COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Boston Edison Company, d/b/a NSTAR Electric, for Approval to Construct a Three-Circuit 345 kV Transmission Line and Ancillary Facilities in the City of Boston and the Towns of Stoughton, Canton and Milton	EFSB 04-1
The Petition of Boston Edison Company, d/b/a NSTAR Electric, for a Determination that the Proposed 345 kV Transmission Line Project is Necessary and Will Serve the Public Convenience and be Consistent with the Public Interest	D.T.E. 04-5
The Petition of Boston Edison Company, d/b/a NSTAR Electric, for an Exemption from the Zoning By-Laws of the Town of Stoughton and the Zoning Code of the City of Boston in Connection with the Construction and Operation of the Proposed 345 kV Transmission Line	D.T.E. 04-7

FINAL DECISION

Selma Urman
Presiding Officer
January 14, 2005

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ABBREVIATIONS

1997 BECo Decision	Boston Edison Company, 6 DOMSB 208 (1997)
1997 Restructuring Act	"the 1997 Electric Restructuring Act" (Chapter 164 of the Acts of 1997)
1998 NEPCo Decision	New England Power Company, 7 DOMSB 333 (1998)
ACEC	Area of Critical Environmental Concern
ACOE	Army Corps of Engineers
Algonquin	Algonquin Gas Transmission Company
ANP Bellingham	ANP Bellingham Energy Company, EFSB 97-1 (1998), 7 DOMSB 39
ANP Blackstone	ANP Blackstone Energy Company, EFSB 97-2/98-2 (1999), 8 DOMSB 1
BECO	Boston Edison Company, d/b/a NSTAR Electric
Boston	City of Boston
Berkshire Power	Berkshire Power Development, Inc., D.P.U. 96-104, at 26-36 (1997)
Boston Gas	Boston Gas Company, D.T.E. 00-24 (2001)
Boston Surrounding Area	Area of communities surrounding downtown Boston
BRA	Boston Redevelopment Authority
CELCo Decision	Cambridge Electric Light Company, 12 DOMSB 305 (2001)
CELT	Capacity, Energy, Loads, & Transmission (yearly reports provided by NEPOOL)
City	City of Boston
cm	centimeter
ComElec Decision	Commonwealth Electric Company, 5 DOMSB 273 (1997)
Company	Boston Edison Company d/b/a NSTAR Electric
Conroy	Conroy Development Company
consolidated proceeding	EFSB 04-1; D.T.E. 04-5; D.T.E 04-7
CZM	Massachusetts Office of Coastal Zone Management
dB	decibels, unweighted

dBA	A-weighted decibels
DCR	Department of Conservation and Recreation
DEM	Massachusetts Department of Environmental Management
Department	Department of Telecommunications and Energy
DG	Distributed Generation
DOMSB	Decisions and Orders of Massachusetts Energy Facilities Siting Board
DOMSC	Decisions and Orders of Massachusetts Energy Facilities Siting Council
DRP	Independent System Operator of New England, Inc. Demand Response Program
DSM	Demand-Side Management
D.T.E.	Department of Telecommunications and Energy
ECMP	Environmental Construction Management Plan
EFSC	Energy Facilities Siting Council
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EMF	electromagnetic field
EOEA	Executive Office of Environmental Affairs
EPA	U.S. Environmental Protection Agency
Epsilon	Epsilon Associates, Inc.
GIS	Gas-insulated switchgear
GWh	gigawatt-hours
HDD	horizontal directional drill
Hz	hertz (cycles per second)
I&M	installation and maintenance
ICAP	Installed Capacity
IPOD	South Boston Waterfront Interim Planning Overlay District
ISO-NE	Independent System Operator of New England, Inc.
kV	kilovolts

L_{90}	sound level exceeded 90% of time
L_{dn}	day night sound levels
L_{eq}	time-averaged sound levels
L_{max}	maximum sound levels
LOLE	a one-day-in-ten-years loss-of-load expectation
LOS	level of service
LSP	Licensed Site Professional
LTE	Long-Term Emergency Ratings
Mass GIS	Massachusetts Geographic Information System
MBTA	Massachusetts Bay Transportation Authority
MCP	Massachusetts Contingency Plan
MDEP	Massachusetts Department of Environmental Protection
MDMF	Massachusetts Division of Marine Fisheries
MDOER	Massachusetts Division of Energy Resources
MDRP	Massachusetts Diesel Retrofit Program
<u>MECo/NEPCo Decision</u>	<u>Massachusetts Electric Company/New England Power Company</u>, 18 DOMSC 383 (1989)
MEPA	Massachusetts Environmental Protection Act
mG	milligauss
MHC	Massachusetts Historical Commission
MHD	Massachusetts Highway Department
<u>MMWEC Decision</u>	<u>Massachusetts Municipal Wholesale Electric Company</u>, EFSB 12 DOMSB 18 (2001)
Motion	Town of Stoughton Motion to Withdraw from proceeding filed 9/24/04
MPO	Boston Metropolitan Planning Organization
MVA	mega-volt-amperes
MVAR	mega-volt-amperes-reactive
MW	megawatts

MWRA	Massachusetts Water Resources Authority
NEA Decision	Northeast Energy Associates, 16 DOMSC 335 (1987)
NEP	New England Power Company
NEPOOL	New England Power Pool
New York Central Railroad	New York Central Railroad v. Department of Public Utilities, 365 Mass. 586 (1964)
Nextel	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)
NHESP	Massachusetts National Heritage Endangered Species Program
1996 NEPCo Decision	New England Power Company, 5 DOMSB 1 (1996)
NML	Noise Monitoring Location
Norwood Decision	Norwood Municipal Light Department, 5 DOMSB 109 (1997)
NPCC	Northeast Power Coordinating Council
NSTAR	Boston Edison Company, d/b/a NSTAR Electric
NSTAR Service Center	Service Center located at the southern boundary of the Hyde Park Substation
Phase I	Installation of cable for one circuit to K Street Substation and one circuit to Hyde Park Substation
Phase II	Installation of cable for second circuit to K Street Substation
PL	Property Line
PSC	Public Service Corporation
PTC	Pipe-type cable
PTI	Power Technologies, Inc.
RAO	Response Action Outcome
RMR	Reliability Must Run
Route 138 switching station	Switching station located at intersection of Route 138 and York St.
ROW	Right of way
RTEP	Regional Transmission Expansion Plan
RTN	Release Tracking Number

Save the Bay	Save the Bay, Inc. v. Department of Public Utilities, 366 Mass.667 (1975)
Section 72	G.L. c. 164, § 72
SEIR	Single Environmental Impact Report
SF_6	Sulfur hexaflouride gas
Siting Board	Energy Facilities Siting Board
SCADA	Supervisory Control and Data Acquisition
SJC	Massachusetts Supreme Judicial Court
SRA	Stoughton Redevelopment Authority
SRA switching station	Alternative switching station site at Stoughton Technology Center
SWPPP	Stormwater Pollution Prevention Plan
Stoughton	Town of Stoughton
Tennessee Gas (2002)	Tennessee Gas Pipeline Company, D.T.E. 01-57 (2002)
TDR	Time-domain reflectography
TMP	Traffic Management Plan
URAM	Utility Release Abatement Measure
USFW	United States Fish and Wildlife
USGen NE	USGen New England, Inc.
USGS	United States Geological Service

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Pursuant to G.L. c. 164, § 69J, the Energy Facilities Siting Board hereby approves, subject to the conditions set forth below, the petition of Boston Edison Company, d/b/a NSTAR Electric, for approval to construct a new three-circuit 345 kilovolt electric transmission line, approximately 17.5 miles in length, and ancillary facilities, for the purpose of connecting the existing 345 kilovolt transmission system located south of Boston with two substations in the City of Boston. Pursuant to G.L. c. 164, § 72, the Energy Facilities Siting Board hereby approves the petition of Boston Edison Company, d/b/a NSTAR Electric, for a determination that the proposed three-circuit 345 kilovolt electric transmission line is necessary, serves the public convenience and is consistent with the public interest. Pursuant to G.L. c. 40A, § 3, and Section 6 of Chapter 665 of the Acts of 1956, the Energy Facilities Siting Board hereby approves, in part, and denies, in part, the petition of Boston Edison Company, d/b/a NSTAR Electric, for exemption from the Zoning By-laws of the Town of Stoughton and the Boston Zoning Code in connection with the proposed transmission project.

I. INTRODUCTION

A. Summary of the Proposed Transmission Project

Boston Edison Company d/b/a NSTAR Electric ("NSTAR" or "Company") is an electric company pursuant to G.L. c. 164, § 1. NSTAR proposes to construct an approximately 17.5 mile, three-circuit 345 kilovolt ("kV") underground pipe-type transmission line, which will connect the existing 345 kV system located south of Route 128 with two key substations in the City of Boston ("Boston" or "City") (Exhs. BECO-1, at 1-1; EFSB-G-1, at 2-4 to 2-7, Fig. 2.2-2). The proposed transmission line will originate at a new switching station to be constructed in the Town of Stoughton ("Stoughton") adjacent to an existing 345 kV transmission line that runs from Walpole to Holbrook (id. at 1-1, 1-2). One of the three circuits will terminate at NSTAR's existing Hyde Park Substation, while the remaining two circuits will terminate at NSTAR's K Street Substation in South Boston (id. at 1-1). To support the new transmission line, NSTAR also proposes to expand facilities at the Hyde Park and K Street Substations and to install a new heat exchanger at the Baker Street Substation in West Roxbury (Exh. EFSB-G-1, at 2-1).

NSTAR stated that it would construct the proposed transmission project in two phases (Exh. BECO-1, at 13). The Company explained that it would complete the construction of the three underground steel pipes to house the transmission circuits in 2005 (id.). The Company would install one circuit of the two-circuit transmission line that terminates at the K Street Substation, and the single-circuit cable to the Hyde Park Substation, by June 2006 ("Phase I") (id. at 1-3). The Company would install the second circuit to the K Street Substation in 2007 ("Phase II") (id.).

NSTAR has noticed two routes for the proposed transmission project. The switching station for the primary route would be located at the intersection of Route 138 and York Street in Stoughton ("Route 138 switching station") (Exh. BECO-1, at 1-2). The purpose of the switching station is to split the existing overhead 345kV transmission circuit between Walpole and Holbrook into two 345 kV transmission circuits and link them to the three proposed underground transmission circuits (Exh. EFSB-G-1, at 2-17). From the Route 138 switching station, the three circuits would travel north in a common trench along Route 138 through the Towns of Stoughton, Canton, and Milton, and then in Boston along Cummins Highway to American Legion Highway (id. at 2-11, Fig. 2-2.1). At this point the circuits would diverge, with a single circuit traveling less than 1 mile to the Hyde Park Substation and the two remaining circuits traveling, in one trench, approximately 6 miles to the K Street Substation (id. at Figs. 2.2-1, 2.2-2 and 2.2-3).

The switching station for the alternative route would be located south of Reebok Drive in the Stoughton Technology Center, at a site owned by the Stoughton Redevelopment Authority ("SRA") ("SRA switching station") (Exh. BECO-1, at 1-3). From the SRA switching station, the three-circuit transmission line would travel north in a common trench, along Technology Center Drive, West Street, Lafayette Street, High Street, Scanlon Drive, and Route 28 through Stoughton, Randolph, and Quincy into Milton (Exh. EFSB-1, at 1-3). At the intersection of Central Avenue and Reedsdale Avenue in Milton, the circuits would diverge and follow different routes into Boston, with a single circuit traveling approximately 3.2 miles to the Hyde Park Substation and the two remaining circuits traveling, in one trench, approximately 7.2 miles to the K Street Substation (Exh. BECO-1, at 1-10).

B. Procedural History

On January 16, 2004, NSTAR filed a petition with the Energy Facilities Siting Board ("Siting Board") seeking approval, pursuant to G.L. c. 164, § 69J, to construct the proposed transmission project. This petition was docketed as EFSB 04-1 ("Siting Board petition"). In addition, the Company filed two related petitions with the Department of Telecommunications and Energy ("DTE" or "Department"): (1i) a petition pursuant to G.L. c. 164, § 72, seeking a determination that the proposed transmission lines are necessary, would serve the public convenience, and would be consistent with the public interest ("Section 72 petition") and (2) a petition pursuant to G.L.c. 40A, § 3 and for an exemption from the Zoning By-laws of the Towns of Stoughton and Canton and pursuant to Section 6 of Chapter 665 of the Acts of 1956 for an exemption from the Zoning Code of the City of Boston ("Zoning Exemption petition").[1] The Section 72 petition was docketed as D.T.E. 04-5; the Zoning Exemption petition was docketed as D.T.E. 04-7.

