Decisions and Orders

Massachusetts Energy Facilities Siting Board

VOLUME 6

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of U.S. Generating Company for Approval to Construct a Bulk Generation Facility and Ancillary Facilities in Charlton, Massachusetts	)))))))	EFSB 96-4

FINAL DECISION

Jolette A. Westbrook
Hearing Officer
November 3, 1997

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FIGURES:

FIGURE 1: Primary Site Vicinity Map
FIGURE 2: Alternative Site Vicinity Map

LIST OF ABBREVIATIONS

Abbreviation	Explanation
AALS	Allowable Ambient Limits
ACOE	Army Corps of Engineers
AFB	Atmospheric fluidized bed
AO	American Optical
BACT	Best available control technology
BPC	Bechtel Power Corporation
BPD	Berkshire Power Development, Inc.
CAAA	Federal Clean Air Act Amendments of 1990
CDM	Camp, Dresser, McKee
CELT	1996 Capacity, Energy, Loads and Transmission Report published by NEPOOL
CGCC	Coal gasification -- combined cycle
Charlton	Town of Charlton
City of New Bedford	City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992)
CO	Carbon monoxide
CO_2	Carbon dioxide
Company	U.S. Generating Company
Court	Massachusetts Supreme Judicial Court
CT	Combustion turbine peaking unit
dBA	A-weighted decibel
DCR	Debt coverage ratios
DEIR	Draft Environmental Impact Report
Department	Department of Public Utilities
DFW	Division of Fisheries and Wildlife
DO	Dissolved oxygen
$/kWh	Dollars per kilowatt-hour
DPA	Dighton Power Associates Limited Partnership

DSM	Demand Side Management
EIA	Energy Information Administration
EMF	Electric and magnetic fields
ENF	Environmental Notification Form
EPA	The United States Environmental Protection Agency
EPC contract	Turnkey construction contract
EPRI	Electric Power Research Institute
ERCs	Emission reduction credits
ERG	Economic Resource Group
FEIR	Final Environmental Impact Report
FERC	Federal Energy Regulatory Commission
Firm gas supply	The assumption used in analyzing fuel costs that gas supply from the wellhead to the proposed facility will be firm
GEP	Good Engineering Practice
gpd	gallons per day
GTCC	Gas-fired combined cycle unit
GTCC alternative	GTCC with oil backup used in the Company's alternative technology analysis
GTF	Generation Task Force
HQ II	Hydro-Quebec Phase II
HRSG	Heat recovery steam generator
IDLH	Immediately Dangerous to Life or Health
IGCC	Integrated coal gasification combined cycle unit
IGCC alternative	The IGCC used in the Company's alternative technology analysis
IPP	Independent power producer
IWPA	Interim Wellhead Protective Area
kV	Kilovolt
KWh	Killowatthours
L_{50}	The level of noise that is exceeded 50 percent of the time

L_{90}	The level of noise that is exceeded 90 percent of the time
LAER	Lowest Achievable Emission Rate
lbs/MMBtu	Pounds per million British thermal units
L_{dn}	24-hour A-weighted equivalent sound level with a 10 decibel penalty applied to nighttime levels
LOS	Levels of service -- a measure of the efficiency of traffic operations at a given location
MAAQS	Massachusetts ambient air quality standards
Mcf/d	Million cubic feet per day
MCZM	Massachusetts Coastal Zone Management
MDEM	Massachusetts Department of Environmental Management
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company
mG	Milligauss
mgd	Million gallons per day
MHD	Massachusetts Highway Department
Millennium	Millennium Power Project
Millennium-in case	A detailed economic analysis based on NEPOOL dispatch practices for the period 2000 through 2005, which include a dispatch analysis of the proposed facility
Millennium-out case	A detailed economic analysis based on NEPOOL dispatch practices for the period 2000 through 2005, which did not include the dispatch of the proposed facility
Mitsubishi	Mitsubishi Heavy Industries
MMWEC	Massachusetts Municipal Wholesale Electric Company
MPP	Millennium Power Project
MPPLP	Millennium Power Partners, L.P.
MVA	Megavoltamperes
MW	Megawatt
NAAQS	National ambient air quality standards
NEC	Nantucket Electric Company

NEES	New England Electric System
NEPCo	New England Power Company
NEPOOL	New England Power Pool
1996 CELT forecast	Regional load forecast derived from NEPOOL's 1996 CELT report reference forecasts of unadjusted summer and winter peak loads
1997 CELT forecast	Regional load forecast derived from NEPOOL's 1997 CELT report reference forecasts of unadjusted summer and winter peak loads
NEPSCo	New England Power Services Company
New Hampshire PUC	New Hampshire Public Utilities Commission
NHESP	Natural Heritage and Endangered Species Program
NOx	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net present value
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
NU	Northeast Utilities
NUG	Non-utility generator
O_3	Ground-level ozone
O&M	Operation and maintenance
Pb	Lead
PC	Pulverized coal facility
PFBC	Pressurized fluidized bed coal facility
PG&E	PG&E Enterprises
PM-10	Particulates
PPA	Power purchase agreement
PPM	Parts per million
PSD	Prevention of significant deterioration

PURPA	Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3
QF	Qualifying facility
ROW	Right-of-way
SACTI	Seasonal/Annual Cooling Tower Plume Impact model
SCR	Selective Catalytic Reduction
SEC	Securities Exchange Commission
SILs	Significant impact levels
Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council
Southbridge	Town of Southbridge
SO_2	Sulfur dioxide
SOx	Sulfur oxides
TAG	EPRI Technical Assessment Guide
TDS	Total Dissolved Solids
TEC	Taunton Energy Center
TELs	Threshold Effect Exposure Lines
TGP	Tennessee Gas Pipeline Company
Town	Town of Charlton
tpy	Tons per year
USGen	U.S. Generating Company
USGenFS	USGen Fuel Services
USGenPS	USGen Power Services, Inc.
USOSC	U.S. Operating Service Company
VOCs	Volatile organic compounds
Westinghouse 501G	Combustion turbine to be used at proposed facility
WMA	Massachusetts Water Management Act
WWTP	Wastewater Treatment Plant
ZBA	Zoning Board of Appeals

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions the petition of U.S. Generating Company to construct a nominal net 360-megawatt natural gas-fired power generation facility and ancillary facilities in Charlton, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

U. S. Generating Company ("USGen" or "Company") has proposed to construct a nominal net 360-megawatt ("MW") natural gas-fired, combined-cycle electric power plant (the "Millennium project" or "proposed project") on approximately 15-acres of a 120-acre site located in the Town of Charlton, Massachusetts ("Town" or "Charlton"). The proposed facility would commence commercial operation in the year 2000 (Exhs. MPP-0, at 1-2; MPP-11, at 6).

The proposed facility would be powered with natural gas delivered through a high-pressure pipeline interconnection with the nearby Tennessee Gas Pipeline Company ("TGP") facility, using low-sulfur (0.05 percent) distillate oil as a back-up fuel (Exhs. MPP-0, at 1-6; MPP-7, at 3, 6). The proposed facility would have an on-site fuel oil storage tank capable of holding enough oil to fuel the proposed facility for three consecutive days (Exhs. MPP-7, at 6; EFSB V-18a).

The major components of the proposed project include: (1) a Westinghouse 501G combustion turbine, which will generate approximately 240 MW of electricity; (2) a heat recovery steam generator ("HRSG"); (3) a steam turbine and generator which will produce an additional 120 MW of electricity; (4) a selective catalytic reduction system for control of nitrogen oxides ("NOx"); (5) a conventional induced mechanical draft wet cooling tower; and (6) a 225-foot exhaust stack (Exhs. MPP-0, at 1-6; MPP-11, at 3; MPP-11, att. 1; EFSB E-47 (rev. A)). Additional components include a 1.2-million gallon fuel oil storage tank, an ammonia storage tank, water tanks and electrical and water treatment equipment (Exhs. MPP-0, at 1-6; EFSB E-122 (rev. A)).

The Company's proposed site is located in an area of Charlton zoned industrial-general (Exh. MPP-0, at 1-1). The site includes steeply sloping terrain and contains densely wooded areas on a significant portion of the site (Exh. MPP-0, at 1-9). The site is currently vacant, although portions have been altered by previous owners (id. at 1-9). The western portion of the site is traversed by existing 115-kilovolt ("kV") electric transmission lines (id.).[1] To the north, the property boundary extends just north of a TGP natural gas pipeline easement and an existing oil line extends along the northern portions of the site (id.). The eastern boundary of the site is irregular, following Cady Brook in some locations, and bordering Route 169 in others (id.). The farthest extent of the site's southern boundary borders Sherwood Lane (id.).

The proposed project would cost approximately $204,725,000 in year 2000 dollars if built at the preferred site (Tr. 10, at 23).

The proposed project is being developed by USGen (Exh. MPP-0, at 1-1). USGen is owned by PG&E Enterprises ("PG&E") and is an affiliate of Millennium Power Partners, L.P. ("MPPLP") (Exhs. MPP-0, at 1-1; EFSB V-2a (rev. A)). MPPLP, which will be the owner of the proposed project, is a Delaware limited partnership qualified to do business in Massachusetts (Exh. EFSB V-2a (rev. A)). USGen and its affiliates have ownership and/or management responsibilities in 17 electric power plants, one natural gas storage project, and two interstate natural gas pipeline projects (id.).

B. Jurisdiction

The Company's petition to construct a bulk generation facility was filed in accordance with G.L. c. 164, § 69H, which requires the Siting Board to implement the energy policies in its statute to provide a necessary 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 electric companies to obtain Siting Board approval for construction of proposed facilities at a proposed site before a construction permit may be issued by another state agency.

1 An additional portion of the site extends to the west of the transmission line toward H. Foote Road; no project development will occur in this area, except for a small portion of the gas and oil laterals to be constructed by TGP (Exh. MPP-0, at 1-9).

As a wholesale electric generator with a design capacity of approximately 360 MW, the Company's proposed generating unit falls squarely within the first definition of "facility" set forth in G.L. c. 164, § 69G. That section states, in part, that a facility is:

> (1) any bulk generating unit, including associated buildings and structures, designed for, or capable of operating at a gross capacity of one hundred megawatts or more.

At the same time, the Company's proposal to construct an electric interconnection, a gas interconnection and other structures at the site fall within the third definition of "facility" set forth in G.L. c. 164, § 69G, which states that a facility is:

> (3) any ancillary structure including fuel storage facilities which is an integrated part of the operation of any electric generating unit or transmission line which is a facility.

C. Procedural History

On September 23, 1996, the Company filed with the Siting Board[2] a petition to construct and operate a nominal net 360-MW natural gas-fired combined-cycle power plant and ancillary facilities in Charlton, Massachusetts.[3] The Siting Board docketed the petition as EFSB 96-4. On October 30, 1996, the Siting Board conducted a public hearing in Charlton. In accordance with the direction of the Hearing Officer, the Company provided notice of the public hearing and adjudication.

Timely petitions to intervene were filed by: David Barbale ("Mr. Barbale"); Kevin L. Foley ("Mr. Foley"); William and Margaret Krukowski (the "Krukowskis"); and

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2 Prior to September 1, 1992, the Siting Board's functions were effected by the Energy Facilities Siting Council ("Siting Council"). See Acts of 1992, Chapter 141. As the Siting Council was the predecessor agency to the Siting Board, the term Siting Board should be read in this Decision, where appropriate, as synonymous with the term Siting Council.

3 In its petition, the Company stated that its proposed project would be a 400 MW generating facility (Exh. MPP-0, at 1-1). On April 18, 1998, the Company filed documentation with the Siting Board stating that, because of a change in the type of generator that would be used, the net nominal capacity of the proposed project would be reduced from 400 MW to 360 MW (Exh. MPP-11).

James E. and Alice T. Madelle (the "Madelles"). In addition, the Siting Board received timely petitions to participate in the proceeding as an Interested Person from: Berkshire Power Development, Inc. ("BPD"); Dighton Power Associates Limited Partnership ("DPA"); and a joint petition from Massachusetts Electric Company and New England Power Company (collectively, "MECo/NEPCo"). The Siting Board also received a late-filed petition to participate in the proceedings as an Interested Person from Cheryl A. Maranda.[4]

The Hearing Officer allowed the petitions to intervene of Mr. Barbale, Mr. Foley, the Krukowskis, and the Madelles as to environmental and cost issues (Hearing Officer Procedural Orders November 7, 1996, at 6-7; December 6, 1996, at 2-3).[5] The Hearing Officer allowed the petitions of BPD, DPA and MECo/NEPCo for Interested Person status and denied the petition of Cheryl A. Maranda to participate in the proceeding as an Interested Person (id.).

In March 1997, the Siting Board received late-filed petitions to intervene from: William C. Sullivan, Sr. ("Mr. Sullivan"); James and Tracy Sullivan (the "Sullivans"); David E. Matte ("Mr. Matte"); Ian MacFarlane ("Mr. MacFarlane"); Dennis P. and Barbara Grenke (the "Grenkes"); James and Deborah Evans (the "Evanses"); Kenneth and Martha Bergstrom (the "Bergstroms"); and Florence M. Scanlon ("Ms. Scanlon"). In April 1997, the Siting Board received late-filed petitions from: Jane Shropshire ("Ms. Shropshire"); Steven Gardner ("Mr. Gardner"); Stephen E. Milosh ("Mr. Milosh"); and Gina M. DiPietro ("Ms. DiPietro").[6] In June 1997, the Siting Board received a late-filed petition to intervene

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4 The petition by Cheryl A. Maranda was filed with the Siting Board on November 7, 1996, one day after the deadline for intervention (Hearing Officer Procedural Order, November 25, 1996, at 1).

5 Mr. Barbale withdrew as an intervenor on January 16, 1997 and Mr. Foley withdrew as an intervenor on January 21, 1997. The Krukowskis and the Madelles withdrew as intervenors on February 12, 1997.

6 During March and April, the Siting Board received letters of concerns from Jeanine LeBlanc, Sharon Sage, Stanley Mann and Pamela A. Wilson. The signatories did not request to intervene in this matter.

from Tammra Russell ("Ms. Russell"), filing in her capacity as Selectman for the Town.[7]

The Hearing Officer denied the late-filed petitions to intervene of Mr. Sullivan, the Sullivans, Mr. Matte, Mr. MacFarlane, the Grenkes, the Evanses, the Bergstroms, Ms. Scanlon, Ms. Shropshire, Mr. Gardner, Mr. Milosh, Ms. DiPietro and Ms. Russell (Hearing Officer Procedural Orders, March 28, 1997, at 5; April 9, 1997, at 4; April 18, 1997; July 24, 1997). On April 3, 1997, Mr. Matte filed a request for reconsideration which the Hearing Officer also denied (Hearing Officer Procedural Order, April 18, 1997, at 4).

The Hearing Officer granted a motion for reconsideration filed by Mr. MacFarlane on April 30, 1997, and allowed Mr. MacFarlane to participate as an Interested Person with expanded rights (Hearing Officer Procedural Order, May 20, 1997, at 6). Unlike other Interested Parties, Mr. MacFarlane was permitted to cross-examine witnesses concerning the issues identified in his petition to intervene, namely, issues relative to noise and air impacts (id. at 7).

On April 18, 1997, the Company submitted updated Information Request responses and Supplemental Prefiled Testimony to reflect the Company's decision to employ Westinghouse in place of General Electric for its turbine technology.

The Siting Board conducted ten days of evidentiary hearings commencing on May 28, 1997 and ending on June 20, 1997. The Company presented the testimony of twelve witnesses: Dr. Susan F. Tierney, principal with the Economics Resource Group ("ERG"), who testified as to the need for the proposed project; Gary A. Lambert, Jr., director of development, northeast region, for the Company, who testified as to viability, site selection, water, alternative technology, air, visual, carbon dioxide ("CO_2"), cost and other issues; Douglas F. Egan, senior vice president, northeast region, for the Company, who testified as to viability and site selection; William B. Daniels, director of finance for the

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7 On June 30, 1997, Richard J. Kwiatkowski, Chairman of the Board of Selectmen for Charlton, and Robert P. Beaudette, Clerk, sent a letter to the Siting Board advising the Siting Board that Ms. Russell's letter "in no way expresses the views of the remaining members of the Board as we . . . have supported this project from the beginning."

Company, who testified as to viability; Patrick J. West, project engineer for the Company, who testified as to noise, water, air, visual, CO_2, traffic and safety issues, and construction cost and alternative technologies; Mark D. Winne, director, combined-cycle maintenance for the Company, who testified as to operation, maintenance and safety; Norman D. Karloff, manager of fuel procurement for the Company, who testified as to the project's fuel acquisition strategy; Michael D. Petit, director, project management services for the Company, who testified as to fuel supply; Frederick M. Sellars, vice president of Earth Tech, who testified as to site selection, noise, water, alternative technology, air, visual, CO_2, traffic, safety, land use and cost issues; Dr. William H. Bailey, president of Bailey Research Associates, Inc., who testified as to electric and magnetic field issues ("EMF"); George F. Hessler, Jr., P.E., an acoustical engineer with Hessler Associates, Inc., who testified as to noise impact and noise mitigation issues; and Kathleen D. Hathaway, manager of project development for the Company, who testified as to site selection.

The Hearing Officer entered 560 exhibits into the record consisting primarily of information and record request responses. The Company entered 44 exhibits into the record. The Company filed its brief on July 11, 1997.

D. Scope of Review

In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct facilities, the Siting Board requires applicants to justify generating facility proposals in five phases. First, the Siting Board requires the applicant to show that additional energy resources are needed. Dighton Power Associates, EFSB 96-3, at 5 (1997) ("Dighton Power Decision"); Berkshire Power Development, Inc., 4 DOMSB 221, 242 (1996) ("Berkshire Power Decision"); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA Decision") (see Section II.A, below). Second, the Siting Board requires the applicant to show that, on balance, its proposed project is superior to alternative approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability. Dighton Power Decision, EFSB 96-3, at 5; Berkshire Power Decision, 4 DOMSB at 243; NEA Decision, 16 DOMSC at 364 (see Section II.B, below). Third, the

Siting Board requires the applicant to show that its project is viable. Dighton Power Decision, EFSB 96-3, at 6; Berkshire Power Decision, 4 DOMSB at 243; NEA Decision, 16 DOMSC at 364 (see Section II.C, below). Fourth, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and in cases where an alternative site has been noticed, that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply. Dighton Power Decision, EFSB 96-3, at 6; Berkshire Power Decision, 4 DOMSB at 243; NEA Decision, 16 DOMSC at 343 (see Section III.A, below). Finally, the Siting Board requires that a proposed project minimize environmental impacts and achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability of supply at the site which is approved. Dighton Power Decision, EFSB 96-3, at 6; Berkshire Power Decision 4 DOMSB at 243; Boston Edison Company, 1 DOMSB 1, 149-153, 186-195 (1993) ("1993 BECo Decision") (see Section III.B below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, § 69H, the Siting Board is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The Siting Board, therefore, must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities. With respect to proposals to construct energy facilities in the Commonwealth, the Siting Board evaluates whether there is a need for additional energy resources to meet reliability, economic, or environmental objectives directly related to the energy supply of the Commonwealth.

In City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"), the Supreme Judicial Court ("Court") concluded that the Siting Board's finding that New England needed additional energy resources for reliability purposes was inadequate in light of the statutory mandate that an energy supply must be necessary for the Commonwealth. 413 Mass. at 489. In addition, the Court noted that, although the Siting Board had argued that its mandate was to ensure an adequate energy supply at minimum cost, "[e]nsuring an adequate supply is not the same as 'provid[ing] a necessary energy supply for the commonwealth (emphasis added)." 413 Mass. at 490, citing G.L. c. 164, § 69H.

In response to the Court's directive in City of New Bedford, the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with its statutory mandate -- to implement the Commonwealth's energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost -- in Eastern Energy Corporation (on Remand), 1 DOMSB at 421-423 (1993) ("EEC (remand) Decision").

With respect to the issue of regional need versus Massachusetts need, the Siting Board noted the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability (id. at 422).

The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration (id.). Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not linked to individual utilities by power purchase agreements ("PPAs") (id. at 416). The Siting Board also noted that the Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A and in this same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3, 4. Accordingly, the Siting Board found that an analysis of regional need must serve as a foundation for an analysis of Massachusetts need. EEC (remand) Decision, 1 DOMSB at 417.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. Dighton Power Decision, EFSB 96-3, at 8; Berkshire Power Decision, 4 DOMSB at 245; New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Board has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Dighton Power Decision, EFSB 96-3, at 8; Berkshire Power Decision, 4 DOMSB at 245; Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. Dighton Power Decision, EFSB 96-3, at 9; Berkshire Power Decision, 4 DOMSB at 245; EEC (remand) Decision, 1 DOMSB at 422. With respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board notes that such analyses of need would be consistent with its statutory obligation to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, 69J. Dighton Power Decision, EFSB 96-3, at 8-9; Berkshire Power Decision, 4 DOMSB at 245-246; Enron Power Enterprise Corporation, 23 DOMSC 1, 49-62 (1991) ("Enron Decision").

Further, while acknowledging that G.L. c. 164, § 69H requires the Siting Board to ensure a necessary supply of energy for Massachusetts, the Siting Board interprets this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources,[8] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Dighton Power Decision, EFSB 96-3, at 8-9; Berkshire Power Decision, 4 DOMSB at 246; Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985) ("1985 MECo/NEPCo Decision"). In doing so, the Siting Board fulfills the requirements of G.L. c. 164, § 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in the New England Power Pool ("NEPOOL").

The Siting Board has found that a demonstration of Massachusetts need based on reliability, economic efficiency or other benefits associated with additional energy resources from a proposed project remains a necessary element of a need review. Dighton Power Decision, EFSB 96-3, at 9; Berkshire Power Decision, 4 DOMSB at 246; EEC (remand) Decision, 1 DOMSB at 417-418. However, in response to the Court's reminder in City of New Bedford that its statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in the EEC (remand) Decision that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth for them to be considered in support of a finding of Massachusetts need.

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8 See Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985); Boston Edison Company, 13 DOMSC at 70-73 (1985).

1 DOMSB at 418. See also Cabot Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 26.

In its first review of a petition by a non-utility generator ("NUG") to construct a jurisdictional facility, the Siting Board found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost-effective qualifying facility ("QF")[9] resources to its utilities' supply mix. NEA Decision, 16 DOMSC at 358. In that case, the Siting Board also found (1) that a signed and approved PPA between a QF and a utility constitutes prima facie evidence of the utility's need for additional energy resources for economic efficiency purposes, and (2) that a signed and approved PPA which includes a capacity payment constitutes prima facie evidence for the need for additional energy resources for reliability purposes (id.). Thus, in cases where a non-utility developer sought to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board has required the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPAs. MASSPOWER, Inc., 21 DOMSC 196, 200 (1990); MASSPOWER, Inc., 20 DOMSC 1, 19-23, 32 (1990) ("MASSPOWER Decision"); Altresco-Pittsfield Decision, 17 DOMSC at 366-367. Two 1995 decisions of the Court, however, bring into question further reliance on such prima facie evidence in this and future cases.[10]

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9 The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3 (PURPA), established a QF category consisting of non-utility electric cogenerators with the capability to generate both electric energy and useable steam. In order to qualify for QF status under PURPA, the cogenerator had to certify to the Federal Energy Regulatory Commission (FERC) that it would sell a specified portion of its steam by-product in addition to its electric sales.

10 In Point of Pines Beach Association v. Energy Facilities Siting Board, the Court noted the Siting Board's statutory requirement to make an independent finding of Commonwealth need, a finding that could not be premised solely on the existence of signed and approved PPAs. 419 Mass. 281, 285-286 (1995) ("Point of Pines"). Referencing its decision in Point of Pines, the Court vacated a final decision of the

(continued...)

Where a non-utility developer has proposed a generating facility for a number of power purchasers that include purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, the need for additional energy resources must be established through an analysis of regional capacity and a showing of Massachusetts need based either on reliability, economic or environmental grounds directly related to the energy supply of the Commonwealth. Dighton Power Decision, EFSB 96-3, at 9-10; Berkshire Power Decision, 4 DOMSB at 248; West Lynn Cogeneration, 22 DOMSC 1, 9-47 (1991) ("West Lynn Decision"). Therefore, consistent with the Siting Board's precedent and reflecting the directives of the Court in City of New Bedford, Point of Pines, and Attorney General, the Siting Board here reviews the need for the proposed project for reliability, economic and environmental purposes.

2. Reliability Need

The Siting Board has found that it is appropriate to consider the need for capacity beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See Dighton Power Decision, EFSB 96-3, at 10; Berkshire Power Decision, 4 DOMSB at 248; West Lynn Decision, 22 DOMSC at 14, 33-34. The Siting Board has acknowledged that the longer time frame is potentially useful regardless of whether need has been established for the first year of proposed operation. If need has been established for the first year, the longer time frame helps ensure that the need will continue over a number of years, and is not a temporary aberration. If need has not been established for the first year of proposed operation, a demonstration of need within a limited number of years thereafter may still be an important factor in reaching a decision as to whether a proposed project should go forward. Thus for the purposes of this review, the Siting Board finds that it is appropriate to explicitly consider need for the proposed facility during the 1999/2000 to 2003 time period.

10(...continued)
Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995) (Attorney General).

a. New England

USGen asserted that there is a need for at least 360 MW of additional energy resources in New England beginning in the year 2000 and beyond (Tr. 1, at 16). In support, the Company presented a series of forecasts of demand and supply for the region based primarily on the 1996 forecast and other data published by NEPOOL (Exh. MPP-0, at 2-5). The Company stated that it combined its demand and supply forecasts to produce a series of need forecasts (id.).

The Company stated that the forecasts of demand and supply are developed from individual forecasts of several underlying factors relative to need for both summer and winter which include: (1) unadjusted peak loads; (2) utility-sponsored demand side management ("DSM") resources available on peak; (3) NUG netted from load; (4) supply resources; and (5) required reserve margin (id. at 2-3). The Company stated that it developed "adjusted" summer and winter peak load by subtracting the DSM and NUG factors from the unadjusted peak load and the resulting peak load was multiplied by a factor reflecting the required reserve margin to yield a forecast of total capacity requirements (id. at 2-3 to 2-5). The Company stated that projected supply resources were then subtracted from the total capacity requirements in each year of the forecast to provide a forecast of the magnitude and need for new energy resources (id. at 2-3).

In the following sections, the Siting Board reviews the Company's demand forecasts, including its demand forecast methods and estimates of DSM savings over the forecast period, and the Company's supply forecasts, including its capacity assumptions and required reserve margin assumptions. The Siting Board then analyzes a series of need forecasts.

i. Demand Forecasts

(A) Description

USGen presented forecasts of unadjusted summer and winter peak load and DSM savings derived from information contained in the 1996 Capacity, Energy, Loads and

Transmission ("CELT") report published by NEPOOL (id.).[11] To develop forecasts of adjusted load, the Company combined each of these peak load forecasts with (1) the 1996 CELT report forecast of NUG netted from load, and (2) one of three forecasts of DSM savings based on the 1996 CELT report forecast of DSM savings (id.).

(1) Demand Forecast Methods

The Company presented a base case summer and winter unadjusted peak load forecast, derived directly from the 1996 NEPOOL CELT report reference forecasts of unadjusted load for summer and winter peak ("1996 CELT forecast") (id.). The Company stated that the 1996 CELT forecast is based on historical trends and expectations about significant economic and demographic trends over the forecast period and provides a reasonable projection of regional demand (id.).[12] The Company also presented the 1996 CELT report high case ("CELT high case") and low case ("CELT low case") demand forecasts, which are based on optimistic and pessimistic economic forecasts, respectively, to demonstrate extreme variation in expected demand and to support a finding of need based primarily on the base case forecast (Exh. MPP-0, at 2-5 to 2-6; Tr. 1 at 30-32).[13]

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11 The Company indicated that the CELT reports include: (1) a high, reference and low forecast of unadjusted load for summer and winter peaks; (2) a forecast of DSM savings; (3) a forecast of NUG netted from load (i.e., power from NUG units located at the site of an end-user which displace power that could be sold by a NEPOOL utility, and which is not available for sale outside the site); and (4) a reference forecast of adjusted load for summer and winter peaks, derived by deducting the forecasts of DSM savings and NUG netted from load from the unadjusted reference load forecast (Exh. MPP-0, at 2-6 to 2-7).

12 The Company indicated that the 1997 CELT forecast was issued by NEPOOL shortly before the start of the hearings and was derived by updating the 1996 CELT forecast in the short-term (1997 to 2000) only (Exh. EFSB N-1(R); Tr. 1, at 21-23). The Company stated that, therefore, the 1997 CELT forecast is higher than the 1996 CELT by 100 to 328 MW for the years 1997 through 2000 and then identical to the 1996 CELT forecast for the remainder of the forecast period (Tr. 1, at 21-23).

13 USGen stated that NEPOOL defines the CELT low case demand forecast as having a (continued...)

The Company indicated that all its demand forecasts were adjusted to incorporate the addition of Nantucket Electric Company ("NEC") load to NEPOOL beginning in 1997 (Exh. MPP-13, at 6).

