company considered: (1) a "no action" alternative; (2) different locations for adding new overhead 345 kV transmission lines in central New England; (3) an underground 345 kV transmission line; (4) a number of non-transmission alternatives ("NTAs") individually and in combination; and (5) a hybrid solution consisting of scaled-back transmission upgrades to the 115 kV transmission system in Massachusetts plus NTAs ("Hybrid Alternative") (Exh. NEP-1, at 3-1). In its analysis of alternatives, the Company focused on the ability of the transmission system to move sufficient power from the west to east within southern New England because the most recent Southern New England Regional Working Group analysis of NEEWS indicated that the need to expand the west-to-east transfer capability was immediate, while the need to expand the east-to-west transfer capability was less urgent (id. app. 1-5, at 1, and app. 3-2, at 3).

The Company rejected the no action alternative because "continued reliance on the existing system configuration without any new facilities or resources would not provide a solution to the existing transmission reliability need in [southern New England]" (Exh. NEP-1, at 3-2). The Company also determined that building only the Connecticut and Rhode Island portions of the IRP, without the Millbury to West Farnum section (the "Modified Project") would not resolve all of the identified thermal overloads from contingencies (Exh. NEP-1, app. 3-2, at 9-10).[21] The Company asserted that, while an underground route would reliably meet the identified need with fewer permanent environmental impacts, such an approach could present significant operational issues (voltage control and the potential for lengthy outage restoration times) and would cost $340.5 million versus $100.1 million for the Project (Exh. NEP-1, at 66).

The Company next focused its analysis of project approach alternatives on the feasibility of demand-side NTAs, such as EE and DR, and supply-side NTAs such as new central generation and distributed generation ("DG") to resolve the identified reliability need without the

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

construction of the Project (Exh. NEP-1, app. 3-1). This analysis, prepared for the Company by ICF Resources International ("ICF"), evaluated the availability, feasibility, and projected costs of NTAs individually, collectively and in combination with various transmission improvements (id., app. 3-1 and 3-2). ICF's initial study, prepared in December 2011, reflected data included in ISO-NE's 2011 IRP Needs Study Update, the results of FCA-4, and the 2010 CELT Report; ICF's revised study in June 2012 (that evaluated the Hybrid Alternative of 115 kV transmission upgrades in Massachusetts in lieu of a new 345 kV Massachusetts line) was issued prior to ISO-NE's Needs and Solution Studies Update in September 2012. A revised ICF study used FCA-5 results and reflected the announced closure of all Salem Harbor units and AES Thames as well as higher levels of EE and DG.

At the request of Siting Board staff, the Company supplemented the ICF studies with a spreadsheet-based analysis that incorporated more current input data on loads, generation, energy efficiency, and other information based on the ISO-NE 2013 CELT report (Exh. EFSB PA-42). In addition, the spreadsheet analysis also included alternative base case sensitivities requested by staff as well as additional sensitivity cases proffered by the Company (id.).

C. Overview of ICF's Analysis

In the two ICF studies noted above, ICF evaluated the ability of the following potential Project approaches to address the identified need:

- One type of NTA (EE, DR, DG or new central generation) alone;
- A combination of NTAs (new central generation, EE, DR, and DG);
- The Connecticut-to-Rhode Island segment of IRP only – with no construction in Massachusetts – plus NTAs;
- A "Hybrid Alternative" consisting of the Connecticut and Rhode Island sections of IRP, plus scaled-back transmission upgrades to the existing 115 kV system in Massachusetts, supplemented by NTAs (id.).

For each type of NTA in ICF's initial 2011 Study, ICF developed a Reference Case and an Aggressive Case forecast. The Reference Case projection was based on the achievement of then-current state goals and approved funding levels. The Aggressive Case projection assumed that the NTA resource would grow at a more rapid rate such that by 2020 the amount of that NTA would exceed the Reference Case level by 17 percent (Exh. NEP-1, app. 3-1, at 5-2).

To evaluate the various NTAs, ICF developed a power flow model using scenarios similar to those prepared by ISO-NE at the time in its base case evaluation of need (id., app. 3-1, at 2-1 to 2-5). ICF studied whether these project alternatives would eliminate modeled thermal and voltage violations, and if so, how they would compare to the Project based on reliability, cost, and environmental criteria (id., app. 3-1, at 4-2 to 4-9; app. 3.2, at 2-7 to 2-8).

D. Potential NTA Resources

1. Energy Efficiency

ICF initially provided a projection of the amount of EE that would be available in 2015 and 2020 based on the amount of EE that had been contracted through ISO-NE's Forward Capacity Market ("FCM") Auction #4 for the 2013-2014 capacity year.[22] ICF added an estimate of incremental EE amounts resulting from procurement mandates and incentive programs of individual New England states (Exh. NEP-1, app. 3.1, at 5-1 to 5-31).[23] For Massachusetts, Connecticut and Rhode Island, ICF developed two projections of EE through 2020: a Reference Case projection that was based on the achievement of existing state goals and on expected legislation in the various states; and an Aggressive Case projection in which the amount of EE grows at a more rapid rate (id., app. 3-1, at 5-2). For Massachusetts, ICF assumed incremental summer peak EE gains of 145 MW per year for the entire state in the Reference Case and 179 MW per year in the Aggressive Case, both through 2020 (id., app. 3-1, at 5-12, 5-13).

Table 11 below shows ICF's projections of EE for each of the three southern New England states and also indicates ISO-NE's EE projections incorporated in its September 2012 Needs Report (Exh. NEP-1, app. 2-5, at 57) and ISO-NE's 2013 CELT Report

22 Forward Capacity Auction four ("FCA-4") was held in August 2010 for resources that would be delivered for a three-year period beginning in the June 2013.

23 Later in the proceeding, in response to an EFSB information request, ISO-NE provided its updated 2013 forecasts of EE as well as the result of the FCA-7 (Exhs. EFSB-PA-42; NEP-JR-3, at 3-4). The Company analyzed the impact of these updated projections on the need for the Project (Exh. EFSB-PA-42).

(Exh. EFSB-ISO-171). ICF noted that its projections of EE included an estimated 5.5 percent reduction in distribution losses that would be associated with not having to generate and transmit power to load (Exh. NEP-1, app. 3-1, at 5-15, 5-16).

Table 11. Comparison of Total EE Forecasts for 2015 and 2020 for Southern New England (Effective On-Peak Summer MWs)

	ICF EE Forecast (MW)		ISO-NE 2012 Needs Report (MW)	ISO-NE 2013 CELT (MW)
	Reference	Aggressive		
2015				
Connecticut	416	434	389	370
Massachusetts	666	700	704	700
Rhode Island	103	114	129	124
2015 Total	1185	1248	1222	1194
2020				
Connecticut	592	705	516	413
Massachusetts	1391	1595	1265	1193
Rhode Island	198	266	236	216
2020 Total	2181	2566	2017	1822

Sources: Exh. NEP-1, app. 3-1, at 5-5 to 5-14; Exh. NEP-1, app. 2-5, at 57; and Exh. EFSB-ISO-171.

ICF observed that its projections of the amount by which EE can be expected to reduce load in southern New England are, in fact, very similar to those of more recent ISO-NE forecasts (Exh. NEP-1, app. 3-2, at 4).[24] ICF stated that the projected levels of EE alone would not be sufficient to eliminate the thermal overloads predicted by its models (Exh. NEP-1, app. 3-1, at 5-17 to 5-18). In its June 2012 update, ICF increased its estimates of EE in Massachusetts and Rhode Island to better account for actual levels achieved in 2011 (Exh. NEP-1, app. 3-2, at 4).

24 As shown in Table 11 above, ICF's initial EE Reference forecast is close to, and in some cases even higher than more recent data would indicate. The ICF Aggressive forecast shows EE levels that exceed those in the 2013 CELT.

Nevertheless, ICF still concluded that EE alone would not be an adequate alternative to the Project (id. at 32).[25]

2. Distributed Generation

ICF provided projections of the amount of DG that it expected to be installed in southern New England (Exh. NEP-1, app. 3.1, at 5-3 to 5-4). ICF's projections of on-peak DG capacity assumed that 75 percent of the DG capacity would be photovoltaic ("PV") and 25 percent would be wind capacity. ICF further assumed that the effective on-peak capacity of PV is 28 percent of nameplate capacity, while the effective on-peak capacity of wind is ten percent of nameplate capacity (id.). For its Reference Case and Aggressive Case projections of DG, ICF started with the DG capacity that had cleared FCA-4 for delivery in 2013-2014, and then added a constant annual increment based on historical growth rates and prevailing state program goals at the time (id.). ICF stated that even with its Aggressive Case projections, DG alone would be insufficient to reduce the level of peak load below the critical load level ("CLL") at which ISO-NE forecasts suggest that thermal violations are likely to occur (Exh. NEP-1, app. 3-2, at 32).

Table 12, below, presents ICF's DG projections, as well as a comparison to more recent DG projections on the record provided by ISO-NE and Synapse Energy Economics (Exhs. NEP-1, app. 3-1, at 5.1.1; EFSB-8; EFSB-36). As illustrated in Table 12 below, even ICFs Aggressive Case projections of effective on-peak DG (both PV and wind) are considerably lower than more recent projections by ISO-NE and Synapse (which are PV only).[26] Specifically, the latest ISO-NE projections of DG (PV only) in southern New England are 79 MW higher in 2015 and 232 MW higher in 2020 than ICF's Aggressive Case. Synapse's DG projection for 2021 (which includes PV and fuel cells) is 405 MW higher than ICF's Aggressive

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25 Exhibit 2-1 in ICF's second report indicates that all forms of NTAs together would not be sufficient to resolve the identified need (Exh. NEP-1, app. 3-2, at 32).

26 ICF's lower DG forecasts are due, in part, to outdated assumptions about state programs that encourage the development of DG (Exh. NEP-1, app. 3-1, at 5-2; Tr. 8, at 1103). The extent of the difference is even greater than it appears as the ICF figures include wind and PV capacity, whereas ISO-NE and Synapse provide PV-only figures.

Case for 2020.[27] However, as will be discussed further in Section IV.E, "NTAs Combined" below, the substitution of either ISO-NE's or Synapse's higher DG projections for those of ICF would not provide sufficient additional local resources to reduce southern New England loads below the CLL.

Table 12: Projections of Effective On-Peak Distributed Generation Capacity (MW)

	ICF Reference Projection		ICF Aggressive Projection		ISO-NE DG Forecast Working Group Projection (2/11/2014)		Synapse Forecast
	2015	2020	2015	2020	2015	2020	2021
Connecticut	57	68	60	78	56.5	118.6	196
Massachusetts	103	122	114	169	214.9	383.1	448
Rhode Island	26	38	27	40	8.8	17.5	48
Southern New England Total	186	228	201	287	280.2	519.2	692

Sources: Exhs. NEP-1, app. 3-1, at 5-2; EFSB-36; EFSB-8. ICF and Synapse projections of effective on-peak capacity have been adjusted to reflect a 28 percent availability factor, while ISO-NE's projection assumes a 35 percent availability factor on peak. For the years 2015 and 2016, ICF appears to have used an Aggressive Case projection for DG that is lower than its Reference Case, which is counterintuitive. The numbers in the table above for the Aggressive Case reflect staff adjustments to the Aggressive Case 2015 projections of DR to make it higher than the Reference Case 2015 projection by an amount equal to one year's assumed increment in DR effective capacity (i.e., 10.7 MW). For years 2016 through 2020, staff assumed that the Aggressive Case DR forecast increased by 10.7 MW per year.

3. Additional Generating Resources

The addition of central generating resources within the eastern section of southern New England[28] would serve to reduce stress and reliability problems on transmission lines used to bring in power from neighboring zones (Exh. NEP-1, app. 3-1, at 6-1 to 6-9). Therefore, additional central generation is another form of NTA (id.). In its initial study, ICF prepared a forecast of new generating resources in the eastern portion of southern New England based on

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[27] Synapse projected nameplate PV capacity in 2021 of 2,470 MW. ICF's 28 percent capacity factor has been applied to Synapse's capacity by Siting Board staff in order to reflect on-peak effective capacity.

[28] The eastern section of southern New England includes ISO-NE's zones known as Northeast Massachusetts/Boston and Southeast Massachusetts, plus a small portion of the West Central Massachusetts zone.

new generating resources listed in the ISO-NE Interconnection Queue[29] ("the Queue") as of April 1, 2011 (id., app. 3-1, at 6-1). ICF asserts that the Queue is the best available indication of where new generating resources are likely to be located in the future. ICF reported that its power flow modeling indicated that the new generation in the eastern portion of southern New England, estimated at 401 MW of summer peak capacity,[30] would reduce the number of modeled thermal violations in the region by 56 percent in 2015, and by 53 percent in 2020 – but would not eliminate such violations (id.). [31]

ICF initially relied on the information in the ISO-NE Queue as of April 1, 2011 (Exh. NEP-1, app. 3-1, at 6-1). However, since that date there have been withdrawals from and additions to the Queue, as well as significant announced retirements of existing units. In ICF's Updated Reference Case, ICF assumed that all existing Salem Harbor units and the AES Thames plant would retire (a decrease of 932 MW of supply in southern New England) (Exh. NEP-1, app. 3-2, at 31).

NEP stated that prior to FCA-8, ISO-NE had received the following NPR requests commencing with the 2017-2018 capacity commitment period: (1) Brayton Point Units 1-4; (2) Brayton Diesel Units 1-4; (3) Bar Harbor Diesels; (4) Medway Diesels; (5) Bridgeport Harbor 2; (6) John Street Units 3, 4, and 5; (7) Ameresco SEMA Demand Response ("DR"); and (8) EnerNOC DR (RR-EFSB-64(2S)). The sum of these retirement requests equals

[29] The ISO-NE Queue consists of generation resources seeking permission to interconnect with the ISO-NE-administered transmission system. The ISO-NE Queue is updated monthly.

[30] ICF assumed that new wind resources would have an effective peak summer capacity of ten percent of nameplate (Exh. NEP-1, app. 3-1, at 5-13). With this assumption, Cape Wind, with its nameplate capacity of 462 MW, was counted as a 46 MW capacity resource.

[31] ICF assumed that between 1,281 and 1,302 MW of new generation would be added in all of southern New England by 2015 and that 2,850 MW would be added by 2020. However, new generation resources added outside of the eastern portion of southern New England would not serve to reduce the stress on west-to-east flows in southern New England. Therefore, it is assumed that the reduction in thermal violations reported in Exhibit 6-7 of Exh. NEP-1, app. 3-1, was primarily associated with the generation added in the eastern portion of southern New England.

approximately 2,480 MW, of which 1,535 MW are at Brayton Point in Somerset. The great majority of the capacity represented by these retirement requests is from resources located in eastern New England. These retirements are in addition to Vermont Yankee's recent retirement announcement, which represents an additional 604 MW. ICF expressed concern that these recently announced retirements of generating capacity, particularly in the eastern section of southern New England, and the potential retirement of other older coal and oil-fired units (such as Canal and the Mystic #7 unit) would impose significant additional stress on the adequacy of southern New England's system capacity (Exh. NEP-1, app. 3-2, at 32).

4. Active Demand Response

Active DR refers to contracts that ISO-NE has with some electric consumers in which those customers are paid to reduce or eliminate their normal load when requested by ISO-NE during stressed system conditions (Exh. NEP-1, app. 3-1, at ES-6). ICF did not prepare a forecast of future levels of DR, but instead estimated the feasibility of obtaining enough DR to plug the gap between the load reductions provided by other NTAs (EE, DG, and generation) and the overall load reduction required to avoid thermal overloads or voltage problems (Exh. NEP-1, app. 3-1, at ES-7). ICF stated that the amount of DR located in southern New England that cleared FCA-5 (DR required to perform in the period June 2014 through May 2015) was 971 MW (id., app. 3-1, at ES-9). The level of DR in southern New England committed in FCA-5 represented an increase of "roughly 350 MW to 400 MW" over the amount of DR committed in FCA-1 (id.).

ICF stated that it would be difficult to expand the amount of DR, as demonstrated by the amount of DR capacity that has delisted in recent FCAs (Exh. NEP-JR-3, at 7). ICF contends that the reliability of DR when called upon has decreased (id. at 6) and that new ISO-NE rules requiring DR to bid into the daily energy market beginning with FCA-8 (for the 2017-2018 capacity supply period) would likely further decrease the amount of DR willing to bid for a capacity supply obligation (id. at 8). ICF noted the possible introduction of more stringent qualification rules for DR, such as those introduced recently in the PJM Interconnection, which would likely reduce interest in supplying DR and increase its cost (id. at 8-9). ICF asserts that, as a result of these factors, it would be difficult for ISO-NE not only to attract new DR capacity, but also to retain existing DR participants (id. at 9).