On February 2 , 2004, the Chairman of the Department issued a Consolidation Order which directed the Siting Board to render a final decision in the three cases ("consolidated proceeding"). The consolidated proceeding was docketed as EFSB 04-1/D.T.E. 04-5/ D.T.E. 04-7. The Siting Board conducted a single adjudicatory proceeding and developed a single evidentiary record for the consolidated proceeding.

The Siting Board initially conducted public comment hearings on the consolidated petitions on March 1, 2004 in Boston, Massachusetts and on March 3, 2004 in Canton, Massachusetts. On March 23, 2004, the Company submitted a supplemental filing that described and evaluated three additional route variations for the primary route, all located within Boston. On May 6, 2004, the Siting Board conducted a public comment hearing on the supplemental filing in Boston, Massachusetts.

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1 By letter dated March 24, 2004, NSTAR notified the Siting Board that the Company is no longer pursuing its earlier proposal to site the switching station at the Canton Industrial Park; accordingly, the Company withdrew its original request for an exemption from the Zoning By-laws of the Town of Canton.

In accordance with the direction of the Presiding Officer, the Company provided notice of the three public comment hearings and adjudication. The Siting Board received timely petitions to intervene from Boston and Independent System Operator-New England, Inc. ("ISO-NE"). Timely petitions to participate as limited participants were received from USGen New England ("USGen NE"), New England Power Company ("NEP"), The Marr Companies, Corkery Tractor and Trailer and Sons, Ruth M. Slocum, and George V. Mileris.[2] The Siting Board received late-filed petitions to intervene from the Town of Stoughton ("Stoughton") and Nancy Munroe. The Presiding Officer granted the petitions to intervene filed by Boston, ISO-NE and Stoughton and the petitions for limited participant status filed by USGen NE[3], NEP, the Marr Companies, Corkery Tractor and Trailer and Sons, Ruth M. Slocum, and George V. Mileris.

The Company presented the testimony of the following witnesses: Henry V. Oheim, Jr., Project Director for NSTAR, who testified concerning project overview, need, project alternatives, route selection, § 72 issues, and comparison of the preferred and noticed alternative routes; Charles P. Salamone, Director of System Planning for NSTAR, who testified concerning need, project alternatives and § 72 issues; Paul F. Barry, Lead Engineer, Transmission Lines Department for NSTAR, who testified concerning route selection, construction, cost and comparison of the preferred and noticed alternative routes; John Zicko, Principal Engineer, Substation Design for NSTAR, who testified concerning switching station design, construction, cost, and comparison of the preferred and alternative switching station sites and the zoning exemption petition; Stephen Carroll, Real Estate Manager for NSTAR, who testified concerning real estate and land acquisition, route selection cost, comparison of the preferred and alternative routes and the zoning exemption petition; Theodore A. Barten, P.E., Managing Principal of

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2 The following residents of Canton, Massachusetts also submitted timely petitions to participate as limited participants: Richard J. Dawson, William and Jean Gefteas, George E. Kalem, Jr., Jean Lambourne, and James Moran. However, based on NSTAR's withdrawal of its alternative proposal to site a switching station at Canton Industrial Park, the aforementioned individuals withdrew their petitions for limited participant status in the proceeding.

3 On January 7, 2005, the Presiding Officer granted the motion of Dominion Energy Salem Harbor, LLC to substitute for USGen NE as a limited participant in the proceeding.

Epsilon Associates, Inc. ("Epsilon"), who testified concerning project overview, project alternatives, route selection, cost, construction, environmental impacts, comparison of the preferred and alternative routes and the zoning exemption petition; Robert O'Neal, CCM, Principal at Epsilon, who testified concerning noise impacts; John K. Downing, Lead Senior Scientist at Shaw Group/Shaw Environmental, Inc., who testified concerning route selection, environmental impacts, traffic, hazardous materials and comparison of the preferred and alternative routes; Peter A. Valberg, Ph.D., Principal at Gradient Corporation, who testified concerning electric and magnetic fields ("EMF"); and Susan K. Haselhorst, Senior Analyst in NSTAR's Policy and Evaluation Group, who testified concerning the Company's energy efficiency programs.

ISO-NE presented the testimony of two witnesses: Stephen G. Whitley, Senior Vice President and Chief Operating Officer of ISO-NE, who testified concerning the need for the proposed transmission upgrades; and Richard Kowalski, Manager of Transmission Planning for ISO-NE, who testified concerning regional transmission planning.

The Town of Stoughton presented the testimony of two witnesses: James Byerley, a Principal Engineer with R. W. Beck, Inc.,who testified concerning the Company's site selection process; and Ivan Clark, Principal and Senior Director of R.W. Beck, Inc., who testified concerning certain environmental impacts of the primary route and alternative routes.

The Siting Board held seventeen days of evidentiary hearings, beginning on July 7, 2004, and concluding on September 4, 2004. Approximately 500 exhibits were entered into the evidentiary record. On September 24, 2004, Stoughton filed a motion to withdraw from the proceeding and to withdraw certain exhibits ("Motion").[4] On October 1, 2004, the Presiding Officer granted, in part, and denied, in part, the Motion, allowing Stoughton to withdraw from the case, but preserving all of the evidence in the record. Boston Edison Company, d/b/a NSTAR Electric, EFSB 04-1/ D.T.E. 04-5/ D.T.E. 04-7, Procedural Order at 1-2 (October 1, 2004)). On October 5, 2004, the Company, ISO-NE and Boston filed briefs. On October 12, 2004, the Company and USGen NE filed reply briefs. The evidentiary record was closed on

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[4] On September 27, 2004, Stoughton amended its Motion, seeking to withdraw additional exhibits.

December 22, 2004.

C. Jurisdiction and Scope of Review

The Company filed its Siting Board petition to construct the proposed transmission project in accordance with G.L. c. 164, § 69H, which requires the Siting Board to implement the energy policies in its statute to provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, and pursuant to G.L. c. 164, § 69J, which requires a project applicant to obtain Siting Board approval for the construction of proposed energy facilities before a construction permit may be issued by another state agency.

As a new electric transmission line with a design rating of 69 kV or greater and a length in excess of one mile, the Company's proposed transmission project falls within the definition of "facility" set forth in G.L. c. 164, § G, which provides that a "facility" includes:

> a new electric transmission line having a design rating of 69 kV or more and which is one mile or more in length on a new transmission corridor.

In addition, the structures that the Company proposes to construct and operate at the Route 138 switching station, and the Baker Street, K Street and Hyde Park Substations fall within the definition of "facility" set forth in G.L.c. 164, § G, which provides that "facility" also includes:

> an ancillary structure which is an integral part of the operation of any transmission line which is a facility.

In accordance with G.L. c. 164, § 69J, before approving a petition to construct facilities, the Siting Board requires an applicant to justify its proposal in three phases. First, the Siting Board requires the applicant to show that additional energy resources are needed (see Section II.A, below). Next, the Siting Board requires the applicant to establish, on balance, its proposed transmission project is superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the identified need (see Section II.B, below). Finally, the Board requires the applicant to show that it has considered a reasonable range of practical facility siting alternatives and that the proposed site for the facility is superior to a noticed alternative site in terms of cost, environmental impact, and reliability of supply (see Section III.A, below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, § 69J, the Siting Board is charged with the responsibility for implementing the energy policies in its statute to provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In carrying out its statutory mandate with respect to the construction of energy facilities such as NSTAR Electric's proposed transmission line, the Siting Board first evaluates whether there is a need for additional energy resources to meet reliability, economic efficiency, or environmental objectives. The Siting Board must find that additional energy resources are needed as a prerequisite to approving a proposed energy facility.[5]

In this instance, NSTAR has offered a need analysis that focuses on system reliability. In assessing reliability, the Siting Board first examines the reasonableness of the Company's system reliability criteria. The Siting Board then evaluates: (1) whether the Company uses reviewable and appropriate methods for assessing system reliability based on load flow analyses or other valid reliability indicators; (2) whether the transmission system meets these reliability criteria; under normal conditions and under certain contingencies, given existing and projected loads; and (3) whether acceleration of conservation and load management programs could eliminate the

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5 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 the Department's Order in D.T.E. 98-84A, Massachusetts electric companies, including NSTAR, 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.

need for such additional energy resources.[6]

In cases where the Company's assessment of system reliability is driven by load projections, the Siting Board also reviews the underlying load forecast. The Siting Board requires that forecasts be based on substantially accurate historical information and reasonable statistical projection methods. See G.L. c. 164, § 69J. To ensure that this standard has been met, the Siting Board has consistently required forecasts to be reviewable, appropriate and reliable. Boston Edison Company, 6 DOMSB 208, at 232 (1997). A forecast is reviewable if it contains enough information to allow full understanding of the forecasting method. A forecast is appropriate if the method used to produce the forecast is technically suitable to the size and nature of the company that produced it. A forecast is reliable if the method provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Boston Edison Company, 6 DOMSB 208, at 232 (1997); Boston Edison Company, 24 DOMSC 125, 146 (1992); Commonwealth Electric Company/Cambridge Electric Company, 12 DOMSC 39, 42 (1985).

2. Description of the Existing System

NSTAR explained that the bulk power system serving customer load in the Greater Boston Area[7] is composed of both generation and transmission elements (Exh. BECO-1, at 2-11).

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[6] The Siting Board notes that, pursuant to c. 249 of the Acts of 2004, applicants proposing a new transmission line are required to provide "... (3) a description of alternatives to the facility, such as other methods of transmitting or storing energy ... or a reduction of requirements through load management; ...." In addition, applicants are required to demonstrate that "projections of the demand for electric power ... include an adequate consideration of conservation and load management." G.L. c. 164, §69 J. However, c. 249 is not applicable here because it was enacted subsequent to the filing of NSTAR's petition. In future cases, the Siting Board may consider in its need analysis whether projections of the demand for electric power include an adequate consideration of conservation and load management. In addition, the Siting Board may consider load management as an alternative approach to meeting the demand for the proposed facility, if such consideration is appropriate in the context of the particular case.

[7] According to NSTAR, the "Greater Boston Area," also known as the "Boston Import

(continued...)

The generation elements in the Greater Boston Area range in size from 10 MW to 800 MW (id.). The principal generators are Mystic Blocks 7, 8, and 9; New Boston 1; Salem Harbor Units 1-4; and Kendall Station (id.).[8] These large generators are supplemented by many small units that total approximately 250 MW (id.). NSTAR stated that the generation facilities collectively provide a total of 3,546 MW of generation (id.).

NSTAR explained that 345 kV overhead lines form a nearly complete ring around the periphery of the Greater Boston Area (Exh. BECO-1, at 4-3). The Company stated that several 345 kV overhead circuits connect this ring to the regional New England transmission system through the Ward Hill, Tewksbury, and Golden Hills Substations to the north, and through substations in West Medway, Medway, Walpole, Ayer and Millbury to the south and west (id. at 2-12, 4-3, and Figs. 1-2, 2-3). NSTAR explained that existing 345 kV lines move bulk power from the northern part of the ring into the interior of the Greater Boston load center, but that from the southern portion of the ring, power must flow over a limited number of 115 kV and 230 kV circuits (Exh. BECO-1, at 4-3 and Fig. 1-2).[9] The Company stated that the Greater Boston Area has an import capability of 3,600 to 3,800 MW (id. at 2-25; Tr. 1, at 21; Tr. 2, at 161).

NSTAR indicated that it has 38 substations within the Greater Boston Area (Exh. BECO-1, Table 2-2). These substations serve peak loads ranging from 10 MW to over 200 MW each (Exh. BECO-1, at Table 2-2). Ten of these substations are located in the Downtown Boston

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[7] (...continued)
Area," is defined by constraints on transmission (Tr. 1, at 20); it consists of the area roughly bounded by Salisbury, Amesbury, Merrimac, Haverhill, Salem (NH), Methuen, Lawrence, Andover, Tewksbury, Wilmington, Burlington, Bedford, Carlisle, Acton, Maynard, Sudbury, Framingham, Ashland, Holliston, Sherborn, Medfield, Dover, Westwood, Dedham and Milton (Exh. EFSB-N-4).