(2) DSM

The Company provided three forecasts of DSM: (1) a base DSM scenario, which is the current forecast of company-sponsored DSM savings used in NEPOOL's 1996 CELT report;[14] (2) a high DSM scenario, which assumes an increase of ten percent in the annual post-1996 growth rate of the base DSM scenario; and (3) a low DSM scenario, which assumes a decrease of 10 percent in the annual post-1996 growth rate of the base DSM scenario (Exh. MPP-0, at 2-7). The Company stated that, historically, NEPOOL has overestimated DSM savings and has consistently revised its forecast of DSM savings downward in each successive forecast since 1990 (id.).[15] The Company stated that in recent years the discrepancy between forecasted DSM and actual DSM levels has diminished and that, therefore the Company assumed a symmetrical band of plus or minus ten percent around the 1996 CELT-reported DSM growth rate (id.). However, the Company noted that this was a conservative assumption on the low-DSM side because utility-sponsored DSM programs have been declining in recent years and will likely continue to decline due to a number of factors including the expected restructuring of the electricity industry (id.).

13(...continued)
90 percent chance of being exceeded and the CELT high case demand forecast as having a ten percent chance of occurring (Exh. MPP-0, at 2-5 to 2-6).

14 The Company indicated that the 1996 CELT report forecast of DSM also was used in the 1997 CELT report (Tr. 1, at 27).

15 The Company noted that in previous cases, the Siting Board has allowed for an uncertainty band around the base-case DSM forecast that was skewed toward the low DSM side. The high DSM scenario has assumed a ten percent increase and a low DSM scenario has assumed a 25 percent decrease (Exh. MPP-0, at 2-7). See Dighton Power Decision, EFSB 96-3, at 12; Berkshire Power Decision, 4 DOMSB at 262.

(3) Adjusted Load Forecasts

The Company stated that to develop forecasts of adjusted load, the 1996 CELT unadjusted summer and winter peak load forecasts were combined with (1) the 1996 CELT report forecast of NUG netted from load, and (2) one of three aforementioned forecasts of DSM savings (Exh. MPP-0, at 2-6 to 2-7). Thus, the Company presented three forecasts of adjusted summer peak load and three forecasts of adjusted winter peak load.

(B) Analysis

The Siting Board previously has acknowledged that the CELT report generally can provide an appropriate starting point for resource planning in New England, and has accepted the use of CELT forecasts for the purposes of evaluating regional need in previous reviews of proposed NUG facilities. Berkshire Power Decision, 4 DOMSB at 272; Cabot Decision, 2 DOMSB at 273-274; NEA Decision, 16 DOMSC at 354. In addition, the Siting Board has relied primarily on the more recent available forecasts in its analysis of need. See Berkshire Power Decision, 4 DOMSB at 257.

Here, the Company provided base case summer and winter demand forecasts based directly on the 1996 CELT forecast and the 1996 CELT report DSM forecast. The Company adjusted the base case summer and winter forecasts by high and low DSM cases, for a total of three summer and three winter adjusted forecasts.

The Company also provided the 1997 CELT forecast but did not update its need forecasts based on the 1997 CELT forecast. As noted above, the 1997 CELT forecast reflects an update to the 1996 CELT forecast in the short-term only, resulting in a 1997 CELT forecast that is higher than the 1996 CELT forecast through the year 2000, then identical to the 1996 CELT forecast for the remainder of the forecast period. Due to the timing of the issuance of the 1997 CELT report and the conservatism of the 1996 CELT forecast relative to the 1997 CELT forecast in the short-term, the Siting Board finds that it is reasonable, for the purposes of this review, to rely on the 1996 CELT forecast.

In addition, the Company provided the CELT high case demand forecast and CELT low case demand forecast as extreme demand forecasts, in order to test the sensitivity of the results of analysis of the base case forecast. As noted above, NEPOOL assigns a low probability of occurrence to each of these forecasts. Consistent with previous Siting Board decisions (see, e.g., Cabot Decision, 2 DOMSC at 274), the Siting Board finds that these forecasts represent a sensitivity analysis of varying economic assumptions rather than forecasts of regional demand.

Overall, the Company has presented one base case forecast adjusted by three forecasts of DSM. Given uncertainties in forecasting demand, the Siting Board has previously found that it is reasonable to include a range of forecasts in a company's reliability need analysis. See, e.g., Berkshire Power Decision, 4 DOMSB at 261, n.23. However, as noted above, the Siting Board has acknowledged the value of the CELT report for regional resource planning and has accepted the use of CELT forecasts for the purpose of evaluating regional need. In addition, in reviewing need forecasts, the Siting Board has placed more weight on the base case forecast. Id. at 274. Here, the Company has provided a recent CELT forecast as a base case forecast and also has provided high and low forecasts for the purpose of demonstrating the range of potential demand. Therefore, the Siting Board finds that it is reasonable, for purposes of this review, to rely on one base case forecast for summer peak load and one base case forecast for winter peak load.

Accordingly, the Siting Board finds that the 1996 CELT forecast is an appropriate base case summer peak load and winter peak load forecast for use in the analysis of regional need for the years 2000 and beyond.

Finally, the Company provided three forecasts of utility-sponsored DSM -- a base case scenario, which is NEPOOL's current forecast of company-sponsored DSM savings, a low DSM scenario which discounts NEPOOL's projected DSM growth rates by ten percent, and a high DSM forecast, which inflates NEPOOL's projected DSM growth rates by ten percent. In recent cases, the Siting Board accepted high and low DSM scenarios which were skewed toward less DSM. See, Dighton Power Decision, EFSB 96-3, at 12; Berkshire Power Decision, 4 DOMSB at 261-262. As noted above, although NEPOOL has historically overestimated DSM savings, in each successive forecast since 1990, NEPOOL has consistently revised its forecast of DSM savings downward and therefore has decreased the discrepancy between forecasted DSM and actual DSM levels. The Siting Board recognizes that the Company's proposed symmetrical bandwidth of uncertainty surrounding the base DSM scenario is a more conservative approach, i.e., an approach relying on smaller high side contingency margins, than the increase of ten percent/decrease of 25 percent that has been accepted by the Board in recent cases. However, this symmetrical bandwidth is consistent with NEPOOL's trend to the successive lowering of its DSM forecasts.

Accordingly, for purposes of this review, the Siting Board finds that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and (3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

In sum, the Siting Board has accepted one forecast of summer peak load and one forecast of winter peak load. In addition, the Siting Board has accepted three forecasts of DSM -- a base case, low case and high case. Therefore, the Siting Board here reviews three forecasts of adjusted summer peak load and three forecasts of adjusted winter peak load.

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

USGen presented three supply scenarios based on the capacity projections in the 1996 CELT report -- a base supply scenario, a high supply scenario, and a low supply scenario (Exhs. MPP-0, at 2-9 to 2-15; MPP-13, at 3-6, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A). The Company indicated that the base supply scenario reflects the resources included in the 1996

CELT report,[16] updated to incorporate current information (Exhs. MPP-0, at 2-10; MPP-13, at 4-6).

The Company stated that it made reductions to the 1996 NEPOOL supply projections to reflect actual changes to the NEPOOL supply including: (1) the removal of the proposed Taunton Energy Center ("TEC") as a committed resource (150 MW summer and winter);[17] (2) the retirement of the Connecticut Yankee unit (560 MW summer, 583 MW winter);[18] (3) the deactivation of the Millstone 1, 2 and 3 units through the summer of 1997 (2,632 MW summer, 2,669 MW winter); and (4) the derating of the Maine Yankee unit by ten percent (87 MW summer, 88 MW winter)[19] (Exhs. MPP-0, at 2-10 to 2-12; MPP-13, at 5 to 6, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A)). The Company stated that it also made additions to the 1996 NEPOOL supply projections to reflect Northeast Utilities ("NU") temporary replacement capacity for the Millstone units for the summer of 1997 (417 MW) (Exh. MPP-13, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A); Tr. 1 at 45-51).[20] In addition,

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16 The Company indicated that NEPOOL supply resources include all existing plants, external purchases and sales, and committed utility and non-utility generation owned or contracted by NEPOOL member utilities that is under construction and/or fully licensed (Exhs. MPP-0, at 2-9; EFSB N-1 (att. A) at 94-97).

17 The Company indicated that the 1996 CELT report included the TEC coal-fired project as committed capacity as of February 2000 under category "T" which signifies "regulatory approval received including building permit, not under construction" (Exh. EFSB N-1 (att.) at 34, 94). The Siting Board notes that on June 28, 1996, the Silver City Energy Limited Partnership withdrew its petition for the TEC facility and on August 22, 1996, the Siting Board rescinded the conditional approval granted Silver City Energy Limited Partnership in Docket No. EFSB 91-100.

18 The Company indicated that in December 1996, the owners of Connecticut Yankee voted to permanently retire the plant (Exh. MPP-13, at 5).

19 USGen indicated that, at the time the petition was filed, the Maine Yankee unit was operating at 90 percent of its capacity under a Nuclear Regulatory Commission ("NRC") ordered derating of ten percent (Exh. MPP-0, at 2-11).

20 Dr. Tierney indicated that the 417 MW was put in service in 1996, largely under emergency approvals in Connecticut which will extend through the fall of 1997 (Tr. 1, at 49).

consistent with NEPOOL assumptions, the Company stated that it assumed that the Hydro-Quebec Phase II ("HQ II") contract, which expires in June 2001, would not be renewed but that the HQ II transmission line would continue to provide reliability benefits with a capacity value of 85 percent of its current capacity (Exh. MPP-0, at 2-10).

The Company stated that it made further reductions to the 1996 NEPOOL supply projections to reflect assumed changes to the NEPOOL supply including: (1) the retirement of the Salem Harbor 1, 2 & 3 units (303 MW summer, 305 MW winter) beginning in the winter of 1999/2000, and (2) the permanent derating of the Maine Yankee unit by ten percent until its scheduled retirement in 2008 (Exh. MPP-0, at 2-11). The Company explained that by 1999, 25 New England units, approximately 1,450 MW of NEPOOL's fossil steam generation capacity, will be operating beyond NEPOOL retirement guidelines and that, therefore, it is reasonable to assume that at least 300 MW of this generation capacity will be retired due to costs, competitive pressures and the requirement of the federal Clean Air Act Amendments of 1990 ("CAAA") (id.). The Company stated that it considered the Salem Harbor 1, 2, and 3 units to be a proxy for this retirement (id.; Exh. MPP-13, exhs. 2.1-5 (rev. A), 2.1-6 (rev. A)).[21] The Company further explained that it assumed operation of the Maine Yankee unit at 90 percent of its full capacity, until its scheduled retirement in 2008, because the NRC has given no indication that approval will be granted to return to production at full capacity (Exh. MPP-13, at 2-11).[22]

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21 The Company stated that this assumption was consistent with Siting Board precedent in the Berkshire Power Decision, 4 DOMSB at 270.

22 The Company asserted that this assumption was conservative in that, at the time of the hearings, the Maine Yankee unit was out of service and that recently reduced staffing and spending levels have decreased the chances of the unit returning to service (Tr. 1, at 18-19). After the close of the hearings, the Siting Board notes that NEPOOL removed the Maine Yankee unit from service on August 6, 1997, following a Board of Directors vote to shut the unit and begin decommissioning.

The Company stated that it also added the capacity of (1) the BPD Project (252 MW summer and winter),[23] and (2) the units that were reactivated in the summer of 1996 as replacement capacity for the Millstone units (167 MW summer, 170 MW winter) (Exh. MPP-0, at 2-12; Tr. 1 at 45-46).[24] Overall, the Company stated that the base case represents a set of supplies that have a reasonable expectation of occurrence over the forecast period, consistent with conservative assumptions and Siting Board precedent (Exh. MPP-0, at 2-12).

The Company stated that the low supply scenario was based on the 1996 CELT report forecasted inventory of available capacity, adjusted for a reasonable set of contingencies that reduce the amount of available generation capacity (id.). For the low supply scenario, the Company assumed reductions to the base supply scenario to reflect: (1) the retirement of 50 percent of all coal-fired and oil-fired capacity included in the 1996 CELT report but operating beyond NEPOOL retirement guidelines beginning in the winter of 1999/2000 (723 MW in summer 2000 increasing to 2,808 MW in summer 2009, 729 MW in winter 1999/2000 increasing to 2,839 MW in winter 2008/2009);[25] (2) the retirement of the

23 USGen stated that it was reasonable to include the base case NUG resources that have received Siting Board approval to account for additional NUG resources that may commence operation during the forecast period (Exh. MPP-0, at 2-12). The Company included the BPD project beginning in the summer of 1999 (id.). The Company noted that the addition of the DPA project, which received Siting Board approval after the close of the proceedings, would not alter the Company's overall need conclusions (Company Brief at 20, n.14).

24 The Company assumed that all replacement measures consisting of actual physical equipment, including units that were reactivated prematurely, would remain in place even when the Millstone units come back in service (Tr. 1, at 45). The Company noted that NEPOOL includes the reactivated units as of their scheduled reactivation dates starting in 2000 (Exh. MPP-0, at 2-11).

25 The Company stated that accelerated retirement of older, less efficient generating units is reasonable for the low supply case, especially in light of the cost pressure that will be created by the CAAA and the expected move to a competitive electricity generation marketplace (Exh. MPP-0, at 2-13).

Millstone 1 unit (641 MW summer, 648 MW winter);[26] (3) the reduction in the capacity value of the HQ II transmission line to 50 percent of its present value beginning in 2001 (520 MW summer, 167 MW winter); and (4) the cancellation of the BPD project (Exhs. MPP-0, at 2-12 to 2-14; MPP-13, at 5, exh. 2.1-6 (rev. A)). In addition, the Company added capacity to reflect continued operation beyond the summer of 1997 of the units put into service in Connecticut in 1996 under emergency approvals due to the outage of the Millstone units (417 MW beginning in summer 1997, dropping to 160 MW in summer 2002, 330 MW in winter 1997/98, dropping to 160 MW in winter 2001/02) (Tr. 1, at 47-51).[27]

The Company stated that the high supply scenario also was based on the 1996 CELT forecasted inventory of available capacity but adjusted for a set of assumptions that increase the amount of available generation over the forecast period (id.). For the high supply scenario, the Company added capacity to the base supply scenario including: (1) 50 percent of planned utility capacity additions classified as under licensing consideration in the 1996 CELT report (3 MW summer and winter); (2) 25 percent of the planned utility capacity additions classified as proposed in the 1995 CELT report (62 MW in summer 2000, increasing to 95 MW in summer 2005, 62 MW in winter 1999/2000, increasing to 100 MW winter 2004/05); and (3) the capacity of the DPA project (170 MW summer and winter)[28]

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26 The Company assumed that, in addition to scheduled retirements of nuclear units, there will be a derating, shutdown or retirement of a portion of New England nuclear capacity due to safety and/or cost considerations (Exhs. MPP-0, at 2-14; MPP-13, at 5). The Company stated that it used the smallest single nuclear unit, Millstone 1, as a proxy to determine the value of such a loss of nuclear capacity (Exhs. MPP-0, at 2-14; MPP-13, at 5).

27 The Company explained that the low supply scenario includes a greater amount of Millstone replacement capacity relative to the base supply scenario to reflect likely reactions to the continued outage of a major New England nuclear generating unit (Exh. MPP-0, at 2-14). The Company also explained that as some of the capacity is included in the 1996 CELT Report as of the year 2000, the adjustment to NEPOOL supply is reduced to 160 MW in 2000 to prevent double counting (id. at 2-11, n.3).

28 The Company indicated that it was appropriate to include NUG facilities with on-going reviews before the Siting Board in the high supply case (Exh. EFSB N-18).

(Exhs. MPP-0, at 2-15; MPP-13, exhs. 2.1-5 (rev. A) 2.1-6 (rev. A). In addition, the Company assumed that: (1) there would be reduction in the capacity value of the HQ transmission line (beginning in 2001, an additional 230 MW summer, 95 MW winter); (2) the Salem Harbor 3 unit would not be retired (an additional 143 MW summer and winter); (3) the Maine Yankee unit would not be derated (an additional 87 MW summer and winter); and (4) a smaller amount of emergency generating capacity put in service due to the outage of the Millstone units would remain in service (a reduction of 85 MW for summer 1998 to 2001, a reduction of 88 MW, for winter 1997/98 to 2000/01) (see n.20, above) (Exhs. MPP-0, at 2-15; MPP-13, exhs. 2.1-5 (rev. A) 2.1-6 (rev. A)).

(2) Reserve Margin

The Company indicated that it incorporated reserve margins consistent with NEPOOL's current projections of required reserve margins (Exh. MPP-0, at 2-8). The Company stated that, for the 1996 through 2000 period, it used the reserve margins from the September 1994 NEPOOL document, "1994 Annual Review of NEPOOL Objective Capability and Associated Parameters" (id.).[29] The Company added that, for the post-2000 period, summer and winter reserve margins were assumed to remain constant at their projected values for the year 2000 (id.).[30] Dr. Tierney indicated that the higher winter reserve requirement is due, in large part, to the reduced amount of backup capacity that is available from Quebec and New Brunswick during the winter (Tr. 1, at 54).

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29 The Company indicated that NEPOOL has not published a new Annual Review and that the data contained in the 1994 Review continues to be used by NEPOOL (Exh. HO-N-3).

30 The Company assumed summer reserve margins as follows: (1) 1994, 22.0 percent; (2) 1995, 23.6 percent; (3) 1996, 22.7 percent; (4) 1997, 22.9 percent; (5) 1998, 22.7 percent; (6) 1999, 22.7 percent; (7) 2000 through 2008, 22.8 percent (Exh. MPP-0, at 2-8). The Company assumed winter reserve margins as follows: (1) 1994/1995, 30.3 percent; (2) 1995/1996, 31.3 percent; (3) 1996/1997, 31.3 percent; (4) 1997/1998, 31.5 percent; (5) 1998/1999, 32.1 percent; (6) 1999/2000 through 2008/2009, 32.0 percent (id. at 2-8 to 2-9).

(B) Analysis

The Company has presented a base supply scenario based on the 1996 CELT report with adjustments for actual, planned and likely changes to NEPOOL supply, a low supply scenario based on possible losses of committed capacity included in the base supply scenario, and a high supply scenario based on possible implementation of additional supply options.

As noted above, the Company's base supply scenario assumes the removal of the capacity of the Salem Harbor 1, 2 & 3 units beginning in 1999 and the derating of the Maine Yankee facility by ten percent over the forecast period. In addition, the base supply scenario assumes the addition of the capacity of the BPD project in 1999 and the capacity of units reactivated as replacements for the Millstone units. Here, the Siting Board considers the reasonableness of these assumptions.

The Siting Board notes that by 1999, the Salem 1-3 units will be operating beyond NEPOOL's retirement guidelines for coal-fired units and that as of 1999, a number of other NEPOOL fossil fuel units also will be operating beyond NEPOOL's guidelines for retirement. It is therefore reasonable to conclude that the Salem Harbor units or an equivalent amount of capacity, operating beyond retirement guidelines, will be retired beginning in 1999, especially in light of CAAA requirements that are likely to take effect in 1999. Therefore, consistent with previous reviews, the Siting Board accepts the Company's assumption of the retirement of Salem Harbor 1-3 units in 1999. See, Berkshire Power Decision, 4 DOMSC at 270. With respect to the Maine Yankee unit, the record demonstrates that the unit is currently out of service, that it previously was operating under an NRC-ordered derating of ten percent, and that in ordering the derating, the NRC did not indicate whether the unit would be allowed to return to operation at its full capacity. Therefore, for purposes of this review, the Siting Board accepts the Company's assumption that the Maine Yankee unit will be derated by ten percent over the forecast period. See n.19, above. See, Berkshire Power Decision, 4 DOMSC at 271.

In addition, the Siting Board recognizes that it is appropriate to account for additional NUG resources that may commence operation during the forecast period in the base case supply scenario. Here, the BPD project is included in the base case supply scenario, while the DPA project, approved after the close of hearings, is not included in the base case supply scenario. For purposes of this review, the Siting Board accepts the Company's assumptions regarding future NUG units. However, due to the historical attrition of generating facilities that have been approved by the Siting Board, the Siting Board questions the Company's threshold of Siting Board approval for including new projects in the base case supply scenario and will address this issue in a subsequent decision. Finally, the Siting Board agrees that it is reasonable to assume that certain units put into service as replacement power for the Millstone units will remain in service over the forecast period.

Accordingly, the Siting Board finds that the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need. In addition, the Siting Board finds that the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and, therefore, that the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need. The Siting Board further finds that the assumptions reflected in the Company's high case supply scenario are reasonable high case assumptions and, therefore, that the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need.

Finally, with respect to reserve margins, the Company used NEPOOL's projected reserve margins for the years 1994 through 2000 and reasonably assumed that the reserve margins would remain at the projected values for the year 2000 in the years 2001 through 2008. Accordingly, and consistent with recent Siting Board decisions, the Siting Board finds that, for the purposes of this review, the reserve margins projected by the Company are appropriate.

iii. Need Forecasts

(A) Description

The Company developed nine summer need forecasts by adjusting the 1996 CELT summer peak load forecasts by each of three DSM scenarios, and combining each of the resulting three summer adjusted demand forecasts with three supply forecasts (Exhs. MPP-0, at 2-15 to 2-16; MPP-13, exh. 2.1-8 (rev. A)). Of these nine summer need forecasts, all demonstrate a sustained need for at least 360 MW of capacity beginning in 2000 (Exh. MPP-13, exh. 2.1-8 (rev. A)). See Table 1. In addition, the Company developed nine winter need forecasts in a similar manner (Exh. MPP-0, at 2-15 to 2-16.) Of these nine winter need forecasts, all demonstrate a sustained need for at least 360 MW of capacity beginning in 2000 (Exh. MPP-13, exh. 2.1-8 (rev. A)).[31] See Table 1, below.

Table 1

RANGE OF REGIONAL NEED CASES

Summer-2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1996 CELT	High	(1,021)	(1,408)	(2,360)
1996 CELT	Base	(1,064)	(1,450)	(2,906)
1996 CELT	Low	(1,105)	(1,492)	(2,948)

[31] In addition, as noted above, in order to demonstrate extreme variations in expected demand, the Company provided summer and winter need forecasts based on the 1996 CELT report high and low demand forecasts (Exh. MPP-0, at 2-5 to 2-6). The Company developed 18 summer need forecasts by adjusting the 1996 CELT report high and low case summer demand forecasts by each of the three DSM forecasts, and combining each of the resulting six summer adjusted forecasts with three supply forecasts (Exh. MPP-13, exh. 2.1-9 (rev. A)). Of these 18 summer need forecasts, each of (1) the nine forecasts based on the high case demand forecast, and (2) the three low case demand forecasts combined with low supply forecasts, demonstrates a need of at least 360 MW of capacity in 2000. However, the six low case demand forecasts combined with the base case or high supply forecasts do not demonstrate a need for at least 360 MW until the 2006 to 2010 time frame (id.). In addition, the Company developed 18 winter need forecasts in the same manner. Of these 18 winter need forecasts, each of (1) the nine forecasts based on the high case demand forecast, and (2) the three low case demand forecasts combined with low supply forecasts, demonstrate a need of at least 360 MW of capacity in 2000. However, like the similarly developed summer forecasts, the six low case winter demand forecasts combined with the base case or high supply forecasts do not demonstrate a need for at least 360 MW until the 2006 to 2010 time frame (id.). The Siting Board notes that NEPOOL defines the CELT low-case demand forecast as having a 90 percent chance of being exceeded. See n.13, above.

Winter - 1999/2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1996 CELT	High	(577)	(979)	(2,864)
1996 CELT	Base	(619)	(1,021)	(2,402)
1996 CELT	Low	(661)	(1,063)	(2,444)

Source: Exhs. MPP-13, exh. 2.1-8 (att.).
Note: Capacity deficits are shown in ().

(B) Analysis

In considering the Company's forecasts of summer and winter peak load, the Siting Board has found that the 1996 CELT forecast is an appropriate base case summer peak load and winter peak load forecast for use in the analysis of regional need for the years 2000 and beyond. In considering the Company's DSM forecasts, the Siting Board has found that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and (3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

In considering the Company's supply forecasts, Siting Board has found that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need; (2) the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and, therefore, that the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need; and (3) the assumptions reflected in the Company's high case supply scenario are reasonable high case assumptions and, therefore, that the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need. In addition, the Siting Board has found that, for the purposes of this review, the reserve margins provided by the Company are appropriate.

The capacity positions under the summer and winter need forecasts based on the 1996 CELT summer and winter peak load forecasts for the year 2000 are shown in Table 1. See Section II.A.2.a.iii.(A), above. All such summer need forecasts show a need for at least 360 MW beginning in 2000. All such winter need forecasts show a sustained need for at least 360 MW beginning in 1999/2000. Accordingly, the Siting Board finds that there is a sustained need for 360 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2000.

b. Massachusetts

The Company asserted that there is a need for new capacity in Massachusetts by the year 2000 or earlier (Exh. MPP-0, at 2-16; Tr. 1, at 9-10). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based primarily on NEPOOL's 1996 CELT forecast prorated to Massachusetts (Exh. MPP-0, at 2-17 to 2-18). The Company stated that it then combined its demand and supply forecasts to produce a series of need forecasts (id.).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including its demand forecast methods and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including its capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the Company's need analyses for Massachusetts.

i. Demand Forecasts

(A) Description

USGen defined the Massachusetts peak load as the peak energy demand from all consumers of electricity within the Commonwealth (id. at 2-17). In developing Massachusetts peak load forecasts for summer and winter, the Company indicated that it relied primarily on information contained in the 1996 CELT report and NEPOOL's most recent Massachusetts-specific forecast of adjusted peak load (id.). The Company presented base case forecasts of summer and winter peak demand for Massachusetts, which include a base case forecast of DSM savings[32] and also adjusted the base case peak demand forecasts to reflect the effects of high and low forecasts of utility-sponsored DSM (id. at 2-22; Exh. MPP-13, exh. 2.2-8 (rev. A)).

(1) Demand Forecast Methods

The Company stated that NEPOOL last published a state-specific forecast for Massachusetts in 1994, in a document titled "Energy and Peak Load Forecast Appendix E, Exhibits: Massachusetts" (Exh. MPP-0, at 2-18). The Company explained that it developed its Massachusetts base case forecast of summer and winter peak load by prorating the 1996 CELT reference forecast by the ratio of the 1994 NEPOOL forecast for Massachusetts to the 1994 CELT reference forecast (id. at 2-17 to 2-18).

Specifically, USGen stated that it calculated a ratio of Massachusetts demand to New England demand for each year from 1996 to 2009 for summer and winter [33] and then applied the year-to-year ratios to the 1996 CELT reference forecast for summer and winter peak loads to estimate a 1996 summer and winter peak load forecast for Massachusetts ("1996 Massachusetts forecast") (id. at 2-17).[34] The Company noted that the 1996 Massachusetts forecast also incorporated the addition of the NEC load beginning in 1997 (id. at 2-17).

In addition, to verify the robustness of its need analysis over extreme variations in demand, the Company presented a high and low forecast of summer and winter peak load demand in Massachusetts, based on prorating NEPOOL's high and low demand forecasts for

32 USGen stated that NEPOOL's individual state forecasts include the effects of NUG-netted from load and Company-sponsored DSM (Exh. MPP-0, at 2-18).

33 The Company stated that the 1994 Massachusetts demand forecast only covers the period through 2009 and that for years 2010 and 2011, it used the ratio for 2009 (Exh. MPP-0, at 2-17).

34 The Company asserted that the Massachusetts to New England ratios developed in this manner are reasonable in light of demographic and economic indicators that show that the Massachusetts economy will continue to grow at a rate at least as fast as that of New England as a whole (Exh. MPP-0, at 2-18).

New England by the method described above (id.; Exh. MPP-13, exh. 2.2-9 (rev. A)); Tr. 1, at 29).

(2) DSM

Consistent with its assumptions regarding scenarios of regional DSM growth, the Company provided base, high and low DSM forecasts for Massachusetts, assuming a ten percent increase and decrease in DSM growth from the base case (Exh. MPP-0, at 2-18). The Company stated that it used the same method to develop Massachusetts DSM forecasts as it used to develop Massachusetts peak load forecasts -- prorating the 1996 NEPOOL regional DSM forecast by the ratio of the 1994 NEPOOL Massachusetts forecast of DSM to the 1994 NEPOOL regional forecast of DSM (id.).[35]

(3) Adjusted Load Forecasts

Consistent with the regional need analysis, the Company stated that it combined the 1996 Massachusetts forecasts of summer and winter peak load with the three aforementioned forecasts of DSM savings to develop forecasts of adjusted load (Exh. MPP-0, at 2-21).

(B) Analysis

The Company provided base case demand forecasts for summer peak load and winter peak load in its Massachusetts need analysis, which correspond to the base case demand forecasts presented in its regional need analysis. USGen also provided high and low forecasts of summer and winter peak load demand in Massachusetts, which correspond to the high and low forecasts presented in the regional need analysis. Additionally, the Company provided high and low DSM cases for Massachusetts, which correspond to the set of assumptions used in the regional need analysis.

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35 The Company stated that NEPOOL's most recent Massachusetts-specific DSM forecast is included in the 1994 report, "NEPOOL Participant Planned Demand-Side Management Impacts on the NEPOOL Forecast, 1994-2009" (Exh. MPP-0, at 2-18).

The Siting Board reviewed the regional demand forecasts in Section II.A.2.a.i, above. Consistent with its findings concerning the regional demand forecasts, the Siting Board finds that (1) the CELT report high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand, and (2) the 1996 Massachusetts forecast of summer and winter peak load which is the 1996 CELT Report's reference forecast of demand for New England, adjusted to reflect Massachusetts' share of demand, is an appropriate base case peak load forecast for use in the analysis of Massachusetts need for the years 2000 and beyond.