Based on procurement costs in the most recent Forward Capacity Auction at the time of the ICF study (FCA-4), in which DR resources were obtained at a cost of $30/kW-year, ICF calculated that to fill the resource gap with DR would cost New England ratepayers $540 per MWh (assuming 50 hours per year of load interruptions) (Exh. NEP-1, app. 3-1, at E-6). Using econometric studies based on industry valuations of lost load ("VOLL"), ICF calculated that the economic cost to participating customers for interrupted load would be approximately $8,412 per MWh (id., app. 3-1, at E-14). ICF estimated that if sufficient DR resources could be obtained, the costs (using VOLL) for DR to solve the resource gap (after other NTAs) for Massachusetts alone would range from a low of $261 million per year in 2015 (assuming Aggressive Case estimates for other NTA resources) to a high of $1.02 billion per year in 2020 (assuming Reference Case estimates for other NTA resources) (id. app. 3-1, at E-13).

E. NTAs Combined

In order to determine whether the MW amounts of NTAs (EE, DG, new generation and DR) projected in sections IV.D.1 through IV.D.4, above, are sufficient to eliminate the need for the Project, ICF relied on ISO-NE's projections of Critical Load Level ("CLL"). CLL is the load level above which power flows from west to east in southern New England begin to cause transmission line overloads (Exh. NEP-1, app. 3-1, at 2-3 to 2-5). To determine the amount of NTAs required to eliminate the need for the project, ICF subtracted the CLL from the ISO-NE projected peak load in the eastern section of southern New England (id.).

As shown in Table 13 below, ICF estimated the amount of NTA capacity, including new generating resources, EE, and DG, available in southern New England through 2020 to achieve the load reduction required to reach the CLL. ICF then subtracted the projected MWs of all NTAs in southern New England from the MWs required to lower projected load to the CLL (id.). If the resulting megawatts were positive, that indicated that the projected quantity of NTAs was insufficient to meet the needed load reduction (id.).

ICF presented two estimates of future NTA resources: a reference case that represents ICF's best estimate based on then-current state programs, FCM results and the ISO-NE new generation queue; and an aggressive case that represents "higher, yet reasonably achievable growth" in resources (Exh. NEP-1, app. 3-1, at 5-2). In both cases, there remains a significant resource gap unmet by NTAs – although these figures do not include DR.[32]

Table 13: ICF Evaluation of Non-Transmission Alternatives to Alleviate Thermal Overloads in Southern New England[a]

	Reference Case (MW)		Aggressive Case (MW)	
	2015	2020	2015	2020
Total Resources Needed to Eliminate Identified Reliability Violations[b]	3,312	6,610	3,312	6,610
Less: New Generating Resources from the ISO-NE Interconnection Queue[c]	896	1,790	896	1,790
Less: Incremental EE and DG[d]	342	1,439	405	1,883
Resource Gap Unmet by NTAs	2,074	3,381	2,011	2,937

Source: Exh. NEP-1, app. 3-2, at 25, 26, except as noted.
a. Resource needs and NTAs aggregated across southern New England (Exh. NEP-1, app. 3-2, at 24).
b. Total megawatts of NTAs (new generation, EE, DG and active DR) that would be required to reduce loads sufficiently to eliminate all thermal overloads (Exh. NEP-1, app. 3-2, at 26).
c. ICF assumed addition of specific units from among 2,850 MW in the ISO-NE Queue as of April 1, 2011; most units in the queue were in western New England and thus less useful for relief of west-to-east stress (Exh. NEP-1, app. 3-1, at 6-1, 6-2, D-3).
d. Exh. NEP-1, app. 3-1, at 5-16, and app. 3-2, at 26. The incremental EE and DG result from ICF's updating of its base year numbers for Massachusetts and Rhode Island to reflect actual results through 2011.

ICF stated that there are great uncertainties associated with projections of the megawatts of NTAs required to reduce load to the CLL (Exh. NEP-1, app. 3-2, at 36-56). These uncertainties include the potential for higher load growth (as a result of more rapid economic

32 ICF asserted that historically DR participants in southern New England "have not performed in a manner that ensures comparable capacity benefits to physical assets such as transmission or power generation facilities" (Exh. NEP-1, app. 3-1, at C-1 and C-2). Based on ISO-NE DR performance assumptions for FCA-6, historical performance rates (MWs provided as a percentage of MWs obligated to be supplied) by DR resources in southern New England has ranged from a low of 64 percent in the Southeastern Massachusetts load zone to a high of 100 percent in the Rhode Island and West/Central Massachusetts load zones) (id. at C-2). ICF also notes that the amount of DR MWs under contract has declined precipitously in New England in the most recent FCAs (Exhs. JR-3, 6-8; EFSB PA-42 at 2-3).

growth and/ or changing weather patterns), retirement of existing generating resources, insufficient state budgets to achieve EE and DG goals, and inability to attract and retain active DR resources (id., app. 3-2, at 37-39). ICF's sensitivity analyses of these uncertainties raised the required capacity of NTAs by 840 MWs to 1,943 MWs as the amount necessary to prevent forecasted 2020 loads from breaching the CLL, at which thermal violations would occur (id., app. 3-2, at 42).

F. The Hybrid Alternative

The Company took the additional step of evaluating whether the Project could be replaced by a combination of NTAs and a scaled-back transmission solution involving upgrades of existing 115 kV lines instead of a new 345 kV line (Exh. NEP-1, app. 3-2, at 1). ICF updated the Reference Case it had used to evaluate NTAs alone, to reflect changes in generator availability and to reflect an expectation of a doubling of energy efficiency peak load reductions relative to the Initial NTA Assessment (id., app. 3-2, at 31).[33] ICF evaluated a set of upgrades to 23 miles of existing 115 kV lines (plus two transformers) that would provide service under these conditions over the period from Project completion to 2020 (id., app. 3-2, at 4). Not including the cost of NTAs,[34] the conceptual-level cost estimate for the 115 kV upgrades is $75 million for the reference case (-25%/+50%), which is considerably less than the $121 million cost of the 345 kV line from Millbury to West Farnum (id., app. 3-2, at 9). However, ICF also reported the levels of upgrades that would be required in five sensitivity cases (such as retirement of Canal Station, or a higher peak demand growth rate) and cautioned that due to the need to design and permit the 115 kV upgrades, implementation of the Hybrid Alternative would delay the in-

33 This ICF assessment included the announced retirements of the Salem Harbor and AES Thames power plants (Exh. NEP-1, app. 3-2, at 4). The only significant new generation proposals in the ISO-NE interconnection queue for eastern New England were Brockton Power and Cape Wind. ICF elected to model Cape Wind in only some cases and Brockton Power in none (id. at 5).

34 The costs of state programs to expand EE and DG were not considered as part of the capital costs of the Project Alternatives. Similarly, the cost of new central generating facilities was assumed to be borne by independent developers and not treated as a Project cost.

service date of the Project, leaving the transmission system vulnerable to potential thermal overloads for an additional 18 months (id., app. 3-2, at 15).

ICF estimated that the cost of the Hybrid Alternative transmission upgrades would be $75 million, or about 62 percent of the cost of the Project. However, the cost estimates of the Hybrid Alternative transmission upgrades were less precise (-25%/+50%) than those of the Project (which were -25%/+25%) and therefore would be likely to increase (id., app. 3-2, at 16).

The potential 115 kV upgrades would need to be significantly expanded in each of five sensitivity cases ICF evaluated relating to load growth, amounts of EE and DG, and generator retirements. ICF determined that the average cost of the 115 kV transmission upgrades required in the reference case and five sensitivity cases would be $156 million (id., app. 3-2, at 15, 47). Any delay the Hybrid Alternative might impose would also make it necessary to include additional costs associated with retaining generators requesting permission to retire (id., app. 3-2, at 15-16).

G. Updated Analysis with Sensitivity Cases Requested by Staff

At the request of Siting Board staff, ICF performed a spreadsheet analysis of NTA solutions that included: (1) imports from Hydro-Quebec and New Brunswick into eastern New England representing an average flow on selected peak load days; (2) inclusion of Footprint Power and Cape Wind by June 2016; (3) updated 2013 CELT load forecasts; and (4) a second generator out in eastern New England (in lieu of assuming HQ Phase II is unavailable) (Exh. EFSB-PA-42(R)). Under this scenario, ICF stated that a spreadsheet analysis resulted in a resource gap of 286 MW by the revised end date of 2022, with smaller gaps in the intervening years (id. at 1). ICF stated that it may be feasible to fill such a gap from 2016 to 2022, but maintained that it would be challenging to do so and that it is doubtful that such an NTA would provide an actual solution to transmission reliability issues (id. at 2).

ICF illustrated the variability of its analysis to assumptions about the generator availability and future NTA levels by exploring sensitivity cases. One sensitivity case assumed retirement of Brayton Point Units 1 through 4; this increased the 2022 gap from 286 MW to 1,772 MW, with a 1,178 MW gap as early as 2013 (Exh. EFSB-PA-42(R) at 3). A sensitivity case with HQ Phase II modeled as unavailable instead of a second eastern Massachusetts generator increased the 2022 gap from 286 MW to 681 MW (id.). ICF opined that achieving these levels of NTA integration to address the resource gap would likely be costly, difficult, and time-intensive, and it questioned whether enough customers would participate (id. at 11). ICF further suggested that many unknown issues and risks make the NTA approach far less robust than the Project (id. at 10).

ICF enumerated several reservations about the analysis requested by staff. ICF noted that in performing only a spreadsheet analysis and not a load flow analysis, it was unable to distinguish the efficacy of a generation resource placed centrally in the load zone from another in a more peripheral location (Exh. EFSB-PA-42(R) at 2). ICF also asserts that some of its earlier evaluations of DR were insufficiently pessimistic, largely based on continuing decreases in active DR bids into the FCM (id. at 2-4). ICF repeated its earlier views on solar as expensive and intermittent (id. at 4-6). ICF also expressed concerns about relying on Hydro-Quebec and New Brunswick imports for reliability purposes absent firm, long-term contracts (id. at 6-7). ICF also voiced concern about power plant retirements following removal of the price floor in FCA-8 (to be held in 2014) and in successive capacity auctions (id. at 7-8). Finally, ICF stated that performance of an NTA would be sensitive to variations in the rate of growth of peak demand (id. at 8).

H. Positions of the Parties

ISO-NE argues that together with the transmission owners, it devoted substantial efforts to identifying a range of potential transmission solutions, from which it selected IRP as the best (ISO Brief at 27). ISO-NE further argues that the September 2012 Solution Study confirmed that IRP continued to meet the identified need (id. at 28). The Attorney General reviewed the case record with respect to NTAs and the Hybrid Alternative, and argues that the Hybrid Alternative involves a substantial amount of speculation, risk, and cost uncertainty (AG Brief at 15-16). The Attorney General concludes that IRP is superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the identified need (id. at 17).

I. Analysis and Findings

The record in this case illustrates how quickly facts that are central to NTA analysis can change, such as new generator additions and withdrawals, existing unit retirements, developments in public policies relating to EE, DR, and DG (particularly renewables), and various other market and economic conditions. Over the course of this proceeding, the Company evaluated the most promising means of avoiding, delaying, or modifying the Project to assess whether a less expensive means of satisfying the need could be identified. The Company's analyses confirmed that NTAs such EE, DR and DG and new central generation facilities under contract in the FCM, either alone or in combination, would not fully resolve the thermal violations that already exist under the contingencies in the eastern region of southern New England that ISO-NE evaluated.

In this case, for the first time in the Siting Board's history, a transmission project applicant offered a hybrid solution that includes both NTAs and a scaled-back transmission project that theoretically could meet reliability needs. The Company gave ample consideration to various hybrid solutions and determined that, while feasible, they were neither cost-effective nor particularly robust in the face of various uncertainties such as additional generator retirements or more rapid growth in peak load requirements. The record demonstrates that a combination of an upgraded 115 kV system in Massachusetts (in lieu of the proposed 345 kV IRP line), plus additional NTAs (such as EE, DG and DR), would not provide the equivalent reliability benefits of the Project, would be more costly, and would not offer any other significant identified advantages.

This proceeding occurred during a time of significant change in the electric power sector, with an unprecedented wave of generation retirement announcements, a surge in distributed power generation such as wind and photovoltaics, and some signs of market interest in new, more efficient and flexible central station projects such as Footprint Power. Given the long lead time to assess system needs, develop a transmission proposal, gain siting and permitting approval and, finally, commence and complete construction, compared to the relatively short time span required for a generator to exit the market, the importance of robust, long-term solutions such as IRP is increasingly apparent.

The NTA studies in this case also point out two important methodological realities that warrant continuing attention by the Siting Board, ISO-NE, and stakeholders: (1) at present, there are limitations on the ability of DR to provide a long-term solution to system capacity needs; and (2) as currently viewed in planning studies, the intermittent production profile of DG resources (such as photovoltaic power) severely limits the ability of this rapidly growing power source to defer or avoid traditional transmission projects. The role of DR in New England in fulfilling its potential of providing sustained long-term capacity benefits, and thereby deferring or avoiding long lead-time, capital-intensive transmission upgrades or other types of system capacity enhancements, is in need of continuing review by the Siting Board and others. With regard to DG resources, we note that ISO-NE has recently convened a working group to address how system planning can better evaluate the capacity benefits provided by DG facilities, despite their intermittent profile (absent storage technologies).

Given the extent and urgency of additional resources needed to ensure reliability, and the limitations in meeting such needs with the NTAs evaluated, the proposed Project would provide an effective and timely solution. In view of the above considerations, the Board finds that the Company's Project is the best approach among the numerous project alternatives considered in providing a robust solution to meeting reliability requirements at the least cost.

V. ROUTE ALTERNATIVES

A. Route Selection

1. Standard of Review

G. L. c. 164, § 69J requires a petition to construct to include a description of alternatives to the facility, including "other site locations." Thus, the Siting Board requires an applicant to demonstrate that it has considered a reasonable range of practical siting alternatives and that its proposed facilities are sited in locations that minimize cost and environmental impacts. To do so, an applicant must meet a two-pronged test. First, the applicant must establish that it developed and applied a reasonable set of criteria for identifying and evaluating alternative routes in a manner that ensures that it has not overlooked or eliminated any routes that, on balance, are clearly superior to the proposed route. Second, the applicant must establish that it identified at least two noticed sites or routes with some measure of geographic diversity.

Hampden County at 35; Lower SEMA at 53-54; Massachusetts Municipal Wholesale Electric Company, 12 DOMSB 18, at 92 (2001).

2. The Company's Route Selection Process

The Company began the route selection process by establishing a route selection study area that would encompass reasonable routes for a 345 kV transmission line between the Millbury No. 3 Switching Station and the West Farnum Substation (Exh. NEP-1, at 4-1). The Company stated that these two endpoints were selected because the most recent ISO-NE study indicated that the most urgent reliability need was the addition of a 345 kV line between those two stations (Exh. NEP-1, app. 3-3, at 37). The Company's study area is bounded by the Millbury No. 3 Switching Station to the north, the West Farnum Substation to the south, Interstate Route 395 to the west and Interstate Route 495 to the east (Exh. NEP-1, at 4-1). The Company stated that it did not consider route locations beyond these limits because it anticipated that any resulting routes would be significantly longer and result in greater environmental impacts and higher costs (id.).

The Company identified six potential routes within the study area, all of which employed existing utility or transportation corridors in order to avoid the costly and lengthy process of acquiring land or easements (Exh. NEP-1, at 4-3, 4-13 to 4-29). The Company stated that it used seven general criteria to identify the potential routes: (1) maximize the use of existing linear corridors; (2) minimize the need to acquire land or easements; (3) minimize impacts on densely developed areas; (4) minimize impacts to environmental resource areas; (5) minimize potential construction constraints (e.g., road crossings, work on ROWs owned by another utility); (6) minimize access constraints to facilitate maintenance work; and (7) minimize costs (id. at 4-3, 4-4, 4-30).

As shown in Table 14 below, three of the potential routes used existing overhead electric transmission corridors and three routes combined segments of existing overhead electric transmission corridors with segments of either railroad corridor, highway corridor, or gas pipeline corridor.

Table 14. Description of Six Route Alternatives

Alternative	ROW Description and Existing Uses	Miles (Total/MA only)	Control of ROW
Route 1	Follows active railroad line most of route and connects to NEP ROW near MA/RI border	21/16.2	Providence/Worcester Railway Co. and NEP ROW
Route 2	Median strip of divided limited access State Route146; connects to NEP ROW near MA/RI border	22/15.4	MassHighway for Route 146; NEP ROW
Route 3 **Route 3A**	Majority of MA route follows active Tennessee Gas Pipeline ROW and connect to NEP ROW near MA/RI border	23.1/14.3 22/17.3	Tennessee Gas Pipeline to NEP ROW
Route 4	Follows existing NEP ROW southeast from Millbury. ROW contains two active 115 kV lines and empty towers used for a former 69 kV line	20.2/15.4	NEP
Route 5	Follows existing NEP ROW east to West Medway, then southeast to Wrentham and finally southwest to West Farnum	37.1/30.4	NEP owns majority of ROW, but requires agreement with NSTAR for use of 2.5 miles of ROW
Route 6	Combines initial portion of Rt. 5 to W. Medway with use of 14.2 miles of NSTAR ROW from West Medway to Uxbridge where it connects to NEP ROW	35.2/30.4	NEP controls 16.2 miles of the ROW in MA while NSTAR controls 14.2 miles

Sources: Exh. NEP-1, at 4-16 to 4-30; RR-EFSB-30.