[8] According to the Company, the New Boston 1 generator is due to be retired prior to 2006 (Exh. BECO-1, at 2-18). According to ISO-NE, the owner of Kendall Station (170 MW) requested permission to deactivate in October, 2004; as of September 2, 2004, ISO-NE had not acted upon this request (id. at 2-19; Tr. 15, at 2047).

[9] Within the Greater Boston Area, the transmission elements include 355 miles of 115 kV transmission lines, 59 miles of 230 kV lines and 91 miles of 345 kV lines (Exh. BECO-1, at 2-11). Of these, approximately 300 miles are overhead lines and 200 miles are underground (id.).

sub-area, ten in the "Surrounding Boston" sub-area,[10] and the remainder in further outlying parts of Greater Boston (Exh. BECO-1, at Table 2-2). Additional substations within the Greater Boston Area are owned by other entities (id. at Fig. 1-2).

3. Reliability of Supply

The Company asserted that the proposed project is needed to maintain its transmission system in compliance with reliability standards of the Northeast Power Coordinating Council ("NPCC"), the New England Power Pool ("NEPOOL"), and ISO-NE (Exh. BECO-1, at 2-1). More specifically, NSTAR asserted that the 345 kV transmission line will alleviate transmission capacity constraints in critical load centers within its service territory (id.). The Company based this conclusion primarily on analyses of transmission overloads under single-contingency conditions (id. at 2-1, 2-16 to 2-22). The Company also asserted that the proposed facilities, in conjunction with other new facilities, are needed to mitigate voltage concerns in the Greater Boston Area (id. at 2-22 to 2-25; Tr. 1, at 44-45). In addition, ISO-NE asserted that the project is needed to address adequate reserve margins during contingencies (Exh. ISO-SGW at 3, 15).

a. Criteria and Methods for Reliability Analysis

NSTAR explained that it must adhere to reliability standards and criteria established by the NPCC and NEPOOL/ISO-NE, as well as to the Company's own reliability standards (Exh. BECO-1, at 2-5). The standards and criteria describe a set of operating scenarios under which system performance should be analyzed, and the characteristics of that performance that are considered acceptable (id. at 2-5 to 2-9). A key test of the transmission system is a thermal analysis, i.e., the determination of whether transmission elements become loaded beyond their capacity ratings under the load-flow conditions that would result from normal system operations

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[10] The "Surrounding Boston" sub-area appears to refer to the area roughly bounded by Chelsea, Everett, Somerville, Arlington, Belmont, Waltham, Weston, Wellesley, Needham, Dedham, and Milton (Exh. EFSB-N-8, Att.).

and various "N-1" contingency situations (id. at 2-8; ISO-SGW-3; ISO-SGW-4, at 7).[11] In addition, the Company analyzes the system's voltage performance, stability, ability to respond to short circuits, and transfer capability (Exh. BECO-1, at 2-8 to 2-9).

NSTAR stated that, consistent with its own and NEPOOL/ISO-NE standards, it analyzed system performance for extreme weather conditions, i.e., performance under peak demand that corresponds to an extreme-weather forecast (Tr. 1, at 94).[12] The Company stated that it used simulation software by Power Technologies, Inc. ("PTI") to develop an analytical model that represents the Company's physical system, then used the model to test the system under different operating scenarios (Exh. BECO-1, at 2-4, 2-7). The operating scenarios included a base case, in which all transmission elements are in service and the generating units exhibit a "typical" level of unavailability, as well as various contingency situations in which transmission elements are out of service, with or without the loss of additional generation (id. at 2-5 to 2-6).

With regard to generation unavailability, NSTAR stated that ISO-NE projected a typical level of generation unavailability of 279 MW for the Boston Import Area for the years 2005 and beyond, based on historical forced outage rates (Exhs. EFSB-N-2(a), at 24; EFSB-N-9; Tr. 1, at 24-25). However, NSTAR assumed an unavailability level of 350 MW, which is approximately equivalent to the output of one of the two Mystic Block 9 gas turbines plus the associated output from its steam turbine (Exh. EFSB-N-9; Tr. 1, at 27). The Company indicated that, given the sizes of the generators within the Greater Boston Area, this outage is the smallest single-unit outage that is at least as large as ISO-NE's projected typical unavailability level (Exh. BECO-1, at 2-19). According to the Company, Mystic 9 would represent the worst location within the Greater Boston Area where a generator unavailability of this magnitude could occur (Tr. 1,

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[11] According to the Company, an "N-1" contingency can be either the loss of one transmission element, or the loss of a transmission element in conjunction with the loss of a major generating unit (beyond the typical level of generator unavailability established by ISO-NE for the area) (Exh. BECO-1, at 2-6; Tr. 1, at 15-18).

[12] The 2003 Greater Boston peak demand forecast for extreme weather conditions was higher than the peak demand forecast for normal weather conditions by 325 MW or 5.9% for the Greater Boston Area, 148 MW or 5.9% for the Surrounding Boston Area, and 60 MW or 5.8% for the Downtown Boston Area (Exh. EFSB-RR-3).

at 27). To analyze those N-1 contingencies in which generation outages beyond the typical unavailability level are a factor, NSTAR explained that it developed generation dispatch scenarios to reflect the unavailability of additional generators (Exh. BECO-1, at 2-18).

In addition to the thermal analysis, the Company assessed voltage levels in the Greater Boston Area under projected peak-load condition (id. at 2-22 to 2-25). The Company stated that the criteria for voltage levels allow no more than a 5% deviation from the transmission element's voltage rating (id. at 2-23).

b. Load Forecasts

In conjunction with a model of the transmission system, a forecast of load levels is needed to conduct a reliability analysis. NSTAR explained that its process of forecasting load for its Greater Boston Area substations is linked to ISO-NE's forecasting process (Exh. BECO-1, at 2-13 to 2-16; Tr. 1, at 91-102). According to the Company and ISO-NE, ISO-NE uses regression models to relate historical electricity use to economic factors, electricity prices, weather, and other factors (Exhs. BECO-1, at 2-13; ISO-SWG at 22). NSTAR stated that ISO-NE develops long-term energy forecasts for each New England state from these models (Exhs. BECO-1, at 2-13; RR-EFSB-22). From the energy forecasts, ISO-NE then derives peak load projections for each state by applying "load factors" (ratios of historic peak loads to total energy use) (Exh. BECO-1, at 2-13; Tr. 1, at 92).[13]

The Company stated that ISO-NE apportions its statewide peak-load forecast to sub-areas within the state by considering forecasts of peak load developed by individual distribution companies for their territories, and allocating the statewide peak proportionately (Exh. RR-EFSB-22; Tr.1, at 101). NSTAR explained that the peak load forecasts it submits to ISO-NE for its Boston Edison and Cambridge Electric service territories are derived by applying load factors to the energy forecasts it develops for those subsidiaries (Exh. RR-EFSB-22). NSTAR stated that its underlying energy forecasts are prepared based upon econometric models for each sector

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13 Energy forecasts pertain to total energy use over a period of time, expressed in units such as megawatt-hours; *peak load* forecasts address power consumption at a point in time, and are expressed in units such as megawatts.

(e.g., residential, commercial, industrial, Massachusetts Bay Transportation Authority ("MBTA"), Massachusetts Water Resources Authority (" MWRA")), and that the models regress historical sales against economic, demographic and weather variables (id.; Exh. RR-EFSB-22 (S)). The Company explained that it evaluates the validity of each regression model through the use of statistical tests, data plots, and comparison of recent actual values with predicted values (Exh. RR-EFSB-22 (S); Tr. 17, at 2277-2278). The Company stated that it used forecasts by Global Insight/Data Resources, Inc. for future values of the driving variables (Exh. RR-EFSB-22; Tr. 17, at 2276).

Once ISO-NE allocates a share of the statewide peak load to NSTAR's territories, NSTAR allocates that load to its own substations (Exh. BECO-1, at 2-14; Tr. 1, at 101). The Company explained that its allocation method employs software that identifies growth potential in the service areas of each of its substations (Exh. BECO-1, at 2-15). The Company stated that the software uses historical peak load data for the substations, as well as demographic data and information about zoning, land use, and infrastructure, to develop factors for allocating the ISO-NE area forecast to the individual substations (id.). NSTAR explained that it also takes into account peak loads for large customers that are expected to join or leave the system (Exh. EFSB-6; Tr. 1, at 104). The Company stated that the resultant substation peak load forecasts reflect extreme weather ("90/10") assumptions, as opposed to normal weather ("50/50") (Tr. 1, at 96).

The Company provided the following projections of peak load, including losses associated with transmission and substation elements, for Downtown Boston, the Surrounding Boston Area, and the Greater Boston Area:

Table 1: Greater Boston Sub-Area Load Forecast (Extreme Summer Peak in MW)

	2002	**2006**	**2008**
Greater Boston Area	5725	5861	6017
Surrounding Area	2611	3002	3141
Downtown Boston	1067	1294	1359

Note: 2002 figures reflect actual data expressed in extreme weather terms. "Surrounding Area" figures include "Downtown Boston" figures; "Greater Boston" figures include "Surrounding Area" figures.
Sources: Exhs. BECO-1, at 2-16; EFSB-N-8; RR-EFSB-3.

The projections show average annual growth rates from 2002 to 2006 of 4.94% in Downtown Boston, 3.55% in the Surrounding Boston Area (inclusive of Downtown), and 0.6% in Greater Boston overall. The Company noted that, when modeling the reliability of particular transmission elements, it used projections of peak load at its individual substations within the Greater Boston Area for the years 2006, 2008, and 2013 (Exh. BECO-1, at 2-14; Table 2-2; Tr. 1, at 95,101).

NSTAR indicated that it administers two demand-side management initiatives within its service territory: a series of energy efficiency programs, and an ISO-NE demand response program ("DRP") (Exh. BECO-1, at 3-5 to 3-8). The Company stated that approximately 5% of its customers participated in its energy efficiency programs in 2002, resulting in a reduction in peak-load summer demand of approximately 21 MW (id. at 3-5).

As a "demand response service provider" for the ISO-NE DRP, NSTAR reported that by the end of 2003 it had approximately 110 participants with a total response capacity of 45 MW, although not all the participants are located within the Boston Import Area (id. at 3-7; Tr. 3, at 323). The Company noted that the total 2003 DRP enrollment for the Greater Boston Area amounts to 80 MW of response capacity (Exh. BECO-1, at 3-7; Tr. 3, at 322). NSTAR stated that it is actively engaged in marketing the DRP program (Tr. 3, at 325). The Company stated that it does not include any demand reduction achieved through the ISO-NE demand response program in its forecasted peak-load demands because the ISO-NE program is designed to address regional capacity constraints and is not generally available to address local area concerns (Exh. RR-EFSB-9).[14]

c. Equipment Loading and Voltage Analysis

Using the system model, load forecasts, and reliability criteria described above, NSTAR performed thermal analyses for 2006, 2008, and 2013, and voltage analyses for 2008. The results are presented below.

i. Thermal Analysis Results: 2006, No Project

The Company's thermal analysis indicated that by 2006, without the Project, several

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14 However, ISO-NE states that its forecasts "are adjusted to consider the moderating effect of demand-side management efforts" (Exh. ISO-NE-SWG at 23).

system elements would be loaded above their long-term emergency ratings ("LTEs") during various contingencies (Exh. BECO-1, at 2-19 to 2-22). Losses of Kendall Unit 4, Mystic Block 8, or the remaining 50% of Mystic Block 9 would cause the worst thermal overloads (id. at 2-18 to 2-19). NSTAR's model indicated that the most significant overloads within the Downtown Boston Area would occur on two 345 kV cables between the Mystic and Kingston Street Substations, two 345/115 kV transformers at the Kingston Street Substation, a 345/115 kV transformer at the Mystic Substation, two 115 kV cables between the Kingston Street and K Street Substations, and two 115 kV cables between the Mystic and K Street Substations (id. at 2-19 to 2-20). The model projected that these facilities would experience loadings at 108 to 130 % of their LTEs (id. at 2-20). For the Surrounding Boston Area, the Company identified additional elements, including the 115 kV cables between the Waltham and Watertown Substations, between the North Cambridge and Brighton Substations, between the Mystic and Brighton Substations and between the Baker Street and Brighton Substations among the facilities of greatest concern (id. at 2-20 to 2-21). These cables would experience loadings at 102 to 155 % of their LTEs (id. at 2-21). Finally, in the southern portion of the Greater Boston Area, the Company's model indicated that 115 kV cables between the West Walpole and Baker Street Substations, a 115 kV line between Framingham and Baker Street, and two 345 to 115 kV transformers in Medway and Walpole would experience overloads of between 101 and 112 % of their LTEs (id.).