With respect to DSM, the Company provided three forecasts of DSM savings corresponding to the forecasts of DSM savings presented in its regional need analysis. The Siting Board reviewed the regional DSM forecasts in Section II.A.2.a.i, above. Consistent with its findings concerning the regional forecasts of DSM savings, the Siting Board finds that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

The Company stated that it developed base, high and low supply scenarios for Massachusetts, consistent with its regional supply scenarios, with adjustments to reflect generating resource ownership and commitments of Massachusetts electric utility companies (Exh. MPP-0 at 2-19).

The Company stated that it used information in the 1996 CELT Report to determine, on a utility-by-utility basis for Massachusetts utilities, the amount of supply available to Massachusetts (id.). The Company stated that this analysis includes the total capability for utility generating capacity and non-utility capacity purchases claimed by utilities serving load exclusively within Massachusetts, combined with a percentage of the capability claimed by Massachusetts utilities that are part of holding companies serving load in multiple states including Massachusetts (id. at 2-19 to 2-20). The Company stated that it allocated an amount of these multi-state holding-companies' capacity to Massachusetts by calculating for each such holding company the ratio of Massachusetts peak load to total peak load on each system, and then using this ratio to apportion to Massachusetts the capacity of each generating facility owned by the holding company (id.).[36,37]

The Company stated that its Massachusetts low case supply scenario is comparable to the regional low case supply scenario. The Company noted that all reductions to the base case supply scenario assumed in the low case supply scenario were prorated to reflect Massachusetts utilities' share of the capacity (id. at 2-20 to 2-21). In addition, the Company stated that its Massachusetts high case supply scenario also is comparable to the regional high case supply scenario, again prorated to reflect Massachusetts utilities' share of the capacity (id. at 2-21).[38]

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36 The Company stated that the ratios are as follows: (1) 0.734 for the Massachusetts portion of New England Electric System's capacity; (2) 0.608 for Eastern Utilities Associates' Massachusetts share; and (3) 0.116 for the Massachusetts share of Northeast Utilities (Exh. MPP-0, at 2-20).

37 The Company included the BPD project in the regional base case supply scenario. See Section II.A.2.a.ii(A), above. The Company indicated that it determined the portion of the BPD project capacity allocated to Massachusetts based on Massachusetts' share of New England coincident peak load (Exh. EFSB N-18).

38 The Company included the DPA project in the regional high case supply scenario. See Section II.A.2.a.ii(A), above. The Company indicated that allocation of a portion of the capacity of the DPA project to Massachusetts in the high case supply scenario also was based on Massachusetts' share of New England coincident peak load (Exh. EFSB N-18).

(2) Reserve Margins

The Company stated that it assumed the same yearly percentage reserve margin requirements for Massachusetts as were assumed for the region (id. at 2-19). These percentages were applied to the Massachusetts load forecasts (id.).

(B) Analysis

The Company provided a base case, low case and high case supply scenario for Massachusetts, corresponding to the supply forecasts presented in its regional need analysis. The Siting Board reviewed those forecasts in Section II.A.2.a.ii, above.

Consistent with its findings relative to the regional need analysis, the Siting Board finds that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need.

The Company assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region. Consistent with its findings relative to the regional need analysis, the Siting Board finds that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

iii. Need Forecasts

(A) Description

Consistent with its regional need forecasts, the Company developed nine summer need forecasts by adjusting the 1996 Massachusetts forecast by each of three DSM scenarios, and combining each of the resulting three summer adjusted demand forecasts with three supply forecasts (Exhs. MPP-0, at 2-21; MPP-0, exh. 2.2-8 (rev. A)). Of these nine summer need forecasts, all demonstrate a sustained need of at least 360 MW of capacity beginning in 2000. Additionally, the Company developed nine winter need forecasts in the same manner (Exh. MPP-0, at 2-21). Of these nine winter need forecasts, three show a sustained need of at least 360 MW of capacity in 1999/2000 and all show a sustained need of at least 360 MW of capacity in 2000/2001 (Exh. MPP-0, exh. 2.2-8 (rev. A)).[39,40] See Table 2, below.

Table 2

RANGE OF MASS NEED CASES

Summer-2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1996 CELT	High	(1,348)	(1,593)	(2,303)
1996 CELT	Base	(1,365)	(1,610)	(2,320)
1996 CELT	Low	(1,383)	(1,627)	(2,337)

Winter-1999/2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1996 CELT	High	51	(161)	(871)
1996 CELT	Base	36	(176)	(887)
1996 CELT	Low	20	(192)	(902)

39 As in the regional need analysis, the Company noted that the recent Siting Board approval of the 170 MW DPA project would not materially change these results.

40 Consistent with the regional need analysis, the Company also provided 18 Massachusetts summer need forecasts and 18 Massachusetts winter need forecasts based on the 1996 CELT report high and low demand forecasts (Exh. MPP-0, at 2-22). Each of the 18 Massachusetts summer need forecasts demonstrate a need of at least 360 MW of capacity in 2000 (Exh. MPP-13, exh. 2.21-9 (rev. A)). Of the 18 Massachusetts winter need forecasts, (1) the nine forecasts based on the high case demand forecast each demonstrate a need of at least 360 MW of capacity beginning in 2000, and (2) the nine forecasts based on the low case demand forecast each demonstrate a need of at least 360 MW in the 2008/2009 to 2010/2011 time frame (id.).

Winter-2000/2001

Demand Case	DSM	High Supply	Base Supply	Low Supply
1996 CELT	High	(738)	(1,014)	(1,092)
1996 CELT	Base	(757)	(1,032)	(1,921)
1996 CELT	Low	(776)	(1,052)	(1,085)

Source: Exh. MPP-13, exh. 2.2-8 (att.).
Note: Capacity deficits are shown in ().

(B) Analysis

Consistent with the regional need analysis, the Siting Board finds that it is appropriate to explicitly consider Massachusetts need for the proposed facility starting in 2000, the year that Millennium Power is proposed to enter service.

The Siting Board has found that (1) the CELT report high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand, and (2) the 1996 Massachusetts forecast of summer and winter peak load which is the 1996 CELT Report's reference forecast of demand for New England, adjusted to reflect Massachusetts' share of demand, is an appropriate base case peak load forecast for use in the analysis of Massachusetts need. In considering the Company's DSM forecasts, the Siting Board has found that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

In considering the Company's supply forecasts, the Siting Board has found that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need. In addition, the Siting Board has found that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

The capacity under the Massachusetts summer and winter need forecasts, based on the 1996 Massachusetts forecast, for the 1999/2000 to 2000/2001 time-frame are shown in Table 2. See Section II.A.2.b.iii.(A), above. All such summer need forecasts show a sustained need for at least 360 MW beginning in 2000. All such winter need forecasts show a sustained need for at least 360 MW beginning in 2000/2001. Accordingly the Siting Board finds that there is a sustained need for 360 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000. See Table 2.

3. Economic Need

a. New England

i. Description

The Company asserted that there is a need for the proposed facility on economic efficiency grounds (Exh. MPP-0, at 2-27). The Company maintained that the proposed facility would provide economic efficiency benefits to the region both under the existing NEPOOL dispatch system and under a modified dispatch system consistent with anticipated electric industry restructuring (id.; Tr. 1, at 79-80).

In support of its assertions with respect to the existing NEPOOL dispatch system, the Company provided a series of detailed economic analyses based on modeling of existing NEPOOL dispatch practices for the 6-year period, 2000 through 2005,[41] which compared the

[41] The Company stated that the current NEPOOL dispatch order is based on the variable costs (i.e., variable fuel costs, and variable operation and maintenance ("O&M") costs of NEPOOL units (Exh. MPP-0, at 2-24). The Company stated that those plants with the lowest marginal cost (i.e., fuel and variable O&M) are dispatched ahead of those with higher marginal costs, subject to operating constraints such as must-run status, minimum run times and unit availability (id. at 2-23). USGen also (continued...)

total incremental costs of two scenarios -- one that included the dispatch of the proposed facility ("Millennium-in case") and another that lacked the proposed facility in the dispatch ("Millennium-out case") (Exhs. MPP-0, at 2-24; MPP-13, exhs. 2.3-4 (rev. A), 2.3-5 (rev. A), 2.3-7 (rev. A); EFSB RR-5). The Company stated that these analyses demonstrate that the proposed facility would provide significant economic efficiency benefits to the region that would be equal to the difference of the region's cost of electricity under these two scenarios (Exh. MPP-0, at 2-24, 2-27). The Company stated that such economic efficiency benefits would accrue to the region either by (1) the displacement by the proposed project of more expensive power sources in NEPOOL's dispatch order, or (2) the offering of a lower-cost alternative for incremental construction (id. at 2-23).

The Company stated that it used the POWRSYM3 model to simulate NEPOOL's dispatch on an hourly basis over the forecast period (id. at 2-24).[42] The Company stated that inputs into the model included: (1) generation supply identical to the base case supply scenario; (2) load growth identical to the summer base peak load forecast; (3) the actual 1994 load duration curve;[43] (4) operating and cost characteristics of individual generating facilities;[44] (5) classification of specific units as must-run;[45] (6) addition of new generic

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41(...continued)
stated that the focus on short-term impacts is appropriate in light of uncertainties about the future structure of the electric industry (id.)

42 The Company indicated that the POWRSYM3 model essentially determines hourly requirements and develops an optimized program of resource utilization in order to meet those needs at the lowest possible cost (Exh. MPP-0, at 2-24).

43 The Company stated that it used the actual load profile for the New England region for 1994 and assumed that the basic shape of the load curve would remain the same over the period of analysis (Exh. MPP-0, at 2-26).

44 The Company stated that data on capacity, heat rates, fuel types, O&M costs, availability rates, and minimum run time was obtained for each generating unit from a number of sources including the 1996 CELT report, the Utility Data Institute Database of electrical generation and the 1996 NEPOOL Generation Task Force ("GTF") Report (Exh. MPP-0, at 2-25).

capacity to meet projected regional capacity requirements;[46] (7) fuel price forecasts; and (8) operating characteristics and dispatch price for the proposed facility (id. at 2-23 to 2-26).

For the generic units, the Company assumed that 80 MW combustion turbine peaking units ("CT") would meet the forecasted need prior to the year 2000 and that 225 MW, advanced technology, gas-fired, combined cycle units ("GTCC") would meet the need for each of the years after 2000 (id. at 2-26; Exhs. MPP-13, exh. 2.3-2 (rev. A); EFSB N-10). USGen stated that operating characteristics and costs of the generic units were derived from NEPOOL long-range planning assumptions presented in the 1996 NEPOOL GTF Report (Exhs. MPP-0, at 2-26, and exh. 2.3-1; EFSB N-12). The Company assumed that the generic GTCC units would be less efficient than the proposed project over the forecast period (Exh. EFSB N-10; Tr. 1, at 60-61).[47]

The Company calculated energy efficiency savings based on two different fuel price forecasts -- one from the 1996 GTF Report ("GTF fuel price forecast") and one from the reference case projections contained in the Energy Information Administration's "Annual Energy Outlook 1996" ("EIA fuel price forecast") (Exhs. MPP-0, at 2-5; EFSB N-10). The Company assumed that the proposed project and the generic GTCC units would operate on

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45(...continued)

[45] The Company indicated that a number of plants in New England are rated as must-run including all conventional hydropower, wood, refuse, landfill, and those fossil facilities specifically identified as must-run by NEPOOL (Exh. MPP-0, at 2-25).

[46] The Company stated that its methodology for dispatching New England's generation presumes that there is sufficient capacity to serve load and reserve at all times during the dispatch period (Exh. MPP-0, at 2-26). Therefore, the Company added incremental generic generating capacity to the base case supply mix when necessary, in both the Millennium-in case and Millennium-out case, to meet load and reliability requirements (id.).

[47] USGen assumed that the performance characteristics of the generics would remain unchanged over the forecast period (Exh. EFSB N-10). The Company explained that although development of new technology would likely increase efficiency of plants in the future, the timing and level of efficiency gains is unknown and, in addition, given lead time required, it is not likely that any improvements would occur within the next five years (id.).

oil for four weeks per year and that dual-fueled units would operate for nine months on natural gas and for three months on oil (Exhs. EFSB N-19 (rev. A); MPP-0, at 2-25).

The Company stated that the POWRSYM3 model provided the NEPOOL system variable dispatch costs associated with each set of assumptions (Exh. MPP-0, at 2-24). The Company stated that the NEPOOL system-wide savings attributable to the proposed facility would be the difference in total costs between the Millennium-in case and Millennium-out case (id. at 2-27). The Company stated that the annual nominal savings were discounted to 1996 dollars to obtain the net present value ("NPV") of economic efficiency savings attributable to the proposed project (id.).

The Company indicated that under the 1996 CELT base case dispatch scenario and GTF fuel price forecast, the proposed project would result in $102.26 million NPV of savings in 1996 dollars over the 6-year forecast period (Exh. EFSB RR-5, att. B). The Company indicated that the NPV of savings would be $12.38 million in 2000, $31.89 in 2001, $6.41 million in 2002, $11.03 million in 2003, $24.06 million in 2004 and $16.48 million in 2005 (id.). The Company indicated that, using the alternative EIA fuel price forecast, there would be a positive net economic benefit to the region of $106.18 million NPV of savings in 1996 dollars over the 6-year forecast period (id. att. C). The Company indicated that the NPV of savings would be $13.74 million in 2000, $32.20 in 2001, $7.47 million in 2002, $12.74 million in 2003, $24.45 million in 2004 and $15.57 million in 2005 (id.).

ii. Analysis

In the past, the Siting Board has determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1985 MECo/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and in Boston Gas Company, 11 DOMSC 159, 166-168 (1984), the Siting Board recognized the benefit of adding economic supplies to a specific utility system. In addition, where a non-utility developer has proposed a generating facility for a number of power purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, the Siting

Board standard indicates that need may be established on either reliability, economic, or environmental grounds. Berkshire Power Decision, 4 DOMSB at 292-93; Cabot Decision, 2 DOMSB at 296-300; NEA Decision, 16 DOMSC at 344-360.

In previous reviews of non-utility proposals to construct electric generation projects, project proponents have argued that additional energy resources were needed in the region based on economic efficiency grounds, i.e., that the construction and operation of a particular project would result in a significant reduction in total cost of generating power in the New England region through the displacement of more expensive sources of power. Berkshire Power Decision, 4 DOMSB at 285-292; Cabot Decision, 2 DOMSB at 292-296; MASSPOWER Decision, 20 DOMSC at 19.

In some cases, the Siting Board rejected companies' arguments, finding problems with elements of their analyses. In those decisions the Siting Board noted that proponents must provide adequate analyses and documentation in support of assertions that their respective projects are needed on economic efficiency grounds. See Eastern Energy Corporation, 22 DOMSC 188, 210-211 (1991) ("EEC Decision"); West Lynn Decision, 22 DOMSC at 14; MASSPOWER Decision, 20 DOMSC at 19.

In more recent reviews of non-utility proposals, the Siting Board has found that the proposed projects were needed for economic efficiency purposes. Berkshire Power Decision, 4 DOMSB at 295-96; Altresco Lynn Decision, 2 DOMSB at 68; Enron Decision, 23 DOMSC at 55-62. The Siting Board has noted that such findings, based on a comprehensive analysis of NEPOOL dispatch, both with and without each proposed project, are necessarily project-specific. The Siting Board also has identified the magnitude and timing of such gains as critical to its review. See Berkshire Power Decision, 4 DOMSB at 293.

Here, the Company has provided a 6-year analysis of economic efficiency savings with a detailed description of its methods and assumptions. The Company's use of two fuel price forecasts in developing dispatch scenarios allows the Siting Board to evaluate the degree to which economic efficiency savings are assured, given uncertainties in fuel prices. In addition, although certain of the Company's assumptions, such as the lack of efficiency improvements in the generic units, raise concerns over the long term, these assumptions are more reasonable in a short term analysis, particularly in the earliest (first two) years of a proposed project's life. The Siting Board notes that the Company assumes an efficiency advantage for the proposed project relative to all new generic GTCC units that come on-line at any point in the six-year period of analysis. Although the Company has significantly shortened the time span of its displacement analysis, relative to that in recent Siting Board cases, the Siting Board questions the reasonableness of assuming an efficiency advantage for more than the one to two initial years. The Company has not adequately demonstrated that such an advantage is likely to be sustained for six years.[48]

The analyses provided by the Company indicate that under both fuel price scenarios, the proposed project would provide substantial economic efficiency savings over the 6-year period from 2000 to 2005, ranging from $102.26 million in 1996 dollars under the GTF fuel price scenario to $106.18 million in 1996 dollars under the EIA fuel price scenario. Further, the analysis indicates that savings in the first two years of the six-year period would range from $44.27 million in 1996 dollars under the GTF fuel price scenario to $45.94 million in 1996 dollars under the EIA fuel price scenario.

As discussed above, the Siting Board is concerned that the Company may have overstated savings by assuming efficiency advantages relative to generic GTCC units placed in service later in the period of the analysis. However, we also recognize that efficiency advantages assumed relative to generic units placed in service during the first two years of the analysis would continue to produce significant dispatch-based savings over the remainder of the six-year period in the Company's analysis, as well as beyond that period. Thus, the Company has established that New England would recognize economic savings of substantial magnitude from the operation of the proposed project during its first two years of operation, and continued savings of significant but less certain amounts over the first six years of

48 The Siting Board is not suggesting that one or two years is a more appropriate time frame for a dispatch analysis of the type developed by the Company. Rather, the Siting Board is suggesting that it is more reasonable to assume that generic units coming on line beyond the first one to two years of the analysis would be equal in efficiency to a proposed project of the same technology.

operation, under a range of fuel price forecasts.

Accordingly, the Siting Board finds that the Company has established that there will be a need in New England for 360 MW of additional energy resources from the proposed project for economic efficiency purposes in the years 2000 through 2005.

b. Massachusetts

i. Description

The Company asserted that Massachusetts will require the proposed facility for economic efficiency purposes (Exh. MPP-0, at 2-27). In support, the Company produced a Massachusetts-specific estimate of economic efficiency benefits associated with the proposed project. Based on the regional dispatch described above,[49] the Company calculated the costs of serving Massachusetts load[50] for the Millennium-in case and Millennium-out case for both the GTF and EIA fuel price forecasts (Exh. MPP-0, at 2-26). USGen stated that it calculated Massachusetts-specific costs by summing Massachusetts' utilities shares in each of the existing plants included in the regional dispatch analysis (Tr. 1, at 76-78). The Company indicated that the Massachusetts-specific economic efficiency benefits associated with the Millennium Power Project for the time period from 2000 to 2005, discounted to year 1996 dollars, would be $82.38 million based on the GTF fuel forecast and $83.85 million based on the EIA fuel forecast (Exh. EFSB-RR-5, at atts. A, D).

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49 The Company stated that all generic units added to the dispatch analysis were included in the analysis for Massachusetts (Tr. 1, at 67-68). Although the Siting Board questions whether this is a realistic assumption, the Siting Board notes that, beyond the first year when the Millennium facility will be on line, the generic additions are the same in the Millennium-in case and Millennium-out case.

50 USGen stated that, due to the coordinated dispatch of all NEPOOL member generation, regional generation dispatch is the appropriate starting point for developing a Massachusetts-specific economic efficiency analysis (Exh. MPP-0. at 2-26).

ii. Analysis

In a previous case, while recognizing that it could not make a finding regarding the extent of savings that would accrue to Massachusetts, the Siting Board found that Massachusetts would share in the regional economic efficiency benefits resulting from the operation of a proposed facility during the first five years of its operation. Berkshire Power Decision, 4 DOMSB at 295-296.

Here, in Section II.A.3.a.ii, above, the Siting Board found that there would be a need in New England for 360 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000. In addition, the Company provided analyses that demonstrated the extent of savings that would accrue to Massachusetts -- savings due to the operation of the proposed facility that would range from $82.38 million to $83.85 million, discounted to year 1996 dollars, over the 2000 to 2005 time period.

Accordingly, the Siting Board finds that there is a need in Massachusetts for additional energy resources produced by the proposed project for economic efficiency purposes in the years 2000 to 2005.

4. Environmental Need

a. New England

i. Description

The Company asserted that the operation of the proposed facility would provide the region with substantial net benefits in the form of reduced system-wide emissions of pollutants, due to the displacement of less efficient, more polluting generation by the proposed facility (Exh. MPP-0, at 2-30). To demonstrate environmental benefits realized from the displacement of existing sources of air pollution, the Company presented a dispatch analysis comparing total system-wide emissions of sulfur dioxide ("SO_2"); (2) NOx; and (3) carbon dioxide ("CO_2") under two scenarios -- the Millennium-in case and the

Millennium-out case (Exhs. MPP-13, exhs. 2.4-2 (rev. A), 2.4-3 (rev. A), 2.4-4 (rev. A); MPP-39).[51]

The Company indicated that it used the POWRSYM3 model and plant-specific emissions data[52] to determine regional emissions for each pollutant in tons per year ("tpy") (Exh. MPP-0, at 2-28). The emissions analysis assumes constant generic unit characteristics, emission rates, and oil/gas mix for dual fuel units over the six-year forecast period (id. at 2-25 to 2-26, 2-28 to 2-29; Exh. EFSB N-10; Tr. 1, at 60-61). However, to prevent an overestimation of the benefits of the proposed facility, the Company stated that it incorporated recent and anticipated environmental regulations into its analysis (Exh. MPP-0, at 2-29 to 2-30). Specifically, the Company stated that it: (1) based NOx emissions on plant compliance with recent NOx control requirements; (2) assumed existing plants would be required to meet CAAA requirements for SO_2 that will be effective in 2000; and (3) included the cost of SO_2 allowances for the proposed project and generic units (id., at 2-29 to 2-30; Exh. EFSB RR-4).[53]

The Company's analysis indicated that emissions of SO_2, NO_x and CO_2 would be reduced in the Millennium-in case, compared to the Millennium-out case, over the 6-year period from 2000 through 2005 (Exh. MPP-13, exhs. 2.4-2 (rev. A), 2.4-3 (rev. A), 2.4-4 (rev. A)). Specifically, the Company's analysis indicated reductions over the six years of: (1) 8,200 tons of SO_2, or 0.71 percent of regional emissions; (2) 3,606 tons of NOx, or 0.82

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51 USGen indicated that the overall methods and assumptions employed in the dispatch analysis of emissions were identical to those employed in the economic efficiency analysis (Exh. MPP-0, at 2-18) (see Section II.A.3.a.i, above).

52 The Company indicated that emission rates for the proposed facility were based on plant-specific data and that emission rates for existing and generic units were based primarily on actual emission rates and GTF report assumptions (Exhs. MPP-0, at 2-28; MPP-13, at 7; EFSB N-17).

53 The Company stated that the dispatch analysis does not reflect NOx offset requirements for the proposed facility and generic units because such offsets may come from emissions reductions outside the power sector (Exh. EFSB N-16).

percent of regional emissions; and (3) 3.30 million tons of CO_2, or 1.27 percent of regional emissions (id.).[54]

In response to requests from the Siting Board staff, the Company also compared the emission reductions attributable to the Millennium project, as developed in its displacement analysis, to the emissions impacts of the proposed facility, as identified in its air quality analysis and included as an input to the Millennium-in case in the displacement analysis (Tr. 1, at 89-93). The Company indicated that the six-year emissions reductions for SO_2, 8,200 tons, actually would be more than ten times larger than the proposed facility's SO_2 emissions of 638.4 tons over the same period (Exhs. MPP-14, att. 1; MPP-13, exh. 2.4-2 (rev. A)). Similarly, the six-year emissions reductions for NOx, 3,606 tons, would be several times larger than the proposed facility's NOx emissions of 978 tons over the same period (Exhs. MPP-14, att. 1; MPP-13, exh. 2.4-3 (rev. A)).

With respect to CO_2, the Company's analyses show that six-year emissions reductions, 3.30 million tons, would be 45 percent of the proposed facility's CO_2 emissions of 7.41 million tons over the same period (Exhs. EFSB E-39; MPP-13, exh. 2.4-4 (rev. A)). The Company's witness, Dr. Tierney, maintained that the comparison did not detract from the Company's analysis indicating that the proposed project would provide CO_2 benefits that help demonstrate a need for the project (Tr. 1, at 91-95). Dr. Tierney explained that the Millennium-in case includes the proposed facility's CO_2 emissions, and at the same time results in lower regional CO_2 emissions than the Millennium-out case (id.).

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54 The Company also ran the POWRSYM3 model assuming that only combustion turbine peaking capacity would be added to meet reliability requirements in both the Millennium-in and Millennium-out cases (Exh. MPP-39). The Company asserted that this comparison more realistically demonstrates the full displacement benefits associated with the Millennium Power project -- reductions of 66,500 tons of SO_2, 17,300 tons of NOx, and 6.1 million tons of CO_2 over the six-year period (id.; Tr. 9, at 29). However, the Company also noted that it was not aware of any new combustion turbines proposed for the New England region while several combined-cycle projects are proposed (Tr. 9, at 31). The Siting Board notes that the Company's original analysis includes more realistic assumptions regarding capacity likely to be added to the region during the forecast period and therefore relies on the original analysis.

ii. Analysis

The Siting Board has held that a project proponent must provide full documentation of its assumptions pertaining to environmental benefits associated with the dispatch of generation capacity. Berkshire Power Decision, 4 DOMSB at 300; Cabot Decision, 2 DOMSB at 326; Altresco Lynn Decision, 2 DOMSB at 99. See also, Enron Decision, 23 DOMSC at 71; MASSPOWER Decision, 20 DOMSC at 388.

In the Enron Decision, the Siting Board found for the first time that a proposed generating project would provide Massachusetts with environmental benefits related to net changes in air emissions from existing and future generating facilities in Massachusetts. 23 DOMSC at 69-73. In more recent decisions, the Siting Board has found that applicants' projects likely would provide short-term air quality benefits for Massachusetts based on the initial displacement of existing generation and associated emissions. Cabot Decision, 2 DOMSC at 329; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 325-335. However, the Siting Board identified shortcomings with those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced generation would be increasingly dispatched over time with continued load growth; (2) the assumption of constant emission rates over time, in pounds per million Btu ("lbs/MMBtu"), for generating units in the analysis; and (3) the failure to address the potential for significant amounts of retirement of existing generating units. Cabot Decision, 2 DOMSC at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333. In a more recent review of a GTCC facility, the Siting Board raised concerns regarding assumed characteristics of future generic GTCC units in the dispatch analysis, including assumed efficiency and size relative to the proposed project.[55] Berkshire Power Decision, 4 DOMSB at 302.

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55 The Siting Board noted that an analysis of air quality benefits works best for the period of time when there is no capacity need and thus, no reason to speculate about the attributes of plants that will be constructed in the future. Berkshire Power Decision, 4 DOMSB at 302. The Siting Board noted that, in the future, it may be appropriate for its review of environmental need to focus on the displacement of older generating units, in the period of time prior to a capacity need. Id.

The Siting Board recognized in those reviews that load growth represents a given for purposes of the Company's dispatch analysis, and that the analysis must assume dispatch of available capacity to meet load growth over time. Cabot Decision, 2 DOMSB at 327; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 333. In the EEC (remand) Decision, the Siting Board further recognized that, to the extent that the applicant's project would in whole or in part replace existing generation that potentially will be retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation. 1 DOMSB at 333.

Here, the Company has provided a comprehensive six-year analysis of dispatch effects on regional emissions for the period from 2000 through 2005. The Company's analysis includes sufficient documentation regarding the methods and assumptions used in the calculation of the net impact of the proposed project on emissions from generation facilities located in the New England region for the Siting Board to evaluate whether there would be significant dispatch-related emissions reductions specific to the operation of the proposed project.

The Company's analytical methods are similar to those used in past Siting Board reviews of generating facilities, although the time frame and some other elements of the analysis are different. Responding to concerns in past Siting Board reviews, the Company has focused its displacement analysis on the short run and taken into account reductions in allowable SO_2 and NOx emissions rates that are likely to become effective before or during the period of analysis. However, other shortcomings identified in past Siting Board reviews, as highlighted above, continue to be a factor in the Company's displacement analysis.

The Siting Board notes that the Company assumes an efficiency advantage for the proposed project relative to all new generic GTCC units that come on-line at any point in the six-year period of analysis. Although the Company has significantly shortened the time span of its displacement analysis relative to that in recent Siting Board cases, the Siting Board questions the reasonableness of assuming an efficiency advantage for more than the initial one to two years. The Company has not adequately demonstrated that such an advantage is likely to be sustained for six years.

Second, the Company's methods leave its displacement analysis open to concerns the Siting Board has identified in past reviews with respect to (1) assumed redispatch of displaced generation over time with continued load growth and (2) failure to address the potential for significant amounts of retirement of existing generating units. As discussed in Section II.A.3.a.i, above, the displacement analysis covers a period in which significant amounts of new capacity are needed to offset load growth and earlier than expected losses of nuclear capacity; such needs potentially reduce the shares of new generation that would be available to permanently displace existing fossil fuel generating capacity. Further, the Company's displacement analysis does not explicitly identify and analyze scenarios incorporating significant amounts of retirement of fossil fuel generation.