Using the criteria noted above, the Company deemed Routes 1, 2, and 3 as unsuitable due to land acquisition issues (with the associated costs and potential delays) and other concerns regarding densely developed areas, construction constraints, and system operations (Exh. NEP-1, at 4-13). The Company then focused its review on the remaining Routes (Routes 4, 5, and 6) in Table 14, above (id. at 4-16 to 4-30).

The next step in the Company's route selection process was to evaluate, score and rank the three remaining candidate routes to determine a preferred route ("Primary Route") and a geographically distinct Noticed Alternative Route. The Company compared the three candidate routes with respect to environmental impacts, reliability benefits, and costs. The Company evaluated environmental impacts relating to the following considerations: residential land use; commercial/industrial land use; open space; road crossings; historical/archeological sites; wetlands; rare species; water crossings; outstanding resource waters; areas of critical environmental concern; tree removal; and vernal pools (Exh. NEP-1, at 4-33). The Company contends that for the Massachusetts portion of the three routes, Route 4 is preferable to Routes 5 and 6 for all environmental impact categories (id. at 4-35 to 4-36). The Company further contends that, Route 4 also has less environmental impact than Routes 5 and 6 considering both the Massachusetts and Rhode Island line segments of the respective routes (id. at 4-32 to 4-37).[35] The Company asserts that the residential environmental impacts for Route 4 are largely temporary and would occur only during construction rather than being permanent impacts related to ongoing operation of the line (Exh. EFSB-RS-1).

The Company estimated the costs to build the Massachusetts portions of each of the three routes and noted that the cost of Route 4 ($69.5 million) would be significantly less than the projected costs of Routes 5 ($198.1 million) or Route 6 ($181.2 million) (Exh. NEP-1, at 4-40). With respect to reliability, the Company stated that all three routes would employ the same basic overhead transmission technology, would require the same substation improvements, would meet relevant reliability standards, and would "generally provide comparable system reliability" (Exh. NEP-1, at 4-39, 4-40).

As the Primary Route, the Company selected Route 4, which had the least environmental impact and the lowest projected construction cost while meeting the reliability need (id.). In order to select the Noticed Alternative Route, the Company relied upon a comparison of the environmental impacts and geographic diversity of Routes 5 and 6 (Exh. NEP-1, at 4-41). The Company observed that Routes 5 and 6 have approximately the same overall weighted scores on environmental impact when the Massachusetts and Rhode Island portions of the Project are combined (id. at 4-41). However, the Company noted that on two criteria that it considers key to facilitating the permitting of overhead transmission lines – residential land use and tree removal – Route 5 is superior, as it avoids a significant portion of the total residential impacts and the tree removal impacts (id.). Therefore, the Company selected Route 5 as its Noticed Alternative Route.

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35 The Company made this determination using a weighting methodology that reflects the Company's judgment as to the relative importance of the individual environmental impacts.

In past decisions, the Siting Board has found various criteria to be appropriate for identifying and evaluating route options for transmission lines and related facilities. These criteria include natural resource issues, land use issues, community impact issues, cost and reliability. Hampden County at 38; Lower SEMA at 55; New England Power Company, 4 DOMSB 109, at 167 (1995). The Siting Board has also found the specific design of scoring and weighting methods for chosen criteria to be an important part of an appropriate site selection process. Boston Edison Company, 19 DOMSC 1, at 38-42 (1989).

Here, the Company developed numerous screening criteria, which it used to evaluate the routing options. These criteria generally encompass the types of criteria that the Siting Board previously has found to be acceptable. The Company also developed a quantitative system for ranking routes based on compilation of weighted scores across all criteria. This is a type of evaluation approach the Siting Board previously has found to be acceptable.

The Siting Board finds that the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternative routes in a manner that ensures that it has not overlooked or eliminated any routes that are clearly superior to the proposed Project.

3. Geographic Diversity

The Company described its Noticed Alternative Route as being 100 percent geographically diverse from the Primary Route, while Route 6 shares approximately 33 percent of the Primary Route (Exh. NEP-1, at 4-41). Although the Company selected a Noticed Alternative Route that offers 100 percent diversity from the Primary Route, the Company stressed its understanding that Siting Board precedent does not require that a noticed alternative route be 100 percent diverse from the primary route. Rather, it contends that Siting Board precedent merely suggests that there be "some measure of geographic diversity" between the primary and noticed alternative routes (Exh. EFSB-RS-6). The Company stated that it selected Route 5 as the Noticed Alternative based on its reduced environmental impacts on residential land use and reduced acreage of tree removal rather than its 100 percent route diversity (id.). The Siting Board finds that the Company's Noticed Alternative Route for the Project reflects some measure of geographic diversity.

4. Conclusions on Route Selection

The Company has: (1) developed and applied a reasonable set of criteria for identifying and evaluating alternative routes in a manner that ensures that it has not overlooked or eliminated any routes that are clearly superior to the proposed project; and (2) identified a range of practical transmission line routes with some measure of geographic diversity. Therefore, the Siting Board finds that the Company has demonstrated that it examined a reasonable range of practical siting alternatives.

The Siting Board notes that the Massachusetts portion of the Company's Noticed Alternative Route is approximately twice the length of the Project's Primary Route and is estimated to cost almost two and a half times more to construct than the Project using the Primary Route (Exh. NEP-1 at 5-72). Further, the Noticed Alternative Route crosses Areas of Critical Environmental Concern ("ACECs") in Upton, uses higher poles, and requires significantly more tree clearing than the Primary Route. Given that the designation of a Noticed Alternative Route requires that the Company expend significant funds,[36] and has the potential to raise concern among abutters and others in the impacted communities,[37] the Siting Board intends to give further consideration in the future as to whether its present requirement of a noticed alternative route is warranted in all cases.

B. Analysis of the Primary and Alternative Route

1. Standard of Review

In implementing its statutory mandate under G.L. c. 164, § 69H, the Siting Board requires a petitioner to show that its proposed facility is sited at a location that minimizes costs

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36 The Company estimates that it had spent $750,000 on the development of the Noticed Alternative Route through November 2012 to identify and inventory environmental impacts, develop preliminary engineering designs, analyze permit requirements, develop and distribute community outreach materials, provide legal notice to abutters and hold a public hearing in Milford (in addition to the hearing in Uxbridge) (RR-EFSB-33). This estimate excludes any Company's expenses during discovery and evidentiary hearings (id.).

37 The Siting Board has not selected a noticed alternative route instead of a company's preferred route in the past 20 years.

and environmental impacts while ensuring a reliable energy supply. To determine whether such a showing is made, the Siting Board requires a petitioner to demonstrate that the proposed route for the facility is superior to the alternative route on the basis of balancing cost, environmental impact, and reliability of supply. Hampden County at 39; Lower SEMA at 57; Russell Biomass LLC, 17 DOMSB 1, at 34 (2009) ("Russell").

Accordingly, in the sections below, the Siting Board examines the environmental impacts, reliability and cost of the proposed facilities along the Primary and Alternative Routes to determine: (1) whether environmental impacts would be minimized; and (2) whether an appropriate balance would be achieved among conflicting environmental impacts as well as among environmental impacts, cost and reliability. In this examination, the Siting Board compares the Primary Route and the Alternative Route to determine which is superior with respect to providing a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

2. Introduction

Using the Primary Route for the Project, NEP would install a 345 kV overhead transmission line along existing ROWs approximately 15.4 miles from the Company's Millbury No. 3 Switching Station in Millbury, Massachusetts, through the towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville to the Rhode Island border (Exh. NEP-1, at 5-2 to 5-3). The Primary Route would follow a ROW that is generally 250 feet wide and is presently occupied by two 115 kV transmission lines and steel lattice transmission towers (without wires) that remain from two 69 kV transmission lines that were taken out of service (id.).

Using the Alternative Route for the Project, NEP would install a 345 kV overhead transmission line from the Millbury No. 3 Switching Station along three existing ROWs for approximately 29.2 miles in Massachusetts through Millbury, Sutton, Grafton, Upton, Milford, Medway, Bellingham, Franklin and Wrentham to the Rhode Island border (id. at 5-3 to 5-4).[38] Presently, several transmission lines of different voltages are in the three ROWs, which vary in

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[38] Both routes continue in Rhode Island to the West Farnum Substation: the Primary Route for another 4.8 miles and the Alternative Route for 7.9 miles (Exh. NEP-1, at 5-2 to 5-3).

width (id.). With use of either the Primary or Alternative Route, the Company would make additions to existing 345 kV and 115 kV facilities in Massachusetts and improvements to the Millbury No. 3 Switching Station (id. at 5-2 to 5-4). The two routes are shown in Figures 4 and 5, below.

Figure 4. Map of the Primary Route

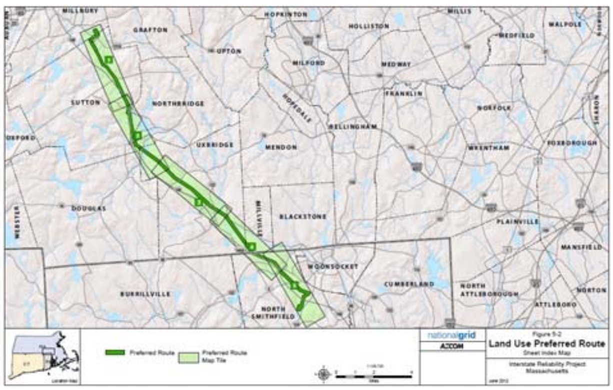

Figure 5: Map of the Alternative Route

Sources: Exh. NEP-1, figures 5-2, 5-9.

3. Environmental Impacts

a. Land Use and Historic Resources Impacts

In general, both the Primary and Alternative Routes are located in lightly populated rural and suburban areas. On average, the Primary Route has approximately ten residences and/or other sensitive receptors per mile that fall within 300 feet of the edges of the ROW; the Alternative Route has approximately twelve per mile. The most prevalent land use along both the Primary Route and the Alternative Route is open land, including ROWs previously cleared and maintained by the Company for use as utility corridors (Exh. NEP-1, at 5-17 to 5-18). Beyond the edges of the cleared ROWs of both routes are significant forested areas that generally provide 300 feet or more of buffer (id.). Other land use classifications common to portions of each route include residential, commercial/industrial, agricultural, non-forested wetlands, water bodies, transportation, and other (such as cemetery, urban, public/institutional) (id.). As shown for each route in Table 15 below, the Company reported that sensitive receptors within 300 feet of the ROWs include residences, businesses, hospitals, schools (and school athletic fields), day care centers, places of worship, and farms (Exh. EFSB-LU-1, Att. (a), Att. (b)).

Table 15. Comparison of Residence Counts and Other Sensitive Receptors Within 300 Feet of ROW Edge

	Primary Route (15.4 miles)			Alternative Route (29.2 miles)		
Distance from ROW Edge	Residences	Other	Total	Residences	Other	Total
0- 25′ of ROW	9	1	10	10	3	13
25-50′ of ROW	10	0	10	26	7	33
50-100′ of ROW	20	0	20	47	6	53
100-200′ of ROW	41	2	43	109	11	120
200-300′ of ROW	58	5	63	127	8	135
Total	**138**	**8**	**146**	**319**	**35**	**354**

Sources: Exhs. EFSB-LU-1, Att.(a), Att.(b); EFSB-EMF-6

With regard to archeological resources, NEP conducted an analysis of both routes and determined that a Paleo-Indian pre-contact site is located within the Primary Route ROW. Given this finding, the Company developed an Archaeological Site Avoidance and Protection Plan ("ASAPP"), approved by the U.S. Army Corps of Engineers ("ACOE"), the Massachusetts State Historic Preservation Officer ("SHPO"), and Tribal Officers (Exh. EFSB-LU-14(S)). Based on NEP's ASAPP and associated Project modifications, the Company reported that the ACOE determined that the Project would not adversely affect the Paleo-Indian site identified within the Primary Route ROW (id.). The Company stated that it had also agreed to take avoidance and protective measures to protect certain items along the ROW identified as potentially significant by the tribal officers and the tribes they represent (id.).

Historic districts and other significant historic resources are nearby on both the Primary and Alternative Routes. The Company stated that, in conjunction with the Massachusetts Historical Commission ("MHC"), it would develop a strategy to minimize impacts to any historic districts currently listed, or with the potential for listing, on the Massachusetts or National Historic Registers (id.; Exh. NEP-1, at 5-31).

Table 16. Archeological and Historic Resource Impacts of the Primary and Alternative Routes

	Primary Route	**Alternative Route**	**Millbury No. 3 Switching Station** **(Same Upgrade for Primary and Alternative Route)**
Archeological Resources	Nine sites of potential archeological significance; one Paleo-Indian site within the ROW; seven pre-contact Native American sites near ROW.	No archeological resources identified.	No archeological resources identified.
Historic-MHC-Architectural Resources	Three historic districts now listed on the MHC or National Historic Register. One remnant 19th century foundation No adverse impacts anticipated.	Two listed historic districts near ROW. MHC shows 13 areas & 175 individual properties not yet evaluated that are near alternative ROW and have potential for listing on Massachusetts or National Historic Register.	No historic resources identified.

Sources: Exhs. NEP-1, at 5-29 to 5-34; EFSB-LU-1, Att. (a), Att. (b); EFSB-LU-6; EFSB-LU-8; EFSB-LU-13; EFSB-LU-14.

The Company explained that installation of new facilities would result in many more acres of tree removal/pruning along the Alternative Route than the Primary Route (Exh. NEP-1, at 5-23, 5-34 to 5-37). NEP anticipated that in most cases along both routes, remaining forest area would be sufficient to maintain present wildlife habitat (id.). The Company expected an expansion of habitat area of herbaceous plants, shrubs, and short trees where larger trees would be removed. (id.). Regardless of the transmission route selected, NEP expected to remove 0.6 acres of vegetation in previously disturbed areas at the Millbury No. 3 Switching Station to accommodate proposed storm water improvements (id. at 5-36).

Table 17. Vegetation and Species Impacts of the Primary and Alternative Routes

	Primary Route	**Alternative Route**	**Millbury No. 3 Switching Station** (Same Upgrade for Primary and Alternative Route)
Removal/Tree Pruning (Impacts in Acres)			
Tree Removal in Forested Uplands - in ROW Off ROW	9.0 2.8	87.8 n/a	n/a
Tree Removal in Forested Wetlands	1.3	7.4	n/a
Tree pruning	9.6	16.6	n/a
Total	22.7	111.8	0.6
Additional Vegetation Control (Herbicides)			
Herbicides	Herbicides currently used for vegetation maintenance. No additional herbicides necessary beyond those currently applied.	Need to increase herbicide use above current levels for vegetation management following tree clearing.	None
Rare Species and Impacts on Rare Species Habitat			
Description and count: listed rare/endangered species	Four state-listed wildlife species and two state-listed plant species at a total of three locations. No federally listed species present.	Five state-listed wildlife species, no state-listed plant species at a total of six locations. No federally listed species.	No state-listed wildlife or plant-species. No federally listed rare or endangered species.
Rare Species Habitat Impact (acres of trees removed)	1.3	4.1	None

Source: Exh. NEP-1, at 5-34 to 5-37, 5-45 to 5-49.

The Company stated that it would put in place mitigation plans under the Natural Heritage and Endangered Species Program ("NHESP")[39] to reduce impacts to rare species and habitats along either route (Exh. NEP-1, at 5-45 to 5-49).[40] NEP reported that NHESP had determined that the Project would result in a "take" of a state-listed rare species (the wood turtle) in Uxbridge. NEP further reported that NHESP permits a project resulting in a "take" of a state-listed species only if the Project meets the standards for issuance of a MESA Conservation and

[39] NHESP regulates state-listed endangered, threatened, and special concern plant and wildlife species pursuant to the Massachusetts Endangered Species Act ("MESA") (Exh. NEP-1, at 5-46).

[40] Specifically, the Company would consult with NHESP to determine whether protection of rare species habitat might require time-of-year restrictions for certain aspects of construction (Exh. NEP-1, at 5-48, 5-49).

Management Permit ("CMP") (Exh. EFSB-RS-1). The Company applied for a CMP in response to the NHESP's "take" determination (Exh. EFSB-RS-1(S3)). NHESP issued a CMP to the Company on May 30, 2013 (see Exh. EFSB-RS-1(S3)(Att. 1)).

The Company stated that Smithfield, Rhode Island, would be the principal staging and laydown site for the Massachusetts and Rhode Island portions of the Project; supplemental staging and laydown would occur at One Lackey Dam Road in Douglas, Massachusetts. Supplemental materials storage for work at the Millbury No. 3 Switching Station would occur at 15 Harback Road in Sutton, Massachusetts (Exhs. EFSB-LU-4(S2); EFSB-LU-4(S3)).[41] The Company described the One Lackey Dam Road property as industrially zoned, located inside a fenced sand and gravel pit, and approximately 2,385 feet from the nearest residence (Exh. EFSB-LU-4(S2)). The Company indicated that the 15 Harback Road property was paved and located within the secure, industrially zoned facilities of a manufacturer of prefabricated steel buildings (Exh. EFSB-LU-4(S3)). NEP stated that Project traffic would, on average, access the 15 Harback Road storage area two to three times per week (id.).[42]

While the types of land use impacts are similar for both routes, the length of the Alternative Route is significantly greater, resulting in more extensive land use impacts. As summarized in Tables 16 and 17 above, the land use impacts of the Project, including historic and archeological resources, tree clearing, tree pruning, vegetation removal and control, rare species, and rare species habitat impacts are greater along the Alternative Route than the Primary Route. Accordingly, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to land use and historic resource impacts.