NSTAR stated that the overloads in the Downtown Boston and Hyde Park/West Roxbury areas are of the greatest concern due to the load requirements and system constraints in these areas (Exh. BECO-1, at 2-22). The Company explained that it currently uses various operational adjustments, including load transfers, system reconfigurations, phase-angle regulator adjustments and fast-response unit dispatch, to keep some facilities within normal ratings during non-contingency conditions, but that as loads increase such adjustments will become increasingly difficult to make without aggravating post-contingency conditions (id. at 3-4; Tr. 1, at 48-54).

The Company's modeling assumed that generator New Boston 1 would be retired prior to 2006 (Exh. BECO-1, at 2-11, 2-18). In response to Siting Board inquiries, NSTAR re-ran its thermal analysis using the assumption that 350 MW from New Boston 1 would be available in

2006. The results indicated that this would alleviate many of the 2006 Downtown Boston overloads, but that significant overloads would persist in the remainder of Greater Boston Area (Exh. RR-EFSB-2, at 4).

ii. Thermal Analysis Results: 2006, Two Circuits

The Company's analysis of the transmission system with the addition of one 345 kV cable from Stoughton to the Hyde Park Substation and one 345 kV cable from Stoughton to the K Street Substation indicated that all the post-contingency loadings previously identified as exceeding elements' LTEs would be brought down to the LTE or lower (Exh. BECO-1, at 2-28). However, several of these loadings would remain above 95% of the LTE (id.).

iii. Thermal Analysis Results: 2008, Two Circuits

According to NSTAR's analysis, by 2008 overloads would re-emerge in the Downtown Boston and Waltham/Watertown areas, even with the first two cables in place (Exh. BECO-1, at 2-29). These overloads would range from 101% of LTE to 106% of LTE (id.).

iv. Thermal Analysis Results: 2008, Three Circuits

The Company stated that the installation of an additional circuit from Stoughton to the K Street Substation would successfully mitigate the contingency overloads that would emerge in 2008 with two circuits installed in 2006 (Exh. BECO-1, at 2-29). With this third circuit in place, the Company's analysis shows that no previously overloaded transmission element would be loaded higher than 95% of its LTE (id.).[15] NSTAR states that these results indicate that three circuits are needed and that the third circuit should be in service for summer 2008 peak load conditions (id.).

15 According to the Company, within the 2006-2013 timeframe, there would be additional overloads in the Downtown Boston Area that are not mitigated by the proposed project (Tr. 2, at 191-192).

v. Thermal Analysis Results: 2013, Three Circuits

NSTAR stated that it carried its modeling through 2013 and found that even with all three circuits in place, contingency overloads would again emerge (Exh. BECO-1, at 2-30). The Company presented results of its analysis that show Downtown Boston transmission elements at 96 to 105% of their LTEs, and surrounding community area elements at 104 to 114% of their LTEs (id.). The Company attributed these overloads to projected load growth in the area (id.).[16]

vi. Voltage Analysis Results

The Company stated that it identified low voltage problems on the 115 kV system serving Downtown Boston and other parts of the Greater Boston Area on a pre-contingency basis by 2008 (Exh. BECO-1, at 2-23). The Company stated that based on these findings, it modified its model to assume the addition of several capacitor banks when analyzing contingencies in 2008 and 2013 (id.). NSTAR then provided results for 2008 showing several instances of voltage more than 5 % above or below the desired levels under the dispatch scenario in which all of Mystic Block 9 is out of service, but without the failure of any transmission elements (id. at 2-23 to 2-24). According to the Company, further analysis showed that without the proposed 345 kV transmission lines, contingency conditions would necessitate the installation of additional capacitor banks to mitigate low-voltage concerns, but that with the proposed project, these capacitors would not be needed (id. at 2-23). However, the Company noted that, under lower-than-projected load conditions, the capacitance provided by the new 345 kV lines would have the potential to cause high voltage conditions (id.). To regulate the voltage effects of the new transmission circuits, the Company stated that it would install shunt reactors at both the proposed Stoughton switching station and the K Street Substation (Exh. BECO-1, at 1-13 and 1-16).

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16 The Company acknowledged that increased energy efficiency, demand response, and distributed generation in its system might defer the need for future upgrades to a time period beyond 2013 (Tr. 3, at 347-349). To do so, however, the Company asserted that the measures would need to target the load in the subareas served by the specific facilities that are expected to experience overloads (id.). For this reason, the Company stated that it is unable to speculate how these measures might affect reliability issues (Exh. COB-R-5).

d. Analysis

The Siting Board consistently has found that if the loss of any single major component of a supply system would cause thermal overloads on other system components, unacceptable voltage levels, or significant customer outages, then additional resources to maintain system reliability are justified. Boston Edison Company, 6 DOMSB 208, at 233 (1997); Norwood Municipal Light Department, 5 DOMSB 109, at 120-121 (1997); 1996 NEPCo Decision, 5 DOMSB 1, at 10 (1996). Here, the Company has shown that it has based the analysis of its system on widely applied standards established by NPCC and ISO-NE to ensure that the electric power systems serving New England and the NSTAR Electric service territory are designed to provide an adequate and reliable electric power delivery system. These standards include criteria pertaining to thermal loads and voltage levels during normal and contingency operations. Accordingly, the Siting Board finds that NSTAR's reliability criteria regarding equipment loadings and voltage levels are reasonable.

With regard to NSTAR's methods for assessing system reliability, the Siting Board examined the Company's assumptions regarding extreme versus normal weather loads and generator unavailability, and its use of modeling. With respect to weather-related load assumptions, the Siting Board has relied on analyses of need based on the use of a high load forecast, in order to reflect uncertainties inherent in system-coincident and peak-day weather. New England Power Company, 5 DOMSB 1, at 17 (1996); New England Power Company, 4 DOMSB 109, at 125 (1995). Similar to past transmission reviews, the Company based its system load assumptions on extreme weather conditions. The Siting Board notes that in this case, the supply area in which need is expected to arise encompasses much of the Greater Boston Area – an area supplied by generation as well as transmission. Although applied in a different context than in past Siting Board reviews, the Siting Board accepts as reasonable the Company's use of extreme weather load assumptions for determining the need for additional resources.[17]

[17] For the Boston Surrounding Area, the difference between the 2003 extreme forecast and the 2003 normal forecast is 148 MW (Exh. RR-EFSB-3). This is comparable to the 139 MW of growth in extreme load forecast for the two years from 2006 to 2008 (Exh. BECO-1, at 2-16).

With regard to its assumptions about generation resources, the Siting Board notes that the Company's base-case level of "typical" generator unavailability was greater than that projected by ISO-NE for the years in question. Specifically, the Company represented ISO-NE's projected average unavailability of 279 MW of generation as the outage of 50% of Mystic Block 9, which has a capacity of approximately 350 MW. Thus, the output of this generator unit is 71 MW greater than ISO-NE's projected average unavailability level. The Siting Board notes that, compared to the projected 2006-2008 growth of 139 MW for the Boston Surrounding Area, the extra 71 MW of assumed unavailability of generation is equivalent to one year's worth of growth. The Company also stated that the Mystic Block 9 represents the most critical generation location with the Greater Boston Area, apparently compounding a conservative assumption about generator unavailability. On the other hand, 50% of Mystic Block 9 is the smallest unit in the Greater Boston Area that is at least as large as ISO-NE's projected unavailability level. Moreover, ISO-NE's projected level of generator unavailability does not account for the possible retirement of Kendall Station. On balance, the Siting Board accepts the Company's assumption concerning generator unavailability.

In addition to detailing its load and generation assumptions, NSTAR has explained how it uses a simulation program to model its system, and has shown how it uses load flow analyses to identify where thermal overloads would occur on the system under contingency conditions. Thus, in considering its assumptions about weather-related load levels and generator unavailability, and its use of modeling to simulate and test its system under a variety of scenarios, the Siting Board finds that the Company used reviewable, appropriate and reliable methods for assessing system reliability.

The record indicates that NSTAR's load forecasting method is a three-step process consisting of (1) an econometric-based system-level projection of energy use across its service areas; (2) an aggregated peak load forecast developed by ISO-NE for Massachusetts; and (3) a substation-level forecast derived by allocating ISO-NE's Massachusetts forecast to NSTAR's individual substations in accordance with local growth potential. The Company has provided enough 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.

The Company also has provided evidence of close coordination with ISO-NE in the development of its forecast. Therefore, the Siting Board finds that NSTAR's load forecast is reviewable, appropriate, and reliable.

The Company has shown that its contingency load flow analyses project thermal overloads on various transmission elements in Downtown Boston and elsewhere in the Greater Boston Area as early as 2006. The Company has used the same approach to demonstrate that thermal problems would re-emerge in 2008 if only two of the proposed three 345 kV circuits were installed. Thus, the Company has demonstrated need for the proposed project to address violations of thermal criteria.

With respect to voltage levels, the Company described its additional assumptions regarding system upgrades and provided analyses that showed violations of its voltage criteria in 2008. However, the Company identified other means of addressing low-voltage problems that could be implemented without the proposed project. The record does not contain sufficient information to determine whether the project is needed to address voltage concerns alone. Consequently, the Siting Board does not rely on the Company's arguments regarding voltage problems in considering the need for this project. However, based on the violations of thermal criteria, discussed above, the Siting Board finds that additional energy resources are needed.

e. Conclusions on Reliability of Supply

The Siting Board has found that the Company used reasonable criteria and reviewable, appropriate, and reliable methods for evaluating system reliability. The Siting Board has also found that the Company used a reviewable, appropriate and reliable load forecast. Further, the Siting Board has found that the Company has demonstrated need for additional energy resources to address violations of thermal criteria. Finally, as further discussed in Section II.B, below, the Siting Board finds that acceleration of conservation and load management programs would not eliminate the need for additional energy resources.

Based on the foregoing, the Siting Board finds that NSTAR has demonstrated that the existing electric transmission system is inadequate to reliably serve projected loads in the Greater Boston Area under certain contingencies. Accordingly, the Siting Board finds that additional energy resources are needed for reliability in the Greater Boston Area.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, § 69H requires the Siting Board to evaluate proposed projects in terms of their consistency with providing a reliable energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost. In addition, G.L. c. 164, § 69J requires a project proponent to present "alternatives to planned action" which may include: (a) other methods of generating, manufacturing, or storing electricity or natural gas; (b) other sources of electrical power or natural gas; and (c) no additional electric power or natural gas.[18]

In implementing this part of its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to such alternative approaches in terms of cost, environmental impact, and ability to meet the identified need. CELCo Decision, 12 DOMSB 305, at 321; Boston Edison Company, 6 DOMSB 208, at 252 (1997) ("1997 BECo Decision"); Boston Edison Company, 13 DOMSC 63, at 67-68, 73-74 (1985). 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. 1997 BECo Decision, 6 DOMSB 208, at 262-263; Commonwealth Electric Company, 5 DOMSB 273, at 300 (1997) ("ComElec Decision"); Massachusetts Electric Company, 18 DOMSC 383, at 404-405 (1989).

2. Identification of Project Approaches for Analysis

The Company considered seven approaches for meeting the identified needs in the Greater Boston Area, including: (1) the proposed underground 345 kV project; (2) a 115 kV transmission alternative; (3) a full or partial overhead 345 kV transmission alternative; (4) a transmission improvements alternative made up of a series of limited, localized reconductoring and expansion projects ("bundled improvements alternative"); (5) a new generation alternative;

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18 G.L. c. 164, § 69J also requires a petitioner to provide a description of "other site locations." The Siting Board reviews the Company's primary route, as well as other possible routes, in Section III.A, below.