At the same time, the Siting Board notes that the Company was able to demonstrate, through its displacement analysis, reductions in six-year regional SO_2 and NO_x emissions that significantly exceed the proposed facility's SO_2 and NO_x emissions over the same period. Although we are concerned, as discussed above, that the Company may have overstated pollutant reductions by assuming efficiency advantages relative to generic GTCC units placed in service later in the period of analysis, we recognize that the analysis shows year-by-year reductions that are larger than the proposed facility's own emissions in each of the first two years of the analysis, as well as cumulatively over all six years.

The Company's displacement analysis shows regional CO_2 emissions reductions which are nearly half of the proposed facility's CO_2 emissions. As in the case of SO_2 and NO_x, we are concerned that the modeled reductions of CO_2 for later years of the analysis may have been overstated by assuming an efficiency advantage for the proposed project relative to generic GTCC units, but also recognize that year-by-year reductions are shown for each of the earlier years of the analysis. We further note, however, that the modeled CO_2 emissions reductions demonstrate displacement benefits that only partially offset the proposed facility's CO_2 emissions. The analysis does not include scenarios incorporating significant amounts of retirement of fossil fuel generation, relative to the extent of fossil fuel capacity expansion, or other offsetting factor that would demonstrate significant progress in meeting environmental goals.[56]

The Company has established that operation of the proposed project would result in reductions in regional emissions of NOx, SO_2, and CO_2, including reductions in emissions of SO_2 and NOx that exceed the proposed facility's own emissions. The Siting Board finds that, on balance, the Company has established that there will be a need in New England for 360 MW of additional energy resources from the proposed project for environmental purposes in the years 2000 through 2005.

b. Massachusetts

i. Description

The Company asserted that Massachusetts needs the capacity represented by the proposed facility for environmental purposes (Exh. MPP-0, at 2-30). Based on the emissions dispatch analysis for the region, the Company produced a Massachusetts-specific estimate of emission reductions (id.). The Company identified actual generating resources located in Massachusetts and compared total emissions from units under the Millennium-in case and Millennium-out case for the years 2000-2005 (Exh. MPP-0, at 2-29 to 2-30).[57]

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[56] We note that for several regional or worldwide air quality concerns, including ozone, acid rain, and climate change, statutory or other policy goals point to a need to avoid or substantially minimize regional or national emissions increases. The pollutants that relate to such concerns include SO_2, NOx, and CO_2. See, Berkshire Power Decision, 4 DOMSB at 302.

[57] The Company noted that estimation of Massachusetts-specific emissions is complicated by the fact that some pollution migrates across state lines, that transport patterns vary for different pollutants, and that uncertainty surrounds the location of incremental units added in the region for reliability purposes (Exh. MPP-0 at 2-30). The Company addressed these concerns by segmenting out the facilities most likely to affect Massachusetts residents directly (i.e., plants sited in Massachusetts), and by assuming for the purpose of the environmental need analysis that all new generating capacity necessary to meet New England's and Massachusetts' reliability needs would be sited in Massachusetts (id.; Tr. 1, at 68).

The Company's analysis demonstrated an emissions savings for all pollutants in the 2000-2005 time period (Exhs. MPP-13, exhs. 2.4-5 (rev. A), 2.4-6 (rev. A), 2.4-7 (rev. A)). Specifically, the Company's analysis showed total reductions over the six years of: (1) 4.5 tons of SO_2, or 0.64 percent of Massachusetts SO_2 emissions; (2) 2.40 tons of NOx, or 0.96 percent of Massachusetts NOx emissions; and (3) 2.80 millions of tons of CO_2, or 1.55 percent of Massachusetts CO_2 emissions (id.).

ii. Analysis

The Siting Board recognizes the complexity in estimating pollutant emissions for Massachusetts due to the transportation of pollutants across state lines and the uncertainty regarding the location of facilities to be developed in the future. The Company's approach for estimating Massachusetts emissions is reasonable and consistent in assuming that the proposed project and all new generic units would be sited under both the Millennium-in case and Millennium-out case in Massachusetts.

In Section II.A.4.a.ii, above, the Siting Board found that there would be a need in New England for 360 MW of additional energy resources from the proposed project for environmental purposes in the years 2000 through 2005. In addition, the Company provided analyses that estimated the extent of pollutant reductions that would apply to Massachusetts.

Accordingly, the Siting Board finds that there is a need in Massachusetts for the additional energy resources produced by the proposed project for environmental purposes in the years 2000 through 2005.

5. Conclusions on Need

The Siting Board has found that there is a sustained need for 360 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2000. In addition, the Siting Board has found that there is a sustained need for 360 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000.

The Siting Board also has found that, consistent with its findings regarding reliability need in New England, there will be a need in New England for 360 MW of additional energy resources from the proposed project for economic efficiency purposes in the years 2000 through 2005. In addition, the Siting Board has found that there is a need in Massachusetts for additional energy resources produced by the proposed project for economic efficiency purposes in the years 2000 to 2005.

Further, the Siting Board has found that there will be a need in New England for 360 MW of additional energy resources from the proposed project for environmental purposes in the years 2000 through 2005. In addition, the Siting Board has found that there is a need in Massachusetts for additional energy resources produced by the proposed project for environmental purposes in the years 2000 through 2005.

Based on a showing of need for 360 MW or more of additional energy resources in the Commonwealth for reliability, economic and environmental purposes beginning in the year 2000, the Siting Board finds that the proposed project is needed to provide a necessary energy supply for the Commonwealth beginning in the year 2000.

B. Alternative Technologies Comparison

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 necessary energy supply for 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, and other site locations; (b) other sources of electrical power or gas, including facilities which operate on solar or geothermal energy and wind, or facilities which operate on the principle of cogeneration or hydrogeneration; and (c) no additional electric power or gas.

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need in terms of cost, environmental impact and reliability.

Berkshire Power Decision, 4 DOMSB at 304; Cabot Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107.

2. Identification of Resource Alternatives

a. Description

To address the identified need for additional energy resources, USGen proposes to construct a nominal 360-MW gas-fired, combined-cycle facility in Charlton, Massachusetts, which would commence commercial operation in June 2000 (Exh. MPP-11, at 4). The Company indicated that the proposed project would operate with an approximate heat rate of 6500 British thermal units per kilowatt hour ("Btu/kWh") and an availability factor of 91.7 per cent (Exh. EFSB RR-31).

The Company stated that it used a three-phase screening process to examine all reasonable alternative technologies, and that, as a first step, it compiled a list of those technologies able to meet the identified need based on reliability considerations (Exh. MPP-0, at 3-2 to 3-3). The Company stated that it considered reliable technologies to be those which the 1993 Technical Assessment Guide ("TAG") classified as "Mature" or "Commercial" (id.).[58] The Company indicated that its initial review of the 1993 TAG resulted in a list of 14 potentially viable technologies: GTCC; pulverized coal ("PC"); atmospheric fluidized bed ("AFB"); pressurized fluidized bed ("PFB"); coal gasification-combined cycle ("CGCC"); combustion turbine-simple cycle; fuel cells; geothermal; solar-photovoltaic; wind; municipal refuse-fired; biomass/wood-fired; nuclear; and energy storage (id.). The Company indicated that five technologies rated other than mature or commercial

[58] The Electric Power Research Institute's ("EPRI") rating system is as follows: mature (significant commercial experience); commercial (nascent commercial experience); demonstration (concept verified by integrated demonstration unit); pilot (concept verified by small pilot facility); laboratory (concept verified by laboratory studies and initial hardware development); idea (no system hardware development). The Company indicated that if two or more variations of a technology had been developed, the Company selected the most viable variation for analysis based on engineering, economic and environmental considerations (Exh. MPP-0, at 3-2).

were eliminated from further consideration (id. at 3-3 to 3-5). USGen stated that the 1993 TAG classified the five eliminated alternatives, PFB, CGCC, fuel cell, geothermal and wind, as "demonstration" technologies (id.).

The Company stated that phase two of its analysis involved examination of the nine technologies selected in the first stage for the following criteria: siting/permitting feasibility; compatibility with baseload operation; and potential ability to develop sufficient, incremental resources in the region to meet the identified need (id. at 3-8). The Company presented its rationale for concluding, on the basis of its second-phase criteria, that the combustion turbine - simple cycle, solar-photovoltaic, municipal refuse-fired, biomass/wood-fired, nuclear and energy storage technologies were not reliable (id.). The Company provided a tabular listing of technologies eliminated and the Company's rationale for their elimination as follows:

Technology Eliminated	Rationale
Combustion Turbine-Simple Cycle	Not cost effective for baseload operation
Solar-Photovoltaic	Insufficient land area to meet the identified need; incompatible with baseload operation
Municipal Refuse-Fired	Permitting/schedule constraints; construction of ten 40 MW units is not feasible; site area limitations
Biomass/Wood-Fired	Insufficient local resources; site area limitations
Nuclear	Permitting/schedule constraints
Energy Storage	Not cost effective for base load operation; site limitations

(id.)

The Company indicated that, on the basis of its phase two criteria, the list of potential technology alternatives to the proposed project was narrowed to the GTCC,[59] AFB and PC

[59] In past cases before the Siting Board, proponents have commonly included a generic version of their proposed technology among the technologies examined as alternatives to the proposed project. Invariably, however, these generic units do not include the project-specific modifications of the proposed project and are, therefore, most unlikely to offer a superior technological alternative. Given such experience, and in

technologies (id. at 3-8 to 3-9). With respect to the three technologies selected for further analysis, the Company provided the following information: (1) the natural gas-fired GTCC unit generates 225 MW, incorporates selective catalytic reduction ("SCR"), operates at a full load heat rate of 7,300 Btu/kWh and has an equivalent availability of 88.9 percent; (2) the coal-fired, circulating AFB generator produces 200 MW, incorporates limestone injection to control SO_2 and particulate matter ("PM") emissions, respectively, operates at a full load heat rate of 9,796 Btu/kWh and has an equivalent availability of 90.4 percent; and (3) the PC unit produces 300 MW, incorporates a spray dryer to minimize SO_2 and a fabric filter to control PM, operates at 9,580 Btu/kWh and has an equivalent availability of 85.5 percent (id. at 3-5 to 3-6; EFSB RR-31). The Company stated that in analyzing alternative approaches to the proposed project it scaled the capacity of each alternative technology to that of the proposed project according to EPRI-developed procedures (Exh. MPP-0, at 3-2).[60]

Thus, in addition to the proposed project, the Company advanced three technology alternatives, one gas-fired and two coal-fired, to the third phase of its technology alternatives analysis (id. at 3-8 to 3-9). The Company indicated that the third phase of its analysis compared the environmental impacts and costs of the technology alternatives to those of the proposed project (id.).

b. Analysis

The record demonstrates that USGen narrowed the number of potential alternative technologies from fourteen to three in two stages. In the first stage, the Company appropriately reviewed a wide range of potential generation and storage technologies and, based on reasonable criteria, narrowed its review to include nine technologies encompassing a range of technology types and fuels. In the second stage, the Company reviewed these

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the interest of a review which addresses credible alternatives to the proposed project, the Siting Board will in future cases review a generic version of the proposed technology only if the generic unit is superior to the proposed project in some respect.

60 The Company stated it used scaling procedures detailed in the 1993 TAG (Exh. MPP-0, at 3-2).

nine technologies and eliminated technologies failing to meet one or more of the Company's stated criteria. The record also demonstrates that the Company used standard industry procedures to scale each evaluated alternative technology to the size of the proposed project.[61]

Thus the record demonstrates that all facilities have been evaluated based on the same output and criteria. The Company has appropriately identified three technology alternatives and two different fuels capable of meeting the identified need in lieu of the Company's proposed project. The Siting Board finds that the proposed project, a GTCC alternative, a coal-fired AFB alternative and a PC alternative are comparable in terms of their ability to meet the identified need. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Board compares the proposed project to each of three technology alternatives: GTCC, AFB and PC.

3. Environmental Impacts

The Company compared the alternative technologies and proposed project with respect to environmental impacts in the areas of air quality, water supply and wastewater, noise, fuel transportation, land use and solid waste. The Siting Board reviews the Company's analysis of environmental impacts below.

The Company stated that, to the extent possible, the alternative technologies and the proposed project were compared based on the same level of net electric output, 360 MW, and assumed to begin commercial operation at the same time, in January of the year 2000 (Exhs. MPP-0, at 3-5; MPP-11, at 8-9; MPP-11, att. 4). The Company indicated that it

61 While the Siting Board recognizes that the TAG is one of the energy industry's standard sources of data, it also notes the limitations of using 1993 data given the accelerating pace of change in the energy industry. The Siting Board therefore will require future petitioners to use current TAG data, or pursue data from alternate sources, especially from the U.S. Department of Energy, the National Renewable Energy Laboratory and associated agencies or entities, if current TAG data is unavailable.

gathered the bulk of its cost and performance data from vendors for the proposed project and from the 1993 TAG for the technology alternatives (Exh. MPP-0, at 3-5).[62]

The Company also indicated that the proposed project offers a higher projected availability factor, 91.7 percent, and lower heat rate, 6,500 Btu/kWh, than any of the alternative technologies (Exh. EFSB RR-31; see Table 4, Section II.B.4.a, below).

a. Air Quality

The Company asserted that the proposed project would be preferable to the three alternative technologies with respect to air quality (Exh. MPP-0, at 3-13, 3-15). In support of its assertion, USGen provided an analysis of the average annual emission rates and the annual amount of emissions of SO_2, NOx, PM-10, carbon monoxide ("CO"), volatile organic compounds ("VOCs") and CO_2 for the proposed project and the technology alternatives (Exh. EFSB RR-29, Table 3.4-1 (rev. A)). In calculating emission rates for the proposed project and the GTCC alternative, the Company assumed use of back-up oil with 0.05 percent sulfur content for 720 hours per year (id.).[63] The Company also assumed that the GTCC alternative would meet the same emissions control standards as the proposed project and would therefore have the same emission rates as the proposed project (Exh. MPP-0, at 3-13).

In reviewing the coal-fired technology alternatives, the Company assumed that the AFB alternative would use high sulfur coal, the PC alternative would use low sulfur coal, and that average annual emissions rates for both would reflect Lowest Achievable Emission Rate ("LAER") technologies (Tr. 8, at 76-77).

USGen indicated that the proposed project would produce fewer annual air emissions of SO_2, NOx, PM-10, CO, VOCs and CO_2 than would all evaluated alternatives (Exhs. MPP-0, at 3-13; EFSB RR-29, Table 3.4-1 (rev. A)). The Company further stated

62 The Company stated that it used fuel price data from the 1996 NEPOOL GTF for the technology alternatives because the GTF provides more detailed fuel price data than does the TAG (Exh. MPP-0, at 3-9).

63 The Company's pending air permit application is based on use of back-up oil for a maximum of 720 hours per year (Exh. MPP-4, att. 6).

that, although the average annual emission rates of the proposed project and the GTCC alternative are comparable, the annual emissions from the proposed project would be lower, reflecting its lower heat rate (Exhs. MPP-0, at 3-13; EFSB RR-29, Table 3.4-1 (rev. A)). See Table 3, below.

Table 3

Alternative Technologies - Pollutant Emissions

	Mil-GTCC	GTCC	PC	AFB
Ann. average emission rates (lbs/MMBTU)				
SO_2	0.0100	0.0101	0.2	0.225
NOx	0.0154	0.0155	0.17	0.15
PM-10	0.0060	0.0061	0.018	0.018
CO	0.0253	0.0253	0.11	0.13
VOC	0.0017	0.0017	0.0036	0.006
CO_2	117	117	204	204
Ann. emissions (tpy), based on assumed availability factor				
Availability Factor	91.7%	88.9%	85.5%	90.4%
SO_2	94	95	1880	2115
NOx	145	159	2196	2095
PM-10	56	62	232	251
CO	237	258	1421	1815
VOC	16	17	46	84
CO_2 (1,000 tpy)	1,096	1,195	2,635	2,849

Source: Exh. EFSB RR-29, Table 3.4-1 (rev. A).

The record demonstrates that, on balance, considering all pollutants, the annual emissions of the proposed project would be lower than those of the three technology alternatives. Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project is slightly preferable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to air quality.

b. Water Supply and Wastewater

The Company asserted that the proposed project and the GTCC alternative would have comparable water requirements and wastewater generation but that each of the coal-fired alternatives would require a significantly greater water supply and would generate significantly greater amounts of wastewater (Exh. MPP-0, at 3-15).

The Company indicated that both the proposed project and the technology alternatives would require water for cooling tower makeup and process water, and assumed that all technology alternatives would include a wet mechanical cooling system for the steam condenser -- the same as that planned for the proposed project (Exh. MPP-0, at 3-15; Tr. 8, at 78). The Company stated that, assuming a 121 MW steam turbine: (a) the proposed project would require 1.459 million gallons per day ("mgd") and the GTCC alternative 1.5 mgd for cooling tower makeup water; (b) the proposed project would require 0.132 mgd and the GTCC alternative would require .134 mgd for process water, including water for steam injection during oil firing; and (c) the total water requirement would be 1.591 mgd for the proposed project and 1.593 mgd for the GTCC alternative (Exh. EFSB RR-30, Table 3.4-2 (rev. A). The Company stated that the AFB and PC alternatives would require a 360 MW steam turbine, and would both have greater requirements for cooling tower makeup and process water than the proposed project: a combined total of 5.849 mgd for the AFB alternative and 6.206 mgd for the PC alternative (id.).

USGen indicated that the proposed project and the GTCC alternative would generate .657 and .658 mgd of cooling tower blowdown, respectively, but no process wastewater (id.). The Company stated that the AFB and PC alternatives would both generate more wastewater than the proposed project: the AFB would generate 9.579 mgd of wastewater and the PC would generate 9.947 mgd (id.).

The record demonstrates that the water requirements of the proposed project would be 99.9 percent of the water requirements of the GTCC alternative, 27 percent of the water requirements of the AFB alternative and 26 percent of the water requirements of the PC alternative. Accordingly, the Siting Board finds that, for purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to water use.

The record further demonstrates that the wastewater generated by the proposed project would be comparable to that generated by the GTCC alternative and approximately 7 percent of the wastewater generated by the AFB and the PC alternatives. Accordingly, the Siting Board finds that, for purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to wastewater discharge.

c. Noise

The Company asserted that the proposed project would be comparable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to noise impacts (Exh. MPP-0, at 3-17).

In comparing the noise impacts of the proposed project to that of the technology alternatives, USGen assumed that each of the technology alternatives could be designed to achieve the same degree of continuous noise mitigation as would be achieved with the proposed project (Exh. MPP-0, at 3-16 to 3-17). However, USGen stated that the coal-fired alternatives would have added sources of noise due to coal usage (id.). USGen stated that on-site noise due to coal delivery, including conveying and crushing, could be mitigated by enclosing the facilities for those operations, but that noise associated with delivery of coal to the site by rail could not be fully mitigated (Tr. 8, at 79 to 81).

The record demonstrates that the noise impacts of the proposed project and the GTCC alternative could be mitigated to the same degree. The record further demonstrates that although the on-site noise impacts of the proposed project and the AFB and PC alternatives technically could be mitigated to the same degree, coal delivery to the site would increase noise impacts of the AFB and PC alternatives relative to the proposed project.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to noise impacts.

d. Fuel Transportation

USGen asserted that the proposed project is slightly preferable to the GTCC alternative and superior to the coal-fired alternatives with respect to fuel transportation impacts (Exh. MPP-0, at 3-17 to 3-18). USGen stated that natural gas would be delivered to the site via an existing high-pressure interstate pipeline which borders the proposed site (Exh. MPP-0, at 3-17). The Company stated that the proposed project will also require fuel oil deliveries when back-up fuel is used (id.). The Company stated that fuel oil would be delivered by truck, deliveries to be scheduled as necessary for refilling (id.). The Company indicated that the unloading rate of oil at the proposed project would not exceed three trucks per hour, and that use of fuel-oil would not exceed 720 hours per 12 month rolling period (id.). The Company stated that the GTCC alternative would have comparable fuel delivery requirements but that, due to its higher heat rate, the GTCC alternative would require greater quantities of natural gas and a greater number of oil deliveries (id.; Exh. EFSB RR-31, Table 3.4-3 (rev. A)).

The Company stated that the PC alternative would use less coal than the AFB alternative and that coal delivery for the PC alternative would fill 10,332 rail cars per year (Exh. EFSB RR-31, Table 3.4-3 (rev. A)). The Company explained that, given a typical 100-car train, this would require the arrival and departure of over 104 trains per year, or two per week (id.; Exh. MPP-0, at 3-19). The Company stated that the AFB and PC alternatives would also require truck delivery of limestone or lime for SO_2 control (Exh. MPP 3-19). The Company explained that it selected the proposed site in part due to its proximity to an existing natural gas pipeline in order to minimize the impacts of gas transportation (id.). The

Company noted that the preferred site has no rail access and that a coal-fired project would likely be sited in close proximity to existing rail lines with adequate capacity to accommodate coal deliveries in order to minimize impacts of fuel transportation (id.). The Company stated that, even assuming the availability of adequate rail infrastructure, delivery of coal by rail to the proposed site would still involve impacts to other users and to abutting communities (id.; Tr. 8, at 81 to 82.).

In comparing the proposed project to the GTCC alternative, the record demonstrates that, due to its higher efficiency, the proposed project would require less natural gas and a smaller number of oil deliveries than the GTCC alternative. The Siting Board notes that the fuel transportation-related impacts of the two projects would not differ on the basis of natural gas delivery, but that the smaller number of truck deliveries of fuel oil would produce fewer impacts. Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be slightly preferable to the GTCC alternative with respect to fuel transportation.

In comparing the transportation impacts of the coal-fired alternatives to the proposed project, the Siting Board notes that a coal-fired facility likely would be sited in proximity to existing rail lines. Because a potential rail route to the proposed site has not been identified, the specifics of the impacts along such a route, based on such factors as existing rail transport volumes, at-grade crossings, and the nature of abutting land uses, have not been identified and mitigation strategies have not been addressed. However, rail transport could have traffic and noise impacts over the life of the project. In light of the overall minimal impacts associated with fuel transportation for the proposed project, rail transport of coal would likely result in greater impacts.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be preferable to the GTCC, AFB and PC alternatives with respect to fuel transportation impacts.

e. Land Use

USGen asserted that the proposed project would be comparable to the GTCC alternative and preferable to the coal-fired alternatives with respect to land use impacts (Exh. MPP-0, at 3-19 to 3-20). USGen indicated that it included both total land requirements and impacts to surrounding uses in evaluating land use impacts of the proposed project and alternatives (id. at 3-19). The Company indicated that the footprint of the proposed project would not exceed 15 acres and that the height of its main components would be 90 feet for the HRSG, 225 feet for the stack and 36 feet for the turbine building (Exh. MPP-11, att. 1). The Company stated that the footprint of the proposed project would be located in the interior of the project site, a 120-acre undeveloped area, mostly wooded, zoned industrial-general, and surrounded by industrial, commercial and residential uses (Exh. MPP-0, at 6-144).

The Company stated that the GTCC alternative could be designed to fit within the 15-acre footprint of the proposed project and that the height and size of the facility components would be comparable to those of the proposed project (id. at 3-19). The Company stated that the coal-fired alternatives would require at least 50 acres for the facility footprint, rail unloading and fuel storage areas (id.). USGen stated that, in addition, the coal-fired alternatives would require a greater number of structures than the proposed project and that the scale of such structures, including the height of the buildings, stacks and cooling towers, would be significantly larger than the components of the proposed project (id.).[64]

The record demonstrates that the footprint of the proposed project and GTCC alternative would require 15 acres within the proposed 120-acre site. The record further demonstrates that the scale and number of buildings required by the coal-fired alternatives would be greater than those required by the proposed project or the GTCC alternative.

The Siting Board notes that due to the size of the proposed site, construction there of the coal-fired alternatives as well as the gas-fired alternatives would likely be possible. The

64 Additional structures associated with the coal-fired alternatives are for coal unloading and handling (Exh. MPP-0, at 3-20).

Siting Board further notes, however, the greater potential for a variety of land use impacts, including local noise and visual impacts, clearance of trees and other vegetation, and disturbance to wetlands, soils and natural habitat, resulting from the greater size and number of buildings associated with the coal-fired alternatives relative to the gas-fired alternatives.

Thus, given the facility footprint and building size requirements of the proposed project relative to the coal-fired alternatives, the land use impacts of the proposed project or the GTCC alternative would be preferable at the proposed site. Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be comparable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to land use impacts.

f. Solid Waste

The Company asserted that the proposed project would be comparable to the GTCC alternative and preferable to the coal-fired alternatives with respect to solid waste impacts (Exh. MPP-0, at 3-20). In support of its assertion, USGen stated that the proposed project and the GTCC alternative would generate minimal amounts of solid waste, approximately 35 tons per year, consisting primarily of incidental office and maintenance waste (id.). In contrast, the Company stated that the solid waste generated by the coal-fired alternatives, consisting primarily of ash, would total 194,126 tons per year for the PC alternative and 261,300 tons per year for the AFB alternative (Exh. EFSB RR-32, Table 3.4-4 (rev. A)). The Company stated that it assumed that solid waste from the coal-fired alternatives would be hauled off-site in railcars and that the ash potentially could be used as back-fill for coal mines (Exh. MPP-0, at 3-20).

The record indicates that the proposed project and the GTCC alternative would produce significantly less solid waste than the coal-fired alternatives. Further, the large quantities of solid waste produced by the coal-fired alternatives would necessitate numerous rail trips to dispose of the waste off-site, although these rail trips would likely not be incremental. The Siting Board notes that the solid waste impacts of coal-fired technologies frequently can be mitigated by shipping coal ash to the mine head via the return trip of the train that transported the coal to the site. However, the record does not provide details of shipment of solid waste off-site and its effect on rail transport requirements. The Siting Board previously has found that, in the absence of detailed plans for the transport and disposal of solid waste in an environmentally beneficial way, solid waste impacts are greater for those technologies that generate greater amounts of waste. Berkshire Decision, 4 DOMSB at 320-321; EEC (remand) Decision, 1 DOMSB at 351-352.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be comparable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to solid waste impacts.

g. Findings and Conclusions on Environmental Impacts

In comparing the overall environmental impacts of the proposed project and the GTCC alternative, the Siting Board has found that the proposed project would be slightly preferable to the GTCC alternative with respect to air quality and fuel transportation impacts and that the proposed project would be comparable to the GTCC alternative with respect to water use, wastewater discharge, noise impacts, land use impacts and solid waste impacts. Accordingly, the Siting Board finds that the proposed project would be slightly preferable to the GTCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the coal-fired alternatives, the Siting Board has found that the proposed project would be preferable to the AFB and PC alternatives with respect to air quality impacts, water use, wastewater discharge, noise impacts, fuel transportation impacts, land use impacts and solid waste impacts. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB alternative and the PC alternative with respect to environmental impacts.

4. Cost

a. Description

USGen asserted that the proposed project would be superior to each of the alternative technologies with respect to cost (Exhs. MPP-0, at 3-13; EFSB A-6a (rev.); Tr. 8, at 58 to 59). In order to compare costs, the Company explained that it modeled the projected total revenue requirements of the proposed project and the GTCC, AFB and PC alternatives over a 20-year period beginning in January of the year 2000, the assumed in-service date of all units (Exh. MPP-0, at 3-9).[65] The Company stated that it then summed the NPV of annual revenue requirements and calculated 20-year nominal levelized costs in dollars per kilowatt-hour ("$/kWh") for each of the alternatives (id.). At the request of the Siting Board, the Company followed the procedures used to model 20-year nominal levelized costs of the proposed project and the GTCC, AFB and PC alternatives to model the same costs over 30 years for the proposed project and the identified alternatives (Exh. EFSB A-6a (rev.)).

As noted in Section II.B.3, above, the Company indicated that the initial cost and performance data were generally taken from vendor supplied data for the proposed project and from the 1993 TAG for the alternative technology units (Exh. MPP-0, at 3-5). USGen stated that inflation rates were taken from the 1996 NEPOOL GTF (id. at 3-10). With respect to fuel prices, USGen indicated that fuel price assumptions were based on the 1996 NEPOOL GTF (Exh. MPP-0, at 3-10). The Company stated that it used fuel price data from the 1996 NEPOOL GTF for the alternative technologies because the GTF provides more detailed fuel price data than does the TAG (id. at 3-5).[66] USGen stated that it also assumed that the proposed project and each alternative would run constantly, limited only by its individual equivalent availability factor (id. at 3-9).

Table 4, below, details the total installed costs, O&M costs, and the 20- and 30-year levelized cost for the alternative technologies. USGen indicated that both the 20- and 30-year levelized cost of the proposed project would be significantly lower than that of the

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65 In projecting total revenue requirements for each alternative, USGen used consistent assumptions with respect to debt ratio and equity ratios, debt interest, after tax return on equity, tax rate, depreciation, inflation rate and fuel escalation (Exh. MPP-0, at 3-10).

66 The Company's witness testified that a dramatic change in pricing of natural gas would be necessary to alter the cost advantage of a natural-gas fired generator such as the proposed project or the GTCC alternative relative to a coal-fired generator such as the AFB or PC alternatives (Tr. 8, at 58 to 59).

alternative technology units (id. at 3-9, 3-11; Exhs. MPP-11, att. 4, Table 3.2-2 (rev. A); EFSB A-6a (rev.); Tr. 8, at 58 to 59).