The Siting Board notes the Company will work with the ASAPP and as otherwise directed by the Massachusetts SHPO to avoid and protect historic resources; further, the

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41 NEP explained that, in keeping with Company practice, its contractor would be responsible for final siting of Project staging and laydown in Massachusetts (Exh. EFSB-LU-4(S)).

42 The Company stated that entry to the Harback Road storage area would be via Route 146 and Harback Road (Exh. EFSB-LU-4(S3)). The Company indicated that the access way to the storage area accommodates large trucks and trailers (id.). The Company also reported that the closest residences are 300 feet and 350 feet away from the storage area (id.).

Company will avoid and protect historic resources as directed by the MHC. The Siting Board also notes that the Company (1) has consulted with the NHESP with regard to establishing a CMP and time-of-year restrictions for rare species habitat protection, as necessary, with specific attention to the wood turtle and its habitat; (2) NHESP has approved the Company's CMP; and (3) the Company has provided a copy of its NHESP-approved CMP to the Siting Board.

The Siting Board further notes recent modification of the Company's storage, staging, and laydown arrangements to include storage, staging, and laydown areas -- at One Lackey Dam Road in Douglas, Massachusetts and at 15 Harback Road in Sutton, Massachusetts, in addition to the principal area planned for Smithfield, Rhode Island. Both Massachusetts staging areas are located at sites currently used for industrial purposes consistent with proposed Project activities. The Siting Board reminds the Company that it must notify the Siting Board of any further modifications or additions to NEP's storage, staging, and laydown for the Project. Given implementation of the mitigation measures and conditions, the Siting Board finds impacts on land use, historic resources, and archeological resources along the Primary Route would be minimized.

b. Wetland and Water Resource Impacts

The Company presented information, summarized in Table 18 below, regarding potential impacts to wetlands and water resources along the Primary and Alternative Routes.

Table 18. Impacts to Water Resources/Wetlands/Vernal Pools

	Primary Route	Alternative Route	Millbury No. 3
Affected Wetlands (Acres)	Temporary: 12.65	Temporary: 57-63	None in construction area
	Permanent: 9.35	Permanent: 42-47	
	Total: 22	Total: 99 - 110	
Vernal Pools	One Certified Vernal Pool ("CVP"); 16 Potential Vernal Pools ("PVP")	Two CVPs; eleven PVPs	None in construction area
Waterbody Crossings	Eleven perennial streams; three rivers; one pond	21 perennial streams; two rivers; one pond	None in construction area

Source: Exh. NEP-1, at 5-38 to 5-45.

NEP has a current Vegetation Management Plan ("VMP") and a Yearly Operational Plan ("YOP") approved by the Department of Agricultural Resources ("DAR") under DAR's ROW regulations, 333 CMR 11.04(4)(c)(2) (Exh. EFSB-LU-5). The intent of these regulations and plans is to prevent contamination of water resources and wetlands during vegetation maintenance activities (id.).

NEP described erosion controls and general best management practices ("BMPs") it would implement to minimize impacts to wetland and watercourse resources (Exh. NEP-1, at 5-44 to 5-55). The Company proposed to offset any permanent, temporary, and secondary wetland impacts (id.). Specifically, the Company indicated that it would cooperate with Massachusetts Department of Environmental Protection ("MassDEP") to meet that agency's wetland mitigation requirements; [43] with MassDEP and the ACOE to satisfy state and federal wetland impact mitigation requirements during the Section 401 and 404 permitting process; and with local Conservation Commissions to meet wetland and water resources mitigation requirements at the municipal level (id.).[44] NEP stated it would need to set aside lands to comply with ACOE Section 404 Permit requirements for impact mitigation, and that the Company owns sufficient land for the Primary Route to meet the set-aside requirement (Exhs. EFSB-LU-3; EFSB-LU-10). The Company indicated it may need to acquire additional land to meet the Section 404 set aside for the Alternative Route (Exh. EFSB-LU-3).

As indicated in Table 18 above, use of the Alternative Route would result in greater wetlands impacts and more extensive water-related impacts, including waterbody crossings and vernal pool impacts. Accordingly, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to wetland and water resources.

The Company is proposing mitigation, including implementation of erosion controls and general BMPs, and to offset any permanent, temporary, and secondary wetland impacts as required by local, state, and federal agencies including local Conservation Commissions, MassDEP, and the ACOE. In addition, the Company has a VMP to address herbicide use.

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[43] M.G.L. c. 131, § 40 and 310 CMR 10.00 address MassDEP's wetland mitigation requirements. The Company has entered into a Memorandum of Agreement with MassDEP, consistent with G.L. c. 21A, § 18(d) seeking Fast Track review and approval of IRP in Massachusetts (Exh. NEP-1, at 5-44 to 5-45).

[44] The Company has received Orders of Conditions from the Conservation Commissions of the Massachusetts communities along the Project route where impacts to wetlands might potentially occur, i.e., Millbury, Sutton, Northbridge, Millville, and Uxbridge (Exhs. EFSB-W-4; EFSB-RS-1(S)).

Therefore, the Siting Board directs the Company to ensure that under its continuing vegetative management program, any application of herbicides is consistent with utility right-of-way Integrated Vegetation Management Practices and applicable rules and regulations of the Commonwealth. Given the mitigation and condition, the Siting Board finds that impacts to wetlands and water resources along the Primary Route would be minimized.

c. Noise Impacts

The Company's noise analysis is based on assessing noise impacts (primarily from construction within the ROW) to sensitive receptors within 50 feet of the ROW edge (Exhs. EFSB-NO-6; EFSB-NO-6(a) (Att.)).[45] NEP reported that noise levels of construction equipment associated with transmission line installation along either route would range from approximately 60 A-weighted decibels ("dBA") (for pickup trucks) to 90 dBA (for dump trucks and heavy duty mowers) measured at 50 feet from the noise source (Exh. NEP-1, at 5-57). The Company also indicated that helicopters might be used for removing towers, setting new structures, or line stringing in areas where access was otherwise difficult (id.). NEP anticipated short-term noise associated with helicopter use would range from approximately 83 to 91 dBA.

With regard to noise impacts, construction activities, sequencing, and associated noise levels would be similar for either the Primary or Alternative Route. However, as noted above, the route length and number of sensitive receptors along the Alternative Route are significantly greater than they are along the Primary Route; consequently, noise impacts associated with the Project along the Alternative Route would be greater than along the Primary Route. Accordingly, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to noise impacts.

The Company would not install any new noise-generating equipment at the Millbury No. 3 Switching Station, where NEP has proposed Project-related improvements (Exh. EFSB-NO-20). In addition, the NEP stated that the Switching Station is more than 1,000

45 See Table 12 above, for a breakdown of receptor locations for the Primary and Alternative Routes (Exh. NEP-1, at 5-19).

feet from the nearest residence and the Company did not anticipate noise impacts of construction at this location (id.).

To mitigate noise impacts of construction, the Company stated it would: require well-maintained equipment with functioning mufflers; prohibit extended idling of construction equipment; operate stationary noise generating equipment, such as whole tree chippers and compressors, away from nearby residences as it is able to do so; confine the operation of noise generating equipment to daylight hours to the extent practicable; comply with the requirements of local noise ordinances, if any, and seek variances only when absolutely necessary; and, coordinate with ROW abutters when unusual levels of noise might be generated adjacent to their residences for extended periods, such as in the case of a rock-drilled foundation excavation of unusually long duration (Exh. EFSB-NO-1). The Company proposed: (1) a Monday through Friday construction day beginning at 7:00 a.m. and continuing for ten-to-twelve hours, depending on season and daylight; and (2) Saturday construction beginning at 7:00 a.m. but ending no later than 5:00 p.m. regardless of the season (Exhs. EFSB-NO-1; EFSB-NO-13). The Company anticipated construction noise of only limited duration along the ROW at any given location (Exhs. EFSB-NO-1; EFSB-NO-14; EFSB-NO-18).[46]

Transmission line construction is noisy by nature, however; accordingly, to ensure mitigation of Project noise impacts to the extent possible, the Siting Board directs the Company to conduct weekday construction from 7:00 a.m. to 6:00 p.m., to conduct no work on Sundays and holidays, and to begin Saturday work at 9:00 a.m. rather than at 7:00 a.m. as the Company has proposed, and to end work on Saturday no later than at 5:00 p.m. Should the Company find that construction performed outside these hours or on holidays or Sundays is necessary, the Company shall seek written permission from the relevant municipal authority prior to the

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46 The Company estimated that at a given location, vegetation removal would require one to two weeks; installation of erosion and sediment controls and access road improvements and maintenance would require one day to one week; removal and disposal of existing transmission line components would require two days; installation of foundations and structures would require two days to two weeks usually, but as many as three weeks or more depending on the depth and hardness of rock encountered; the actual work of conductor and shield wire installation would require two to three hours; and ROW restoration would require one day (Exhs. NEP-1, at 5-57; EFSB-NO-7).

commencement of such work, and provide the Siting Board with a copy of such permission. If the Company and municipal officials are not able to agree on whether Sunday, holiday or extended weekday or weekend construction should occur, the Company may file a written request for prior authorization from the Siting Board, provided that it also notifies the relevant municipal authorities in writing of such request.

Furthermore, the Siting Board directs the Company, in consultation with the towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville to develop a combined or, separately for each town, a community outreach plan for construction of the Project. The outreach plan(s) should, at a minimum, set forth procedures for providing prior notification to affected residents of: (1) the scheduled start, duration, and hours of construction; (2) any construction the Company intends to conduct that, due to unusual circumstances, must take place outside the hours detailed above; (3) the availability of web-based Project information; and (4) complaint and response procedures including the Company's contact information.

The Siting Board finds that, with the implementation of the Company's proposed mitigation, in addition to implementation of conditions limiting construction hours and development of a community outreach plan, noise impacts resulting from the construction of the Project along the Primary Route would be minimized.

d. Visual Impacts

The Company presented information, summarized in Table 19, below, regarding potential visual impacts along the Primary and Alternative Routes.

Table 19. Visual Impacts (Changes in Pole Heights and Residential Views)

Current View of Existing Facilities for Residences ≤ 300’ from ROW			
	Primary Route	Alternative Route	Millbury No. 3 **(Same Upgrade for Primary and Alternative Route)**
No view Partially obstructed Unobstructed	55 93 4	90 220 37	No change
Change in View, Post-Construction for Residences ≤ 300’ from ROW			
	Primary Route	Alternative Route	Millbury No. 3
Residences ≤ 300’ from ROW	152	347	No change
no change	134	253	
minor change	10	44	
moderate change	3	31	
major change	5	19	
residences w/ some change	18	94	
% residences w/ some change	12 percent	27 percent	
Pole Heights			
	Primary Route	Alternative Route	Millbury No. 3
New structure heights	Avg. height existing: 75 ft. Typical new: 85-90 ft. Height range: 60-140 ft.	Comparable pole heights but a longer route	The proposed structures within the Millbury Switching Station will not exceed the height of existing structures

Sources: Exhs. NEP-1, at 5-2 to 5-5, 5-54; EFSB-V-9; EFSB-V-9(a) Att.; EFSB-V-10(a)Att.; EFSB-LU-6.

NEP stated that the construction of Line 366 along either the Primary Route or the Alternative Route would be on steel H-frame structures, with construction on steel monopole structures at a limited number of locations (Exh. NEP-1, at 5-3 to 5-5; Tr. 1, at 161-162). According to the Company, typical structures would be approximately 85 feet to 90 feet tall; existing structures along both routes are 75 feet tall on average (Exh. NEP-1, at 5-3 to 5-5). The Company anticipated that the height of structures for the Project in Massachusetts along the Primary or the Alternative Route would range from 60 feet to 140 feet (id.).

The Company indicated that along either the Primary or Alternative Route, it would use the shortest support structures feasible for the Project given the voltage of the transmission line and the safety clearances required (Exh. NEP-1, at 5-3 to 5-5). As shown in Table 19, relative to the Primary Route, the Alternative Route would result in more significant visual impacts of the Project for a greater number of nearby residents. In addition, the longer length of the Alternative Route would result in a greater number of new structures than on the Primary Route

(RR-EFSB-9). Accordingly, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to visual impacts.

To minimize visual impacts of the Project along the Primary Route, the Company stated it would install new structures near existing 115 kV transmission line equipment or at the previous location of the dismantled 69 kV transmission line equipment (Exh. NEP-1, at 5-55). The Company also submitted a Visual Mitigation Plan to address visual impacts to property owners (Exhs. EFSB-V-10(S); EFSB-V-10(a)(S) Att.). Under provisions of the Visual Mitigation Plan, the Company has proposed a protocol for contacting all owners of properties within 300 feet of the ROW where construction of the Project might negatively affect the view (Exh. EFSB-V-10(a) Att.). As part of the Visual Mitigation Plan, the Company would provide property owners with access to landscaping services (including fences or walls) through their own contractors or contractors engaged by the Company (id.). The Visual Mitigation Plan would establish a budget and specific requirements for the Company in connection with its obligations to affected property owners along the Primary Route (id.).

In several recent transmission line cases the Siting Board has directed the petitioners to implement an off-site screening program consisting of vegetative plantings and/or other screening. Here, the Company has proactively developed its own off-site screening program, referred to as the Visual Mitigation Plan described above. The Siting Board commends the Company for addressing the need to mitigate the visual impacts associated with the construction of the proposed transmission line along the Primary Route. However, while the intent and concept of the Visual Mitigation Plan generally address the issue of visual mitigation, to be consistent with other recently approved projects, the Siting Board directs the Company to incorporate the following requirements into its Visual Mitigation Plan:

(a) upon completion of construction, notify in writing by first class mail with delivery confirmation all owners of property located on or abutting the ROW of the option to request that the Company provide off-site screening. The Company would follow up with a phone call to non-responding property owners for whom a phone number is accessible. The off-site screening may include, but is not limited to, shrubs, trees, window awnings and fences, provided that the Company's operating and maintenance requirements for its ROW facilities are met;

(b) provide property owners with a selection of generic renderings of possible mitigation approaches. Such renderings shall be for guidance purposes only, and shall not limit a property owner's ability to request different mitigation;

(c) meet with each property owner who requests mitigation to determine the type of mitigation package the Company would provide, provided that the Company has received a response from the property owner within three months of receipt of the Company's written notification;

(d) honor all property owners' requests for reasonable and feasible mitigation that are submitted within six months of a meeting with the Company and/or its consultants;

(e) issue a warranty to property owners to ensure that all plantings are established and replaced if needed at the end of one year from the date of planting, provided that the property owners reasonably maintain the plantings;

(f) submit to the Siting Board for its approval, at least three months before the conclusion of construction, a draft of the notification letter to property owners prior to mailing; and

(g) submit a compliance filing within 18 months of completion of construction detailing: (i) a list of all properties that were notified of the available off-site landscaping; (ii) the number of property owners that responded to the offer for off-site mitigation; (iii) a list of any property owners whose requests were not honored, and the rationale therefor; (iv) a general description of the types of off-site landscaping provided; and (v) the average cost of landscaping per property.

The Siting Board finds that, with the Company's proposed placement of new structures to minimize visual impacts, and with the condition regarding the implementation of the off-site screening program described above, visual impacts from construction of the Project along the Primary Route would be minimized.

e. Magnetic Field Impacts

The Company modeled pre-Project and post-Project magnetic field levels in milligauss (“mG”) for the Primary Route and the Alternative Route under existing and proposed configurations for both annual average loading (“AAL”) and annual peak loading (“APL”) (Exhs. NEP-1, at 5-62 to 5-71; NEP-1, at 5-1 to 5-63).[47] Table 20 below, shows the AAL magnetic field level comparison for existing conditions and modeled magnetic field levels for 2020, post-Project.

For the Primary Route, there are approximately 19 residences within 50 feet of the edges of the ROW, and 20 residences within 50-100 feet of the edges of the ROW (see Table 15 above; Exh. EFSB-EMF-6). For the Alternative Route there are approximately 36 residences within 50 feet of the edges of the ROW, and 47 residences within 50-100 feet of the edges of the ROW (See Table 15).

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47 Depending on patterns of power demand on the bulk transmission system, magnetic fields can change hourly, or over longer time periods (Exh. NEP-1, app. 5-2). NEP explained that it used forecasted AAL for modeling magnetic fields because AALs provide good predictions of the magnetic fields on any randomly selected day of the year (Exh. NEP-1, app. 5-2, at 2). NEP also calculated magnetic fields for annual peak loading (“APL”) to capture maximum loading that might occur for a few hours or days during the year (id.).