(6) a demand-side management alternative; and (7) a distributed generation alternative (Exh. BECO-1, at 3-2 to 3-17).[19]

a. Underground 345 kV Project

The proposed underground 345 kV project consists of installing three underground circuits, each extending from south of Boston to one of two Boston area delivery points (Exh. BECO-1, at 3-2 to 3-3). Under the Company's proposal, new underground circuits would originate from a point along the existing West Walpole-Holbrook 345 kV transmission line and supply additional power to the Hyde Park Substation in the Surrounding Boston Area and K Street Substation in downtown Boston (id. at 3-3). The Company confirmed that, with one new circuit on-line to each of these substations in 2006 and a second new circuit on-line to K Street Substation in 2008, the Greater Boston Area would receive reliable supplies consistent with applicable standards relating to thermal ratings and system voltages for 2006 to 2008 and beyond (id. at 2-27 to 2-31, 3-3). For purposes of project comparison, the Company estimated the cost of the underground 345 kV project at $177 million (id. at 3-24).

b. 115 kV Transmission Alternative

The Company indicated the 115 kV transmission alternative would include installing eight or nine underground 115 kV transmission circuits, each extending from south of Boston to one of two Boston area delivery points (Exh. BECO-1, at 3-11). The Company stated that the capacity of this number of 115 kV underground circuits could match the capacity of the proposed 345 kV project (id. at 3-11). The Company noted that, to avoid overheating, no more than three circuits could be placed in the same trench; therefore, the trench miles of construction potentially would be three times greater than with implementation of the proposed underground 345 kV project, and routing of transmission lines could be required along more streets (id. at 3-11). The

19 The Company also considered a no-build alternative. The Company determined that this approach would prevent it from providing uninterrupted service to the Boston area consistent with its service obligation (Exh. BECO-1, at 3-4). Therefore, this approach was not considered further (id.).

Company concluded that the 115 kV transmission alternative could provide sufficient new capacity to meet identified needs (id. at 3-11). The Company estimated the cost of the 115 kV transmission alternative at $270 million (id. at 3-29).

c. Overhead Transmission Alternative

The Company indicated that the overhead transmission alternative would involve either installing two overhead circuits extending in succession to two Boston area delivery points, or installing two overhead circuits to the first delivery point, then installing underground circuits from there to the second delivery point (Exh. BECO-1, at 3-10; Exh. EFSB-PA-4). The Company stated that the capacity of one overhead 345 kV circuit could match the capacity of three underground 345 kV circuits (Exh. BECo 1, at 3-10). The Company indicated, however, that the project would require at least two overhead circuits to provide mutual backup consistent with applicable reliability criteria (id. at 3-20).[20]

The Company stated that it identified only two existing rights-of-way originating south of Boston that could accommodate overhead 345 kV transmission lines directly supplying Boston area delivery points from which identified needs could be met: (1) a railroad ROW extending to the Hyde Park Substation; and (2) a railroad ROW extending to the Baker Street Substation in West Roxbury (id. at 3-10 to 3-11). However, the Company rejected these routes on feasibility grounds, explaining that both rail corridors are too narrow and would entail other feasibility concerns, such as traversing densely developed areas, crossing extensive wetlands, or being subject to extensive work restrictions due to frequent train passage (id. at 3-11). The Company stated that the nearest ROW capable of feasibly accommodating 345 kV overhead transmission was a power line corridor which comes to within four miles of the most westerly possible

[20] While agreeing that this requirement would have the additional unintended result of generally providing added transmission capacity into the Boston area, relative to other alternatives, the Company maintained that such a capacity margin would provide no reliability advantage (Exh. EFSB-PA-4). The Company explained that no need for the higher capacity has been identified at project delivery points, and further, that the project already has been designed to maximize the amount of power delivery that can be absorbed by the Boston area 115 kV system (id.).

delivery point, Baker Street Substation (id.). The Company rejected this option on cost and practicality grounds, after determining that ROW acquisition needs to reach Baker Street Substation would amount to nearly 100 acres, and would involve areas of high property value, areas containing open space reservations, and areas of wetlands and flood plains associated with the Charles River (id.). Finally, the Company stated that even if overhead transmission could reasonably be extended to an initial delivery point in the Surrounding Boston Area, no potential overhead rights-of-way are available to continue to a second required delivery point in downtown Boston (id.).

d. Bundled Improvements Alternative

As part of the bundled improvements alternative, the Company identified a series of transmission system upgrade projects, including reconductorings of existing transmission lines, new transmission lines, and substation expansions, designed to alleviate thermal overloads at all system locations requiring additional capacity beginning in 2006 (Exh. BECO-1, at 3-12 to 3-16). The Company indicated that this alternative would include: (1) several underground transmission projects within the Surrounding Boston Area, including approximately 6-7 miles of new two-circuit 345 kV transmission, 9 miles of new two-circuit 115 kV transmission, 3 miles of new single-circuit 115 kV transmission, and 2.5 miles of reconductored single-circuit 115 kV transmission, together with associated substation improvements; (2) a new 10.5-mile single-circuit 115 kV transmission line traversing the southwest portion of the Greater Boston Area, parallel to an existing line, along a partial underground-overhead route from Walpole to Needham, together with associated substation improvements; and (3) 6 miles of reconductored two-circuit underground 345 kV transmission traversing the northern portion of the Greater Boston Area from Woburn to Mystic Station, together with added heat exchanger equipment at Mystic and Saugus Substations (id. at 3-12 to 3-17, 3-23 to 3-24, 3-29 to 3-30). While designed to meet the identified need, the Company asserted that the multiple projects would require a series of siting applications and approvals, and that given the lead times for such filings it was doubtful the Company could complete the siting process and construct all of the needed projects by 2006, or even 2008 (id. at 3-16 to 3-17). The Company estimated a cost of $192 million for the bundled improvements alternative (id. at 3-29).

e. New Generation Alternative

The Company stated that the transmission system in Downtown Boston has been configured around generation provided in the past by New Boston Unit 1, and stated that new generation consistent with this system has the potential to alleviate reliability concerns (id. at 3-10). However, citing its need analysis showing contingency transmission overloads by 2006 in two distinct areas – Downtown Boston and the Hyde Park/Baker Street area – the Company asserted that new generation would need to be installed in both of these areas to meet the identified need (id.). The Company stated that new generation takes approximately five years to permit and construct; given this lead time, and the need to add new generation facilities in two locations, it determined that new generation was not a viable alternative to meet the identified need in 2006 (id.).

f. Demand-side Management Alternative

To identify the demand-side management ("DSM") alternative, the Company considered the ability of "maximum potential" implementation of energy efficiency programs and demand response programs in the Boston area to meet the identified need (Exh. BECO-1, at 3-5 to 3-7). The Company indicated that the identified need for added capacity amounts to 800 MW by 2006, and that of this amount 478 MW is to meet needs centered in the Hyde Park and Baker Street area and 327 MW is to meet needs centered in downtown Boston (id. at 3-5; Tr. 2, at 194-195). Addressing energy efficiency measures first, the Company indicated the Massachusetts Division of Energy Resources ("MDOER") has estimated that the maximum potential cost-effective reduction in energy use in Massachusetts is 4% per year; however, netting out the projected annual load growth of 1.5%, NSTAR estimated that the maximum rate of reduction in the Boston area net of load growth is 2.5% per year (Exh. BECO-1, at 3-6; Tr. 2, at 205-206). The Company noted that currently funded energy efficiency program levels capture about one-third the maximum cost-effective implementation rate of 4% (Exh. BECO-1, at 3-6).

Turning to demand response programs, NSTAR cited a 2003 assessment it conducted concluding that there is a demand response potential of approximately 200 MW in its service territory (id. at 3-7). The Company noted that reductions of 45 MW in NSTAR's service territory and 80 MW in the Greater Boston Area already were enrolled in ISO-NE's ongoing Demand Response Program as of October 2003 (id.). Taking together the maximum potential levels of implementation for energy efficiency programs and demand response programs, the Company concluded that it would take 7-8 years, or until 2011 or 2012, to meet the identified need (Exh. EFSB-PA-3). Therefore, the Company determined that it would not be feasible to rely on DSM to meet the identified need (Exh. BECO-1, at 3-6, 3-8).

The City of Boston argued that a balanced approach to system planning that includes a sustained and aggressive program of energy and load reduction through DSM is required to address both environmental and reliability concerns (Boston Brief at 4).

g. Distributed Generation Alternative

The Company indicated that the identified need theoretically could be met by the addition of distributed generation ("DG") capacity in the Boston area, but stated that hundreds of DG sites in a geographically confined area would be required for this purpose (id. at 3-9; Tr. 2, at 247-248). In support, the Company indicated that the need for added capacity amounts to 800 MW by 2006, and that with currently available technologies the largest DG units produce a maximum of 20 MW each (Exh. BECO-1, at 3-9). The Company noted that larger-sized units such as reciprocating engines and combustion turbines could be considered, reducing the number of units needed to produce the target capacity, but many units still would be required (id.). Addressing constraints for reliance on DG, the Company stated capacity requirements to supply the Boston area could not be satisfied by intermittent sources, such as solar and wind, and that for most other forms of DG, allowances for outage rates would be a factor in determining the required capacity for meeting the overall Boston-area need (Exh. BECO-1, at 3-9, 3-19). Further, the Company asserted that because DG capacity would need to be sited at specific locations to address identified Boston-area needs, siting and permitting constraints would be a potential difficulty for successfully implementing an appropriately configured DG alternative (id. at 3-19 to 3-20; Exh. EFSB-PA-5). Therefore, the Company determined that it would not be feasible to rely on DG to meet the identified need (Exh. BECO-1, at 3-9, 3-20).

h. Analysis

The Company claimed that, with the exception of the 115 kV transmission alternative, all of the project approaches identified as alternatives to the proposed underground 345 kV project would fail to meet the identified need or be an impractical way to meet that need. The Siting Board agrees that, based on the likely lead time requirements for permitting and implementation, the new generation alternative and the overhead alternative would fail to meet the identified need. Based on requirements for new or expanded ROW in built-up and environmentally sensitive areas, with high land cost, the record reasonably establishes that the overhead alternative also would be an impractical approach based on both cost and environmental considerations.

The Siting Board further agrees with the Company that, in this case, the DSM alternative and the DG alternative do not provide reliable means of meeting the identified need. The Company's analysis establishes that maximum potential implementation of cost-effective DSM would provide net load reductions in the affected area falling well short of the target of 800 MW by 2006. The Company established that DG would pose substantial uncertainties for meeting that same 800 MW target by 2006, given that the approach would entail implementing multiple, relatively small DG projects, would require ensuring backup arrangements for the varied outage characteristics of those projects, would require ensuring a locational distribution of DG suitable to meet the wide array of system contingencies underlying the Company's Boston area need, and would require that the foregoing be accomplished for a set of prospective DG resources outside the Company's control.[21]

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[21] The Siting Board notes that, although the identified need in this case could not be met by DSM or DG either separately of in combination, it is important to acknowledge the benefits of incorporating DSM and DG into system planning. The Department has recognized the importance of DG as a resource option in the restructured electric industry. Investigation re: Distributed Generation, D.T.E. 02-38-B, at 40 (2004); Distributed Generation NOI, D.T.E. 02-38, at 1 (2002); Competitive Market Initiatives, D.T.E 01-54, at 11 (2001). Here, the record indicates that even with the construction of the three-

(continued...)

The Company has claimed that the bundled improvements alternative, like the overhead alternative and the new generation alternative, could not meet the identified need due to the lead time needed to permit and construct the many separate transmission projects that make up this approach. The Siting Board notes that, while the simultaneous permitting of the many elements of the bundled approach would be difficult, that difficulty should not preclude a further examination of a distinct alternative within NSTAR's control.

Accordingly, the Siting Board further reviews the proposed underground 345 kV project, the 115 kV transmission alternative and the bundled improvements alternative.

3. Reliability

The Company stated that, with the lower voltage alternative, the installation of a greater number of lines compared to the underground 345 kV project would lead to a higher level of exposure to contingency outages (Exh. EFSB-PA-6). At the same time, this presence of more lines would result in a smaller percentage of transmission capacity being unavailable under a given contingency, such as the loss of a single line (Exh. BECO-1, at 3-20).

With respect to the bundled improvements alternative, the Company asserted that the approach violates its "basic engineering construct" – to pursue transmission system upgrades and additions that address the greatest possible number of system requirements with a single project in order to minimize risks and disruptions associated with project construction (Exh. BECO-1, at 3-16). The Company further noted that, to construct two to four of the specific projects under this alternative, the Company would need to remove existing lines from service for extended periods of time, posing greater risk that overloads may occur during contingencies or that customers may lose service (id. at 3-17). Finally, the Company noted that the bundled improvements alternative would provide an increase in the Boston area import capability of only

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[21] (...continued)
circuit 345 kV transmission line, contingency overloads in the Greater Boston Area will recur in 2013. Given the long planning horizon between this Decision and 2013, it is conceivable that implementation of DSM programs combined with third-party efforts to develop DG could have an effect on the nature or timing of future transmission and distribution upgrades in the Greater Boston Area.