Table 4

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

	Millennium	GTCC	AFB	PC
Fuel	Gas/Oil	Gas/Oil	Coal	Coal
Unit Size (MW, Nominal)	360	360	360	360
Fuel Price ($1995/MMBtu)	2.48	2.48	1.57	1.57
Equivalent Availability (percent)	91.7	88.9	90.4	85.5
Full Load Heat Rate (Btu /kWh)	6,500	7,300	9,796	9,580
Total Plant Investment ($2000/kW)	570	660	1,916	1,812
Fixed O&M ($1995/kW-yr)	20.15	29.7	41.59	59.19
Variable O&M (1995 mills/kWh)	1.1	0.4	6.0	2.6
20-Yr Nominal Levelized Cost ($/kWh)	*	.0480	.0716	.0708
30-Yr Nominal Levelized Cost ($/kWh)	*	.0526	.0770	.0762

1. 1995 fuel prices for gas-fired units are based on 100 percent load factor.
2. Total Plant Investment includes total cost of plant, permitting, land, interconnection, AFUDC, start-up and inventory, and working capital.

* The 20-year nominal levelized cost for the proposed project was less than $0.0480/kWh; the 30-year nominal levelized cost for the proposed project was less than $0.0526/kWh.

Source: Exhs. MPP-11, att. 4; EFSB A-6a (rev.); EFSB RR-29; EFSB RR-31.

b. Analysis

The record indicates that the 20- and 30-year levelized costs of the proposed project would be less than the 20- and 30-year levelized cost of each of the technology alternatives, given the Company's assumptions regarding capital costs, interest rates, and fuel prices.[67]

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be preferable to the GTCC, AFB and PC alternatives with respect to cost.

5. Reliability

a. Description

The Company asserted that the proposed project is preferable to each of the technology alternatives with respect to reliability (Exh. MPP-0, at 3-24). In analyzing the reliability of the proposed project and the technology alternatives, the Company assessed (1) the anticipated availability of each technology and corresponding energy source, and (2) the likelihood that the technology would be available at the time for which the first need for new capacity has been identified (id. at 3-22).

The Company stated that projects that rely on a mature, commercially available technology have a reliability advantage over technologies whose expected cost and performance characteristics have yet to be fully demonstrated and are based primarily on engineering estimates (id.). The Company indicated that the proposed project and the GTCC and PC alternatives use technologies classified as mature in the 1993 TAG, but that the AFB technology is classified as commercial and is therefore somewhat less reliable (id.). The Company stated that the proposed project and the GTCC alternative use essentially the same

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[67] The Siting Board notes, however, that the Company's analysis does not provide for future uncertainty in fuel price forecasts. This issue is only generally addressed by the Company's statement that the cost advantage of the natural gas alternatives, including the proposed project, relative to the coal alternatives is unlikely to change due to market fluctuations of the price of natural gas and coal. An analysis of the sensitivity of cost comparisons to changes in fuel prices -- for example, an analysis showing a range of costs for technology alternatives depending on fuel prices -- would have been particularly relevant in this case, since there is no fuel contract for the proposed project.

technology and in this respect, therefore, offer equivalent reliability (id.).[68] The Company also stated, however, that the proposed project would have an anticipated availability of 91.7 percent, higher than any of the other technology alternatives (see Table 4, above) (id.). In addition, the Company stated that it selected the proposed project over the GTCC alternative for reasons of efficiency and the demonstrated performance of the turbine associated with the proposed project (id.). The Company further stated that it has arranged for firm fuel delivery through U.S. Generating Fuel Service ("USGenFS") (Exh. MPP-8, att. 2).[69] Thus, the Company concluded that the proposed project is comparable to the GTCC alternative and superior to each of the coal-fired units with respect to reliability (Exh. MPP-0, at 3-24; Tr. 8, at 72).

b. Analysis

The record demonstrates that the availability of the proposed project would be 91.7 percent and that the technology of the proposed project is classified as mature by the 1993 TAG. The Company has also indicated that the proposed project would have a firm transportation contract, and has presented a back-up fuel strategy that ensures that the plant can operate even if natural gas is temporarily unavailable (see Section II.C.3.b, below).

In comparing the reliability of the proposed project to the reliability of the GTCC alternative, the Siting Board notes that the availability factor for the GTCC alternative is assumed to be 88.9 percent, 2.8 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the GTCC alternative, does not represent a significant

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68 The Company also stated that the PC technology, although considered mature, might be somewhat less reliable than the proposed project or the GTCC alternative due to the more complex nature of a coal plant (Exh. MPP-0, at 3-22).

69 Under the Company's precedent agreement, USGen's fuel supplier will provide to the proposed project (1) a 365 day firm natural gas supply, subject to 30 days of recall, and (2) an alternative fuel when it exercises its recall rights (see Section II.C.3.b, below).

difference for the purposes of this review. In addition, the GTCC technology is classified as mature by the 1993 TAG. Further the Siting Board assumes comparable fuel supply arrangements for the two technologies. Accordingly, the Siting Board finds that the proposed project and the GTCC alternative would be comparable with respect to reliability.

In comparing the reliability of the proposed project to that of the coal-fired alternatives, the Siting Board first notes that the record in this case does not address any differences in the reliability of a natural gas supply delivered via pipeline and a coal supply delivered via rail.

In comparing the reliability of the proposed project to the reliability of the AFB alternative, the Siting Board notes that the availability factor for the AFB alternative is assumed to be 90.4 percent, 1.3 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the AFB alternative, does not represent a significant difference for the purposes of this review. The proposed project, however, is classified as a mature technology, denoting significant operating experience, while the AFB alternative is classified as a commercial technology, denoting limited operating experience. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB alternative with respect to reliability.

In comparing the reliability of the proposed project to that of the PC alternative, the Siting Board notes that the availability factor of the PC alternative is 85.5 percent, 6.2 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the PC alternative, does not represent a significant difference for the purposes of this review. In addition, both technologies are classified as mature. Accordingly, the Siting Board finds that the proposed project and PC alternative would be comparable with respect to reliability.

Therefore, the Siting Board finds that the proposed project would be comparable to the GTCC and PC alternatives and preferable to the AFB alternative with respect to reliability.

6. Comparison of the Proposed Project and Technology Alternatives

In order to establish that a proposed project is preferable to technology alternatives in its ability to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternative approaches in its ability to address the previously identified need in terms of environmental impact, cost, and reliability.

In Sections II.B.3, II.B.4 and II.B.5, above, the Siting Board has compared the proposed project to generating technology alternatives that have been determined capable of meeting the identified need, on the basis of their specific environmental impacts, costs and reliability. Based on its comparison, the Siting Board has found that the proposed project would be: (1) slightly preferable to the GTCC alternative and preferable to the AFB and PC alternatives with respect to environmental impacts; (2) preferable to the GTCC, AFB and PC alternatives with respect to costs; and (3) comparable to the GTCC and PC alternatives and preferable to the AFB alternative with respect to reliability.

Accordingly, the Siting Board finds that the proposed project is superior to the GTCC alternative, the AFB alternative and the PC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

C. Project Viability

1. Standard of Review

a. Existing Standard

The Siting Board determines that a proposed NUG is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. Dighton Power Decision, EFSB 96-3 at 24; Berkshire Power Decision, 4 DOMSB at 346.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frame and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. Dighton Power Decision, EFSB 96-3 at 24; Berkshire Power Decision, 4 DOMSB at 345.

b. Company's Position

The Company argued that while the proposed project meets the Siting Board's existing standard for viability, the evidence required to demonstrate that an applicant meets that standard should be reconsidered and modified (Exhs. MPP-0, at 4-1 to 4-2; MPP-2, at 2-12; Company Brief at 30). Specifically, with respect to the first test of viability -- that financing and construction will go forward as planned -- the Company asserted that evidence of a project's competitiveness in the market should be sufficient when coupled with evidence that the proponent has previously financed and constructed a reasonably similar facility within a time frame similar to the proposed schedule and, further, has demonstrated that sufficient financial resources are available for the project (Exhs. MPP-0, at 4-1 to 4-2; MPP-2, at 6-9; Tr. 2, at 79-83; Company Brief at 31). The Company acknowledged that a detailed review and approval of the terms of a turnkey construction contract ("EPC contract") may still be necessary for developers without a proven project management track record (Tr. 2, at 80-81). However, the Company advocated that where a project proponent has a proven track record in developing comparable facilities and faces substantial project and financial risk if a project fails to materialize on schedule, market forces may be reasonably relied upon as a substitute for Siting Board analysis and approval of the terms of an EPC contract (Exhs. MPP-0, at 4-2; MPP-2 at 9; Tr. 2, at 80-82). Mr. Egan suggested five factors which the Siting Board could use to measure comparability of facilities: size, fuel type, technology, location, and regulatory structure (Tr. 2, at 122-23).

With respect to operational viability, the Company asserted that the Siting Board should review contracts for fuel supply and O&M only when project developers have either a poor record or little comparable experience with respect to those functions (Exh. MPP-2, at 10; Tr. 2, at 91-93). The Company argued that a merchant plant such as the proposed project cannot obtain financing or generate adequate revenues to cover fixed costs unless it has a low-cost, reliable fuel supply and adequate O&M services, and that as the market changes over time, those strategies and services may need to change as well (Exh. MPP-0, at 4-2). The Company stated that, like long-term power sale contracts, long-term fuel and transportation contracts and long-term O&M contracts with fixed terms are inconsistent with the new, more competitive, more flexible market (id. at 4-2; Exh. MPP-2, at 10-12; Tr. 2, at 91-93). The Company argued that Siting Board review and approval of long-term fuel, transportation, and O&M contracts should no longer be necessary to satisfy the Siting Board's viability test, and that requiring merchant plants to enter into long-term contracts of this nature may, in fact, jeopardize their long-term viability (Exh. MPP-2; Tr. 3, at 43-46, 119-20). Further, Mr. Egan noted that when the terms and conditions of a fuel agreement, EPC contract or O&M contract are specified in a Siting Board decision in the public domain, the bargaining power of the applicants is compromised and that in turn necessarily increases the cost of those services to the project, leading to higher cost resources (Exh. MPP-2; Company Brief at 31-32).

In addition, the Company stated that a long-term, dedicated firm gas transportation contract would negatively impact the viability of the proposed project (Exhs. MPP-7, at 8; EFSB RR-37). Mr. Egan testified that if the Company were required to enter into a long-term, dedicated firm gas transportation agreement, it would run the risk that over time its fuel costs would become significantly out of market, threatening the viability of the project (Tr. 2, at 89-90, 112-13). The Company therefore argued that the Siting Board should not require USGen to enter into a long-term fuel supply contract with dedicated firm gas transportation arrangements (Exh. MPP-7, at 7-8; Tr. 2, at 81-85, 112-13).

c. Analysis

USGen has argued that, while the Siting Board should continue to apply its existing standard of review for viability in evaluating merchant plants, it should not continue to evaluate a "network of contracts" as part of that review in cases where an applicant has considerable experience in the development and operation of generating facilities. In support of its position, the Company has raised concerns about the confidentiality of the information provided as part of the review of such contracts. It also has argued that Siting Board directives requiring developers to provide final versions of EPC and O&M contracts as a condition of approval may unduly limit the developer's bargaining power and actually increase the cost or reduce the viability of a proposed project.

The Siting Board understands USGen's concerns about the proliferation of confidential information in its proceedings. We also note that, in determining whether a proposed NUG project is likely to be viable as a reliable least-cost source of energy over the planned life of a proposed project, proponents that have relatively little experience in the development of a major generating facility have been asked to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. Nevertheless, we are hesitant to set forth a specific level of experience that would exempt applicants from a review of their contracts without first hearing arguments from other interested parties as to how such a change might affect the relative competitiveness of potential facility developers, and thus the level of competition in the electric market in Massachusetts.

In addition, the Siting Board believes that it is appropriate at this time to reexamine its fundamental standard of review for viability in light of ongoing changes in the electricity industry. The standard that was developed for NUGs selling capacity to utilities under long-term contracts may not be appropriate for merchant plants intending to sell power under short-term contracts or on the spot market. Therefore, in order to solicit a full range of comments on the appropriate purpose and scope of its review of generating facility viability, the Siting Board will issue a Notice of Inquiry within three months after the final decision is issued in this case, unless the statute under which the Siting Board operates is amended so as to obviate the need for such an inquiry. After comments are received, the Siting Board will either affirm its current standard of review or articulate a new one. In the interim we will continue to apply our existing standard of review, while remaining flexible as to the evidence required to meet that standard.[70]

2. Financiability and Construction

a. Financiability

In considering a proponent's strategy for financing a proposed project, the Siting Board considers whether a project is reasonably likely to be financed so that the project will actually go into service as planned. The Company asserted that a number of factors -- the project's heat rate, low cost and low environmental impacts, the successful development experience of the Company, the interest and commitment of the equipment supplier, and the need for the proposed project at the time of commercial operation -- assure that the proposed project is financiable either under the current regulatory system or in a restructured environment (Exh. MPP-0, at 1-2, 4-3; Tr. 4, at 18-23, 28).

The Company asserted that it has extensive experience in financing and raising capital for projects comparable to the one proposed and, through its affiliate organizations, has more than adequate access to professional resources and funding to complete the proposed project (Exhs. MPP-0, at 4-3; MPP-10, at 3-4; Tr. 4, at 30-31). USGen reported that it has arranged financing for 17 projects in the amount of over five billion dollars, representing a total of 3,369 MW (Exh. MPP-0, at 4-3; Tr. 4, at 11). Further, the Company reported that in 1995, Company revenues from generating projects totaled more than $870 million (Exh. MPP-0, at 4-3).

The Company explained that the proposed facility is to be financed as a merchant plant, without signed long-term power contracts (Tr. 4, at 31). The Company acknowledged that the proposed project would be the first USGen owned facility in the United States to be

70 The Company's arguments regarding the necessity of a long-term gas transportation contract are addressed in Section II.C.3.b, below.

financed as a merchant plant (id. at 33; Exh. V-29).[71] The Company identified several options that are available to it for financing its proposed project (Exh. MPP-0, at 4-3; Tr. 4, at 33-34). The Company explained that merchant plant financing requires an equity contribution in the 30 to 50 percent range, which is an increase over equity required for conventional methods of independent power producer ("IPP") financing based on long-term contracts (Exh. MPP-0, at 4-3; Tr. 2, at 20). However, the Company asserted that PG&E has access to substantial amounts of capital for equity investment for such projects (Exh. MPP-0, at 4-3; Tr. 4, at 30-31). Further, the Company reported that the equity component of the project would be financed internally, and that the Company would only need to secure the debt necessary for the project (Tr. 4, at 33). Finally, the Company asserted that the fact that it has a high level of equity capitalization in the project serves to mitigate potential risks that could arise during financing (id. 4, at 43).

The Company stated that financing for the proposed project is scheduled to be completed by January 1998 to support the proposed on-line date of early 2000 (Exh. MPP-0, at 4-3). The Company noted that it has established banking relationships with over 40 commercial banks, several institutional lenders, and leading investment banks (id. at 4-3; Tr. 4, at 14-16). The Company stated that it has financed five projects in public financing markets, including the first Securities and Exchange Commission registered investment-grade offering for an IPP and three projects financed with unenhanced tax-exempt bonds (Exh. MPP-0, at 4-3 to 4-5; Tr. 4, at 11-13). The Company stated that it is recognized by the finance community as a premier borrower; both its bank and bond financings have been over-subscribed (Tr. 4, at 13).

To demonstrate financiability under conventional financing, the Company provided pro forma analyses based on four price forecasts: high, base, and low case forecasts

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71 The Company explained that while the use of merchant plant financing is new to the generating industry, it has been used in other industries, such as mining, and lenders are familiar with its application (Tr. 4, at 4). Further, the Company provided information on the use of successful merchant plant financing in countries outside of the United States (Exh. MPP-32).

submitted to the New Hampshire Public Utilities Commission ("New Hampshire PUC")[72] and a New England Electric System ("NEES")/NEPOOL price forecast (id. at 25-26; Exh. MPP-34).[73] For each of the three New Hampshire PUC forecasts, the Company conducted three sensitivity analyses: (1) a base case that assumes that 100 percent of the project's capacity is sold; (2) a second case that assumes 75 percent of the project's capacity is sold; and (3) a third case where the energy charge was reduced by ten percent with 100 percent sale of the project's capacity (Exh. MPP-34; Tr. at 25-26). The pro formas show minimum debt coverage ratios ("DCRs") in the 1.5 to 5.7 range, while the average DCRs ranged from 2.4 to 6.0 (Exh. MPP-34). The minimum return on equity projected in the pro formas was nine percent, with rates of return ranging up to 25 percent and higher (id.). The Company asserted that this range of debt coverage ratios and equity rates of return would be more than adequate to attract project financing (Tr. 4, at 28).[74]

The Company indicated that it would market the output from the proposed facility on a short-term basis through USGen Power Services, Inc. ("USGenPS"), an affiliated power marketing company (Exh. EFSB V-6). The Company indicated that USGenPS would focus on selling the output to investor-owned utilities, municipal utilities, and to other power marketers, and that it anticipates additional classes of power purchasers in a deregulated market (id.). The Company reported that USGenPS has been an active power marketer since 1993 and currently ranks in the top 15 percent of U.S. licensed marketers (Exh. MPP-0, at 1-5). The Company maintained that USGenPS executed transactions totaling one million megawatt hours ("MWh") in the first quarter of 1997 and it is projecting transactions totaling seven to ten million MWh for the 1997 calendar year (Exh. EFSB V-28). The Company

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72 These price forecasts were submitted in the New Hampshire PUC proceeding Restructuring New Hampshire's Electric Industry, Docket No. DR 96-150.

73 USGen also submitted pro formas based on its internal price forecasts and assumptions (Exhs. EFSB V-3; EFSB V-40).

74 The Company stated that these DCRs exceed even the Standard & Poor's criteria for bond financing, a more stringent standard than the requirements for bank financing (Tr. 4, at 23-25).

asserted that there has been a great deal of interest in purchasing power from the proposed project based on confidential inquiries from power marketing organizations and utilities (Exhs. MPP-1, at 5; EFSB V-6).

The Siting Board recognizes that the proposed project, as well as the two most recent generating projects reviewed by the Siting Board, are being financed as merchant plants. Further, a number of petitions pending before the Siting Board involve projects categorized as merchant plants. The nature of the new power supply market is such that short-term power contracts will be the vehicle for selling the output from the proposed facilities. Therefore, as in prior cases, the Siting Board will focus on the financial experience of the proponent, the ability to market the output of the proposed facility, financial indicators such as DCRs and rates of return, and the ability to produce reliable, low cost electricity. However, evidence of signed long term contracts will not be required to establish financiability.

The record indicates that the Company has a broad range of experience in the overall project development process, including financing. The Company has developed numerous IPPs and cogeneration plants, including facilities that have been approved by the Siting Board. These include facilities which are comparable in size, fuel type, technology, locational setting, and regulatory environment to the proposed project (see Section II.C.2.b). In addition, PG&E has substantial capital resources for equity investment in power projects and the proposed project's equity component will be financed internally.

The range of assumptions provided by the Company in its pro formas is generally reasonable and consistent with Siting Board reviews in prior proceedings. The Company's pro formas indicate that the proposed project is financiable based on projections of DCRs and rates of return on equity for differing levels of output sold under conventional financing.

In accordance with its status as a merchant plant facility, the Company has presented a range of alternative financing approaches which assume that long-term contracts will not be signed. The success of merchant plant financing is dependent on the market cost of electricity, and the ability of the Company to produce reliable, low cost electricity. The Company has asserted that it will be able to produce its power at a very competitive rate.

The Siting Board notes that the Company has employed a power marketer with significant experience in power sales transactions. Further, the Company has actively sought to contact financing institutions regarding the potential of merchant plant financing.

Based on the foregoing, the Siting Board finds that the Company has established that its proposed project is financiable.

b. Construction

In considering a proponent's strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Berkshire Power Decision, 4 DOMSB at 332. The Company stated that with its affiliates it develops, constructs, owns and operates electric power and cogeneration facilities (Exh. MPP-0, at 4-5). The Company stated that it is experienced in the entire spectrum of services necessary to develop, construct and operate environmentally superior electric power facilities, and that it currently is managing the operation of or constructing 17 generating plants throughout the United States (id.).

Here, the Company indicated that it plans to negotiate an EPC contract with Bechtel Power Corporation ("BPC") (Exh. EFSB V-12 (supp. A)). The Company stated that BPC has over 40 years of experience in providing engineering and construction services for power plant developers and operators (Exh. MPP-0, at 1-4). The Company provided information which indicated that BPC has installed over 240 energy facilities, totaling approximately 69,000 MW (id.). The Company stated that BPC will design and construct the plant to achieve substantial completion within 30 months after the Notice to Proceed is given by USGen (Exh. MPP-0, at 4-6).

The Company has submitted a sample EPC contract, including terms the Company generally expects to include in any final EPC contract (Exhs. EFSB V-12 (supp. A); EFSB E-116). The sample EPC contract provides the owner with a fixed price for the proposed project based on an agreed scope of work (Exh. EFSB V-12 (supp. A)). The Company stated that, according to the sample EPC contract, BPC would be responsible for all design, engineering, procurement, delivery, construction tasks, installation and training needed to bring the plant into operation at guaranteed output, heat rate, emissions, noise and other performance levels (id.). The Company explained that the sample EPC contract, which is a precursor to the EPC contract, contains a set of binding terms and conditions for the engineering and construction of the proposed facility, including provisions for: (1) a fixed price with monthly progress payments to the contractor; (2) a guaranteed schedule; (3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date, or (b) operation guarantees; (4) bonuses for early completion and improved performance; (5) warranties; (6) insurance; and (7) performance and facilities testing (id.).

The Company explained that the 501G[75] turbine was developed through an alliance of three companies -- Westinghouse, Mitsubishi Heavy Industries ("Mitsubishi") and Fiat Avio (Exh. EFSB V-31 (rev.)). The Company indicated that the first 501G turbine, owned by Mitsubishi, entered commercial operation in Japan in June, 1997 (Exh. V-46, supp. A). The Company indicated that the Mitsubishi unit is similar in almost all respects to the Westinghouse unit, with the exception of minor manufacturing differences (Tr. 2, at 130). In addition to the testing of the 501G turbine in Japan, the Company stated that Westinghouse intends to fully test and validate its unit in the summer of 1999 (id. at 131). The Company indicated that the first 501G turbine will be operating and fully tested prior to the commercial operation date for the facility (Exhs. MPP-11, at 4-5; EFSB V-31 (rev.)).

The Company also asserted that Westinghouse has guaranteed an equipment delivery schedule which will support a commercial operation date for the proposed project of June 1, 2000 (Exh. MPP-11 at 4). The Company stated that a detailed term sheet was negotiated and executed with Westinghouse for the 501G combined cycle configuration to be supplied for the project (Exh. EFSB V-9 (rev. A)). The Company reported that output and heat rate for the equipment are guaranteed with liquidated damages to be assessed if the guaranteed

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75 At the time it filed its petition, USGen expected to use a 400 MW General Electric 107H turbine for this project (Exh. MPP-0, at 1-6). However, during the course of this proceeding, the Company informed the Siting Board of its intention to substitute the Westinghouse 501G turbine, due to a substantial delay in the expected in-service date of the General Electric 107H turbine (Exhs. EFSB V-31; MPP-11, at 5).

levels are not achieved and that the agreement with Westinghouse provides for a reliability run performance test (id.). The Company stated that the availability projected for the life of the facility is approximately 92 percent, which is well within industry standards (id.). Further, the Company indicated that if necessary, the Mitsubishi unit could be employed at the same cost, and that the schedule contains the flexibility to accommodate such a change (Tr. 2, at 132-133).

The Company stated that the proposed project would be interconnected with the regional electric transmission grid via a single 115 kV transmission line which would extend approximately 100 feet between the facility's switchyard and the W-123, 115 kV transmission line ("W-123 line") on New England Power Services Company's ("NEPSCo") Southwestern corridor (Exh. EFSB E-112). The Company stated that NEPSCo is currently completing a final interconnection study for the project (Exhs. EFSB E-180; EFSB RR-40, supp. A; Tr. 10, at 36). The Company stated that after consultation with NEPSCo, it has selected an interconnection plan that involves reconductoring the W-123 circuit between the point of interconnection and the Carpenter Hill substation (Exh. MPP-37, at 1; Tr. 6, at 11; Tr. 10, at 5-6).[76] The Company stated that NEPSCo would reconductor the W-123 line by replacing the existing conductors with a bundled conductor (Exhs. MPP-18 at 3; EFSB RR-40, supp. A).

The Company indicated that it has been notified by NEPSCo that the reliability of the W-123 circuit exceeds 99 percent, as the forced outage rate of the W-123 line was 1.5 minutes over the past five years (Exh. RR-40, supp. A). The Company stated that the reconductoring of the W-123 line would be completed in time to meet the identified need in the summer of 2000, and would serve as a viable transmission link for the planned life of the facility (Exhs. MPP-18, at 3-4; MPP-37, at 1-2 Tr. 10, at 5-6).

In the past, the Siting Board has found that a signed agreement for the design and construction of a proposed project provides reasonable assurances that the proposed project is

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76 The Company also pursued, but ultimately rejected, a two-line interconnection plan (see Section III.B.2.g, below).

likely to be constructed on schedule and will be able to perform as expected. Dighton Power Decision, EFSB 96-3 at 26-27; Berkshire Power Decision, 4 DOMSB at 335; Altresco-Pittsfield Decision, 17 DOMSC at 380. Here, the Company has submitted a sample EPC contract. In addition, the record in this proceeding indicates that the Company and BPC have significant experience in the design and construction of generation plants which use technology similar to that proposed for this project and have successfully completed comparable projects.

The Siting Board accepts that the Company's experience in negotiating EPC contracts for comparable projects contributes strongly to its ability to negotiate an acceptable final EPC contract. It also notes that the Company has stressed its intentions to provide low cost, clean power and has stated that its construction practices are structured to fulfill these objectives. However, in the absence of a final EPC contract between USGen and BPC, the record contains no assurance that BPC actually will be the EPC contractor for this project. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed EPC contract between USGen and BPC or a comparable entity that contains provisions that provide reasonable assurance that the project would perform as a low cost, clean power producer.

The Company has demonstrated that the reconductored W-123 line would provide sufficient capacity for delivering power to the grid. However, the Siting Board notes that while the Company has worked with NEPSCo in the preparation of an interconnection and load flow study, the Company has not entered into a signed interconnection agreement with NEPSCo enabling transmission access. Failure to negotiate a final interconnection agreement acceptable to both parties would prevent the proposed project from providing energy to the Commonwealth and the region. See Berkshire Power Decision, 4 DOMSB at 336. However, if the Company provides a signed interconnection agreement, it will be able to establish that its proposed project is likely to be capable of being dispatched as expected. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed interconnection agreement between the Company and NEPSCo.

Finally, the Siting Board notes that the proposed the 501G turbine began commercial operation in June of 1997, and therefore has limited operating experience. While the record indicates that Westinghouse would be responsible for correcting any problems with the turbine, the proposed project cannot go forward as planned if there are unexpected delays in turbine development or testing. The Siting Board notes, however, that the time between commercial operation of the Mitsubishi 501G turbine and the operation of the Millennium project is at least two years. Because the Westinghouse 501G turbine is virtually identical to the Mitsubishi 501G turbine commercial testing for one is indicative of the operating capability of the other. Moreover, the Company has indicated that the Mitsubishi 501G turbine could be substituted for the Westinghouse 501G turbine if necessary to meet the on-line date. The Siting Board reiterates that a project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal (see Section IV, below). Should the 501G turbine, in either the Westinghouse or Mitsubishi configuration, be unable to perform substantially as expected, USGen would be required to notify the Siting Board as explained in Section IV, below.

Accordingly, upon compliance with the above conditions that the Company provide the Siting Board with (1) a copy of a signed EPC contract between USGen and BPC or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, and (2) a copy of a signed interconnection agreement between the Company and NEPSCo providing the proposed project with access to the regional transmission system, the Siting Board finds that the Company will have established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives.

The Siting Board has found that the Company has established that its proposed project is likely to be financiable. The Siting Board has also found that, upon compliance with the above conditions relative to a signed EPC contract and a signed agreement for access to the regional transmission system, the Company will have established that its proposed project is likely to be constructed within applicable time frames and capable of meeting the Company's performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, the Company will have established that its proposed project meets the Siting Board's first test of viability.

3. Operations and Fuel Acquisition

a. Operations

In determining whether a proposed NUG project is likely to be viable as a reliable, least-cost source of energy over the planned life of the proposed project, the Siting Board evaluates the ability of the project proponent or other entities to operate and maintain the facility in a manner which ensures a reliable energy supply. Dighton Power Decision, EFSB 96-3 at 27; Berkshire Power Decision, 4 DOMSB at 337; Altresco-Pittsfield Decision, 17 DOMSC at 381-382. In a case where the proponent has relatively little experience in the development and operation of a major energy facility, that proponent has been asked to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks have historically been enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the facility. Berkshire Power, 4 DOMSB at 337-339; Altresco-Pittsfield Decision, 17 DOMSC at 382-383.