Table 20. Magnetic Field Levels – Primary Route[48]

	Annual Average Magnetic Field Levels, Pre- and Post-Construction, mG									
Segment	**West Side of ROW** (w/ number of homes within 50′)				**Maximum on ROW**		**East Side of ROW** (w/ number of homes within 50′)			
	50′ off ROW		Edge-of-ROW		Maximum		Edge-of-ROW		50′ off ROW	
	Pre	Post	Pre	Post	Pre	Post	Pre	Post	Pre	Post
MA-1A	0.5	10.5 (5)	0.9	29.5	20	94.5	3.3	6.0	1.3	3.3 (3)
MA-2	N/A	9.9 (3)	N/A	28.4	N/A	97.0	N/A	28.4	N/A	9.9 (0)
MA-3	0.3	10.4 (3)	0.6	29.2	9.8	94.9	1.1	3.7	0.4	2.4 (3)
MA-7	0.4	2.0 (3)	0.8	4.2	32.7	100.0	1.0	27.4	0.5	9.3 (2)

Sources: Exhs. NEP-1, at 5-64; EFSB-EMF-7

Magnetic field levels decrease as the distance increases from the transmission line (Exh. NEP-1, at 5-62). With respect to Project construction along the Primary Route, the Company stated that magnetic field levels would increase from existing levels on both ROW edges and in almost all ROW cross-sections, with larger increases on the west ROW edge adjacent to the proposed 345 kV transmission line (id. at 5-63). For the Alternative Route, the existing modeled magnetic field levels are more varied and somewhat higher than along the Primary Route (id. at 5-66). However, with Project construction along the Alternative Route, magnetic field levels would decrease from existing levels along some of the cross-sections (id. at 5-66 to 5-67).[49]

The Company considered different phasing configuration of the new 345 kV line in order to minimize magnetic field levels (Exh. NEP-1, app. 5-2, at 15). The Company explained that the proposed configuration is the aggregate optimal phasing which resulted in the minimum magnetic fields at the edge of the ROW taking all segments together, for 2020 AALs (id.). In

48 To model magnetic fields, the Company divided up the Massachusetts portion of the Primary Route into eight segments (Exhs. NEP-1, at 5-64; EFSB-EMF-1). Table 20 does not include Segments MA-1, MA-4, MA-5, and MA-6 since there are no homes within 50 feet of the edge of the ROW; zero to three homes within 50 to 100 feet of the edge of the ROW; and the pre- and post-project magnetic field levels identified by the Company are similar (Exh. EFSB-EMF-1).

49 Along the Alternative Route, existing AAL magnetic field levels range from 0.5 mG to 39.5 mG at the ROW edge; post construction, these levels would range from 2.2 mG to 26.1 mG in 2020 (Exh. NEP-1, at 5-67).

addition to optimizing phasing, the Company asserted that by locating the proposed line on an existing ROW and using the Primary Route, which minimizes the number of residences in proximity to the ROW, it has taken reasonable and prudent steps to minimize magnetic field levels (id. at 5-71). The Company also evaluated a number of mitigation alternatives including: (1) structure height increases; (2) placing the new line closer to the center of the ROW; (3) delta or vertical configurations; (4) reducing the spacing between phase conductors; (5) phase rolls (optimal phasing for each segment); (6) undergrounding the transmission line; (7) passive shielding loops; and (8) split phasing (Exh. EMF-2; RR-EFSB-23). The Company concluded that the items listed above would be either too costly and/or not cost-effective, could increase environmental impacts such as visual, land use, and construction noise impacts, and could potentially increase magnetic field levels in some locations along the ROW (RR-EFSB-23).

The record shows that calculated magnetic field levels would decrease in some sections along the Alternative Route, while magnetic field levels along the Primary Route would increase in all sections. Fewer homes, however, are within 50-foot of the Primary Route ROW edge than within the same area of the Alternative Route. Further, calculated magnetic field levels along both the Primary Route and Alternative Route ROWs would be within approximately the same range with construction of the Project. The Siting Board therefore finds that the Primary Route and Alternative Route are comparable with respect to magnetic fields.

The Project would incorporate certain measures to minimize magnetic field levels, including, but not limited to: (1) the location of the Project on an existing ROW, which creates some magnetic field cancellation; (2) use of phase arrangements that maximize such magnetic field cancellation; and (3) selection of a ROW with a relatively small number of nearby residences. The Company considered some additional measures to reduce magnetic field impacts for residences near the ROW. Those measures, however, would increase Project costs substantially and could increase environmental impacts; they potentially would reduce magnetic field impacts in some parts of the ROW but increase magnetic field impacts elsewhere. The Siting Board finds that the magnetic field impacts from transmission line construction and operation along the Primary Route would be minimized.

f. Traffic

The Company asserted that Project construction would have minimal traffic impacts (Exh. NEP-1, at 5-60). The Company plans to deliver vehicles, equipment, and material to laydown yards first, then to the ROW along a route that would minimize inconvenience to the public (Exh. EFSB-T-3). NEP indicated that its principal staging and laydown area would be in Smithfield, Rhode Island, with possible supplemental use of the Millbury No. 3 Switching Station (Exh. EFSB-LU-4). The Company anticipated temporary roadway closures, 37 for the Primary Route and 66 for the longer Alternative Route, to string new transmission lines over public roadways (Exh. NEP-1, at 5-60). The Company stated that its contractor would coordinate with local police departments to arrange traffic management as required (Exh. EFSB-T-3).

According to the Company, construction crew traffic, approximately 75-to-100 workers daily, would travel during Project installation from staging to construction areas along either the Primary or the Alternative Route (Exh. NEP-1, at 5-59 to 5-61). The three major construction activities – site prep, drilling, and transmission line construction – would be spread out along the ROW, not concentrated in one location (id.). NEP reported that the location of the Millbury No. 3 Switching Station was at the end of a short, dedicated road with no outlet; 15-to-20 construction crew vehicles would enter and exit the site daily over approximately 20 months (id.).

The potential traffic impacts of the Project along both the Primary and Alternative Routes would be minimal. For both routes, the Company has indicated the possible use of two staging and equipment laydown areas – an area at the Millbury No. 3 Switching Station and a site in Smithfield, Rhode Island. Based on Company estimates, twice as many road closures would be necessary to string transmission lines over roadways if the Project were constructed along the Alternative Route than if constructed along the Primary Route. Furthermore, the longer Alternative Route would extend the Project's temporary traffic construction impacts beyond the duration of such impacts along the Primary Route. Consequently, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to traffic impacts.

The Company has proposed mitigation measures to minimize traffic impacts of the Project, including, but not limited to, development and implementation of traffic management plans, appropriate signage for work zones, the use of flaggers, selection of the shortest feasible delivery routes for materials, use of police details when and where appropriate, timely communication of Project schedules to local officials and residents, and acquisition of all necessary state highway permits (Exh. NEP-1, at 5-60 to 5-61).

Because the Company has not yet finalized its plans to mitigate traffic impacts of the Project, the Siting Board directs the Company, in consultation with municipalities and Company contractors, to develop and implement a traffic management plan to minimize traffic disruption. The Company's plan shall include, but not be limited to, the following measures: (1) signs erected to identify construction work zones; (2) police details and/or flagmen to direct traffic near public road crossings; (3) police details and/or flagmen to direct traffic at construction work sites along roads; and (4) the use of the shortest feasible construction material delivery routes. Given the above mitigation and condition, the Siting Board finds that the traffic impacts from construction and operation of the transmission line along the Primary Route would be minimized.

g. Air Impacts

As a transmission facility, operation of the proposed Project along either the Primary Route or the Alternative Route generally would not contribute to air impacts. Emissions from construction vehicles are a concern, however. The Company has committed that all diesel-powered non-road construction equipment with engine horsepower (hp) ratings of 50 and above used for 30 or more days over the course of Project construction will have EPA-verified (or equivalent) emission control devices installed, such as oxidation catalysts or other similar technologies (Exh. NEP-1, at 5-15). NEP also stated that it would, in keeping with Company policy, use ultra-low sulfur diesel fuel and require that all construction vehicles (whether operated by the Company or by a construction contractor) limit vehicle idling to no more than five minutes in most cases (id.).[50]

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50 In accordance with the Massachusetts anti-idling requirements (M.G.L. c. 90, § 16A; c. 111, §§ 142A – 142M; and 310 CMR 7.11), the Company would limit idling time to five minutes unless engine power were necessary for the delivery of materials or to operate vehicle accessories such as power lifts (Exh. NEP-1, at 5-15).

The Company indicated that proposed changes at its Millbury No. 3 Switching Station would have potential implications for air impacts of the Project (Exh. EFSB-A-4). The Company reported that five circuit breakers using sulfur hexafluoride gas ("SF_6") are presently in place at the Switching Station, with a total of 1,825 pounds of SF_6 (id.). NEP explained that upgrades performed as part of the Project would result in the replacement of three of the five existing circuit breakers and the addition of four new circuit breakers at the Switching Station, resulting in nine circuit breakers with a total SF_6 quantity of 3,285 pounds (id.).[51,52] NEP indicated it would not store any SF_6 on site in conjunction with the Project (id.).

NEP stated that its Project-related SF_6 leakage rate would likely be less than 0.5 percent per year, and that this rate would be consistent with NEP's procurement specifications (i.e., purchase of circuit breakers with an SF_6 leakage rate of less than 0.5 percent per year) (Exhs. EFSB-A-4; EFSB-A-8; RR-EFSB-13).[53,54]

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51 The Massachusetts Clean Energy and Climate Plan for 2020 identifies SF_6 as a non-toxic but highly potent greenhouse gas ("GHG") and estimates one pound to have the same global warming impact as eleven tons of CO_2. See G.L. c. 21N. Reducing SF_6 emissions is an important policy goal of the Clean Energy and Climate Plan. The Siting Board's mandate requires it to ensure the consistency of new energy facilities with the Commonwealth's current health, environmental protection, and resource and development policies. In accordance with this mandate, the Siting Board reviews the Company's proposed use of SF_6 to ensure reduction of SF_6 emissions to the maximum extent possible.

52 The Company reported that it has a total nameplate capacity of 106,014 pounds of SF_6 for all equipment at its Massachusetts facilities (Exh. EFSB-A-2).

53 NEP distinguished between the design SF_6 emission rate and the manufacturer-provided commercial guarantee for the annual average emission rate of the proposed equipment (Exh. EFSB-A-8). The Company stated that it would use circuit breakers with a design emission rate of not more than 0.1 percent per year (id.). The Company specified that the manufacturer (Mitsubishi) of the equipment it would use guaranteed SF_6 emissions of no more than 0.5 percent per year (id.). The Company reported, based on a review of equipment suitable for its Project, that the design emission rates and guaranteed annual average rates for its proposed circuit breakers were standard for the industry (id.).

54 NEP provided vendor data stating that, while Mitsubishi does not test or guarantee its circuit breaker to the 0.1 percent level, its field data and original design verification data are consistent with a 0.1 percent leakage rate (RR-EFSB-14(S2)).

With respect to mitigation, NEP reported that it entered into an SF_6 Emissions Reductions Partnership Memorandum of Understanding ("MOU") with the USEPA in December 2003 (Exh. EFSB-A-3). NEP explained that, in the course of construction and operation of the Project, it would activate elements of the Company's SF_6 reduction program, including, but not limited to, monitoring, prioritizing, and repairing leaking SF_6 equipment, and providing SF_6-specific training to its maintenance employees (Exhs. EFSB-A-4; EFSB-A-7(A)).

The Company reported that the improvements for its Millbury No. 3 Switching Station, and therefore the use of SF_6, would be the same whether construction of the Project occurred along the Primary or the Alternative Route (Exh. NEP-1, at 5-5).

The Siting Board notes that air impacts along the Primary Route and the Alternative Route would be comparable in nature, but that the greater length of the Alternative Route and the resulting longer duration of construction would produce greater construction equipment air impacts. The Siting Board finds construction along the Primary Route is preferable to the Alternative route with respect to air impacts.

The Companies have specified mitigation for construction equipment air emissions including using ultra-low sulfur diesel fuel in diesel-powered construction equipment, limiting vehicle idling to five minutes, and retrofitting all diesel-powered non-road construction equipment prior to construction.

As NEP has agreed, the Siting Board directs that the Company ensure that all diesel-powered non-road construction equipment with engine horsepower ratings of 50 and above to be used for 30 or more days over the course of Project construction must have USEPA-verified (or equivalent) emission control devices, such as oxidation catalysts or other comparable technologies (to the extent that they are commercially available) installed on the exhaust system side of the diesel combustion engine. Prior to the commencement of construction, the Company shall submit to the Siting Board certification of compliance with this condition. In terms of SF_6 air impacts, NEP has proposed installing circuit breakers at its Millbury No. 3 Switching Station with a guaranteed SF_6 emissions rate of no more than 0.5 percent per year and a design annual SF_6 leakage rate of less than 0.1 percent, along with pressure switches with alarms and leak detection equipment.[55] The Company would also comply with USEPA SF_6 reporting requirements. In addition, the Siting Board directs the Company to inform the Board if it adds SF_6 to any equipment at its Millbury No. 3 Switching Station or replaces any equipment at the Millbury No. 3 Switching Station due to SF_6 loss within five years of the completion and initial operation of the Project, after which time the Company will consult with the Siting Board to determine whether the Siting Board will require continuing reporting, as deemed appropriate.[56] The Company will also annually submit to the Siting Board a copy of its annual SF_6 report to MassDEP.

With the diesel retrofit conditions noted above and the Company's reliance on new equipment to help minimize future SF_6 leakage rates, the Siting Board finds that, potential emissions impacts from the Project's construction and operation along the Primary Route would be minimized.

h. Other

The Company indicated that construction of its Project would involve certain hazardous materials including Mineral Oil Dielectric Fluid ("MODF") in voltage transformers and station service transformers, acid in batteries, and diesel fuel in an emergency generator at its Millbury No. 3 Switching Station (Exh. EFSB-S-2). The Company also anticipated the need to dispose of hazardous paints (containing lead and cadmium) in conjunction with removal of existing 69 kV metal transmission structures along the Primary Route ROW in preparation for Project

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55 In April 2014, MassDEP promulgated final regulations that require companies to purchase new gas-insulated switchgear with a manufacturer's guaranteed SF_6 emission rate of one percent or less. The new regulations also include requirements for maintenance and handling of SF_6, and require that National Grid and NSTAR comply with a declining SF_6 emission rate standard by 2020 (see 310 CMR 7.72).

56 In the Hampden County Decision, the Siting Board directed NEP to provide a compliance filing within one year of operation of the West Hampden Substation detailing the actual SF_6 leakage rate at the Substation. Hampden County at 66. In the instant case, the Company has stated that it is not technically feasible to measure the SF_6 leakage rate of the breakers to determine if they are meeting the design leakage rate (Tr. 3, at 431-434, 447-452).

construction (id.).[57] To ensure safe handling and storage of hazardous substances during construction and operation of the Project, the Company stated it would ensure its contractors' adherence to regulatory requirements, best management practices, and a Project-specific spill prevention, containment, and response plan (Exh. EFSB-S-2).[58]

With specific reference to the Primary Route, the Company stated that it would, to the extent possible, recycle any materials generated by dismantling of transmission structures along the Primary Route ROW (Exh. NEP-1, at 5-10). NEP indicated that it would transfer any components not salvageable, together with debris the Company was unable to recycle, to an approved off-site disposal facility, and would do so in accordance with all applicable laws and regulations (id.).

The Company indicated that throughout Project construction, an environmental monitor would be employed to enforce compliance with all federal, state and local permitting requirements and NEP policies (Exh. NEP-1, at 5-15). NEP stated that as part of its public outreach during construction, the Company would coordinate with local police departments and emergency responders to inform them of construction activities as they occur in each municipality (Exh. EFSB-S-4). The Company declared that it would also require each of its contractors to prepare a Health and Safety Plan for the contractor's employees (id.).

The Siting Board notes that the Company's plans for hazardous material and solid waste management and for the health and safety of residents and workers engaged on its Project would be comparable whether the Project were constructed along the Primary or the Alternative Route.

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57 NEP submitted copies of National Grid's Guidance Document EG-1702 and National Grid Safety Procedure F-608 (Exhs. EFSB-S-2(b)(Att.); EFSB-S-2(c)(Att.). The Company stated that it would manage removal of painted metal structures in accordance with National Grid's Guidance Document EG-1702, with work methods conducted in accordance with National Grid Safety Procedure F-608 (Lead Compliance Plan) (Exh. EFSB-S-2). The Company specified that it would use containment controls and high efficiency particulate air vacuum collection techniques to contain and collect fugitive paint chips that might be generated during the removal of the steel towers (id.). NEP further explained that it would remove to a secure container and dispose of recovered paint chips at a National Grid-approved receiving facility (id.).

58 The Company provided copies of the applicable guidance documents and plans (Exhs. EFSB-S-1(a)(Att.); EFSB-S-1(b)(Att.); EFSB-S-2(a)(Att.); EFSB-S-2(c)(Att.)).