200 MW, compared to an increase of 800-1000 MW with the proposed 345 kV project (id.).

The record demonstrates that the proposed underground 345 kV project and the 115 kV transmission alternative would provide generally similar reliability. The lower voltage alternative has the potential to experience more contingency outages, but as an offsetting factor it would provide higher availability under certain such outages.

The record demonstrates that the bundled improvements alternative would provide sufficient capacity to meet identified needs related to thermal and voltage capabilities, and provide some increase in import capability. However, compared to the underground 345 kV project, the bundled improvements alternative has the disadvantages of requiring numerous regulatory filings that could complicate timely implementation, and requiring that some existing circuits be taken out of service during construction. In addition, although providing added import capability, the amount of increase under the bundled improvements alternative would be a quarter of that available with use of the underground 345 kV project.

Accordingly, the Siting Board finds that the 115 kV transmission alternative is comparable to the underground 345 kV project, and the underground 345 kV project is preferable to the bundled improvements alternative, with respect to reliability.

4. Environmental Impacts

The Company asserted that, compared to the underground 345 kV project, the 115 kV transmission alternative would require triple the miles of street excavation (Exh. BECO-1, at 3-23). The Company asserted that there is little difference in the short-term impacts of constructing 115 kV lines and 345 kV lines underground along streets, and concluded that there is no environmental reason to favor use of the 115 kV transmission alternative (id.).

Regarding the bundled improvements alternative, the Company first noted that the extent of new underground transmission construction required as part of the multiple projects included under that approach within the Greater Boston Area, and the associated environmental impact, would equal or exceed that of the new underground transmission construction required for the proposed underground 345 kV project (Exh. BECO-1, at 3-23 to 3-24). The Company then asserted that since the bundled improvements alternative would also include a new 10.5-mile partial overhead-underground Walpole-Needham line and 8.5 miles of reconductoring of existing two-circuit lines, the overall project scale and associated environmental impact of the bundled improvements alternative would be greater than that of the proposed 345 kV project (id. at 3-24).

The record demonstrates that the 115 kV transmission alternative would entail substantially more lengthy in-street construction than the underground 345 kV project; additionally, this alternative would require siting lines along several routes, rather than one route, to each delivery point, and would require additional equipment at substations to accommodate additional circuits. Thus, while not addressing other possible differences such as the relative size or depth of underground transmission facilities, the record establishes that the overall scale of construction impact clearly would be greater with use of the 115 kV transmission alternative than the 345 kV underground project.

The Company has demonstrated that the scale of transmission construction impacts would be somewhat greater with the bundled improvements alternative as well, compared to the underground 345 kV project, although not to the same degree as with the 115 kV transmission alternative. The bundled improvements alternative also would entail more extensive installation of associated equipment at substations, since it would involve a greater number of transmission projects. As an offsetting consideration, there appears to be no need under the bundled improvements alternative to install a substation or similar facility at a new site, comparable to the new switching station facility required as part of most of the routing options for the underground 345 kV project. On balance, however, the incremental environmental impacts of a 10.5-mile partial overhead-underground transmission line, required as part of the bundled improvements alternative, outweigh the offsetting consideration of using a new switching station site under the 345 kV underground project.

Accordingly, the Siting Board finds that the underground 345 kV project is preferable to the 115 kV transmission alternative and the bundled improvements alternative with respect to environmental impacts.

5. Cost

The Company estimated that the total capital cost of the transmission project would be

$177 million[22] if the underground 345 kV project is used, $270 million if the 115 kV transmission alternative is used, and $192 million if the bundled improvements alternative is used (Exh. BECO-1, at 3-24 to 3-25, 3-28 to 3-30).

The record demonstrates that the capital cost of the underground 345 kV project would be $93 million less than that of the 115 kV transmission alternative and $15 million less than that of the bundled improvements alternative. In addition, because the bundled improvements alternative would provide a significantly smaller increase in import capability, some of the potential savings in generation costs that is anticipated with use of the underground 345 kV project would be foregone with use of the bundled improvements alternative (see Section III.C.5.b, below).

Accordingly, the Siting Board finds that the underground 345 kV project is preferable to the 115 kV transmission alternative and the bundled improvements alternative with respect to cost.

6. Conclusions: Weighing Need, Reliability, Environmental Impacts, and Cost

The Siting Board has found that the underground 345 kV project, the 115 kV transmission alternative and the bundled improvements alternative could meet the identified need for thermal and voltage capability. The Siting Board also has found that the 115 kV transmission alternative is comparable to the underground 345 kV project, and the underground 345 kV project is preferable to the bundled improvements alternative, with respect to reliability; and further found that the underground 345 kV project is preferable to the 115 kV transmission alternative and the bundled improvements alternative with respect to environmental impacts and cost. Accordingly, the Siting Board finds that the underground 345 kV project is preferable to both the 115 kV transmission alternative and the bundled improvements alternative with respect to providing a reliable energy supply for the Commonwealth, with a minimum impact on the

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22 The Company's comparison of project approaches was based on initial cost estimates developed for the proposed underground 345 kV project. In Section III.C.5.a, below, the Siting Board reviews updated cost estimates for that approach, based on more detailed analysis of likely project cost.

environment at the lowest possible cost.

III. ANALYSIS OF THE PRIMARY, ALTERNATIVE AND HYBRID ROUTES

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69J-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 and 69J. Further, G.L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate, the Siting Board requires a petitioner to demonstrate that it examined a reasonable range of practical siting alternatives, and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. CELCo Decision, 12 DOMSB 305, at 326; MMWEC Decision, 12 DOMSB 18, at 89; New England Power Company, 21 DOMSC 325, at 376 (1991).

A. Route Selection

1. Standard of Review

G.L. c. 164, § 69J provides that a petition to construct a proposed facility must include "a description of alternatives to [the applicant's] planned action" including "other site locations." G.L. c. 164, § 69J. In past reviews of alternative site locations identified by an applicant, the Siting Board has required the applicant to demonstrate that it examined a reasonable range of practical siting alternatives. See CELCo Decision, 12 DOMSB at 323; MMWEC Decision, 12 DOMSB at 119; 1998 NEPCo Decision, 7 DOMSB 333, at 374. In order to determine whether an applicant has considered a reasonable range of practical alternatives, the Siting Board has required the applicant to 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 which ensures that it has not overlooked or eliminated any routes which, on balance, are clearly superior to the proposed route. CELCo Decision, 12 DOMSB at 323; MMWEC Decision, 12 DOMSB at 119; 1998 NEPCo Decision, 7 DOMSB 333, at 374. Second, the applicant must establish that it identified at least two noticed sites or routes with some measure of geographic diversity. CELCo Decision, 12 DOMSB at 323; MMWEC Decision, 12

DOMSB at 119; 1998 NEPCo Decision, 7 DOMSB 333, at 374.

2. Route Selection Process

NSTAR stated that it conducted a systematic route selection study to select two potential transmission line routes that: (1) balanced impacts on the human and natural environment and cost; (2) provided a reliable technical solution to the identified needs; and (3) could be permitted, constructed, and placed into service by the summer of 2006 (Exh. BECO-1, at 4-1). In addition, after the route selection study was completed, NSTAR worked with affected communities to refine its primary and alternative routes. The route selection study and these consultations, which together make up the route selection process for this project, are discussed below.

a. Southern Terminus to Everett/Andrew Square

NSTAR began its route selection study by identifying a "study area" within which all potential routes would be located (Exh. BECO-1, at 4-2). The Company stated that the transmission project was designed to improve the reliability of the regional power grid by moving bulk power from the existing 345 kV transmission system into both NSTAR's K Street Substation in South Boston, and the Hyde Park/West Roxbury area; consequently, the project would have termination points at the K Street Substation and at either the Hyde Park or West Roxbury Substations (id. at 4-2 to 4-3). The Company also stated that, while existing 345 kV lines serve the Greater Boston Area from the north via Tewksbury, there are no 345 kV lines serving Boston from the 345 kV system to the south of the city (id. at 4-3). The Company therefore concluded that the proposed 345 kV transmission project should originate from the existing 345 kV transmission system between NSTAR's existing Holbrook and West Walpole Substations (id.). Given these points of origination and termination, the Company identified an approximately 235 square mile study area bounded on the south by the existing 345 kV line between Holbrook and Walpole, on the west by an existing 115 kV transmission line running from Walpole to Westwood, and on the north by a line extending roughly along Route 9 to the K Street Substation (id. at 4-4).

NSTAR stated that it next identified an "initial universe" of approximately 30 potential routes and route variations within the study area (id.). The Company began by identifying potential switching station sites along the existing 345 kV line between the West Walpole and Holbrook Substations, seeking sites located at or near the intersection of the 345 kV line and other transmission rights-of-way, rail lines, highways, or streets (Exh. EFSB-SS-38, at 1). The Company stated that an ideal switching station site would be immediately adjacent to the existing 345 kV right-of-way; at least six acres; relatively level; without significant mapped wetlands or streams; vacant or currently in use for commercial or industrial purposes; zoned industrial; located in an area of compatible land use; and well-buffered from residential areas (id. at 2; Tr. 4, at 392). The Company also considered the existing Holbrook and West Walpole Substations as potential starting points for the transmission line (Exh. BECO-1, at 4-2). From the potential switching station sites, the Company developed potential routes north to Boston, using the following route selection guidelines:

* Select direct, rather than more circuitous routes;
* Use existing rights-of-way and easements where possible;
* Avoid crossing cemeteries, war memorials, and similar lands;
* Where possible, avoid crossing public land dedicated to wildlife conservation, public recreation, or other Article 97 uses;[23]
* Where possible, avoid significant residential and densely developed mixed-use areas;
* Avoid roads or streets known to have a high density of underground utilities;
* Where possible, avoid crossing mapped wetlands and disrupting significant water resources;
* Where possible, avoid crossing mapped rare or endangered species habitats (id. at 4-4 to 4-5).

NSTAR grouped its initial universe of routes into ten basic route options, including eight underground routes, a partial submarine route, and a partial overhead route (id. at 4-5). The Company reviewed these ten routes to select a smaller number for detailed study and evaluation

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[23] Lands acquired by the Commonwealth and protected under Article 97 of the Commonwealth's constitution may not be used for other purposes except by two-thirds vote of both houses of the state legislature. MA Const. art. 97.

(id. at 4-9). At this stage of its process, NSTAR consulted with right-of-way owners, including the Massachusetts Highway Department ("MHD"), Transit Realty/MBTA, and the Algonquin Gas Transmission Company ("Algonquin"), and with officials from Stoughton, Canton, Milton, Randolph, Quincy, and Boston (id.; Exh. EFSB-SS-3). The Company stated that the MHD strongly discouraged the use of Routes I-95 and 24, and indicated that it preferred the primary route, Route 138 to Route 28, in part because portions of Route 28 had recently been reconstructed (Exh. BECO-1, at 4-9). The Company learned that, in order to avoid interference with rail operations, Transit Realty/MBTA would permit NSTAR to construct along railroad ROWs between 1:00 a.m. and 4:00 a.m. only (id. at 4-9 to 4-10). Algonquin informed NSTAR that the terms of its pipeline easements did not permit the collocation of electric transmission lines within the ROW; based on this information, and the relatively narrow width of the pipeline ROW, NSTAR concluded that construction of the transmission line along an Algonquin ROW would require the negotiation of new or widened easements with many landowners, which would considerably extend the project timeline (id. at 4-10). Based on this information, NSTAR eliminated: (1) a route following Interstate 95 through Sharon, Norwood and Canton; (2) a route following the Red Line right-of-way through Braintree, Quincy, North Quincy, and Dorchester; (3) a route following the Amtrak Main Line through Canton, Dedham, Hyde Park, Roslindale, and Jamaica Plain; and (4) variations to the Route 28 alternative involving the use of Route 24 and the Algonquin ROW (id.). The Company also eliminated: (1) a partial submarine route running underground from the Holbrook Substation to the Weymouth Fore River, then for 11.5 miles in the Fore River, Quincy Bay, Boston Harbor, and the Reserved Channel, due primarily to permitting complexity and high initial cost estimates; and (2) a route following Route 37 through Braintree, Quincy and Dorchester, because it was comparable in length to two other highway-based options, but had significant disadvantages, including a minimum six-mile single-circuit run to the Hyde Park Substation, use of the main southeast commuting corridor to Boston, and space limitations at the existing Holbrook Substation (id. at 4-10 to 4-11).