The Company stated that it plans ultimately to negotiate a contract, complete with penalty and incentive provisions, with U.S. Operating Service Company ("USOSC"), an experienced O&M contractor (Exh. MPP-0, at 4-7). Here, the Company has provided a sample O&M agreement with USOSC for illustrative purposes, to show the types of considerations the Company has included for comparable contracts in the past (Exh. EFSB V-13). The Company stated that it is important to maintain flexibility in the terms of the agreement at this point in the development process in order to allow the project to adapt to market conditions throughout the development process, optimizing its efficiency (Tr. 3, at 53-55). The Company further explained that O&M contracts for merchant plant facilities would be less prescriptive in their intended goals and expectations of the operator, insuring the necessary degree of flexibility (id. at 46).[77]

The Company stated that USOSC is well qualified to perform the services necessary to assure reliable operation and maintenance of the proposed project (Exh. MPP-0, at 4-7). The Company reported that USOSC currently provides day-to-day management services for plant operations and maintenance at thirteen operating non-utility power plants, eleven of which are owned or partially owned by the Company, representing more than 2,800 MW (Exh. MPP-9, at 3). The Company stated that USOSC is currently mobilizing to operate three additional power plants which total over 600 MW (id.).

The Company stated that the O&M services that USOSC would provide to the Millennium project would be comparable to those provided for the Company's other combined-cycle gas-fired plants in Hermiston, Oregon; Pittsfield, Massachusetts; East Syracuse, New York; and Doswell, Virginia (Exh. MPP-9, at 4; Tr. 3, at 41-42). The Company stated that the experience USOSC has developed at these other facilities will be highly relevant to its operation of the Millennium project (Exh. MPP-9, at 4-5). The Company stated that its ability to operate and maintain such facilities is demonstrated by the reliability track record of its plants, and noted that combined-cycle facilities operated by the Company and USOSC have an average availability rate of over 90 percent and an average forced outage rate below 2 percent (id. at 6)

In past cases, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance objectives. Dighton Power Decision, EFSB 96-3 at 28; Berkshire Power Decision, 4 DOMSB at 338; Altresco-Pittsfield Decision, 17 DOMSC at 382. The Siting Board notes that the Company has provided a sample O&M contract and accepts that the Company's and USOSC's experience in operating, maintaining, and managing comparable facilities is strong evidence

77 Mr. Winne testified that it would be important to maintain flexibility in such matters as the scheduling of planned outages, in order to provide capacity when economically beneficial or necessary to support the regional system (Tr. 3, at 54-56).

that the Company will be able to negotiate an acceptable final O&M contract. The Siting Board notes that the Company has stressed its intention to provide low-cost, clean power and has stated that its O&M practices would be structured to fulfill these objectives. However, while the record supports an expectation that USGen will contract for a low cost, clean power project, it does not include a final O&M contract. Therefore, the Siting Board requires USGen to provide the Siting Board with a copy of a signed O&M contract between USGen and USOSC or a comparable entity, that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer.

Accordingly, upon compliance with the condition to provide a signed O&M contract between USGen and USOSC, or a comparable entity, the Siting Board finds that the Company has established that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

b. Fuel Acquisition

In considering an applicant's fuel acquisition strategy, the Siting Board has considered whether such a strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project.

The Company stated that the evolution of the electric industry in Massachusetts and New England toward a more competitive system will require it to develop a flexible fuel and transportation procurement strategy (Exhs. MPP-0, at 4-7; Tr. 3, at 71-72, 109-110; Company Brief at 30-33). Noting that PPAs historically have had an initial term of 20 years, the Company predicted that in a more competitive environment, PPA terms will be significantly shorter and in a different form than those used by the industry in the past (Exh. MPP-0, at 4-7; Tr. 3, at 71-72).

The Company stated that it will be entering into a precedent agreement with USGenFS to supply a 365 day firm natural gas supply subject to 30 days of recall, with delivery to the facility off the TGP mainline (Exh. MPP-7, at 2-3; Tr. 3, at 68, 103). The Company explained that USGenFS is responsible for supplying an alternative fuel to the facility when it exercises its recall rights (Tr. 3, at 103). The Company indicated that the precedent agreement would be in effect for a period of ten years and that the terms of the agreement reflect the flexibility required by the project to operate in a deregulated and competitive electric market (Exhs. MPP-7, at 2-3; MPP-30; Tr. 3, at 68).[78] The Company also indicated that under the terms of the precedent agreement, it would have the option of reselling any natural gas volumes that USGen does not elect to use (Tr. 3, at 84).

To provide for on-site delivery of natural gas to the facility from the TGP mainline, the Company stated that it has entered into discussions with TGP and other third-party contractors to bid competitively for the construction of a high pressure lateral to the facility (Exh. MPP-0, at 4-8). The Company asserted that sufficient capacity exists on the TGP system in the area of the project to ensure a reliable gas supply (Exhs. EFSB V-16; EFSB V-36).[79] The Company noted that because it would contract for natural gas to be delivered to the facility at the interconnection with the TGP, the burden of maintaining transportation capacity on the TGP system to ensure firm gas deliveries would reside with the supplier, USGenFS (Exh. MPP-0, at 4-8; Tr. 3, at 78). The Company stated that by relying on USGenFS, it would avoid the increased cost associated with contracting for firm pipeline capacity as well as any other associated pipeline demand charges and/or supplier demand charges which, in turn, would allow USGen to maximize the benefit of the proposed project to the customer[80] (Exhs. MPP-0, at 4-8; MPP-7, at 4).

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78 The Company stated that in the event that USGen contracts for the sale of power from the facility on a long-term basis, it would review and implement a natural gas supply strategy which will ensure the operation of the facility to meet such commitment using either domestic or Canadian supply sources (Exh. MPP-0, at 4-9).

79 The Company stated that the TGP's current winter design capacity is approximately 800,000 million cubic feet per day ("Mcf/d"), approximately twelve times the project's requirements if run at full capacity, and ample to provide a reliable fuel supply to the project (Exhs. EFSB V-16; MPP-8, at 10).

80 The Company stated that if it were required to enter into a long-term fuel supply agreement which includes long-term dedicated firm transportation arrangements, the additional cost to the project would be between $60 million and $200 million over a ten-year period (Exhs. MPP-7, at 8; EFSB RR-37; Tr. 2, at 88-90). The Company (continued...)

The Company asserted that USGenFS has substantial experience in providing natural gas to comparable facilities, including the MASSPOWER, Selkirk, and East Syracuse facilities (Exh. MPP-8, att. 2). The Company stated that USGenFS currently manages the fuel supplies for all of the Company's northeastern gas-fired projects, representing daily gas volumes in excess of 360,000 Mcf/d, and on behalf of 20 local distribution company's in the New York/New England area supplied through Alberta Northeast Gas and Boundary Gas, Inc. (Exhs. MPP-0, at 4-8; MPP-7, at 3). In addition, the Company stated that USGenFS currently manages over 680 MMcf/d of firm natural gas supplies and pipeline transportation services (Exh. MPP-8, at 3). Further, the Company reported that USGenFS retains an equity position and administrative role in both the Iroquois Gas Transmission System and the Portland Natural Gas Transmission System (Exhs. MPP-0, at 4-8; MPP-7, at 3). The Company's witness testified that USGenFS manages approximately 45 percent of all gas used by IPPs in Massachusetts, and 25 percent of all gas used by IPPs in New England (Tr. 3, at 99). The Company also indicated that USGenFS serves approximately ten percent of all gas generation capacity in Massachusetts, and approximately six percent of all gas generation capacity in New England (Exh. EFSB RR-7).

The Company stated that it expects that its air permit will allow it to burn low-sulfur oil for 30 days each year (Tr. 3, at 88). The Company explained that USGenFS may recall up to 30 days of natural gas service per year, and USGenFS will be responsible for delivery of No. 2 distillate fuel oil for the plant's full requirements (id. at 68, Exh. MPP-7, at 3). The Company estimated that USGenFS would exercise its recall rights on approximately ten days in an average year, coincident with the number of needle peak days, which correspond to weather patterns (Exh. EFSB V-36a; Tr. 3, at 80, 108). Further, the Company indicated that, in the event of a gas supply interruption, it would attempt to purchase economic energy on the spot market, if available, rather than burn oil (Exh. MPP-7, at 6; Tr. 8, at 116-17).

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[80](...continued)
argued that a long-term fuel supply contract including long-term dedicated firm transportation arrangements would therefore negatively impact the viability of the project and impose higher prices on consumers (id.).

The Company indicated that it would retain a three-day supply (approximately 25,000 barrels ("bbls")) of No. 2 fuel oil on-site (Exh. MPP-7, at 6). The Company stated that USGenFS has entered into supply discussions with Coastal Oil Marketing and Sprague Energy, both of which maintain distillate fuel oil terminals in the greater Boston and New England area, and would use local tanker truck transportation in order to deliver distillate fuel oil to the site (Exhs. MPP-0, at 4-8 to 4-9; EFSB V-18a). The Company explained that in addition to constructing on-site off-loading facilities, it has entered into discussions with various third-party contractors to competitively bid and construct a fuel oil lateral which will connect with the Mobil Oil Products line adjacent to the TGP mainline and the facility site (Exhs. MPP-8, at 8-9; EFSB V-18a). The Company asserted that whenever practical, it will access and use excess space in the Mobil Oil Products line to deliver distillate fuel oil to the facility, and that it expects that the pipeline would be used for off-peak deliveries (Exh. EFSB V-18a; Tr. 3, at 74).

The Company stated that USGenFS is an experienced, competent supplier which currently manages over 75,000 bbls of No. 2 fuel oil inventory for northeastern electric projects (Exh. MPP-8, at 3). The Company also noted that USGenFS has experience dealing with the Mobil Oil products pipeline for Ocean State Power, for which USGenFS managed the gas and liquid fuel supply prior to the fourth quarter of 1996 (id.). The Company asserted that having both pipeline capability and truck transport capability as an alternative fuel source provides greater security that oil will be on-site when needed and may provide a lower cost of delivered fuel oil to the project (Exh. EFSB V-18b).

The Company stated that additional gas supplies will soon be available in New England as a result of the development of new, high-pressure pipelines, expansion of existing facilities, and new storage facilities (Exhs. MPP-7, at 9; MPP-29; EFSB V-36b; Tr. 3, at 65-67). The Company indicated that projects such as the Portland Natural Gas Transmission System, the Maritimes & Northeast Pipeline, the Avoca Natural Gas Storage project, Distrigas' improved delivery capability, and incremental annual long haul firm transportation capacity on the Iroquois Gas Transmission line are expected to provide additional gas supplies to the region (Exhs. MPP-7, at 10-11; EFSB V-36b; Tr. 3, at 67). The Company asserted, however, that the viability of the proposed project does not depend on these new projects, and that sufficient capacity to serve the proposed project already exists on the TGP mainline (Exh. EFSB V-16).

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project. Dighton Power Decision, EFSB 96-3 at 28; Berkshire Power Decision, 4 DOMSB at 343. The Siting Board has recognized that, in considering a petitioner's fuel acquisition strategy, it is appropriate to consider the need for flexibility, the expected shorter timeframe of PPAs in a restructured electric industry, and the industry-wide shift away from long-term gas supply contracts. Dighton Power Decision, EFSB 96-3 at 28; Berkshire Power Decision, 4 DOMSB at 343. Nevertheless, the Siting Board must still be convinced that a low-cost, reliable fuel supply will be available to a proposed project in order to determine that a proposed project will be capable of providing a necessary energy supply consistent with its mandate.

In reviewing a proposed project's fuel acquisition strategy, the Siting Board necessarily focuses on the project's primary fuel supply. However, backup fuel supplies and/or contingency plans for interruptions in primary fuel supplies also have consistently been considered by the Siting Board. Berkshire Power Decision, 4 DOMSB at 343; Altresco Lynn Decision, 2 DOMSB at 150-151; Altresco-Pittsfield Decision, 17 DOMSC at 384-389.

Here, the Company has presented a fuel acquisition strategy that involves: (1) the intent to contract with an affiliated fuel supplier for a 365 day firm natural gas supply, subject to 30 days of recall, delivered to the facility off the TGP mainline; and (2) a specific back-up supply plan, including a three-day, on-site oil supply transported either by truck or pipeline, with the intent to contract for fuel oil from USGenFS, and the ability to switch to oil for limited operation.[81]

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81 The Siting Board notes that, although the Company has submitted an air permit application that, if approved, would allow it to burn oil for a maximum of 30 days per year, the Company states that it expects to minimize its reliance on oil and (continued...)

The Siting Board notes that a signed precedent agreement has been executed between USGen and USGenFS. The precedent agreement provides for a firm supply to be arranged by USGenFS, which would bear full responsibility for ensuring that the proposed project receives the fuel supply necessary for operating the facility in a low cost and reliable manner. In past decisions, the Siting Board generally has reviewed final fuel transportation and/or supply contracts between proponents and pipeline companies. While the Siting Board has not required proponents to submit signed long-term fuel supply contracts in recent cases, it still has required firm transportation contracts from a major interconnection point as assurance that a proponent's gas supply strategy is viable.

In its most recent review of a gas-fired facility with a back-up oil supply, the Siting Board required a firm transportation contract from an interconnection point just outside New England to the proposed project site in Massachusetts. Berkshire Power Decision, 4 DOMSB at 344. Upstream of that gas supply point, the Siting Board accepted a gas supply management arrangement whereby a gas service company would be responsible for the daily workings of all of the gas supply and gas transportation contracts for the proposed facility. Id.

The Siting Board acknowledges that there is a benefit to the flexible gas procurement approach contemplated for the proposed project. In this case, the Company has elaborated on the additional costs, both in dollars and lost efficiency, that would be associated with a dedicated long-term firm gas transportation contract. Further, the Company has demonstrated that it has experience in procuring fuel for comparable facilities, and that its projected supplier, USGenFS, has substantial experience in delivering fuel to comparable

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[81](...continued)

estimates that the fuel recall provision will be invoked approximately 10 days per year, coincident with needle peak days. The Siting Board notes however, that under USGen's gas supply strategy incorporating a 30 day recall provision on behalf of USGenFS, the recall option lies squarely with USGenFS, and is not confined to weather related situations to trigger the recall. The Siting Board further addresses this issue in Section III.B.2.a, below.

facilities. In addition, the Siting Board recognizes that USGenFS, by virtue of its size and scale in the marketplace, has an enhanced ability to supply gas on a long term basis. Consequently, the Siting Board will not require USGen to enter into a firm transportation contract for the proposed project.

However, the Siting Board notes that at this point in time, the industry is in a period when the demand for and the supply and deliverability of natural gas in New England are in flux. This is the first case reviewed by the Siting Board in which the petitioner plans to rely on delivery of gas to a project delivery point on an interstate pipeline without a firm transportation arrangement for any portion of a supply route. While the Company has described a number of projects that would increase gas capacity into New England, these projects are, for the most part, still in the planning and permitting stages. Moreover, future generating facilities also must be factored into any calculation of future supply and demand for gas delivered to New England. As discussed in the need analysis above (see Sections II.A.2. and II.A.3) sustained generating capacity expansion is expected for at least the first six years of the life of the proposed project, with new gas-fired power plants as the principal sources of the supply assumed in the Company's need analysis. Consequently, increased demands on the existing gas supply system are very likely. In the absence of a dedicated transportation arrangement, the Siting Board cannot be certain that USGen's fuel supply strategy will continue to be viable at the time that project construction commences.

Therefore, to allow the Siting Board to monitor developments affecting gas capacity into New England, which relates to USGen's expectations as to the reliability of its fuel supply strategy, the Siting Board requires USGen to provide periodic updates on the status of gas supply projects to increase gas capacity into New England. Specifically, prior to commencement of construction, the Company must submit to the Siting Board an updated assessment which reasonably confirms the continued ability of USGenFS to transport gas to the proposed project, based on updated information as to developmental status, regulatory approvals, and completion of projects intended to supply natural gas to New England. This assessment must be updated annually until USGen begins construction of the proposed project.

Accordingly, the Siting Board finds that, based on the compliance with the above condition that until commencement of construction USGen provide the Siting Board with an updated fuel acquisition assessment, indicating the continued availability of a reliable supply of gas to power the proposed facility, the Company will have established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project.

The Siting Board has found that the Company has established that (1) upon compliance with the condition relative to providing a signed O&M contract, the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) upon compliance with the condition relative to an annually updated fuel acquisition assessment, its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project. Accordingly, the Siting Board finds that the Company has established that its proposed project meets the Siting Board's second test of viability.

4. Findings and Conclusions on Project Viability

The Siting Board has found that upon compliance with the conditions in Sections II.C.2.b, II.C.3.a, and II.C.3.b, above, USGen will have established that (1) the proposed project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project.

Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, USGen will have established that its proposed project is likely to be a viable source of energy.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Site Selection Process

The Siting Board has a statutory mandate to implement the energy policies in G.L. c. 164 §§ 69H-69Q to provide a necessary 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 and requirement, the Siting Board requires a petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347; 1993 BECo Decision, 1 DOMSB at 27.

1. Standard of Review

In order to determine whether a facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347; NEA Decision, 16 DOMSC at 381-409. In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Board requires the proponent to satisfy a two-pronged test. First, the facility proponent must establish that it developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347; Berkshire Gas Company (Phase II), 20 DOMSC 109, 174-180 (1990) (1990 Berkshire Decision). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity.[82] Dighton Power Decision, EFSB 96-3 at 32; Berkshire Power Decision, 4 DOMSB at 347-348; NEA Decision, 16 DOMSC at 381-409.[83]

In the sections below, the Siting Board reviews the Company's site selection process, including its development of siting criteria and application of those criteria, and the geographic diversity of the Company's primary and alternative sites.

While our standard of review at this time remains the unchanged, we note that on August 18, 1997, Infrastructure Development Corporation ("IDC") requested that the Siting Board issue an advisory ruling regarding the Siting Board's practice of requiring notice of an alternative site. On September 16, 1997, the Siting Board issued an advisory ruling stating, inter alia, that formal noticing of two sites for a proposed generation facility such as IDC is not required as a matter of law or Siting Board regulation and is not necessary as a matter of policy. Advisory Ruling at 4. Accordingly, the Siting Board stated that IDC will be permitted to notice only its preferred site.

2. Development and Application of Siting Criteria

The Company indicated that its initial site selection process was designed to: (1) identify a reasonable universe of site alternatives; (2) identify a consistent set of objective

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82 When a facility proposal is submitted to the Siting Board, the petitioner is generally required to present (1) its preferred facility site or route, and (2) at least one alternative site or route. These sites and routes often are described as the "noticed" alternatives because these are the only sites and routes described in the notice of adjudication published at the commencement of the Siting Board's review. In reaching a decision in a facility case, the Siting Board can approve a petitioner's preferred site or route, approve an alternative site or route, or reject all sites and routes. The Siting Board, however, may not approve any site, route or portion of a route which was not included in the notice of adjudication published at the commencement of the proceeding.

83 The Siting Board notes that proposed sites or routes located in the coastal zone as defined under the Massachusetts Coastal Zone Management ("MCZM") program and the Coastal Zone Management Act, 16 U.S.C. § 1453, are subject to additional regulatory requirements. See 980 C.M.R. 9.00 et seq. However, the proposed site is not located in the coastal zone, and is not subject to these regulations.

site evaluation criteria; and (3) select from the universe of sites the site for the proposed project that was least cost, with the least environmental impacts (Exh. MPP-0, at 5-1). The Company indicated that its site selection process consisted of three phases: Phase I, the identification, screening, scoring and ranking process; Phase II, environmental investigation and project definition; and Phase III, evaluation, and testing of public and regulatory acceptance of the proposed project (Exh. MPP-42, att. 1; Tr. 10, at 53-57).[84]

a. Description

The Company stated that it narrowed its site search to the Commonwealth of Massachusetts due to the following factors: (1) the Commonwealth's proximity to load centers; (2) favorable regulatory environment for merchant plants; and (3) the Company's extensive experience in Massachusetts (Exh. MPP-0, at 5-4). The Company explained that it further narrowed the geographic scope of its review to the area east of Springfield to ensure proximity to load centers and west of Hopkinton to ensure the reliability of its gas supply (id. at 5-4 to 5-5; Tr. 4, at 65-66).[85]

The Company explained that it developed two types of site selection criteria (1) threshold criteria that each site was required to meet in order to be further considered as a site for the proposed facility, and (2) more detailed screening criteria (Exh. MPP-0, at 5-5). The Company stated that its threshold criteria included: (a) limitation to location(s) within three miles of the intersection of an electric transmission line of at least 115 kV and a

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84 The Company indicated that Phase I took place from February to April, 1996; Phase II, April through mid-June 1996; and Phase III occurred from mid-June through August, 1996, at which point, the Company made the final decision to propose the selected site (Exhs. MPP-42, att. 1; MPP-41 at 3-6).

85 The Company indicated that although additional pipelines are proposed to be constructed, which may increase the reliability of gas supplies east of Hopkinton, such lines are only in the proposal stage (Tr. 3, at 83-85).

portion of the TGP system sized over 20 inches in diameter;[86] (b) a minimum site size of at least 15 buildable acres; (c) suitability for industrial development; and (d) accessibility to roadway infrastructure (id. at 5-5).

The Company explained that once it developed the specific geographic universe it analyzed two categories of sites (1) sites already owned by the Company and its affiliates, and (2) sites that met the basic threshold criteria (id. at 5-2). Of the Company-controlled sites, the Company determined that only one, the MASSPOWER facility in Springfield, met the geographic requirements set forth above, but further determined that the site lacked sufficient buildable space[87] (id. at 5-5 to 5-6). The Company indicated that eight sites met the threshold criteria: two in Charlton, one in Grafton, one in Oxford, one in Southbridge, two in Sutton, and one in Upton (id. at 5-6).

The Company stated that it used 12 detailed screening criteria to rank the eight selected sites: (1) proximity to gas pipelines; (2) proximity to electric transmission line; (3) site size and buffering potential;[88] (4) site zoning designation; (5) adequacy of roadway

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86 The Company noted that proximity to interconnects has been recognized as a legitimate siting criteria. See, e.g., Bay State Gas Company, 21 DOMSB 1, 55 (1990). The Company asserted that the TGP was selected for its high pressure supply and diverse set of supply sources, so as to optimize pricing strategy and fuel availability (Exhs. MPP-0 at 5-4; EFSB S-1). The Company indicated that siting a facility along a pipeline smaller than 20 inches in diameter or on spurs would place a significant constraint on the reliability of the project's gas supply since the facility's gas demand is 56,000 Mcf/d and a single 20 inch pipeline is capable of transporting only 150,000 to 300,000 Mcf/d, whereas the two main trunk lines currently move 800,000 Mcf/d (Exh. EFSB RR-8). The Company further asserted that locating a facility on a spur line raises even more significant reliability constraints in the event of a physical problem with the pipeline (id.; Exh. EFSB S-20).

87 The other sites in Massachusetts owned by the Company or its affiliates also suffered from a lack of extra buildable space or problems with either the electrical or gas interconnect. The Company indicated that it considered these issues significant enough to exclude the sites from further consideration (Exhs. EFSB S-3; EFSB S-18).

88 This factor included an evaluation of the shape of the parcel, along with any geographic feature that would prevent the placement of a facility away from one or (continued...)

infrastructure; (6) water availability; (7) topography; (8) wetlands/waterbodies; (9) potential for site contamination; (10) air quality dispersion environment; (11) proximity to sensitive receptors;[89] and (12) wastewater disposal availability (id. at 5-18 to 5-24).

The Company indicated that it first assigned each screening criterion a weighting factor based on whether the project team considered the criterion very important (three points), moderately important (two points) or of minor importance (one point) (id.).[90] The Company then evaluated each potential site by assigning suitability ratings of high (two points), medium (one point) or low (zero points) for each criterion (id.)[91] Finally, the Company developed an overall suitability score for each site by multiplying the weighting factor by the individual suitability score (id. at 5-26).[92]

Based on this evaluation, the three highest scoring sites were placed on a short list. These three sites were: (1) the primary site (the Charlton Industrial site), (2) the Grafton site, and (3) the alternative site (the Charlton Central site) (id. at 5-25). The Company stated

[88](...continued)
more of the site boundaries (Exhs. EFSB S-9; EFSB S-22; Tr. 4, at 68-70). The Company indicated that it did not consider the abutting zoning, terrain, or absence of natural buffers such as vegetation as part of this category (Exh. EFSB S-9).

[89] This factor included both noise and visual impacts (Exh. EFSB S-12). Although the Company acknowledged that noise and visual impacts may not always be coincident, it stated that this factor is a reasonable surrogate for both, and that noise and visual impacts were separately considered once the short list of sites had been developed (id.; Tr. 4, at 93-94).

[90] Of the twelve screening criteria, four were determined to be very important, four were determined to be of moderate importance, and four were determined to be of minor importance (Exh. MPP-0, at 5-26).

[91] The Company stated that had it used a 3:1:0 rating, similar to the rating process described in the Berkshire Power Decision, 4 DOMSB at 351, the relative rankings of the sites would have been essentially unchanged (Tr. 4, at 76).

[92] The Company indicated that multiple visits were made to each site by project engineers, and project development, environmental, siting, and permitting specialists as part of the quantitative scoring process (Exh. EFSB S-7).

that, after further analysis, it determined that development of the Grafton site would be difficult, as the site had been approved for use as a residential subdivision, was bounded by a large wetland area which served as a habitat for rare wetlands wildlife, and would have required a new transmission line to cross an area of open space owned by the town and a non-profit organization (id.; Exh. EFSB S-14). The Company then determined that although both Charlton sites were viable, the primary site was superior to the alternative site due to: (1) the industrial zoning of the primary site; (2) the primary site's proximity to a major state highway; (3) the alternative site's greater proximity to residential areas; (4) greater compatibility of land uses at the primary site; and (5) reduced noise, visibility, and air impacts at the primary site (id. at 5-25 to 5-27).

The Company stated that it has a policy of evaluating community acceptance as part of the siting process (Tr. 10, at 80). The Company explained that during Phase I of its site selection process, it met with town officials and elected representatives, including the Chairman of the Board of Selectmen, the Chairman of the Economic Development Commission, and the Town Planner (Exh. MPP-42, att. 1). The Company asserted that the town officials were very receptive to the project (Exh. EFSB S-11b).[93] The Company testified that in its experience, meaningful input from the community as a whole is difficult to solicit until a specific site has been identified, more definitive information about the project is available and at least preliminary information about the basic environmental impacts of the project are known (Exh. MPP-41 at 3; Tr. 4, at 89-90, Tr. 10, at 54-56; Company Brief at 22). The Company maintained that it did not believe broader public meetings would have been productive during Phases I and II of the site selection process pending this more intensive environmental evaluation (Exh. MPP-41 at 4; Tr. 10, at 56-57, 96-102).

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93 During Phase I, the Company developed materials to help the community understand the visual impacts of the proposed project, and engaged community members in discussions to identify their concerns. The Company also hosted a tour of its Ocean State Power facility for the Economic Development Commission (Tr. 10, at 69).

The Company further stated that after more complete environmental information was tentatively available during Phase II of the site selection process in May and early June 1996, it met with the closest residential neighbor[94] and industrial neighbors and a wider array of town officials, while at the same time beginning a more intensive evaluation of the environmental information pertaining to the site (Exh. MPP-42, att. 1). The Company explained that it made a public announcement of the project on June 17, 1996, at the end of Phase II, and that the Company immediately filed the project's Environmental Notification Form ("ENF") (id.).

The Company further stated that once enough information had been collected to prepare the ENF, it was ready to test the receptiveness of the broader community to the project as part of Phase III of the site selection process (Exh. MPP-41, at 5).[95] The Company reported that during June, July and August 1996, its representatives met with the local newspapers, participated in public meetings or hearings and otherwise presented information about the project and evaluated public reaction to the project (id.; Exhs. MPP-42; MPP-44; Tr. 10, at 72-75). The Company also reported that it experienced positive community reactions (Tr. 10, at 75). The Company indicated that if it had encountered a high degree of public opposition by public officials who were approached earlier, the Company would have revisited its selection of the preferred site (id. at 57, 88). The Company stated that it was only after Phase III was completed in August 1996 that the Company made the final decision on site selection (Exh. MPP-41, at 5).

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94 The closest residential neighbor owned the home on Sherwood Lane slated to be purchased by the Company (Exh. EFSB E-174; Tr. 4, at 135). The Company stated that it did not meet or consider meeting with any other residential neighbors at that time (Tr. 4, at 135).

95 Specifically, the Company met with the Charlton Conservation Commission, Charlton Board of Selectmen, Southbridge Town Council, and attended the MEPA scoping session (Exh. MPP-42; Tr. 10, at 72-75).

b. Analysis

The Siting Board notes that the majority of its past generation facility reviews have concerned cogeneration facilities. However, the Siting Board previously has stated that the site selection criteria developed for an IPP should be similar to criteria developed for a cogeneration facility, except for the steam host locational requirement. Berkshire Power Decision, 4 DOMSB at 351; Enron Decision, 23 DOMSC at 127. Here, the Company has developed a broad array of criteria which address the critical issues associated with the siting of generating facilities and which are generally consistent with site selection criteria which the Siting Board has found to be appropriate in previous reviews. Berkshire Power Decision, 4 DOMSB at 349-351; Cabot Decision, 2 DOMSB at 380-381; MASSPOWER Decision, 20 DOMSC at 378-379.