The Siting Board consequently finds potentially hazardous material and solid waste impacts, as well as related safety impacts comparable along either the Primary or the Alternative Route. The Siting Board also recognizes, however, that the Company has proposed comprehensive mitigation, discussed above. Based on the Company's proposed mitigation, the Siting Board finds that impacts from potentially hazardous material and solid waste associated with the Project along the Primary Route would be minimized. In addition, the Siting Board finds that potential safety impacts from the Project's construction along the Primary Route would be minimized.

4. Cost

The Company estimated total Project cost along the Primary Route at $67,420,000 and along the Alternative Route at $216,480,000 (Exh. EFSB-C-1(R)). Table 21, below, indicates these as well as additional costs, including: (1) costs of site preparation for construction are under "labor"; (2) "labor" and "material" costs together cover any costs for transmission line construction/installation; (3) transmission line operation and maintenance ("O&M") costs include vegetation management, annual inspections, ROW access road maintenance, and any support costs; and (4) substation O&M costs include SF_6 gas monitoring, equipment testing, inspection and maintenance, and associated support costs (id.).[59]

[59] NEP stated that the replacement of existing air blast circuit breakers with SF_6 circuit breakers would result in a net reduction of O&M cost after Project completion despite an increase in the total number of circuit breakers (Exh. EFSB-C-1(R)).

Table 21. Estimated Costs of the Primary and Alternative Routes (2011$)

	Primary Route	Alternative Route	69 kV Removals	Millbury No. 3
Material	$12,440,000	$48,910,000	$0	$10,632,000
Labor (Construction)	$29,310,000	$85,550,000	$1,390,000	$9,350,000
ROW (Acquisition)	$0	$0	$0	$0
Engineering, Permitting, Indirects (includes costs of environmental analysis)	$11,910,000	$37,830,000	$310,000	$4,345,000
Escalation	$5,710,000	$18,340,000	$140,000	$2,601,000
AFUDC	$0	$0	$0	$0
Contingency	$8,050,000	$25,850,000	$260,000	$3,672,000
Total	$67,420,000	$216,480,000	$2,100,000	$30,600,000
Annual O&M	$42,000	$45,000	$0	($8,000)

Sources: Exhs. NEP-1, at 5-73; EFSB-C-1(R)

Although the Siting Board does not have jurisdiction over regulatory cost recovery, the Siting Board's statutory mandate is to review the need for, cost of, and environmental impacts of transmission lines. G.L. c 164, § 69H. In order to review the costs of the Project, and in an effort to identify the factors that may lead to cost overruns and delays in construction of approved facilities, the Siting Board directs the Company to submit to the Board an updated and certified cost estimate for the Project prior to the commencement of construction. Additionally, the Siting Board directs NEP to file semi-annual compliance reports with the Siting Board starting within 60 days of the commencement of construction, that include projected and actual construction costs and explanations for any discrepancies between projected and actual costs and completion dates, and an explanation of the Company's internal capital authorization approval process.

As Table 21 shows, annual Project O&M costs as well as ROW acquisition costs would be comparable for both the Primary and Alternative Route. The greater length of the Alternative Route however would increase overall Project costs significantly. Accordingly, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to cost.

5. Reliability

In terms of assessing reliability of transmission projects, the Company typically assesses total exposure (length) of the transmission line, location of the facilities, types of construction methodology, and access to the line for repairs. Both the Primary and Alternative Routes would use 345 kV overhead transmission lines, and the Company stated that the design of the transmission line along either route would result in a transmission system that fully meets the requirements and relevant reliability standards (Exh. NEP-1, at 5-73 to 5-74).

The main reliability difference between the Primary Route and the Alternative Route is the greater length of the Alternative Route (id. at 5-73). The Company asserts that the longer Alternative Route would require more structures and more circuit miles of conductors, which would increase exposure to contingencies (id. at 5-73 to 5-74). Nonetheless, based on the same overall design and use of overhead 345 kV technology, the Company concludes that reliability is comparable regardless of which route is selected (id. at 5-74; Company Brief at 179). On this basis, the Siting Board finds that reliability is comparable for the Primary and Alternative Routes.

6. Conclusion

The Siting Board finds that the information provided by the Company regarding the Project's environmental impacts is substantially accurate and complete. In comparing the environmental impacts of the two routes, the Siting Board finds above that the Primary Route is preferable to the Alternative Route with respect to land use and historic resources impacts, water resource and wetlands impacts, noise impacts, visual impacts, traffic impacts, air impacts, and safety, and that the Primary Route and Alterative Routes are comparable with respect to hazardous materials and solid waste impacts, and magnetic field impacts.

The Siting Board notes that the two routes both use existing ROWs and thus share the advantage of avoiding the environmental impacts of construction through a new corridor. Furthermore, while both ROWs pass through relatively undeveloped areas, fewer residences are proximate to the Primary Route than to the Alternative Route. The shorter length and fewer nearby sensitive receptors to the Primary Route combine to make it the preferable route with respect to environmental impacts. Given the above comparison, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to environmental impacts. Finally, the Siting Board finds that the Primary Route is preferable to the Alternative Route with respect to cost and the Primary Route and the Alternative Route are comparable with respect to reliability. The Siting Board therefore finds that the Primary Route is preferable to the

Alternative Route with respect to providing a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Based on the information presented in Section V.B, above, the Siting Board finds that, with the implementation of the Company's proposed measures, the specified mitigation and conditions included herein, and compliance with all local, state and federal requirements, the environmental impacts of the proposed Project along the Primary Route would be minimized.

Based on its review of the record, the Siting Board finds that the Company provided sufficient information regarding cost, reliability, and environmental impacts to allow the Siting Board to determine whether the Project has achieved a proper balance among cost, reliability, and environmental impacts. The Siting Board finds that the proposed Project along the Primary Route would achieve an appropriate balance among conflicting environmental concerns as well as between environmental impacts, reliability, and cost.

VI. CONSISTENCY WITH POLICIES OF THE COMMONWEALTH

A. Standard of Review

G.L. c. 164, § 69J requires the Siting Board to determine whether plans for construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth.

B. Analysis and Conclusions

1. Health Policies

In Section 1 of the Electric Utility Restructuring Act of 1997, the Legislature declared that "electricity service is essential to the health and well-being of all residents of the Commonwealth…" and that "reliable electric service is of utmost importance to the safety, health, and welfare of the Commonwealth's citizens…" See c. 14 of the Acts of 1997, Section 1(a) and (h). In Section III.D above, the Siting Board found that the Project would improve the reliability of electric service in Massachusetts and New England. In addition, in Section V.B.3.g, the Siting Board requires the Company to use only retrofitted off-road construction equipment to limit emissions of particulate matter during Project construction. This condition is consistent with MassDEP's Diesel Retrofit Program designed to address health concerns related to diesel emissions. In Section V.B.3, the Siting Board finds that the Project's magnetic field, traffic, hazardous materials, and air impacts have been minimized. Accordingly, subject to the Company's specified mitigation and the Siting Board's conditions set forth in Section X, below, the Siting Board finds that the Company's plans for construction of the Project are consistent with current health policies of the Commonwealth.

2. Environmental Protection Policies

In Section III.B.3, above, the Siting Board reviewed how the Project would meet various state environmental protection requirements. The Siting Board also: (1) considered the Project's environmental impacts, including those related to water resources, wetlands, endangered species, land use, historical resources, air emissions, noise, and visual impacts; and (2) concluded that subject to the specified mitigation and conditions set forth below, the Project's environmental impacts have been minimized. See Section IX, below, for a discussion of the applicability of the Massachusetts Environmental Policy Act ("MEPA") Greenhouse Gas Emission Policy and Protocol.

Subject to the specified mitigation and conditions set forth in this Decision, the Siting Board finds that the Company's plans for construction of the Project are consistent with the current environmental policies of the Commonwealth.

3. Resource Use and Development Policies

In 2007, pursuant to the Commonwealth's Smart Growth/Smart Energy policy produced by the Executive Office of Energy and Environmental Affairs, Governor Patrick established Sustainable Development Principles. Among the principles are: (1) supporting the revitalization of city centers and neighborhoods by promoting development that is compact, conserves land, protects historic resources and integrates uses; (2) encouraging reuse of existing sites, structures and infrastructure; and (3) protecting environmentally sensitive lands, natural resources, critical habitats, wetlands and water resources and cultural and historic landscapes. In Section V, the Siting Board reviewed the process by which the Company sited the Project. The Siting Board finds that the Project would be located wholly within existing overhead utility ROWs and an existing switching station in Millbury. Therefore, the Project would encourage the reuse and revitalization of existing energy infrastructure to help ensure the provision of reliable electric service in the Commonwealth and New England. Additionally, the Project has been designed and conditioned to avoid or minimize impacts to natural and cultural resources.

Subject to the specific mitigation and the conditions set forth in this Decision, the Siting Board finds that the Company's plans for construction of the Project are consistent with the current resource use and development policies of the Commonwealth.

VII. ANALYSIS UNDER G.L. C. 40A, § 3 - ZONING EXEMPTIONS

Pursuant to G.L. c. 40A, § 3, the Company requests individual zoning exemptions from the Town of Millbury Zoning Bylaws ("Millbury Zoning Bylaw"), the Town of Sutton Zoning Bylaw ("Sutton Zoning Bylaw"), the Town of Northbridge Zoning Bylaw ("Northbridge Zoning Bylaw"), the Town of Uxbridge Zoning Bylaw ("Uxbridge Zoning Bylaw"), and the Town of Millville Zoning Bylaw ("Millville Zoning Bylaw") for the proposed transmission line and related switching station improvements. The Company also seeks a comprehensive zoning exemption from each municipality's zoning bylaw.

A. Individual Zoning Exemptions

1. Standard of Review

G.L. c. 40A, § 3 provides, in relevant part, that:

> Land or structures used, or to be used by a public service corporation may be exempted in particular respects from the operation of a zoning ordinance or by-law if, upon petition of the corporation, the [Department] shall, after notice given pursuant to section eleven and public hearing in the town or city, determine the exemptions required and find that the present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public . . .

Thus, a petitioner seeking exemption from a local zoning bylaw under G.L. c. 40A, § 3 must meet three criteria.[60] First, the petitioner must qualify as a public service corporation.

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60 G.L. c. 40A, § 3 applies to the Department. The Department refers zoning exemption cases to the Siting Board for hearing and decision pursuant to G.L. c. 25, § 4. When deciding cases under a Department statute, the Siting Board has the power and the duty:

Save the Bay, Inc. v. Department of Public Utilities, 366 Mass. 667 (1975) ("Save the Bay"). Second, the petitioner must demonstrate that its present or proposed use of the land or structure is reasonably necessary for the public convenience or welfare. Massachusetts Electric Company, D.T.E. 01-77, at 4 (2002) ("MECo/Westford"; Tennessee Gas Pipeline Company, D.T.E. 01-57, at 3-4 (2002) ("Tennessee/Agawam"). Finally, the petitioner must establish that it requires exemption from the zoning ordinance or bylaw. Boston Gas Company, D.T.E. 00-24, at 3 (2001) ("Boston Gas").

2. Public Service Corporation

a. Standard of Review

In determining whether a petitioner qualifies as a "public service corporation" ("PSC") for the purposes of G.L. c. 40A, § 3, the Massachusetts Supreme Judicial Court has stated:

> among the pertinent considerations are whether the corporation is organized pursuant to an appropriate franchise from the State to provide for a necessity or convenience to the general public which could not be furnished through the ordinary channels of private business; whether the corporation is subject to the requisite degree of governmental control and regulation; and the nature of the public benefit to be derived from the service provided.

Save the Bay at 680. See also, Boston Gas at 3-4; Berkshire Power Development, Inc., D.P.U. 96-104, at 26-36 (1997) ("Berkshire Power").[61]

> to accept for review and approval or rejection any application, petition or matter related to the need for, construction of, or siting of facilities referred by the chairman of the department . . . provided, however, that in reviewing such application, petition or matter, the board shall apply department and board standards in a consistent manner.

G.L. c. 164, § 69H.

[61] The Department interprets this list not as a test, but rather as guidance to ensure that the intent of G.L. c. 40A, § 3 would be realized, i.e., that a present or proposed use of land or structure that is determined by the Department to be "reasonably necessary for the convenience or welfare of the public" not be foreclosed due to local opposition. See Berkshire Power at 30; Save the Bay at 685-686; Town of Truro v. Department of Public Utilities, 365 Mass. 407 (1974) ("Town of Truro"). The Department has interpreted the "pertinent considerations" as a "flexible set of criteria which allow the Department to

b. Analysis and Conclusion

The Company is an electric company as defined by G.L. c. 164, § 1 and, as such, qualifies as a public service corporation. Hampden County at 81. Accordingly, the Siting Board finds that the Company is a public service corporation for the purposes of G.L. c. 40A, § 3.

3. Public Convenience or Welfare

a. Standard of Review

In determining whether the present or proposed use is reasonably necessary for the public convenience or welfare, the Department must balance the interests of the general public against the local interest. Save the Bay at 680; Town of Truro at 407. Specifically, the Department is empowered and required to undertake "a broad and balanced consideration of all aspects of the general public interest and welfare and not merely [make an] examination of the local and individual interests which might be affected." New York Central Railroad v. Department of Public Utilities, 347 Mass. 586, 592 (1964) ("NY Central Railroad"). When reviewing a petition for a zoning exemption under G.L. c. 40A, § 3, the Department is empowered and required to consider the public effects of the requested exemption in the State as a whole and upon the territory served by the applicant. Save the Bay at 685; NY Central Railroad at 592.

Therefore, when making a determination as to whether a petitioner's present or proposed use is reasonably necessary for the public convenience or welfare, the Department examines: (1) the need for, or public benefits of, the present or proposed use; (2) the present or proposed use and any alternatives or alternative sites identified;[62] and (3) the environmental impacts or

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respond to changes in the environment in which the industries it regulates operate and still provide for the public welfare." Berkshire Power, D.P.U. 96-104, at 30; see also Dispatch Communications of New England d/b/a Nextel Communications, Inc., D.P.U./D.T.E. 95-59-B/95-80/95-112/96-113, at 6 (1998). The Department has determined that it is not necessary for a petitioner to demonstrate the existence of "an appropriate franchise" in order to establish PSC status. See Berkshire Power at 31.

62 With respect to the particular site chosen by a petitioner, G.L. c. 40A, § 3 does not require the petitioner to demonstrate that its primary site is the best possible alternative, nor does the statute require the Department to consider and reject every possible alternative site presented. Rather, the availability of alternative sites, the efforts necessary to secure them, and the relative advantages and disadvantages of those sites are

any other impacts of the present or proposed use. The Department then balances the interests of the general public against the local interest and determines whether the present or proposed use of the land or structures is reasonably necessary for the convenience or welfare of the public. Boston Gas, D.T.E. 00-24, at 2-6; MECo/Westford at 5-6; Tennessee/Agawam at 5-6; Tennessee Gas Company, D.T.E. 98-33, at 4-5 (1998).

b. Analysis

With respect to the need for, or public benefits of, the Project, the Siting Board found in Section III.D, above, that additional energy resources are needed for reliability. In Section IV, the Siting Board analyzed a number of different project approaches other than the Company's proposed 345 kV transmission line that the Company might use to meet the reliability need (such as a hybrid alternative utilizing a 115 kV transmission line; and NTAs including EE, DR and DG) and concluded that the proposed approach is preferable to other approaches. The Siting Board also reviewed the Company's route selection process in Section V.A, and determined that the Company applied a reasonable set of criteria for identifying and evaluating routes to ensure that no clearly superior route was missed. The Siting Board also compared the benefits of the Primary and Alternative Routes and concluded that the Primary Route is preferable to the Alternative Route in providing a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Finally, regarding Project impacts, in Section V.B.3, the Siting Board reviewed the environmental impacts of the Project and found that, while the Project may result in some local adverse impacts, the impacts of the proposed Project would be minimized with the implementation of certain mitigation and conditions. The Siting Board also found that area residents would benefit from the Project as it would improve the reliability of electricity delivery.

Based on the foregoing, the Siting Board finds that the general public interest in constructing the Project outweighs identifiable adverse local impacts. Accordingly, the Siting

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matters of fact bearing solely upon the main issue of whether the primary site is reasonably necessary for the convenience or welfare of the public. Martarano v. Department of Public Utilities, 401 Mass. 257, 265 (1987); NY Central Railroad at 591.

Board finds that the proposed Project is reasonably necessary for the convenience or welfare of the public.