NSTAR next assessed the environmental attributes and construction costs of the five remaining candidate routes.[24] These routes included:

(1) the Route 28 Alternative, which begins at a new 6.25 acre switchyard in Stoughton, runs along streets in Stoughton and Randolph to Route 28, continues in Route 28 through Randolph, Quincy and Milton, then runs in streets through parts of Milton and Dorchester to Everett Square;

(2) the Route 138 Alternative, which begins at a new switchyard in Stoughton, runs along Route 138 in Canton and Milton, then along Blue Hill Avenue in Milton and Boston to Mattapan Square, then along Blue Hill Avenue and Columbia Road to Everett Square;

(3) the Route 1 Alternative, which begins at a new switchyard off Route 1 in Sharon, runs along Route 1 through Sharon, Walpole, Norwood, Westwood and Dedham, then along Washington Street through West Roxbury, Roslindale, Jamaica Plain and Roxbury, then in streets to Andrew Square;

(4) the Route 1A Alternative, which begins at NSTAR's existing West Walpole Substation, then runs along Route 1A through Walpole, Norwood, Westwood and Dedham, then along Route 109 into Boston, then in streets to Andrew Square; and

(5) the Partial Overhead Alternative, which begins at NSTAR's existing West Walpole Substation, then follows an existing transmission corridor above-ground for 9.5 miles through Walpole, Medfield, Norwood, Dover, and Westwood, then proceeds underground in streets to Andrew Square (id. at 4-11 to 4-15).

NSTAR evaluated the potential environmental impacts of the five candidate routes using sixteen environmental criteria divided into two categories: human environment and natural environment (id. at 4-16). The human environment criteria included residential land use, commercial/industrial land use, sensitive land uses, historic resources, traffic volume, traffic congestion potential, public transportation facilities, and visual impacts (id. at 4-16 to 4-17). The

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[24] The Company noted that each of these route options reaches either Everett Square or Andrew Square in Boston, and then proceeds across South Boston to the K Street Substation (Exh. BECO-1, at 4-11). The Company therefore compared the five candidate routes from the originating switchyard to Everett/Andrew Square, and separately evaluated potential routes across South Boston (id.). The Company's development of the Everett/Andrew Square to K Street route is described in Section III.A.2.c, below.

natural environment criteria included wetlands, protected habitat, surface waters, stream crossings, drinking water supply, Areas of Critical Environmental Concern ("ACEC"), potential subsurface contamination, and tree clearing/disturbance (id. at 4-17). The Company divided each of the potential routes into either three or four segments of roughly comparable land use[25], and rated each of the segments on each of the environmental criteria using a scale of 1 to 3, where 1 represented the lowest potential impact, and 3 represented the highest potential impact (id. at 4-17, 4-22).[26] The Company then "length-weighted" the score for each route segment by multiplying the score by the length of the route segment in miles (id. at 4-22).[27] The total route scores were the sums of the length-weighted segment scores (id.). The resulting scores are shown in Table 2, below.

The Company stated that it incorporated environmental impacts at the originating switching station site into its analysis of the first segment of each route alternative (Tr. 4, at 450,

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25 The Route 28 and Route 138 Alternatives each were divided into four segments, including one single-circuit segment running from Mattapan Square to the Hyde Park Substation (Exh. BECO-1, at Tables 4-2 and 4-3). The Route 1, Route 1A, and Partial Overhead Alternatives each were divided into three segments, including one single-circuit segment running from Mattapan Square to the Hyde Park Substation (id. at Tables 4-4, 4-5 and 4-6). The Company argued that the segmentation was necessary because it could not assign meaningful scores on criteria such as residential land use or commercial/industrial land use for the routes as a whole, since each route ran through both suburban and urban areas (Tr. 4, at 444-445).

26 The Company stated that the team developing the rankings consulted three principle resources: a set of large-scale aerial photographs with geographic information system overlays, notes from on-ground observations of the routes, and a compilation of quantitative data such as traffic counts, linear footage of wetlands crossed, and information on historic districts (Tr. 4, at 432-433).

27 The Company argued that length-weighting was needed to capture the distance and duration over which human and environmental impacts would be experienced (Company Brief at 51). The Company asserted that the length-weighting helped to compensate for the fact that some routes were divided into three segments, while others were divided into four segments (Tr. 4, at 488-489). The Company argued that length weighting was appropriate for the most important criteria being evaluated (id. at 502). It stated that, when evaluating other types of criteria, the team considered density per mile, so that a five-mile segment with three or four stream crossings would receive the same score as a ten-mile segment with ten stream crossings (id. at 501-502).

457-458). The Company indicated that certain types of switching station impacts (e.g., visual, wetlands and habitat impacts) were picked up explicitly by the relevant criteria (id. at 449). The Company also argued that its standards for selecting potential switching station sites, combined with appropriate facility design, would ensure that any impacts from switching station operation would be confined to the site and its very immediate surroundings (id. at 450-454).[28] The Company therefore concluded that a separate analysis of switching station impacts was not a necessary part of the route study, and that it was appropriate to focus the study primarily on the effects of transmission line construction (id. at 455, 465).[29]

To evaluate the potential construction costs for the five candidate routes, NSTAR engineers developed conceptual level cost estimates for each route using unit pricing for standard pipe-type cable installation in streets and roads (id. at 4-23).[30] The Company indicated that costs common to all five routes (including construction of new switching facilities at the starting point of each route, new facilities at either Hyde Park or West Roxbury, and new facilities at the K Street Substation) were not included in the cost comparison (id.). The conceptual cost estimates also are included in Table 2, below.

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28 The Company noted that all four switching station sites under consideration at that time were zoned industrial, and that three of the four sites were proximate to residential areas (Exh. EFSB-SS-38, at 4).

29 To test the sensitivity of the environmental scores to differing value judgements about the importance of certain criteria, the Company conducted two sensitivity analyses (Exh. BECO-1, at 4-26). In the first analysis, it assigned a double weight to three criteria: residential land use, traffic volume, and traffic congestion (id.). In the second analysis, it assigned a double weight to all of the human environment criteria (id. at 4-27). The rank ordering of the route scores did not change in either analysis (id. at 4-26 to 4-27).

30 The Company used unit costs of $7,130,00 per mile for those portions of the underground route where three electrical circuits would be installed; $5,280,000 per mile for two circuits; and $3,300,000 for a single circuit (Exh. BECO-1, at 4-23). It used a unit cost of $2,700,000 per mile for the overhead portions of the Partial Overhead Alternative (id.). The resulting costs were adjusted to reflect incremental land acquisition costs for the switchyards (id. at Table 4-14).

Table 2: Environmental and Cost Scoring of Candidate Routes

Route Alternative	Length (miles)	Environmental Score	Conceptual Cost (millions)
Route 138	15.57	352	$108.9
Route 28	17.02	377	$110.3
Route 1	19.82	514	$128.7
Route 1A	19.95	546	$133.9
Partial Overhead	24.24	690	$137.2

Sources: Exh. BECO-1, Tables 4-2 to 4-6, 4-14, 4-21, 4-28.

The Company noted that two of the five candidate routes – the Route 28 Alternative and the Route 138 Alternative – had considerably lower (better) environmental scores than the other three routes, as well as considerably lower conceptual costs (Exh. BECO-1, at 4-24 to 4-26). The Company therefore selected these two routes as the primary and alternative routes presented in the initial petition (id. at 4-26). The Company stated that it also considered whether there were any differences with respect to the reliability of the five candidate routes (id. at 4-28). It concluded that the Route 28 and Route 138 Alternatives might have a small reliability advantage over the Route 1 and 1A Alternatives, due simply to their shorter length (id.). The Company stated that the partial Overhead route would be marginally less reliable than the underground routes, both because it involved some above-ground line, and because it required a second transition facility; however, the Company noted that this minor difference in reliability was less important that the Partial Overhead route's higher costs and environmental impacts (Tr. 4, at 486).

The Company stated that, while its route selection study was sufficient to establish the two best routes, further environmental analysis was done to determine which of the two route alternatives should be the primary route (id. at 504). These more detailed analyses are discussed in Section III.C, below.

NSTAR indicated that, after filing its petition, it had a number of meetings with City of Boston officials regarding routing issues. These discussions resulted in certain amendments to the Petition.[31] In particular, officials expressed concern that the disruption caused by construction along Blue Hill Avenue could harm financially struggling businesses; the City suggested that by using American Legion Highway instead, the Company could minimize the disruption and avoid existing underground utilities in Blue Hill Avenue (id. at 674-675). Therefore, on March 24, 2004, the Company filed a supplement to the Siting Board Petition identifying a variation to the primary route that would avoid the 2.5 mile stretch of Blue Hill Avenue between the Boston city line and its intersection with Columbia Road (Exh. BECO-1, at E-1). Instead of using this portion of Blue Hill Avenue, the Company proposed to run all three circuits of the proposed transmission line west along Cummins Highway to American Legion Highway (id.). From this point, a single circuit would run south on American Legion Highway to the Hyde Park Substation, as originally proposed; the remaining two circuits would continue northeasterly along American Legion Highway to its intersection with Blue Hill Avenue, then return to the primary route as originally filed (id.). The Company stated that the cost of this route variation would be higher than the cost of constructing directly up Blue Hill Avenue from Mattapan Square, primarily because it requires the construction of an additional 7400 feet of circuit length (id. at E-11). However, the Company indicated that, given American Legion Highway's moderate level of traffic and the nature of adjoining land uses (primarily parkland, cemeteries, and municipal land), construction along American Legion Highway is likely to be less disruptive than construction along the more heavily traveled and populated Blue Hill Avenue (id. at E-4). Overall, the Company concluded that the primary route up to Everett Square, using the American Legion Highway alternative, was best able to provide a reliable supply of energy at the least cost, while minimizing environmental impacts (Company Brief at 76).

b. Everett/Andrew Square to K Street Substation

NSTAR stated that it used the methods described in Section III.A.2.a, above, to develop

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[31] The first set of amendments pertains to the primary route between its southern terminus and Everett/Andrew Square, and is discussed here. The second set pertains to the route between Everett/Andrew Square and the K Street Substation, and is discussed in Section III.A.2.b, below.

environmental scores and circuit cost estimates for three possible routes through South Boston: (1) Alternative 1, which runs along Boston Street north to Andrew Square, then along Dorchester Street, East 4th Street, I Street, East 3rd Street and K Street to the K Street Substation; (2) Alternative 2, which runs along Boston Street north to Andrew Square, then along Preeble Street, Columbia Road, I Street, East 3rd Street and K Street to the substation; and (3) Alternative 3, which runs east from Everett Square along Cottage Street, Crescent Avenue, Day Boulevard, I Street, East 3rd Street and K Street to the substation (Exh. BECO-1, at 4-16, 4-22, 4-23). The environmental scores and costs are shown in Table 3, below. Based on these scores and costs, the Company selected Alternative 1 as its primary route through South Boston to K Street. The Company noticed Alternatives 2 and 3 as alternative routes through South Boston, and additionally noticed sections of Columbia Road, Dorchester Street, and Old Colony Road as workarounds in South Boston (id. at Fig. B).

Table 3: Environmental and Cost Scoring of Boston Routes

Boston Route	Length (miles)	Environmental Score	Conceptual Cost (millions)
Alternative 1	2.03	51	$10.760
Alternative 2	2.24	54	$11.870
Alternative 3	2.36	57	$12.510

Source: Exh. BECO-1, Tables 4-7, 4-13.