However, the Siting Board has concerns regarding one of the twelve criteria the Company used to rank sites, and with the Company's omission of a specific criterion. First, the Siting Board notes that the criterion, proximity to sensitive receptors, encompasses both noise and visual impacts. The Siting Board notes that in a number of prior cases, project proponents have evaluated noise and visual impacts as separate criteria at this stage in the site selection process.[96] While the Company maintains that the distance to sensitive receptors is a suitable proxy for both noise and visual impacts, the Siting Board notes that these impacts are not always coincident, and therefore, use of a single criterion may limit the accuracy of the site selection process as it relates to noise and visual impacts.

The Siting Board acknowledges that proximity to a sensitive receptor is a contributing factor to both the noise and visual impacts (see Sections III.B.2.d and III.B.2.c, below).

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96 The Siting Board notes that in the past, a number of petitioners have separated out noise and visual impacts as two distinct criteria. Berkshire Power Decision, 4 DOMSB at 350-351; Altresco Lynn Decision, 2 DOMSB at 168; Enron Decision, 23 DOMSC at 126. Further, in the Cabot Decision, while the two criteria were grouped, aesthetics and noise were scored separately. 2 DOMSB at 377.

However, noise impacts are a function of both distance and ambient noise levels,[97] while visual impacts are a function of screening and topography, as well as distance.[98] Evaluation of the single criterion, distance to sensitive receptors, may therefore result in a misstatement of the project's likely noise and visual impacts. Moreover, noise and/or visual impacts have often proven to be among the most significant environmental issues in generating facility cases (see Sections III.B.2.d and III.B.2.c, below). See Dighton Power Decision, EFSB 96-3 at 47-48, 55-58; Berkshire Power Decision, 4 DOMSB at 394-396, 403-406; Enron Decision, 23 DOMSC at 210-212, 223. Therefore, the Siting Board will require future proponents, at the site screening level, to assess visual impacts based on vegetative and other screening potential as well as proximity to sensitive receptors, and assess noise impacts based on indicators of background noise as well as proximity to sensitive receptors.[99]

Further, the Siting Board notes that the Company did not include a criterion relating to community support either in its four threshold criteria or in its twelve screening criteria. Despite this omission, the record clearly demonstrates that the Company engaged in extensive discussions with local officials during its site selection process, and suggests that these discussions were critical to the selection of the primary site. In future cases, the relationship

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97 In this case the noise analysis shows that Receptor 6, H. Foote Road, has as high a noise impact as any of the receptors, a nighttime L_{90} increase of 10 dBA, yet it is not the closest receptor to the proposed facility (see Section III.B.2.d).

98 In this case, the analysis shows significant visual impacts at Harrington Road, which are attributed to the topography and lack of on-site screening between the Harrington Road residences and the proposed facility. Further, the Siting Board notes that the Harrington Road residences are not the nearest residences to the proposed facility, bringing into question the adequacy of distance as a sole criterion for visual impacts (see Section III.B.2.c, below).

99 The Siting Board notes that it does not expect petitioners to conduct background noise monitoring for all identified alternative sites. Rather, indicators such as the presence of heavily travelled roadways or industrial/commercial development, as well as proximity to receptors, provide a reasonable basis to assess noise impacts at the screening level.

between such discussions and the proponent's quantitative site evaluation process should be clearly set forth.

The record also indicates that the Company did not seek community input regarding the proposed site from neighboring residents until Phase III of its site selection process, after initial regulatory filings had been made. The Siting Board previously has recommended that both the local community and local government be included in an open, participatory site selection process from the inception of a project. Berkshire Power Decision, 4 DOMSB at 356; Altresco Lynn Decision, 2 DOMSB at 173. In response, USGen has argued that it is more effective to present a project to the community, and seek its support, after a specific site has been selected and preliminary design work and environmental studies have been completed. The Siting Board hereby clarifies its recommendations regarding community input into the site selection process, in light of USGen's comments.

The Siting Board is charged with providing for a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, & 69J. Consequently, in reviewing a petition to construct a generating facility, the Siting Board considers whether the proposed project is needed, whether it is viable (that is, whether it is likely to provide the needed energy resources) and whether it minimizes cost and environmental impacts. The Siting Board recognizes that local government support is critical to the viability of projects such as USGen's, and that the level of local government support therefore is an appropriate site selection criterion. Local officials may also be able to help project proponents identify and respond to potential cost and environmental issues associated with proposed sites.

However, the Siting Board believes that it may be useful for project developers to assess community, as well as local government, support prior to a final decision regarding a project site. In particular, timely discussions with potential residential, commercial and industrial neighbors may alert the developer to site specific issues that would affect the Siting Board's analysis of the cost or environmental impacts of the proposed project at a potential site. The Siting Board acknowledges that it is also possible to identify many such issues by screening potential sites based on surrounding land uses and the proximity of sensitive receptors such as schools and residents. If a developer chooses to delay its public outreach until late in the site selection process, as USGen has done in this instance, it should be extremely careful to give adequate weight to such considerations in its quantitative site evaluation process. It should also be prepared to incorporate additional mitigation into its project design, or to select another site for its project, if a new, and potentially serious, concern is raised when public outreach finally takes place.

With the exception of the development and application of the criterion for community input and the use of combined noise and visual criteria, the Company incorporated a systematic quantitative approach to comprehensively evaluate site attributes based on their relative importance for ensuring a least-cost, minimum-environmental-impact project consistent with previous decisions. Berkshire Power Decision, 4 DOMSB at 353; 1993 BECo Decision, 1 DOMSB at 57-58; MASSPOWER Decision, 20 DOMSC at 378-379. Therefore, the Siting Board finds that (1) the Company has developed a reasonable set of criteria for identifying and evaluating alternative sites, and (2) the Company has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures that it has not overlooked or eliminated any clearly superior site.

c. Geographic Diversity

In this section, the Siting Board considers whether the Company's site selection process included consideration of site alternatives with some measure of geographic diversity. The Company asserted that it has identified at least two noticed sites with some measure of geographic diversity (Exh. MPP-0, at 5-27). The Company noted that the sites are located 2.5 miles apart in Charlton (id.). However, the Company stated that the sites are separated by intervening terrain and that the surrounding uses of the two sites differed (id. at 1-9, 1-14, 5-27). Further, the Company indicated that one site is larger than the other, and that the noise, and visual impacts would be different at the two sites (id.).

The Siting Board requires that an applicant must provide at least one noticed alternative with some measure of geographic diversity. Dighton Power Decision, EFSB 96-3 at 35; Berkshire Power Decision; 4 DOMSB at 357; 1990 Berkshire Decision, 20 DOMSC at 181-182. The Siting Board notes that there is no minimum distance that is sufficient to establish geographic diversity in any given case. The Siting Council has previously determined that two sites in the same town can provide adequate geographic diversity for a generating facility review. Berkshire Power Decision, 4 DOMSB at 357; Enron Decision, 23 DOMSC at 130; NEA Decision, 16 DOMSC at 385-388. Further, in a transmission line case, the Siting Council stated that simple quantitative diversity thresholds were not appropriate for evaluating geographic diversity. New England Power Company, 21 DOMSC 325, 393 (1991). Here, the Company has provided two sites located 2.5 miles apart in the same town with varying environmental characteristics.

Accordingly, the Siting Board finds that the Company has identified at least two practical sites with a sufficient measure of geographic diversity.

3. Conclusions on Site Selection Process

The Siting Board has found that: (1) the Company has developed a reasonable set of criteria for identifying and evaluating alternative sites; (2) the Company has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures that it has not overlooked or eliminated any clearly superior sites; and (3) the Company has identified at least two practical sites with a sufficient measure of geographic diversity.

Accordingly, the Siting Board finds that the Company has considered a reasonable range of practical facility siting alternatives.

B. Comparison of the Proposed Facilities at the Primary and Alternative Sites

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed site for the facility is superior to the noticed alternative on the basis of balancing cost, environmental impact and reliability of supply. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; Berkshire Gas Company, 23 DOMSC 294, 324 (1991).

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; Eastern Energy Corporation, 22 DOMSC 188, 334, 336 (1991) ("EEC Decision"). A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; EEC Decision, 22 DOMSC at 334, 336.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276-277; EEC Decision, 22 DOMSC at 334, 336. Compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 277; EEC Decision, 22 DOMSC at 334, 336. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in specific facility proposals. Berkshire Power Decision, 4 DOMSB at 358-359; Silver City Decision, 3 DOMSB at 277; EEC Decision, 22 DOMSC at 334, 335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular review must be clearly described and consistently applied, to the extent practicable, from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination.[100] Berkshire Power Decision, 4 DOMSB at 359; Silver City Decision, 3 DOMSB at 277; 1993 BECo Decision, 1 DOMSB at 39-40, 154-155, 197. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Berkshire Power Decision, 4 DOMSB at 359; Silver City Decision, 3 DOMSB at 278; 1993 BECo Decision, 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental impacts of the proposed facilities at the Company's primary and alternative sites to determine (1) whether the Company's proposal minimizes specific sets of environmental impacts, and (2) which site is preferable based on each specific set of environmental impacts. The Siting Board then examines the cost of the proposed facility, including costs of further mitigation, in order to determine whether an appropriate balance would be achieved among conflicting environmental concerns and among environmental impacts, costs and reliability. Finally, the Siting Board compares the two sites to determine which is preferable with respect to providing a necessary energy supply for the Commonwealth at the least cost with a minimum environmental impact.

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100 The Siting Board notes that project proponents are required to submit to the Siting Board a description of the environmental impacts of the proposed facility. G.L. c. 164, § 69J. Specifically, Siting Board regulations require that a proponent of a generating facility provide a description of the primary and alternative sites and the surrounding areas in terms of: natural features, including, among other things, topography, water resources, soils, vegetation, and wildlife; land use, both existing and proposed; and an evaluation of the impacts of the facility in terms of its effect on the natural resources described above, land use, visibility, air quality, solid waste, noise, and socioeconomics. 980 C.M.R. § 7.04(8)(e).

2. Environmental Impacts

a. Air Quality

i. Applicable Regulations

The Company indicated that regulations governing air impacts of the proposed facility include National Ambient Air Quality Standards ("NAAQS") and Massachusetts Ambient Air Quality Standards ("MAAQS");[101] Prevention of Significant Deterioration ("PSD") requirements; New Source Review ("NSR") requirements; and New Source Performance Standards ("NSPS") for criteria pollutants (Exh. MPP-0, at 6-2). In addition, the Company indicated that the proposed facility would fall under Title IV Sulfur Dioxide Allowances and Monitoring regulations beginning in the year 2000 (Exh. MPP-4, att. 6, at 3-4).[102]

The Company indicated that under NAAQS, all geographic areas are classified as attainment, non-attainment or unclassified for six criteria pollutants: SO_2, PM-10, NOx, CO, ground-level ozone ("O_3") and lead ("Pb") (Exh. MPP-0, at 6-4). The Company further indicated that, although the Charlton area is classified as "attainment" or "unclassified" for SO_2, PM-10, NOx, CO and Pb, the entire Commonwealth of Massachusetts is in serious non-attainment for O_3 (id.).

The Company indicated that under PSD requirements, the proposed project must (1) demonstrate compliance with NAAQS, and (2) apply Best Available Control Technology ("BACT") to NOx and CO, pollutants for which emissions may potentially exceed 100 tons per year ("tpy") (Exh. MPP-4, att. 6 (rev.) at 3-2, 5-1).

The Company further indicated that under NSR requirements, the proposed facility must apply Lowest Achievable Emission Rate ("LAER") technology and emissions offsets to any directly emitted pollutant which is a precursor to O_3, and which the proposed facility

101 The MDEP has adopted the NAAQS limits as MAAQS.

102 The Company indicated that it will be required to obtain SO_2 allowances each year equal to the actual number of tons of SO_2 emitted to comply with Title IV Sulfur Dioxide Allowances and Monitoring regulations (Exh. MPP-4, att. 6, at 3-4; Tr. 9, at 24). The Company added that SO_2 allowances would be available for purchase through the Chicago Mercantile Exchange (Tr. 9, at 24-25).

may emit at levels greater than 50 tpy (Exhs. MPP-0, at 6-5; MPP-4, att. 6 (rev.) at 5-1). Thus, the Company must apply LAER technology to control NOx (see Table 3) (Exh. MPP-0, at 6-5). With regard to NSPS requirements, the Company indicated that emissions of regulated pollutants -- NOx and SO_2 for the proposed facility -- would fall significantly below those levels (Exhs. MPP-0, at 6-5; MPP-4, att. 6 (rev.) at 5-1).

In addition, the Company noted that the proposed facility would also incorporate BACT for SO_2, Pb, VOCs and air toxics, pollutants regulated as part of the MDEP air plans approval process (Exhs. MPP-0, at 6-6; MPP-4, att. 6 (rev.) at 4-1).

ii. Primary Site

(A) Emissions and Impacts

The Company indicated that the proposed facility would emit regulated pollutants, including criteria and non-criteria pollutants, and CO_2 (Exh. MPP-4, at 4-8 to 4-14). The Company asserted, however, that air quality impacts from the proposed facility would be minimized through the use of efficient technology, advanced pollution control equipment, clean fuels, and acquisition of NOx offsets (Exh. MPP-0, at 6-2, 6-22, 6-24). The Company also asserted that dispatch of the proposed project in preference to older, oil-fired generating plants would result in NOx, SO_2 and CO_2 displacement (id. at 6-24).

The Company estimated the quantity of pollutants that would be emitted from the proposed facility on the basis of information from government data centers, from manufacturers and vendors of equipment and from literature reviews (Exhs. MPP-4, att. 6, App. B; EFSB E-18(b) (rev. A); Tr. 8, 117-120). The Company provided calculations of air emissions for the proposed facility based on firing low-sulfur distillate oil for 720 hours and natural gas for the remainder of the year, both at 100 percent load (Exhs. MPP-4, att. 6, at 5-7, 5-9; MPP-14, att. 1, at 1).[103] The Company asserted that, because it would operate

[103] The Company also modeled a scenario in which natural gas was used for 365 days per year at 100 percent load (Exh. MPP-4, att. 6, at 5-7, 5-9).

as a merchant power plant, the proposed facility would require the ability to use oil for up to 720 hours per year (Exh. MPP-0, at 4-7 to 4-8).[104]

The Company maintained that its proposed facility would incorporate BACT for CO, PM-10, SO_2, Pb, and VOCs, as well as both BACT and LAER for NOx (Exhs. MPP-4, att. 6, at 4-8, 4-12; MPP-4, att. 6 (rev.) at 4-1 to 4-3). The Company further maintained that emission rates for non-criteria pollutants and sulfuric acid would also represent BACT (Exh. MPP-4, att. 6, at 4-12 to 4-13; MPP-4, att. 6 (rev.) at 4-3 to 4-4). In support of its contention that assumed facility emission rates would represent BACT and/or LAER for the identified pollutants, the Company provided information regarding control options for the proposed facility (Exh. MPP-4, att. 6, at 4-8 to 4-14).

The Company asserted that predicted air pollutant concentrations resulting from emissions from the proposed facility would be "insignificant" relative to ambient air quality standards (id.; Exh. MPP-14, att. 1, at 2). In support of its assertion, the Company provided local air quality modeling results[105] indicating that impacts of the proposed facility

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104 The Company asserted that without the ability to use oil for up to 720 hours per year, the proposed facility would lack the flexibility to meet need or to produce power at the lowest possible cost (Exh. MPP-0, at 4-7; MPP-7, at 8). The Company, however, also indicated its expectation that the proposed facility would burn oil for less than 720 hours annually (Tr. 8, at 112). Specifically, the Company estimated that its fuel contractor, USGenFS, would recall approximately ten days of natural gas in an average year, but that use of oil would likely occur less frequently because, in the event of a gas supply interruption, the Company would attempt to purchase energy on the spot market whenever economic (Exh. EFSB V-36a; Tr. 3, at 80, 87 to 89, 108; see Section II.C.3.b). The Company also stated that facilities operated by the Company have burned oil five or fewer days per year over the past five years (Tr. 8, at 112 to 113).

105 The Company indicated that it conducted screening-level modeling for all expected operating load conditions using the EPA SCREEN3 computer program (Exhs. MPP-4, att. 6, at 5-1; MPP-4, att. 6 (rev.) at 5-1). The Company stated that air pollutant concentrations were modeled at simple terrain locations (below stack height) and at complex terrain locations (terrain locations above plume height), and that intermediate terrain (terrain between stack top and plume height) was evaluated by comparing the SCREEN3 output for complex and simple terrain (id.). Results for the load

(continued...)

on ambient concentrations of criteria pollutants would be below SILs, assuming a stack height of 225 feet (Exhs. MPP-4, att. 6, at 5-1; MPP-4, att. 6 (rev.) at 5-2: EFSB E-50; EFSB E-52).

The Company presented a displacement analysis for the six-year period 2000 to 2005, indicating that regional emissions of SO_2, NOx and CO_2 would be less with construction and operation of the Millennium project than without the proposed facility. For the two criteria pollutants SO_2 and NOx, the six-year reductions in regional emissions would be several-fold larger than the proposed facility's own emissions over the same period. See Section II.4, above.

The Company also provided predicted ambient concentrations of air toxics from the proposed facility (Exh. EFSB E-36 (rev.)). The Company indicated that the concentrations were derived by scaling from the refined level ISCST2 and CTSCREEN model results for SO_2 (Exh. MPP-4, att. 3, at 7-20).[106] Based on its analysis, the Company stated that concentrations of air toxics from the proposed facility with a 225-foot stack would be below applicable standards[107] for all cases (Exhs. EFSB E-36 (rev.); MPP-0, at 6-17).

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[105](...continued)
conditions that produced the highest predicted concentrations were then compared to significant impact levels ("SILs") or ambient air quality standards/PSD increments (id.). Additional, more refined modeling techniques -- the EPA-recommended ISCST3 computer program (which incorporates hourly meteorological data) and the CTSCREEN complex terrain screening model -- were used to evaluate operating scenarios which resulted in predicted concentrations above SILs at the screening level (id. at 5-2). The Company indicated that for those scenarios where screening-level modeling resulted in emissions at above-SILs concentrations, refined analyses using the ISCST3 and CTSCREEN models showed that impacts of the proposed facility on ambient concentrations of criteria pollutants would be below SILs (id. at 5-14 to 5-20).

[106] Scaling was performed for each air toxic by dividing the SO_2 concentration by the SO_2 emission rate and then multiplying by the emission rate for each air toxic (Exh. MPP-4, att. 3, at 7-20).

[107] Applicable standards are MDEP Threshold Effects Exposure Limits ("TELs") and annual average Allowable Ambient Limits ("AALS") (Exh. MPP-4, att. 6, at 5-20 to 5-21).

The Company asserted, citing supporting documentation, that ambient concentrations from its proposed facility would have no negative impacts on sensitive vegetation and soils (Exh. EFSB E-27 (rev.)).

The Company also analyzed emissions from the cooling tower.[108] The Company stated that emissions from the cooling tower would consist primarily of tiny water droplets, or "drift", and water vapor (Exh. MPP-0, at 6-26). The Company stated that drift may contain chemicals and minerals contained in the cooling tower makeup water, including salts, VOCs, dissolved and suspended solids from the treated effluent from the Town of Southbridge ("Southbridge") Wastewater Treatment Plant ("WWTP"), plus trace quantities of biocide (sodium hypochlorite) and scale inhibitors added to the makeup water (Exh. EFSB E-25). The Company also stated that the proposed facility would incorporate high efficiency drift eliminators to minimize the impacts of drift, and that the drift emissions rates modeled by the Company would be supported by vendor guarantees (Exh. MPP-0, at 6-26; Tr. 5, at 32 to 33; Tr. 9, at 6-7).[109] Based on calculations made in support of its Air Plan Approval Application, the Company concluded that drift emissions would comprise a small fraction of total facility particulate emissions, would likely settle on site, and would

108 The visual and fogging/icing impacts of emissions from the cooling tower are discussed in Sections III.B.2.c and III.B.2.f, respectively, below.

109 The Company stated that since the identified metals would not be expected to volatilize from the cooling tower, it did not anticipate that the metals would be included in the water vapor plume in appreciable quantities (Exhs. EFSB E-25; MPP-4, att. 6, at 4-11 to 4-12). The Company stated that VOCs found in the cooling tower make-up water might be emitted, but that most VOCs would be volatilized in the wastewater treatment process at the Southbridge WWTP (Exhs. EFSB E-25; MPP-4, att. 6, at 4-10 to 4-11). The Company therefore anticipated that concentrations of VOCs, and thus their rate of emission from the cooling tower, would be insignificant (Exhs. EFSB E-25; MPP-4, att. 6, at 4-11; MPP-4, att. 6 (rev.) at 4-3).

have no significant environmental or health impacts (Exhs. EFSB E-25; MPP-4, att. 6, at 4-11 to 4-12; MPP-4, att. 6 (rev.) at 4-3; IP-RR-4).[110]

(B) Offset Proposals

The Company indicated that, to comply with non-attainment NSR for NOx, it would obtain NOx offsets at a minimum ratio of 1.2 to 1.0 (Exh. MPP-0, at 6-20). The Company noted that, as implemented by MDEP, offsets are generated by obtaining MDEP-certified Emission Reduction Credits ("ERCs") in an amount five percent greater than that needed based on the 1.2 to 1.0 ratio, i.e., a total ERC requirement of 1.26 times maximum facility NOx emissions (id.). The Company stated that, based on the expected facility emissions of 164 tpy, the proposed facility will require 211 tons of NOx ERCs per year (Exh. MPP-4, att. 6 (rev.) at 3-2, 4-5). The Company stated that it has identified potential sources of NOx offsets and that one likely source is New England Power Company shutdown credits from the discontinuation of operation of the NEC units (Exh. EFSB E-35; Tr. 9, at 22-23).[111]

The Company indicated that the proposed facility would emit 1,234,801 tpy of CO_2 and asserted that the CO_2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. EFSB E-39 (rev. A); EFSB E-40 (rev. C); Tr. 9, at 30). The Company argued that the displacement of 3.30 million tons of CO_2 from other facilities over the period 2000-2005, as a result of the operation and dispatch of the

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110 With respect to health impacts, the Company also explained that it anticipated no cultivation and dispersion of airborne microorganisms (legionella, for example) via the cooling towers due to the treatment of the primary source of water (from the Southbridge WWTP) for pathogen removal, the further chlorination of water at the proposed facility, the stress on any surviving bacteria of the aerosolization process and the general inhospitability of atmospheric conditions to bacterial survival (Exh. EFSB E-34).

111 Mr. Sellars stated that in order for the MDEP to grant a conditional air plans approval, the source of NOx offsets must be identified and that NOx offsets for the full permitted amount of intended emissions must be in place prior to facility operation (Tr. 9, at 23-24).

proposed facility, would contribute to the minimization of CO_2 impacts from the proposed facility (Exhs. MPP-13, at exh. 2.4-4 (rev. A); MPP-39; Tr. 1, 98; Tr. 9, at 26-29).

The Company proposed a CO_2 mitigation donation in the amount of $300,000 in the first year of facility operation (Exh. EFSB E-40 (rev. C); Tr. 9, at 30). The Company explained that this amount reflects an offset of one percent of emissions at up to $1.50 per ton and is consistent with the requirements of the Siting Board set forth in the Dighton Power Decision, EFSB 96-3 at 40 (Exh. EFSB E-40 (rev. C)).[112] However, the Company also indicated that a more appropriate amount would be $231,072 -- the net present value ("NPV") of one percent of emissions at $1.50 per ton over 20 years, assuming three percent inflation each year and a discount rate of ten percent (id.).

In support of its argument that the proposed facility would displace CO_2 emissions from other facilities, the Company provided a displacement analysis for the six-year period 2000 to 2005. The analysis showed a six-year reduction in regional CO_2 emissions of 3.30 million tons, representing 45 percent of the proposed facility's CO_2 emissions of 7.41 million tons over the same period. See Section II.A.4, above.

iii. Alternative Site

The Company stated that applicable air quality regulations, proposed facility emissions and control technologies, existing ambient air quality, offset proposals, and impacts to vegetation and soils would be the same for the proposed facility at either the primary or alternative sites (Exhs. MPP-0, at 7-2 to 7-6; MPP-14, att. 1, at 1 to 3, 7; EFSB E-27 (rev.)).

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112 The Siting Board notes that an offset of one percent of annual facility CO_2 emissions of 1,234,810 tons, at $1.50 per ton equals $18,510 per year or $370,200 for twenty years. The Company stated that the proposed donation, in 2000 dollars, is based on the equivalent donation accepted in the Dighton Power Decision, scaled to reflect the larger size of the proposed Millennium facility, and is a rounded net present value of the identified twenty-year amount, plus a significant premium to account for future price fluctuations (Exh. EFSB E-40 (supp. C)).

iv. Analysis

(A) Emissions and Impacts

The Company has demonstrated that emissions of criteria and other regulated pollutants from the proposed facility at either the primary or the alternative site would have acceptable impacts on existing air quality.

The record shows that the Company proposes to rely on oil-fired generation for limited periods, not to exceed 30 days per year, only when gas is unavailable and when it cannot economically meet its obligations through the market. The Siting Board notes a precedent for permitting 30 days of oil firing in a recent case. Berkshire Power Decision, 4 DOMSB at 440. However, the petitioner in that case represented that oil-fired operation would not exceed 100 hours in most years. Id. at 361, 440 to 441.

In addition, the Siting Board notes that petitioners in other recent gas-fired facility cases have proposed less than 30 days of oil-fired generation per year and as much as 365 days of gas-fired generation. Dighton Power Decision, EFSB 96-3, at 39; Cabot Decision, 2 DOMSB at 366; Altresco Lynn Decision, 2 DOMSB at 146.[113] Thus, while recognizing the constraints of the changing regulatory environment under which the proposed facility may operate, the Siting Board also notes that the estimate of annual oil-fired generation in the instant case is higher than in other recently reviewed cases.

The Siting Board further notes, however, the Company's testimony estimating the likely frequency of oil-fired operation of the proposed facility at no more than ten days in an average year and very probably less. The likelihood that the proposed facility will burn oil less than ten days is predicated on the Company's plan to purchase cost-effective energy on the spot market to replace at least some of the natural gas supply likely to be recalled by its fuel contractor, USGenFS. The Siting Board also notes the Company's testimony that

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113 Specifically, recent applicants before the Siting Board have estimated annual oil use as follows: Dighton Power estimated no oil use, Berkshire Power estimated between 64 and 100 hours, Altresco Lynn estimated 5 days and Enron expected no oil use. Dighton Power Decision, EFSB 96-3, at 29; Berkshire Power Decision, 4 DOMSB at 343; Altresco Lynn Decision, 2 DOMSB at 149; Enron Decision, 23 DOMSB at 114.

facilities operated by the Company have burned oil five or fewer days per year over the past five years.

Thus, the Siting Board relies on the Company's testimony and the record with respect to air quality impacts in concluding that the 335 day natural gas contract planned by the Company for the proposed facility, combined with the flexibility to burn oil for 720 hours per year when necessary, is likely to be a cost-effective means of achieving air quality impacts well below those predicted by the Company's model based on thirty days of oil firing.

The Siting Board expects the Company to limit its use of oil to 10 days or less in most years. In addition, the Siting Board encourages the Company to make every effort to limit its use of oil to 5 or fewer days, and to modify its fuel supply arrangements as necessary and possible to ensure that this goal is achieved.

Accordingly, the Siting Board finds that the air quality impacts of the proposed facility at the primary site would be minimized, consistent with minimizing cost.

The record shows that there is no significant difference between air quality at the primary and alternative sites with construction of the proposed facilities. Therefore, the Siting Board finds that the primary site would be comparable to the alternative site with respect to air quality.

(B) Offset Proposals

The Company has presented offset analyses for NOx and CO_2 -- pollutants which potentially contribute to regional ozone concerns and national and international climate change concerns, respectively. With respect to NOx, the Company has established that it has a viable plan in place to obtain NOx ERCs consistent with non-attainment NSR and MDEP requirements.

In the Dighton Power Decision, the Siting Board set forth a new approach to meeting CO_2 mitigation requirements that requires developers of generating facilities to make a monetary contribution within the early years of facility operation to one or more cost effective CO_2 offset programs to be selected in consultation with the Siting Board staff.

EFSB 96-3, at 42-43.[114] The Siting Board stated that it expected future contributions to be in the range of Dighton's contribution, which was based on an offset of one percent of facility emissions at $1.50 per ton, to be donated in the early years of the project. Id. at 43.

Here the Company has proposed a donation of $300,000 for CO_2 offsets, to be provided in one installment, in the first year of facility operation. The Company also presented a displacement analysis indicating that operation of the proposed facility would reduce regional CO_2 emissions by 3.30 million tons over the 2000-to-2005 period, offsetting 45 percent of the proposed facility's CO_2 emissions.

The Company asserts that the $300,000 donation amount was based on a doubling of the CO_2 mitigation requirement in the Dighton Power Decision as the proposed facility will emit approximately twice as much CO_2 as the Dighton Power facility. However, as noted above, the Company indicated that a more appropriate amount would be $231,072, the NPV of offsets over 20 years, calculated at one percent of emissions at $1.50 per ton.