4. Individual Exemptions Required

a. Standard of Review

In determining whether exemption from a particular provision of a zoning bylaw is "required" for purposes of G.L. c. 40A, § 3, the Department looks to whether the exemption is necessary to allow construction or operation of the petitioner's Project. New England Power Company d/b/a National Grid, D.P.U. 12-02, at (2012); NSTAR Electric Company, D.P.U. 11-80, at 4 (2012); Tennessee Gas Company, D.P.U. 92-261, at 20-21 (1993).[63]

b. Introduction

The Company asserts that the only way the Project can be built without any risks of delay associated with the failure to obtain permits, is to obtain zoning exemptions from all zoning provisions that could potentially be interpreted as requiring zoning relief (Exhs. EFSB-Z-6 through EFSB-Z-10). Specifically, NEP asserts that unless the requested individual exemptions are granted, there is some likelihood that the provisions of the bylaws from which exemptions are requested would result in adverse interpretations, burdensome requirements, delays, and undue expenses, as well as contribute to legal uncertainty, as part of the zoning review (Exh. NEP-2-1, at 5). The Company also argues that the requested zoning exemptions are required because: (1) the provisions of the bylaws are likely to conflict with state and industry standards;

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63 It is the petitioner's burden to identify the individual zoning provisions applicable to the Project and then to establish that exemption from each of those provisions is required:

> The Company is both in a better position to identify its needs, and has the responsibility to fully plead its own case . . . The Department fully expects that, henceforth, all public service corporations seeking exemptions under c. 40A, § 3 would identify fully and in a timely manner all exemptions that are necessary for the corporation to proceed with its proposed activities, so that the Department is provided ample opportunity to investigate the need for the required exemptions.

New York Cellular Geographic Service Area, Inc., D.P.U. 94-44, at 18 (1995).

(2) constructing the Project would require variances, which are difficult to obtain, constitute a legally disfavored form of relief, and are susceptible to overturn on appeal; (3) construction of the Project would require special permits which contain findings that can be subjective in nature, with the opportunity for appeals; (4) zoning bylaws are, in general, difficult to apply to energy infrastructure projects; and (5) the discretionary and subjective nature of the permit-granting criteria governing such issues as variances, special permits, and site plan review may result in burdensome or restrictive conditions (Exh. NEP-2-1, at 5; Company Brief at 184-185). In addition, the issuance of use variances is expressly prohibited in Uxbridge; not expressly authorized in Sutton and Millville; allowed in Millbury; and allowed only in non-residential zones in Northbridge (Exh. EFSB-Z-14 (rev)).

c. List of Exemptions Sought

In addition to the general reasons cited above, Tables 22 through 26, below, summarize: (1) each of the specific provisions of the zoning bylaws from which the Company seeks exemptions; (2) the relief available from the towns through the local zoning process; and (3) the Company's argument as to why it cannot comply with the identified zoning provisions and/or why the available zoning relief is inadequate.

Table 22. The Company's Position – Millbury Zoning Bylaw Exemptions

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Use Regulation Article 2, Section 23.2	Special Permit	The transmission line is not allowed as of right in the Suburban II zoning district.
Pre-Existing Nonconforming Use Article 1, Section 16.32	Special Permit	The transmission line may be a change or substantial extension of a pre-existing nonconforming use in the Suburban II zoning district.
Earth Transfer Article 3, Section 36.3	Variance	Excavation required to construct could be considered "earth transfer or relocation" which is prohibited in the Floodplain District.
Floodplain District Article 3, Section 36.4	Special Permit	The transmission line is not allowed as of right in the Floodplain District. A Special Permit for uses and structures to be located in a floodplain is granted only upon a showing of good or sufficient cause.

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Pre-existing Use in a Floodplain District Section 3140	Special Permit	The transmission line may be a change or substantial extension of a pre-existing nonconforming use in the Floodplain District.
Height and Setbacks Article 2, Sections 23.32, 25.3, and 26.3	Variance	The transmission line exceeds the maximum height in the Industrial I, Business II, and Suburban II zoning districts; and a component at the Switching Station exceeds the maximum height in the Industrial I zoning district.
Fence/Fence Height Article 1, Section 16.32; Article 3, Section 35.7	Special Permit	The new fence may be a "reconstruction, extension or structural change" of a pre-existing nonconforming structure. If the fence is not a pre-existing nonconforming structure, the fence would exceed the maximum height restriction.
Yard Setback Article 2, Sections 23.32, 25.3, and 26.3	Variances	The transmission line may not comply with yard setback requirements
Vegetation Removal Article 3, Section 35.6; Article 2, Sections 25.3 and 26.3	Special Permits	The transmission line would require vegetation removal in general, and vegetation removal in yard setbacks.
Wetland Fill Article 3, Section 35.23	Special Permit	The transmission line requires wetland fill activities.
Site Plan Approval Article 1, Section 12.41	Site Plan Approval	Site plan review is required for the Switching Station. Site Plan review can be discretionary. The Company asserts that it must have the discretion to design the Project in a manner that is consistent with established utility standards in order to ensure reliable operation.
Parking and Loading Article 3, Sections 33.2 and 33.4	Variance	The Switching Station will not comply with the minimum parking and loading requirements as the Project will not include any parking or loading facilities.

Source: Exh. NEP-2, at 17-18.

Table 23. The Company's Position – Sutton Zoning Bylaw Exemptions

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Use Regulation Article III, Section A.4	Special Permit	The transmission line is not allowed as of right in the R-1 or B2 zoning districts.
Pre-Existing Nonconforming Use Article 1, Section C.2.a	Section 6 Finding	Replacing the existing 69 kV line with the new transmission line may be a change or substantial extension of a pre-existing nonconforming use in the B2 zoning district.

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Groundwater Protection District Article 3, Section 36.3	Special Permit	The transmission line is not allowed as of right in the Groundwater Protection District.
Setbacks Article III, Section B.3, Table 2, and footnote 11	Variance	The transmission line will not comply with yard setback or zoning district requirements.
Site Plan Approval Article IV, Sections C.2 and C.3	Site Plan Approval and Waiver	Site plan review is required for the transmission line. Site Plan review can be discretionary. The Company asserts that it must have the discretion to design the Project in a manner that is consistent with established utility standards in order to ensure reliable operation.
Signage and Sign Setbacks Article IV, Section A and Section A.3.b.7	Variance	The transmission line will not comply with signage or signage setback requirements. The Project includes warning signs on the transmission poles and structures required by the Department.

Table 24. The Company's Position – Northbridge Zoning Bylaw Exemptions

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Table of Height and Bulk Regulations	Variance	The transmission line exceeds the maximum height in the B-3 and I-2 zoning district.
Table of Area Regulations	Variance	The transmission line may not comply with yard setbacks.
Site Plan Article X, Sections 173-49.A	Site Plan Approval	Site plan review is required for the transmission line. Site Plan review can be discretionary. The Company asserts that it must have the discretion to design the Project in a manner that is consistent with established utility standards in order to ensure reliable operation.
Table of Area Regulations, Note 8 Setbacks and Visual Buffers	Variances	As portions of the transmission line are located in an I-2 Zoning District that abuts a residential zoning district, the line may not comply with setbacks and would require a visual buffer.
Grading Restrictions Article V, Section 173-18.2.A	Special Permit	The transmission line will not comply with grading restrictions, which prohibit final slopes of 15 percent or greater on 50 percent or more of the property.
Signage Article VII, Sections 173-22.B, 173-23, and 173-24	Variance	The transmission line will not comply with signage requirements. The Project includes warning signs on the transmission poles and structures required by the Department.

Sources: Exhs. NEP-2, at 25; NEP-2-1, at 24.

Table 25. The Company's Position –Uxbridge Zoning Bylaw Exemptions

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Use Regulations Article III, § 400-10 and Appendix A, Table of Use Regulations	Special Permit	The transmission line is not allowed as of right in the R-A Zoning District.
Pre-existing Nonconforming Use Article III, §400-12.B	Special Permit for Section 6 Finding	The transmission line may be a change or substantial extension of a pre-existing nonconforming use in the R-A Zoning District.
Use Regulations Article III, §400-10 and Appendix A, Table of Use Regulations	None Available	The transmission line is expressly prohibited in the R-C, A, I, and B Zoning Districts.
Pre-existing Nonconforming Use Article III, §400-12.F	Special Permit	Reestablishment of a pre-existing nonconforming use for a de-energized 69 kV line may be required.
Floodplain and Groundwater Protection Overlay Districts Article III, §§400-37 and 400-38	None Available	The transmission line is prohibited in the Floodplain and Groundwater Protection Overlay Districts that affect the R-C, A, I, and B Zoning Districts.
Height Restrictions Article IV, §400-13 and Appendix B, Table of Dimensional Requirements; Article III, §400-14.B	Variance	The transmission line will exceed the maximum height restriction in general and may exceed the maximum height restrictions for corner lots.
Setbacks Article IV, §§400-13 and 400-14, and Appendix B, Table of Dimensional Requirements	Variance	The transmission line may not comply with yard setbacks.

Source: Exh. NEP-3, at 28-29.

Table 26. The Company's Position – Millville Zoning Ordinance Exemptions

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Use Regulation Article 111, Sections 1(A)(2) and 2(F)(4)	Special Permit	The transmission line is not allowed as of right in the VR Zoning District.
Setbacks Article IV, Section 2, Schedule of Dimensional Requirements	Variance	The transmission line may not comply with yard setbacks. It is difficult for a linear project to demonstrate unique conditions relating to soil, shape or topography in order to be granted a variance.

Individual Zoning Exemption Requested	Available Relief from Town	Why Project Cannot Comply: Company's Position
Signage Article V, Sections 1(C) and 1 (G)	Special Permit	The transmission line will not comply with signage requirements. The Project includes warning signs on the transmission poles and structures required by the Department.

Source: Exh. NEP-2, at 31.

d. Consultation with the Municipalities

The Siting Board favors the resolution of local issues on the local level whenever possible to reduce local concern regarding any intrusion on home rule authority. Thus, the Siting Board encourages zoning exemption applicants to consult with local officials, and in some circumstances, to apply for local zoning permits, prior to seeking zoning exemptions from the Department under G.L. c. 40A, § 3. Hampden County at 85-86; New England Power Company, EFSB 09-1/D.P.U. 09-52/09-53, at 75-77 (2011) ("Worcester"); Russell Biomass LLC, 17 DOMSB 1, at 60-63 (2009) ("Russell").

The Company in this case did not apply to the towns for any local zoning relief before filing its Zoning Petition with the Department. However, the Siting Board has held that applying for local zoning permits in advance of filing a zoning exemption petition is not required where to do so would likely be futile, or where the Company has met the spirit and intent of Russell by engaging in outreach with the affected municipalities regarding the Company's plan to seek zoning relief from the Department. Other factors supporting a finding that the spirit and intent of Russell have been met are that the affected municipalities do not object to the Company seeking such relief, and that the Company has made a good faith effort to abide by the reasonable recommendations of the municipalities with respect to the Project. Hampden County at 86; Worcester at 76-77; see also, GSRP at132-133.[64]

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64 The Department has adopted and clarified the Russell principle in subsequent Department zoning exemption decisions: e.g., Tennessee Gas Pipeline Company, D.P.U. 11-26, at 26 (2012); New England Power Company, D.P.U. 09-136/09-137, at 34-37 (2011); New England Power Company, D.P.U. 09-27/09-28, at 47 (2010); Western Massachusetts Electric Company, D.P.U. 09-24/09-25, at 33 (2010).

With respect to outreach to local authorities, the Company stated that it engaged in substantial and good faith consultations with numerous officials of the towns of Millbury, Sutton, Northbridge, Uxbridge and Millville regarding the applicability of the respective zoning bylaws to the Project and its intention to seek the necessary zoning exemptions (Exh. NEP-2, at 6).[65] The towns of Millbury, Sutton,[66] Northbridge, Uxbridge and Millville have all written letters of support for the Board's granting of both individual and comprehensive zoning exemptions (Exhs. NEP-2-1 (Att. E; Att. G; Att. I; Att. K; Att. M; Att. S)). In addition, the Company conducted outreach to the town governments, and none of the towns elected to intervene in the proceeding (Exh. EFSB-Z-16).

e. Analysis and Findings

The Company has identified in Tables 22 through 26, the provisions of the bylaws from which it seeks exemption to minimize delay in the construction and ultimate operation of the Project.

Based on the information detailed in Tables 22 through 26 above, the Company would need to seek numerous variances and Special Permits, as well as three Site Plan approvals from the five towns. The Department concurs with the Company that variances are difficult to obtain, constitute a disfavored form of relief, and are susceptible to being overturned on appeal. Consequently, the need to obtain variances is likely to result in an adverse outcome, a burdensome requirement, or an unnecessary delay. Further, the Uxbridge Zoning Bylaw expressly prohibits the granting of use variances, therefore, no relief can be obtained from the

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65 The Company conducted zoning meetings with: (1) the Millbury Town Planner, and the Building Inspector; (2) the Sutton Town Planner, and the Building Inspector; (3) the Northbridge Inspector of Buildings; (4) the Uxbridge Inspector of Buildings and Zoning Enforcement Officer; and (5) the Millville Building Commissioner and Zoning Officer (Exhs. EFSB-Z-1 through EFSB-Z-5).

66 In a December 28, 2011 letter to the Company, the Town of Sutton stated it would support such exemptions "provided the Town and its citizens will have an opportunity to comment on the Project at a public hearing in one or more of the Massachusetts towns in which the Project will be located and that the notice of such public hearing will be sent to abutters of the Project, as well as Town officials" (Exh. NEP-2-1, (Att. G)). The Board notes that the public comment hearing held in Uxbridge afforded such an opportunity.

Town. The Department also concurs with the Company that the potentially discretionary and substantive nature of conditions associated with the granting of Special Permits may result in restrictive or burdensome conditions. Additionally, substantive requirements of a Site Plan approval could conflict with established industry standards for design and construction. Thus, requiring the Company to seek Site Plan approval may result in denial of such approval, which would preclude construction of the Project. Both Special Permits and Site Plan approval may be appealed, thus delaying, or prohibiting Project implementation.

The Siting Board finds that the substantive sections of the Millbury, Sutton, Northbridge, Uxbridge, and Millville Zoning Bylaws, included in Tables 22 through 26 above, would or could affect the Company's ability to implement the Project as proposed. Accordingly, the Siting Board finds that NEP has demonstrated that the requested zoning exemptions are required pursuant to G.L. c. 40A, § 3.

5. Conclusion on Request for Individual Zoning Exemptions

As described above, the Siting Board finds that: (1) the Company is a public service corporation; (2) the proposed use is reasonably necessary for the public convenience or welfare; and (3) the specifically named zoning exemptions set forth in Tables 22 through 26 are required for construction of the Project, within the meaning of G.L. c. 40A, § 3. Additionally, we find that the Company engaged in good faith consultation with the towns of Millbury, Sutton, Northbridge, Uxbridge and Millville. Accordingly, the Siting Board grants the Company's request for the individual zoning exemptions listed above in Tables 22 through 26.

B. Comprehensive Zoning Exemptions

1. Standard of Review

The Company has requested a comprehensive exemption from the Millbury, Sutton, Northbridge, Uxbridge, and Millville Zoning Bylaws. The Siting Board will grant such requests on a case-by-case basis and only where the applicant demonstrates that issuance of a comprehensive exemption could avoid substantial public harm by serving to prevent a delay in the construction and operation of the proposed use. Hampden County at 93; Worcester at 81; GSRP, at 135.

In order to make a determination regarding substantial public harm, the Department and the Siting Board have articulated relevant factors, including, but not limited to, whether: (1) the Project is time sensitive; (2) the Project involves multiple municipalities that could have conflicting zoning provisions that might hinder the uniform development of a large project spanning these communities; (3) the proponent of the project has actively engaged the communities and responsible officials to discuss the applicability of local zoning provisions to the Project and any local concerns; and (4) the affected communities do not oppose the issuance of the comprehensive exemption. Hampden County at 89; Worcester at 82; GSRP at 136-137.

2. Company Position

The Company asserts that the Project is needed immediately in order to implement system improvements to meet and enhance system reliability, thereby avoiding substantial public harm (Exhs. NEP-2-1, at 32). NEP asserts that under both N-1 and N-1-1 contingencies, the system currently experiences thermal overloads and voltage performance issues and, therefore, the Project is time sensitive (Company Brief at 208).

The Company opines that due to the number of zoning provisions across the five towns and the unique attributes of the IRP compared to the usual type of project regulated at the local level, it would be imprudent to take the risk of seeking only individual exemptions given the scope, cost, and importance of the Project (RR-EFSB-20). The Company points to the greater regulatory certainty provided by the granting of a comprehensive zoning exemption with regard to all current and future provisions of the zoning bylaws (Company Brief at 210). Further, NEP asserts that any design change that may be necessary to mitigate environmental impacts of the Project could be promptly implemented (id.). The Company concludes that the granting of a comprehensive exemption would ensure the timely completion of the Project (id.).

3. Analysis and Conclusions

The granting of a comprehensive zoning exemption falls under a stricter standard of review than the granting of individual zoning exemptions. It is not enough to be required for construction of the Project; the granting of a comprehensive exemption must also avoid the potential for substantial public harm. As compared to the granting of individual zoning exemptions, which are tailored to meet the construction and operational requirements of a particular project, the granting of a comprehensive exemption serves to nullify a municipality's zoning code in its entirety with respect to the project under review. Thus, compared to the granting of individual zoning exemptions, which entail specific demonstrations that an exemption is required, a comprehensive zoning exemption constitutes a broader incursion upon municipal home rule authority. In the absence of a showing that substantial public harm may be avoided by granting a comprehensive exemption, the granting of such extraordinary relief is not justified. Tennessee Gas Pipeline Company, D.P.U. 11-26, at 31 (2012); NSTAR Electric Company, D.P.U. 08-1, at 36-37 (2009); Russell, EFSB 07-4/D.P.U. 07-35/07-36, at 71-72; Massachusetts Electric Company, D.T.E. 04-81, at 24 (2009); Tennessee Gas Pipeline Company, D.T.E. 01-57, at 11 (2002).