As noted previously, NSTAR had discussions with the City of Boston over routing issues after filing its Petition, and, on March 24, 2004, it filed a supplement to the Siting Board Petition identifying two additional route segments that could be used as part of the routing through South Boston: one along Columbia Road between Dorchester Avenue and Kosciuszko Circle, and another within Moakley Park parallel to Day Boulevard (Exh. BECO-1, at E-2 to E-3). These two route segments, combined with already-noticed route segments, created a fourth possible route through South Boston: from Everett Square along Columbia Road to Kosciuszko Circle, then north within Moakley Park paralleling Day Boulevard, then along I Street, East 3rd Street and K Street to the substation (id.). The Company indicated that use of the Moakley Park variation would allow it to follow Day Boulevard while avoiding traffic disruptions associated with in-street work, and that if this route segment were used, construction would take place in the late fall or winter months (id. at E-3, E-4).

c. Other Potential Routes

During the proceeding, Siting Board staff and the parties examined two routing options that combined the use of the alternative route's switching station site with elements of the primary route. At staff's request, the Company analyzed a "hybrid route", which combines the southern portion of the alternative route and its single-circuit component (from the SRA switching station to Mattapan Square in Boston) with the northern portion of the primary route (from Mattapan Square to the Hyde Park and K Street Substations). Specifically, the hybrid route would begin at the SRA switching station site, run in Stoughton and Randolph streets to Route 28, then proceed along Route 28/Randolph Road/Randolph Street to Reedsdale Street, Brook Street, and Blue Hill Parkway, then follow Blue Hill Parkway to the Neponset River crossing in Mattapan Square (Exh. RR-EFSB-20, at 1). From this point, the hybrid and primary routes would be the same (id.). The Company indicated that the southern portion of the primary route is 9.1 miles long, while the southern portion of the hybrid route is 9.76 miles long (id.). The Company scored the southern portions of the primary and hybrid routes as described in Section III.A.2.a, above, using information available at the time of the evidentiary hearings; the southern portion of the primary route received a raw score of 43 and a length-weighted score of 196, while the hybrid route received a raw score of 47 and a length-weighted score of 230 (Exhs. RR-EFSB-20(a); Att.; RR-EFSB-20(b) Att.). The Company asserted that the key differences between the primary and hybrid routes included: fewer residences along the southern portion of the primary route; fewer sensitive land uses along the primary route; greater potential for nighttime construction along the primary route; and support for the primary route from the Town of Canton Selectmen, the Town of Milton Selectmen, and the Canton Association of Industries (Exh. EFSB-RR-20, at 3). The Company also stated that it preferred to construct on a major road, such as Route 138, rather than on the residential streets that make up a significant portion of the southern part of the hybrid route (Tr. 5, at 583-584). The Company indicated that the hybrid route would cost approximately $6.0 million more to construct than the primary route; this difference would be partially offset by the lower acquisition cost for the SRA switching station site, resulting in a net additional cost of $2.4 million for the hybrid route (Exh. RR-EFSB-16, at 1).

In addition, the Company analyzed the “Monroe Route”, which would begin at the SRA switching station site in Stoughton and run along Technology Center Drive, Page Street, York Street and Randolph Streets, ultimately joining the primary route at the intersection of Randolph Street and Route 138 (Exh. EFSB-SS-25). The Company indicated the Monroe Route would be approximately 4.3 miles long, while the corresponding segment of the primary route is approximately 2.9 miles long, and that use of the Monroe route would add approximately $6,860,000 to the cost of the transmission project (id.; Exh. EFSB-SS-27, at 1-2). The Company also noted that the Monroe Route would travel on narrow roads through a residential area, and stated that, because of the area road layout and the width of the streets, people living on cul-de-sacs off the route might experience eight-to-ten mile detours during construction (Tr. 4, at 540-543).

d. Analysis

NSTAR has described a complex, multi-step route selection process designed to identify two potential transmission line routes (including substation sites and transmission corridors) that provide a reliable technical solution to the needs it has identified, balance environmental and human impacts and cost, and can be permitted, constructed, and placed into service by the summer of 2006. The criteria explicitly examined in the Company’s formal environmental assessment address the environmental and human impacts of the construction and operation of the proposed transmission lines. These are types of criteria that the Siting Board previously has found to be appropriate for the siting of energy facilities. See NSTAR Decision, 13 DOMSB at 177; MMWEC Decision, 12 DOMSB at 125; 9 DOMSB at 43-44; New England Power Company, 4 DOMSB 109, at 167 (1995). In addition, at other stages of its route selection process, NSTAR has explicitly or implicitly considered criteria including project cost, reliability, proximity to a viable switching station site, ease of permitting, ease of construction (including presence of underground utilities), impacts on local businesses, ability to mitigate construction impacts, and the preferences of right-of-way owners, affected state agencies, and municipal officials. These are also appropriate criteria to consider in selecting a route for a project that must provide "a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost."

In identifying potential routes into Boston, NSTAR initially cast a broad net, considering the major transportation and utility corridors that intersected the existing 345 kV line between the West Walpole and Holbrook Substations. The Company also considered a partial submarine route that approached the K Street Substation via Boston Harbor. This methodical approach, focused on existing corridors, ensured that the Company did not overlook any clearly superior route into Boston. The Company narrowed its initial universe of potential routes down to five candidate routes based in large part on proximity to viable switching station sites and on input from the right-of-way owners (including MHD, Algonquin, and the MBTA) regarding the desirability and ease of construction along potential routes. The partial submarine route was eliminated due to permitting complexities and high projected costs, and a route along Route 37 was eliminated because it appeared similar to two other highway-based options, but had significant disadvantages which those routes did not have. The record indicates that the Company did not eliminate any clearly superior routes in narrowing its initial universe of routes down to the five candidate routes into Boston.

NSTAR next developed environmental rankings and cost estimates for the five candidate routes, and qualitatively assessed any reliability differences among the routes. Based on these analyses, the Company divided the five candidate routes into three clusters: the Route 28 and Route 138 alternatives, which had relatively low costs and environmental impact scores; the Route 1 and Route 1A alternatives, which had somewhat higher costs and environmental impact scores; and the partial overhead alternative, which had the highest costs and environmental impact scores, and marginally lower reliability than the underground lines. The Company stated that it considered the cost estimates and environmental scores for the Route 138 and Route 28 alternatives to be indistinguishable at this level of analysis; it therefore carried both alternatives forward, one as the primary route and one as the alternative route.

During the proceeding, concerns were raised about two aspects of the Company's environmental assessment: the use of segmentation and length-weighting, and the level of consideration given to permanent impacts at the new switching station site. The Company has stated that it evaluated the routes in segments because it could not meaningfully rank the routes as a whole on most criteria, as the routes ran for considerable distances through diverse suburban and urban areas. The Siting Board agrees that it would be difficult to assign a single, meaningful score on a criterion such as residential land use to a 15 to 25 mile route that runs through both densely and sparsely developed residential and commercial areas. The decision to segment the routes was a thoughtful response to this problem. However, the division of the routes into a different number of segments of different lengths necessitated the use of length-weighting. Length-weighting is appropriate for certain of the criteria evaluated in the environmental assessment – for example, a five-mile stretch of right-of-way with a high potential for traffic congestion clearly has greater impacts than a similar three-mile stretch of right-of-way. However, many environmental criteria are best evaluated as a single number: total acres of disturbed wetlands, total number of streams crossed, total square footage of tree clearing or disturbance. Length-weighting the raw scores for these types of criteria could bias the environmental assessment in favor of the shorter routes. The Company stated that it attempted to compensate for this possibility by assigning scores based on density of impacts, so that a shorter segment with two or three stream crossings might get the same stream crossing score as a longer segment with five or six stream crossings. To the extent that the Company was able to accomplish this, the potential for bias in favor of the shorter routes might be reduced, but not eliminated. Given the potential for bias inherent in length-weighting, and additional analytical complexity that would be needed to fully overcome this bias, the Siting Board recommends that future applicants avoid this approach and seek a different means of comparing lengthy routes.

The record shows that the two shortest routes did indeed receive the lowest environmental scores, and that the longest route received by far the highest score. This is, on its face, a logical result – the construction of a longer route is likely to cause greater disruption than construction of a similar, shorter route. Moreover, the Partial Overhead route, which received the worst environmental score, also is the only route with a potential for extensive permanent visual impacts resulting from the construction of a long stretch of overhead transmission line. There is no indication in the record that the Route 1, Route 1A, or Partial Overhead alternatives have significant environmental advantages that went unrecognized in the route selection process. The Siting Board therefore concludes that, while the use of length-weighting likely biased the environmental assessment toward shorter routes, it did not lead the Company to eliminate a clearly superior transmission line route.

Questions were also raised during the proceeding as to whether the Company should have separately evaluated environmental impacts at each of the substations and switching stations associated with the candidate routes. The Company has argued that impacts at the existing K Street, Hyde Park, and West Roxbury Substations are identical for all routes, and that each of the four potential switching station sites (one existing, three new) is sufficiently large and well-buffered to ensure that offsite impacts would be minimal. The Company also has argued that the visual, wetlands, and tree-clearing impacts associated with construction at each of the switching station sites were explicitly incorporated in the ranking of the first segment of each route alternative. Finally, the Company has noted that three of the four switching station sites associated with the five candidate routes had proximate residential areas.

The Siting Board is not persuaded by the Company's a priori assumption that the offsite impacts of the switching station would be minimal at all locations. This is a question that receives further analysis in Section III.C, below. However, the record does not suggest that the Company's decision to evaluate the switching station site as part of the first route segment led it to eliminate a clearly superior transmission line route. The record indicates that all of the switching station sites under consideration are industrially zoned, and that the switching station sites associated with the Route 1, Route 1A, and Partial Overhead alternatives are located in proximity to residential areas. Thus, in eliminating the Route 1, Route 1A, and Partial Overhead alternatives, the Company did not eliminate a clearly superior switching station site. The Siting Board concludes that the Company's decision not to separately rank the switching stations sites did not lead the Company to eliminate a clearly superior transmission line route.

With respect to the portions of the primary and alternative routes within Boston, the Siting Board notes that the potential paths through Boston to the Hyde Park and K Street

Substations are very numerous. Here, NSTAR has worked closely with the City, and after consultation has selected a route that, while somewhat longer and costlier than that originally proposed, minimizes the use of the heavily trafficked Blue Hill Avenue in favor of a wider, less developed road with fewer existing utilities. Similarly, after consultation with the City, NSTAR has offered a route through South Boston that minimizes work in congested streets.

Overall, 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 which ensures that it has not overlooked or eliminated any routes which, on balance, are clearly superior to the proposed route. In making this finding, the Siting Board notes that the Company, throughout its route selection process, placed considerable emphasis on selecting a route that could be permitted, constructed, and placed in service by June 2006. The Company does not appear to have sacrificed a clearly superior routing option to reach this goal. However, it is apparent from the record that the Company did not allow sufficient time to complete its route selection process before filing with the Siting Board, as is evidenced by the continuing negotiations with the City of Boston over routing options during the proceeding. In fact, the Company had not identified major elements of its final primary route through Boston at the time it filed its Siting Board petition. As a consequence, this proceeding was renoticed several months after the Company's initial filing. The Siting Board urges NSTAR and other utilities to identify their approaching infrastructure needs and begin developing routing options well in advance of the date of need, so that similar situations can be avoided in the future.

3. Geographic Diversity

NSTAR began its site selection process by identifying an initial universe of approximately 30 potential routes and route variations within a 235 square mile study area encompassing all or part of 21 municipalities (Exh. BECO-1, at Fig. 4-1). This initial universe of route options was grouped into ten basic routes, ranging from a partial overhead route located in Walpole, Medfield, Dover, Needham, Dedham and Boston in the west, to a partial underwater route located in Braintree, Weymouth, the Fore River, Quincy Bay, Boston Harbor, and the Reserved Channel in the east (id. at Fig. 4-2). Potential southern switching station locations were considered in Walpole, Sharon, Canton, Stoughton, Randolph, and Holbrook (id.).

From these ten basic routes, the Company has selected two practical routes which are geographically distinct from their beginning until they meet in Everett Square in Boston. The Company also has identified four distinct routes from Everett Square to the K Street Substation; while there is some overlap between the four routes, the only route segment common to all four is a short stretch along I Street, East 3rd Street and K Street leading to the K Street Substation. Consequently, the Siting Board finds that NSTAR has identified a range of practical transmission line routes with a considerable measure of geographic diversity.

4. Conclusions on Site Selection

The Siting Board has found that (1) NSTAR 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 route; and (2) NSTAR has identified a range of practical transmission line routes with a considerable measure of geographic diversity. Consequently, the Siting Board finds that NSTAR examined a reasonable range of practical siting alternatives.

In reaching this finding, the Siting Board notes that the Company has brought forward as its alternative route the Route 28 alternative, which received an environmental ranking very close to that of the primary route, and which has similar cost and reliability attributes. In addition, the Siting Board notes that elements of the Company's primary and alternative routes can be combined to create a "hybrid route" that combines certain positive aspects of both routes. Therefore, in Section III.C, below, the Siting Board reviews the environmental impacts, costs, and reliability of the primary, alternative, and hybrid routes to determine which route best meets the Siting Board's mandate to provide for a reliable energy supply for the Commonwealth, with a minimum impact on the environment, at the lowest possible cost.

B. Description of the Primary, Alternative, and Hybrid Routes

1. Primary Route

The primary route begins at a new switching station to be constructed on a 14-acre,