The Siting Board has considered and granted comprehensive exemptions that have typically involved reliability-based projects that were time sensitive, and spanned several municipalities, where conflicting interpretations could arise. Hampden County, at 92-93; Worcester, at 82; GSRP, at 137. Here, the Project is located across five towns, encompassing a distance of 15.4 miles. Importantly, as discussed in Sections III.B through III.D above, the IRP is needed to address important and immediate reliability issues in southern New England. In addition, the Company engaged in substantial good faith consultations with numerous officials of the towns of Millbury, Sutton, Northbridge, Uxbridge and Millville regarding the Project, and each of the five towns has written a letter of support for the Board's granting of a comprehensive zoning exemption. The Department finds that completion of the Project is time sensitive and that delay may result in substantial public harm.

Finally, the Environmental Controls of the Millbury Zoning Bylaw, Section 35 regulate not only the nature and characteristics of the facility to be constructed, but also the on-going operation of the proposed facility.[67] Were the Siting Board to grant a comprehensive zoning exemption from the Millbury Zoning Bylaw, local zoning control over certain relevant environmental considerations listed in Section 35 would no longer be applicable to the ongoing

67 Section 35 contains Sections 35.1, 35.21, 35.22, 35.23, and 35.3 through 35.7 (Exh. NEP-2-1 (Att. N) at 74-75).

operation of the proposed facility. Braintree Electric Light Department, 16 DOMSB 78, at 186-187 (2008). The Company has testified that it is able to meet the bulk of these requirements, and that generally, the requirements do not apply to construction impacts, with the exception of the individual exemptions detailed in Section VI.A, above: Sections 35.23 – Wetland Fill, 35.6 – Vegetation Removal, and 35.7 – Fences, which the Siting Board finds are required.

The Siting Board finds that the Company has met the burden of demonstrating that substantial public harm could result from delays in commencement and completion of the Project as affected by municipal zoning provisions in Millbury, Sutton, Northbridge, Uxbridge, and Millville. Accordingly, the Siting Board approves the Company's request for a comprehensive exemption from the Millbury, Sutton, Northbridge, Uxbridge, and Millville Zoning Bylaws, with the exception related to the enforcement of Sections 35.1, 35.21, 35.22, 35.3, 35.4, and 35.5 of the Millbury Zoning Bylaw. These comprehensive exemptions shall apply to the construction and operation of the proposed facility as described herein, to the extent applicable. See Planning Bd. of Braintree v. Department of Public Utilities, 420 Mass. 22, at 29 (1995).

C. Decision on G.L. c. 40A, § 3

The Siting Board finds pursuant to G.L. c. 40A, § 3 that construction and operation of the Company's Project is reasonably necessary for the public convenience or welfare. Accordingly, subject to the conditions set forth in this decision, the Siting Board approves the Company's Petition for an exemption from the provisions of the Millbury, Sutton, Northbridge, Uxbridge, and Millville Zoning Bylaws set forth in Tables 22 through 26 subject to the conditions set forth in Section X. The Siting Board further approves the Company's Petition for comprehensive exemptions from the Millbury, Sutton, Northbridge, Uxbridge, and Millville Zoning Bylaws, with the exception related to the enforcement of Sections 35.1, 35.21, 35.22, 35.3, 35.4, and 35.5 of the Millbury Zoning Bylaw, subject to the conditions set forth in Section X.

VIII. ANALYSIS UNDER G.L. C. 164 § 72

A. Standard of Review

G. L. c. 164, § 72, requires, in relevant part, that an electric company seeking approval to construct a transmission line must file with the Department a petition for "authority to construct and use . . . a line for the transmission of electricity for distribution in some definite area or for supplying electricity to itself or to another electric company or to a municipal lighting plant for distribution and sale … and shall represent that such line would or does serve the public convenience and is consistent with the public interest. . . . The [D]epartment, after notice and a public hearing in one or more of the towns affected, may determine that said line is necessary for the purpose alleged, and would serve the public convenience and is consistent with the public interest."[68]

The Department, in making a determination under G.L. c. 164, § 72, is to consider all aspects of the public interest. Boston Edison Company v. Town of Sudbury, 356 Mass. 406, 419 (1969). Section 72, for example, permits the Department to prescribe reasonable conditions for the protection of the public safety. Id. at 419-420. All factors affecting any phase of the public interest and public convenience must be weighed fairly by the Department in a determination under G.L. c. 164, § 72. Town of Sudbury v. Department of Public Utilities, 343 Mass. 428, 430 (1962). In evaluating petitions filed pursuant to G.L. c. 164, § 72, the Department relies on the standard of review established for G.L. c. 164, c. 40A, § 3 for determining whether the proposed Project is reasonably necessary for the convenience or welfare of the public.

B. Analysis and Decision

Based on the record in this proceeding and the above analyses in Sections III through V, and with implementation of the specified mitigation measures proposed by the Company and the conditions set forth by the Siting Board in Section X, below, the Siting Board finds pursuant to G.L. c. 164, § 72 that the proposed transmission line is necessary for the purpose alleged, would serve the public convenience, and are consistent with the public interest. Thus, the Siting Board approves the Section 72 Petition.

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68 Pursuant to G.L. c. 164, § 72, the electric company must file with its petition a general description of the transmission line, a map or plan showing its general location, an estimate showing in reasonable detail the cost of the line, and such additional maps and information as the [Siting Board] requires.

IX. SECTION 61 FINDINGS

MEPA provides that "[a]ny determination made by an agency of the Commonwealth shall include a finding describing the environmental impact, if any, of the project and a finding that all feasible measures have been taken to avoid or minimize said impact." G.L. c. 30, § 61. Pursuant to 301 C.M.R. § 11.01 (3), these findings are necessary when an Environmental Impact Report ("EIR") is submitted by a petitioner to the Secretary of Environmental Affairs, and should be based on such EIR. Where an EIR is not required, G.L. c. 30, § 61 findings are not necessary. 301 C.M.R. § 11.01 (3). In the instant case, the record indicates that a Draft EIR and Final EIR were required for the Project and ancillary facilities. Therefore, a finding under G.L. c. 30, § 61 is necessary for the Company's Zoning Exemption Petition and its Section 72 Petition.[69]

The Siting Board recognizes the Commonwealth's policies relating to GHG emissions, including G.L. c. 30, § 61 and the Executive Office of Energy and Environmental Affairs Greenhouse Gas Emission Policy and Protocol. The Siting Board notes that the Project would have minimal GHG emissions as it is an overhead transmission line.[70] As such, the Project would not have direct emissions from a stationary source or indirect emissions from energy consumption. The Siting Board addressed indirect emissions from off-road construction vehicles and equipment and SF_6 emissions for the Millbury Substation in Section V.B.3.g, above, and imposed conditions to minimize such emissions.

In Section V.B.3, above, the Siting Board conducted a comprehensive analysis of the environmental impacts of the Project and finds that the impacts of the Project along the Primary Route would be minimized and that the Project along the Primary Route would achieve an appropriate balance among conflicting environmental concerns as well as among environmental

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69 The Siting Board is not required to make a G.L. c. 30, § 61 finding under G.L. c. 164, § 69J as the Siting Board is exempt from MEPA requirements. G.L. c. 164, § 69I

70 The Secretary's Certificate on the Environmental Notification Form issued on December 30, 2011 states: "The Interstate Reliability Project is subject to the MEPA Greenhouse Gas (GHG) Emissions Policy and Protocol ('the Policy') because it requires an Environmental Impact Report. I have determined that this project will produce minimal greenhouse gas emissions. I therefore find that this project falls within the Policy's *de minimis* exception." Exh. NEP-5, app. B, at 9.

impacts, reliability, and cost. Accordingly, the Siting Board finds that all feasible measures have been taken to avoid or minimize the environmental impacts of the Project.

X. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H to 69Q, to provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. Thus, an applicant must obtain Siting Board approval under G.L. c. 164, § 69J, prior to construction of a proposed energy facility.

In Section III.D, above, the Siting Board finds that the existing electric transmission system is inadequate to reliably serve current and projected loads in southern New England under certain contingencies, and thus additional energy resources are needed in Massachusetts and more broadly across the southern New England region.

In Section IV.I, above, the Siting Board finds that the Project, on balance, is superior to the alternative project approaches in terms of cost and environmental impact and with respect to the ability to reliably meet the identified need. The Siting Board thus finds that the Project is preferable to the identified project alternatives with respect to providing a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Section V.A.4, above, the Siting Board finds that the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternatives to the Project in a manner that ensures that the Company has not overlooked or eliminated any routes that, on balance, are clearly superior to the Project. The Siting Board also finds that the Company has identified a range of practical transmission line routes with some measure of geographic diversity. Consequently, the Siting Board finds that NEP has demonstrated that it examined a reasonable range of practical siting alternatives.

In Section V.B.6, above, the Siting Board finds that the proposed facilities along the Primary Route would be preferable to the proposed facilities along the Alternative Route with respect to providing a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Section V.B.3, above, the Siting Board reviewed environmental impacts of the Project and finds that with the implementation of the specified mitigation and conditions, and compliance with all applicable local, state and federal requirements, the environmental impacts of the Project along the Primary Route would be minimized.

In Section VI, above, the Siting Board finds that with the implementation of specified mitigation and conditions, the Project is consistent with the health, environmental and resource use and development policies of the Commonwealth.

Accordingly, the Siting Board APPROVES the Company's Petition to construct the Project using the Primary Route, as described herein, subject to the following Conditions A through I.

In addition, the Siting Board has found pursuant to G.L. c. 164, § 72 that NEP's proposed facilities are necessary for the purpose alleged, and will serve the public convenience and are consistent with the public interest, subject to the following Conditions A through I.

In addition, the Siting Board has found pursuant to G.L. c. 40A, § 3 that construction and operation of the Company's proposed facilities are reasonably necessary for the public convenience or welfare. Accordingly, the Siting Board approves NEP's Petition for an exemption from certain provisions of the zoning bylaws of Millbury, Sutton, Northbridge, Uxbridge and Millville, as enumerated in Section VII above. The Siting Board grants the Company's Petition for a comprehensive exemption from the operation of the zoning bylaws of Millbury, Sutton, Northbridge, Uxbridge and Millville, as described in Section VII.

The Siting Board APPROVES the Companies' Petition subject to the following conditions:

A. The Siting Board directs the Company to ensure that under its continuing vegetative management program, any application of herbicides is consistent with utility right-of-way Integrated Vegetation Management Practices and applicable rules and regulations of the Commonwealth.

B. The Siting Board directs the Company to conduct weekday construction from 7:00 a.m. to 6:00 p.m., to conduct no work on Sundays and holidays, and to begin Saturday work at 9:00 a.m. rather than at 7:00 a.m. as the Company has proposed, and to end work on Saturday no later than at 5:00 p.m. Should the Company find that construction performed outside these hours or on holidays or Sundays is necessary, the Company shall seek written permission from the relevant municipal authority prior to the commencement of such work, and provide the Siting Board with a copy of such permission. If the Company and municipal officials are not able to agree on whether Sunday, holiday or extended weekday or weekend construction should occur, the Company may file a written request for prior authorization from the Siting Board, provided that it also notifies the relevant municipal authorities in writing of such request.

C. The Siting Board directs the Company, in consultation with the towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville, to develop a combined or, separately for each town, a community outreach plan for construction of the Project. The outreach plan(s) should, at a minimum, set forth procedures for providing prior notification to affected residents of: (1) the scheduled start, duration, and hours of construction; (2) any construction the Company intends to conduct that, due to unusual circumstances, must take place outside the hours detailed in Condition D, above; (3) the availability of web-based Project information; and (4) complaint and response procedures, including the Company's contact information.

D. The Siting Board directs the Company to incorporate the following requirements into its Visual Mitigation Plan:

(i) upon completion of construction, notify in writing by first class mail with delivery confirmation all owners of property located on or abutting the ROW of the option to request that the Company provide off-site screening. The Company would follow up with a phone call to non-responding property owners for whom a phone number is accessible. The off-site screening may include, but is not limited to, shrubs, trees, window awnings and fences, provided that the Company's operating and maintenance requirements for its ROW facilities are met;

(ii) provide property owners with a selection of generic renderings of possible mitigation approaches. Such renderings shall be for guidance purposes only, and shall not limit a property owner's ability to request different mitigation;

(iii) meet with each property owner who requests mitigation to determine the type of mitigation package the Company would provide, provided that the Company has received a response from the property owner within three months of receipt of the Company's written notification;

(iv) honor all property owners' requests for reasonable and feasible mitigation that are submitted within six months of a meeting with the Company and/or its consultants;

(v) issue a warranty to property owners to ensure that all plantings are established and replaced if needed at the end of one year from the date of planting, provided that the property owners reasonably maintain the plantings;

(vi) submit to the Siting Board for its approval, at least three months before the conclusion of construction, a draft of the notification letter to property owners prior to mailing; and

(vii) submit a compliance filing within 18 months of completion of construction detailing: (i) a list of all properties that were notified of the available off-site landscaping; (ii) the number of property owners that responded to the offer for off-site mitigation; (iii) a list of any property owners whose requests were not honored, and the rationale therefor; (iv) a general description of the types of off-site landscaping provided; and (v) the average cost of landscaping per property.

E. The Siting Board directs the Company, in consultation with municipalities and Company contractors, to develop and implement a traffic management plan to minimize traffic disruption. The Company's plan shall include, but not be limited to, the following measures: (1) signs erected to identify construction work zones; (2) police details and/or flagmen to direct traffic near public road crossings; (3) police details and/or flagmen to direct traffic at construction work sites along roads; and (4) the use of the shortest feasible construction material delivery routes.

F. The Siting Board directs that the Company ensure that all diesel-powered non-road construction equipment with engine horsepower ratings of 50 and above to be used for 30 or more days over the course of Project construction must have USEPA-verified (or equivalent) emission control devices, such as oxidation catalysts or other comparable technologies (to the extent that they are commercially available) installed on the exhaust system side of the diesel combustion engine. Prior to the commencement of construction, the Company shall submit to the Siting Board certification of compliance with this condition.

G. The Siting Board directs the Company to inform the Board if it adds SF_6 to any equipment at the Millbury No. 3 Switching Station or replaces any equipment at the Millbury No. 3 Switching Station equipment due to SF_6 loss within five years of the completion and initial operation of the Project, after which time the Company will consult with the Siting Board to determine whether the Siting Board will require continuing reporting, as deemed appropriate. The Company will also annually submit to the Siting Board a copy of its annual SF_6 report to MassDEP.

H. The Siting Board directs the Company to submit to the Board an updated and certified cost estimate for the Project prior to the commencement of construction. Additionally, the Siting Board directs NEP to file semi-annual compliance reports with the Siting Board starting within 60 days of the commencement of construction, that include projected and actual construction costs and explanations for any discrepancies between projected and actual costs and completion dates, and an explanation of the Company's internal capital authorization approval process.

Because issues addressed in this Decision relative to this facility are subject to change over time, construction of the Project must be commenced within three years of the date of the decision.

In addition, the Siting Board notes that the findings in this decision are based upon the record in this case. Project proponents have an absolute obligation to construct and operate the Project in conformance with all aspects of the proposal as presented to the Siting Board. Therefore, the Siting Board requires New England Power Company d/b/a National Grid or its successors in interest, to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. New England Power Company d/b/a National Grid or its successors in interest are obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

The Secretary of the Department shall transmit a copy of this Decision and the Section 61 findings contained herein to the Secretary of the Executive Office of Energy and Environmental Affairs and the Company shall to serve a copy of this decision on the Towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville; and the Boards of Selectmen of the Towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville; and the Planning Boards of the Towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville; and the Zoning Boards of Appeals of the Towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville, within five days of its issuance. The Company shall certify to the Secretary of the Department within ten business days of issuance that such service has been made.

Stephen H. August

Stephen H. August
Presiding Officer

Dated this 16th day of May 2014

APPROVED by the Energy Facilities Siting Board at its meeting of May 15, 2014, by the members present and voting. Voting for approval of the Tentative Decision as amended: Steven Clarke, Acting Energy Facilities Siting Board Chair/Designee for Richard Sullivan, Secretary, Executive Office of Energy and Environmental Affairs; Ann. G. Berwick, Chair, Department of Public Utilities, Jolette A. Westbrook, Commissioner, Department of Public Utilities, Mark Sylvia, Commissioner, Department of Energy Resources, Laurel MacKay, Designee for Commissioner, Department of Environmental Protection; Erica Kreuter, Designee for Secretary, Executive Office of Housing and Economic Development; Kevin Galligan, Public Member; and Penn Loh, Public Member.

Steven Clarke, Acting Chair
Energy Facilties Siting Board

Dated this 16th day of May 2014.

Appeal as to matters of law from any final decision, order or ruling of the Siting Board may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Board be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).