The Siting Board notes that a contribution representing one percent of emissions at $1.50 per ton of CO_2, over 20 years, would equal $370,000. Therefore, consistent with the CO_2 offset requirement in the Dighton Power Decision, the Siting Board requires the Company to provide CO_2 offsets through a donation of $370,000 to be paid in five annual installments of $74,000 during the first five years of facility operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board. However, the Siting Board recognizes that the Company may choose to provide the entire donations within the first year of facility operation. If the Company chooses to provide the entire donation within the first year of facility operation, the CO_2 offset

[114] Previously, the Siting Board required developers to commit to a specific program of CO_2 mitigation, such as a tree planting or forestation program, designed to offset a certain percentage of emissions within the early years of facility operation. See Berkshire Power Decision, 4 DOMSB at 373-374.

requirement would be a donation in the amount of $305,000 to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board.[115]

Accordingly, the Siting Board finds that implementation of the foregoing NOx and CO_2 offset measures would be consistent with a minimization of environmental impacts with respect to air quality.

b. Water-Related Impacts

In this section, the Siting Board addresses the water-related impacts of the proposed facility, including: (1) the water supply requirements of the facility and related impacts on affected water supply systems and on wetlands and other water resources; (2) the water-related discharges from the facility, including wastewater discharges and discharges from on-site stormwater management facilities, and related impacts on wastewater systems and on wetlands and other water resources; and (3) the construction impacts of the proposed facility and associated interconnection facilities on wetlands and other water resources.

The Company stated that non-potable water supply needs for the proposed facility would average 2.5 million gallons per day ("mgd") with a maximum water demand of approximately 2.8 mgd (Exhs. MPP-0, at 6-52; MPP-4, att. 3 at 12-8; Tr. 7, at 95-96). The Company indicated that the largest volume of water will be used for an evaporative wet cooling tower, with most of the remainder used for other industrial processes on-site (Exh. MPP-0, at 6-52).[116]

The Company compared the use of the proposed evaporative wet cooling tower to four alternative cooling technologies -- a dry cooling system where no water would be required for an evaporative cooling process, two hybrid wet/dry cooling systems and a wet

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[115] The Siting Board notes that the donation of $305,000 is calculated on the NPV of the 20-year amount of $370,000, paid over 5 years, with an inflation rate of three percent and a discount rate of ten percent.

[116] The Company stated that the industrial processes that require water include: steam cycle make-up, quench water, NOx control under oil firing conditions only, and plant equipment service water (Exh. MPP-0, at 6-52 to 6-55).

surface air system (Exhs. EFSB E-63; EFSB E-146). The Company stated that, compared to alternative cooling technologies, the evaporative wet cooling tower has significant cost advantages, including higher plant efficiency, and lower noise and land use impacts (Exh. EFSB E-63).[117] The Company therefore concluded that the evaporative wet cooling tower alternative was the least cost cooling alternative consistent with minimizing impacts to the environment and the surrounding community (id.).

The Company asserted that the facility design maximizes conservation and recycling of water because cooling water requirements, which constitute the majority of facility water needs, will be met by use of secondary treated effluent (Exh. EFSB E-64).

The Company stated that the facility also would require up to 100,000 gallons per day ("gpd") of potable water for sanitary and steam cycle makeup needs (Exh. MPP-4, att. 3, at 12-8).

i. Primary Site

(A) Water Supply

The Company stated that its primary supply for non-potable water would be treated effluent from the Southbridge WWTP, and its supplemental backup supply would be withdrawal from the Quinebaug River (Exh. MPP-0, at 6-53). The Company stated that it has entered into a Memorandum of Understanding ("MOU") with the Town of Southbridge ("Southbridge") whereby Southbridge would make available up to 2.0 mgd of treated effluent to the facility (Exh. EFSB-E-64; Tr. 7, at 95-96).[118] The Company provided a 1996 engineering study completed by Camp, Dresser and McKee ("CDM") which indicated that

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117 The Company stated that there would be greater fuel use with dry cooling technology (Exh. EFSB E-63). The Company stated that additional fuel use would have greater environmental impacts than water use due to air quality impacts and due to the fact that water is a renewable resource (and the primary water source is already recycled) while fossil fuels are neither renewable nor recyclable (id.).

118 The Company indicated that the historical average daily flow from the WWTP is 2.01 mgd, with a historical minimum of 1.5 mgd and a historical maximum of 10.0 mgd (Exh. MPP-4, att. 3, at 12-9).

2.0 mgd from the Southbridge WWTP would be available for the proposed facility, except during summer drought conditions where between 1.0 and 2.0 mgd would be available (Exh. MPP-0, at 6-57). USGen noted that, for a consistent supply of this volume, the CDM study recommended that a holding tank be provided at the proposed facility and that facility effluent be returned to the headworks of the WWTP (id.).

The Company indicated that the balance of facility non-potable needs, and the full non-potable needs in the event of an interruption of the supply from the WWTP, would be obtained via withdrawal of Quinebaug River water through an existing intake structure located at the American Optical ("AO") facility in Southbridge (Exh. MPP-0, at 6-52). The Company stated that AO is permitted to withdraw up to 11.32 mgd of Quinebaug River water pursuant to a Massachusetts Water Management Act ("WMA") registration, but that AO withdraws less than its permitted amount (Exhs. MPP-4, att. 3 at 12-12; EFSB-E-66a; EFSB E-67).[119] The Company noted that the AO use of the Quinebaug River water for a once through cooling system is nonconsumptive (i.e., the withdrawal volume is returned as wastewater), while the Company's use would be largely consumptive (Tr. 7, at 119-120). Thus, the Company stated that although it has entered into a transfer agreement with AO for the right to use 2.5 mgd of AO's permitted water withdrawal and to use AO's intake structure, the MDEP has required the Company to file a surface water withdrawal permit pursuant to G.L. c. 21G for approval of its use of the AO-registered water withdrawal (Exhs. EFSB RR-24; EFSB V-47 (supp. B)-A at 3-7 to 3-8; Tr. 7 at 119). The Company indicated the permit application was filed in September 1997 and is currently under review by the MDEP (EFSB V-47 (supp. B)-A at 3-9).

USGen asserted that the Quinebaug River water supply would be reliable, even under dry summer, low flow conditions when use of Southbridge WWTP water could be restricted (Exhs. EFSB E-68; EFSB E-71(b) att. A at 8). USGen explained that the United States Army Corps of Engineers ("ACOE"), pursuant to an agreement with AO, will release upon

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119 The Company noted that AO's 1995 average withdrawal was 6.8 mgd and that its annual average withdrawal from 1991 to 1995 was 8.18 mgd (Exh. EFSB-E-67).

request up to 10.3 cubic feet per second ("cfs") from the upstream Brimfield reservoir (Exh. EFSB E-68).[120]

The Company acknowledged that the G.L. c. 21G permit likely would contain provisions in the form of a mitigation plan intended to ensure the protection of riverine resources (Exh. EFSB RR-26 (supp.A). The Company stated that it is currently preparing a mitigation plan that may include releases from the Brimfield reservoir by the ACOE (id.). However, the Company asserted that operation of the proposed facility would not have an adverse effect on the Quinebaug River and that any reasonable permit conditions relative to river flow could be met such that the facility operation would not be restricted (Millennium Initial Brief at 27; Exh. MPP-0, at 6-137). In support, the Company provided an analysis of existing conditions of the Quinebaug River and the projected impacts of the proposed facility on river flow, water quality and aquatic ecology within a study area extending from the Westfield Dam, located to the west of the AO facility to a point south of the Massachusetts/Connecticut border (Exh. MPP-0, at 6-61 to 6-107, Fig. 6.3-4).[121] The Company evaluated four facility water withdrawal scenarios[122] under four river flow conditions[123] and compared impacts to existing conditions without the operation of the

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[120] The Company indicated that this agreement has been in effect since 1962 and will terminate in 2012 when the Company will seek its renewal (Millennium Initial Brief at 27; Tr. 7, at 127-128). The Company further stated that, to its knowledge, AO has never been denied a requested release by the ACOE (Exh. EFSB-E-68, Tr. 7, at 127; Tr. 8, at 8).

[121] This analysis considered the effects of the water withdrawal, as well as the discharge of water from the facility to the Quinebaug River at the Southbridge WWTP discussed in Section III.B.2.b.i(B), below.

[122] The four facility operating scenarios are: (1) summer typical operating conditions; (2) winter typical operating conditions; (3) fuel oil firing condition; and (4) low WWTP makeup water conditions, in which use of AO withdrawals are maximized (Exh. MPP-0, at 6-101).

[123] The four river flow conditions are: (1) the average summer flow; (2) the extreme low flow -- the seven day average low flow which has a probability of occurring once (continued...)

proposed facility (id.). Based on this analysis, the Company concluded that the Millennium Power project would cause (1) a negligible change in the depth and velocity of flows in the Quinebaug River under all of the modeled scenarios,[124] and (2) minimal water quality changes for the lowest flow and average summer flows[125] (Exhs. MPP-4, att. 3 at 12-57 to 12-73). The Company also concluded that any such changes in river flow and water quality

[123](...continued)
in ten years ("7Q10"); (3) the two-year peak flow; and (4) the five-year peak flow (Exhs. MPP-0, at 6-63, 6-102; EFSB E-77).

[124] The Company stated that the maximum predicted change in river velocity would occur under 7Q10 flows for summer typical operating conditions and low WWTP makeup water conditions, where there would be a decrease of 0.10 feet/second, nine percent less than existing conditions (Exh. MPP-4, att. 3 at 12-57 to 12-58). The Company stated that the maximum change in river depth would also occur under 7Q10 flows, with the same operation conditions, where there would be a decrease of 0.14 feet, 10 percent less than existing conditions (id.).

[125] The Company stated that the various operating scenarios caused water quality changes under 7Q10 and average summer flow conditions (Exh. MPP-4, att. 3, at 12-67). The Company stated that the worst case scenario would be 7Q10 flow and low WWTP makeup water conditions (id. at 12-67 to 12-72). However, the Company noted that operation of the proposed facility under low WWTP make-up conditions likely would be during storm events due to low quality of WWTP water, but that increased stormwater runoff to the Quinebaug River likely would compensate for additional withdrawal of river water by the proposed facility (Exh. MPP-0, at 6-105). The Company stated that under 7Q10 flow and low WWTP makeup water, there would be: (1) a maximum increase in water temperature of 2.7 degrees Fahrenheit over the existing temperature of approximately 88 degrees Fahrenheit; (2) a very slight decrease in dissolved oxygen ("DO") concentrations; (3) an increase in total dissolved solids ("TDS") from under 25 mg/L to a maximum of 150 mg/L; and (4) a decrease in total phosphorous and copper from decreased WWTP discharge rates (Exh. MPP-4, att. 3, at 12-67 to 12-78). USGen noted that facility discharge would not alter the chemical constituents of the river due to rapid mixing of the discharge within the water stream (Exh MPP-0, at 105-106). USGen also noted that any increase in temperature would be associated with a reduction in upstream water available for mixing rather than an increase in outfall temperature (Exh. EFSB V-47 (supp. B)-A at 3-25).

would have negligible impacts on aquatic ecology (id. at 12-79 to 12-86).[126,127] The Company noted that a Draft Environmental Impact Report ("DEIR") filed in conjunction with a 1991 proposed cogeneration facility at the AO site identified the allowable safe yield of the Quinebaug River to be 16.5 cfs (Exh. MPP-4, Exh. 3, at 2-13, 12-55 to 12-56). The Company also noted that the withdrawal for the proposed Millennium facility would be well within such yield, but that the specific methodology used at that time for calculation of the allowable safe yield has been abandoned by the MDEP (id.).[128] USGen added that its analysis of projected impacts to the Quinebaug River is included in its DEIR and that the Certificate of the Secretary of Environmental Affairs on the DEIR ("Certificate") dated December 16, 1996, indicates that the Company's use of the AO-registered water is not likely to adversely impact the quality of the Quinebaug River (id.).

The Company stated that the proposed facility would access non-potable water via a new water pipeline (Exh. MPP-0, at 1-12). USGen indicated that the new water pipeline would begin at the Southbridge WWTP, travel overland near the Quinebaug River to the AO intake structure, and then traverse industrial property and roadways to reach the primary site

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126 The Company stated that its analysis showed that there would be small shifts from glide habitats to rifle habitats in limited areas for limited periods of time, but argued that these shifts would be within normal ranges of stream variation, and that there would be no increase in eutrophication or significant shifts in the types and quantity of aquatic vegetation or fish (Exh. MPP-4, att. 3, at 12-79 to 12-82). In addition, the Company stated that temperature changes would be within the range of normal temperature variations, the minimal changes in DO levels would not constrain or stress aquatic biota, and that the increase in TDS would not adversely impact aquatic biota, given that fresh water species tolerate a wide range of TDS concentrations (id. at 12-82 to 12-85).

127 In response to comments of the State of Connecticut Department of Environmental Protection concerning potential downstream impacts to the Quinebaug River in Connecticut, the Company responded that minimal impacts to water flow, quality and ecology within its study area would be further attenuated downstream in Connecticut (Exh. EFSB V-47 (supp. B)-A at 3-54 to 3-57).

128 The Company indicated that the DEIR analysis of the cogeneration facility's proposed consumptive use of 0.634 mgd found that impacts to the Quinebaug would not be significant (Exh. MPP-4, exh. 3, at 12-14).

(Exh. MPP-0, at 1-13; MPP-14, att. 2). The Company stated that it is has applied for Sewer Connection and Extension Permits from the MDEP in conjunction with its water withdrawal permit under M.G.L. Chapter 21G (Exh. EFSB RR-26 (supp. A).[129]

In addition, the Company stated that up to 100,000 gpd of potable water would be supplied by the Town of Southbridge (Exh. MPP-4, att. 3, at 12-8). The Company stated that the Town of Southbridge has expressed its intent to provide potable water and to allow a tie-in to an existing water pipeline located to the west of Route 169 in the site vicinity (id. at 12-13).

(B) Water-Related Discharges

The Company indicated that the maximum wastewater discharge from the proposed facility would be 1.0 mgd, and that wastewater would flow from the proposed facility to the influent side of the Southbridge WWTP via a new pipeline to be constructed along the same route as the water supply pipeline from the WWTP and AO (Exh. MPP-0, at 1-6 to 1-7, 6-57, 6-60). The Company noted that the wastewater would be retreated in the Southbridge WWTP and discharged to the Quinebaug River (id. at 6-53 to 6-56; Exh. EFSB E-71(b), att. A at 8). The Company indicated that the CDM study found that the Southbridge WWTP

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129 Mr. Sellars explained that the Sewer Connection and Extension Permit would apply to the water supply pipeline from the Southbridge WWTP to the proposed facility (Tr. 7, at 148-149). He stated that an Industrial Users Discharge Permit, which would apply to the wastewater return pipeline from the proposed facility to the Southbridge WWTP and the discharge to the Southbridge WWTP, also would be required (id. at 148).

would be capable of accepting a 1.0 mgd[130] return flow from the proposed facility until the flow from Southbridge reaches 8.0 mgd (id. at 6-57).[131]

USGen stated that the wastewater discharge to the Southbridge WWTP would consist primarily of cooling tower blowdown and filter backwash, but would contain chemicals used to treat facility process water (id. at 6-52 to 6-55; Exhs. EFSB E-75, EFSB E-32(a), EFSB RR-25).[132] The Company indicated that the Southbridge WWTP is currently meeting its National Pollutant Discharge Elimination System ("NPDES") permit limits and that it would continue to meet its permit limits while accommodating the wastewater discharge from the proposed facility (Exh. EFSB E-74). USGen added that its analysis of the projected impacts of the proposed facility on the Quinebaug River flow (described above in Section III.B.2.b.i.(A)), included consideration of the impact of the discharge of the facility wastewater through Southbridge WWTP to the Quinebaug River and, as noted above, concluded that the impacts, including impacts to water quality, would be minimal.

The Company indicated that a stormwater management program has been designed to protect surface water resources, vernal pools and other wetland resources on site

130 The Company noted that an average daily discharge flow in excess of 1.0 mgd would not be essential under any operating or maintenance condition and that a greater discharge flow, beneficial under certain conditions such as maintenance outages, would not be discharged unless it was acceptable to the Southbridge WWTP (Exh. EFSB E-73c).

131 USGen indicated that for the last eight years, the average flow to the Southbridge WWTP has been 2.0 mgd and that Southbridge is not projecting large increases in the average daily flow in the near future (Exh. EFSB E-73(b)). The Company noted that facility wastewater flow potentially could exceed the Southbridge WWTP's hydraulic capacity under storm conditions where the Southbridge WWTP was receiving heavy stormwater infiltration (Tr. 7, at 144-145). However, the Company indicated that, under such storm conditions, it would coordinate operation with the Southbridge WWTP and hold cooling tower blowdown if necessary (Exh. EFSB V-47 (supp. B)-A.

132 The Company noted that pretreatment of wastewater, with the exception of oil/water separators, would not be required prior to discharge to the Southbridge WWTP (Exh. EFSB E-75).

(Exh. MPP-4, att. 3, at 11-1 to 11-12; Tr. 8, at 29, 37). The Company explained that measures are included in the design of the proposed facility to ensure that post-construction peak storm water flows and stormwater nutrient and sediment loading would be comparable to pre-construction conditions (id. at 11-5 to 11-12). The Company stated that these measures include a stormwater management basin to contain stormwater, rip-rap ditches and level spreaders to prevent stormwater from reaching erosive velocities in the access driveway drainage ditches, and drainage swales to collect runoff and to divert it from disturbed areas (id. at 11-5 to 11-6).[133] In addition, USGen stated that it would implement "Best Management Practices,"[134] including erosion control measures, vegetation programs, periodic inspections, good housekeeping procedures, and employee training, to further mitigate the effects of stormwater runoff (id. at 11-8 to 11-11).

(C) Construction Impacts

The Company maintained that construction of the proposed facility would have not have an adverse effect on water resources, including on-site wetlands, Cady Brook,[135] the Quinebaug River and associated wetlands along the route for the water supply and wastewater return pipelines, and existing groundwater resources in the vicinity of the site (Exhs. MPP-0, at 6-36; MPP-4, att. 3, at 10-4 to 10-49; EFSB E-80).

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133 USGen noted that a benefit of the proposed facility is that the sediment level and total phosphorus currently reaching wetlands will be decreased by the stormwater management measures (Exh. MPP-4, Exh. 3, at 11-11 to 11-12; Tr. 8, at 38-39).

134 The Company stated that "Best Management Practices" include activities and management practices that prevent or reduce pollution of "waters of the United States" (Exh. MPP-4, att. 3, at 11-8).

135 USGen indicated that Cady Brook traverses the eastern portion of the site and that facility grading will be within 200 feet of Cady Brook (Exhs. MPP-0, at 1-11; MPP-4, att. 5, at 3-1). The Company stated that, although the project is not subject to the newly-enacted Rivers Protection Act, construction within the 200-foot riverfront areas would comply with the substantive provisions of that Act (Exh. EFSB-E-80; Tr. 8, at 36-37).

The Company identified eight on-site wetlands,[136] and stated that impacts would be limited to (1) temporary disturbance of 3,500 square feet of wetlands associated with the installation of the natural gas and oil pipeline interconnections,[137] and (2) permanent alteration of 1,000 square feet of wetlands associated with the construction of the access road to Sherwood Lane (Exhs. MPP-0, Appendix B; MPP-4, att. 3 at 10-4 to 10-22, 10-29; EFSB V-47 (supp. B)-A at 3-15). The Company stated that wetlands disturbed by the installation of the pipeline interconnections would be restored and stabilized and that wetlands altered by the access road construction would be replicated on a one to one basis (EFSB V-47 (supp. B)-A at 3-15).

The Company stated that erosion and sedimentation controls and other construction techniques would minimize wetland impacts (Exh. EFSB V-47 (supp. B)-A at 2-20 to 2-21). The Company stated that on-site wetland impacts were also minimized by design considerations including: (1) installation of the gas and oil pipeline interconnections along a common ROW for the majority of the route; (2) construction outside wetland areas to the greatest extent possible; (3) placement of the pipeline interconnections close as possible to the edge of the existing NEP ROW while taking into account NEP concerns about transmission line safety; and (4) maintenance of a permanently cleared pipeline corridor at the narrowest feasible width -- 30 feet (Exh. EFSB E-82 (rev. A)). Exhs. MPP-14, at 6 to 7; EFSB E-84, EFSB E-86).[138]

The Company also indicated that, in order to conform to the industrial zoning of the area, Sherwood Lane, a Town-owned road would be widened (Exh. MPP-4, exh. 3,

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136 The Company indicated that two of the wetland areas are classified as isolated land subject to flooding and are subject only to federal jurisdiction, as they are not large enough to be regulated under the Massachusetts Wetlands Protection Act (Tr. 8, at 15-16).

137 The Company noted that construction of the electric transmission line interconnect would not involve alteration of any wetland areas (Exh. EFSB E-86).

138 USGen noted that the TGP would maintain the ROW and that herbicides or other chemical agents would not be used for ROW maintenance (Exh. EFSB E-151).

at 10-29).[139] The Company indicated that the road widening could entail the permanent alteration of 2,125 square feet of wetlands abutting the roadway (Exh. EFSB V-47 (supp. B)-A at 3-7).[140] The Company noted that remaining wetland areas along the roadway would be protected from construction impacts by the installation of siltation barriers (Exh. MPP-4, att. 5, at 3-1).

The Company indicated that marbled salamanders, classified as a "threatened" species in Massachusetts under the Massachusetts Endangered Species Act, have been observed in a vernal pool within a wetland area located close to the proposed facility footprint (Exh. EFSB E-95A; Tr. 8, at 27). The Company indicated that the Massachusetts Division of Fisheries and Wildlife Natural Heritage and Endangered Species Program ("NHESP") requires a conservation plan which demonstrates that construction of the proposed facility would result in a long-term net benefit to the marbled salamander (Exh. INT-5 (rev. A); Tr. 8, at 27-31). The Company stated that its conservation plan which has been presented to the NHESP includes: (1) permanent protection for the vernal pool and undeveloped mature forest area;[141] (2) construction of three experimental vernal pools creating additional breeding populations; and (3) funding for research on marbled salamanders and evaluation of the experimental vernal pools (Exh. EFSB RR-27 (supp. A).[142] In addition the Company stated that it would

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139 USGen indicated that Sherwood Lane improvements would be conducted jointly by the Company and the Town of Charlton (Exh. EFSB V-47 (supp. B)-A at 2-11).

140 The Company stated that, because the Town of Charlton does not own sufficient property in the vicinity to allow for wetland replication, the Company has developed an on-site wetland replication plan which will be submitted to the Charlton Conservation Commission for approval (Exh. EFSB V-47 (supp. B)-A at 3-7).

141 USGen indicated that it would place a conservation easement on approximately 55 acres of mature forest -- 20 acres on-site adjacent to the vernal pool and 35 acres off-site located west of the transmission line under a Company option to purchase (Exh. EFSB RR-27 (supp. A)).

142 USGen indicated that NHESP had requested additional information in order to complete its review of the Company's conservation plan and that the NHESP would issue a Conservation Permit for the proposed facility when the Company's conservation plan was accepted (Exhs. EFSB RR-27 (supp. A); INT-5 (rev. A)).

relocate the switchyard to minimize facility encroachment on preferable habitat for the marbled salamander (Exh. EFSB V-47 (supp. B)-A at 2-11; Tr. 8, at 28-29).

The Company also stated that the proposed water supply and wastewater return pipelines, which connect the site to the AO intake structure and the Southbridge WWTP, will be constructed within existing roadways except for one overland segment along the Quinebaug River between AO and the Southbridge WWTP (Exhs. MPP-0, at 1.4-3; MPP-14, at 7; MPP-4, att. 3 at 10-31). The Company stated that the wetland impact of the pipelines would involve the temporary disruption of 1800 square feet of an intermittent stream and its associated wetland within the overland portion of the route (Exh. EFSB V-47 (supp. B)-A at 2-8). The Company added that following installation of the pipelines, the surface would be returned to its original contours and seeded (id.).

After the close of hearings, the Company indicated that an area of estimated habitat for the wood turtle, a Massachusetts species of special concern, is located in the vicinity of the AO intake structure and that it would be necessary for the proposed water supply and wastewater return lines to traverse this area (Exh. EFSB RR-27 (supp. B)). The Company stated that construction of the pipelines through this area would result in the temporary disturbance to potential wetland and upland habitat for the wood turtle (id.). The Company stated that it would propose a mitigation plan to the NHESP that is essentially identical to a recently approved plan for an interstate pipeline proposed in Massachusetts (id.).[143]

Finally, USGen stated that three wells designated as public water supply wells are located within one-half mile of the site and that portions of the facility footprint are located within the Interim Wellhead Protective Area ("IWPA") for wells for two businesses located in the vicinity of the site (Exh. MPP-0, at 6-33, 6-36). However, the Company maintained that groundwater resources would be protected by the design of storage areas and extensive

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[143] The Company indicated that the mitigation plan would include: (1) pre-construction surveys by a qualified biologist; (2) capture and relocation of any observed wood turtles to an adjacent suitable area; (3) construction of temporary silt fencing to prevent migration of wood turtles into the construction area; and (4) daily trench inspection and construction monitoring by a qualified biologist (Exh. EFSB RR-27 (supp. B)).

spill prevention and containment measures, consistent with federal and state requirements, that will be incorporated into the design and operational plans of the proposed facility (id. at 6-36). See Section III.B.2.f.i, below.

ii. Alternative Site

The Company also evaluated the impacts of the proposed facility on water resources at the alternative site (Exh. MPP-0, at 7-7 to 7-14). The Company indicated that water supply and discharge requirements would be the same at the alternative site, and that therefore the predicted impacts to the Quinebaug River would be the same as at the primary site (id. at 7-7). The Company also indicated that stormwater management practices would be similar for both sites (id. at 7-13 to 7-14). In addition, the Company indicated that the wetlands impacts anticipated for construction of the water and wastewater lines would not result in any significant impact or direct alteration of wetland resources (id. at 7-10 to 7-13).

The Company stated that, as with the primary site, no construction would be required within wetland areas for the facility footprint (id. at 7-12). However, the Company stated that approximately 10,800 square feet of wetlands would be disturbed for the construction of the natural gas pipeline and that temporary and limited permanent alteration of wetlands would be required for the electric interconnection, including installation of three transmission structures in wetlands resulting in the permanent alteration of 800 square feet of wetlands (id. at 7-12). The Company added that there are no known public water supply wells within one-half mile of the alternative site and that the alternative site is not located within the IWPA of any public water supply wells (id. at 7-13).

iii. Analysis

The record demonstrates that the Company's water supply plan minimizes the use of potable water at both the primary and alternative site by relying on treated effluent from the Southbridge WWTP and additional back-up supplies from the Quinebaug River via an existing intake structure. The record also demonstrates that the Company's water supply plan is likely to be viable. An independent engineering study has confirmed the ability of the

Southbridge WWTP to supply treated effluent in the required amounts and the Southbridge WWTP has agreed to supply treated effluent. In addition, AO has agreed to transfer the withdrawal rights for the Company's full water needs under AO's registered withdrawal and the Company has applied to the MDEP for a water withdrawal permit under G.L. c. 21G. The record further demonstrates that dry cooling would significantly reduce the water supply needs of the proposed project but that dry cooling would increase costs, and also would produce increases in noise and land use impacts, and decrease the efficiency of the proposed facility.

The record also demonstrates that the Company's water supply plan would convert a currently-registered nonconsumptive use of Quinebaug River water to a consumptive use, would divert treated effluent from the Quinebaug River and would return facility effluent containing cooling treatment additives to the Quinebaug River via the Southbridge WWTP. Thus, the Company's water supply plan raises concerns regarding potential impacts to the Quinebaug River. However, the Company provided a comprehensive analysis of potential impacts of its water supply plan to the Quinebaug River. This analysis indicated that impacts to Quinebaug River flow would be limited, with changes in river depth and velocity of no more than 10 percent under the worst case scenario. As noted in the Certificate on the DEIR, the analysis also indicates that the Company's use of the AO-registered water is not likely to adversely impact the quality of the Quinebaug River. The Siting Board recognizes that the worst case scenario -- extreme low river flow combined with low WWTP makeup -- would be an unlikely or short-lived event given that low WWTP makeup would probably occur during storm events which, in turn, would result in greater runoff to the river. The Siting Board also notes that the MDEP will review potential impacts to the river within the context of the G.L. c. 21G permit application and may require maintenance of minimum flows and/or post operational monitoring. The Siting Board notes that it has previously examined the effect of a generating facility's use of treated effluent and associated water withdrawals on waterways and approved that facility subject to development of a resource monitoring, assessment and mitigation plan, to be developed in conjunction with the MDEP. See Enron Power Decision, 23 DOMSB at 171-72 (1991).

In a previous review of a generating facility that proposed to use an existing potable water supply for an evaporative wet cooling tower rather than air cooling technology, the Siting Board found that impacts with respect to water supply had not been minimized due to the use of wet cooling. See, Berkshire Power Decision, 4 DOMSB at 385. The Siting Board then reviewed the balance among water use impacts, noise impacts, and cost, and determined that in that case the use of evaporative cooling would minimize environmental impacts consistent with the minimization of costs. Id. at 441.

Here, the Company has developed a water supply plan that does not require use of an existing potable water supply for a wet cooling tower and has provided information describing the higher costs and increased land use and noise impacts associated with air cooling technology. In addition, the Company has provided a comprehensive analysis which indicates that the Company's water supply plan will not have a significant impact on the Quinebaug River. The Company's analysis is supported by the Secretary of Environmental Affairs and will be further reviewed by the MDEP. The Company acknowledges that MDEP likely will impose conditions regarding maintenance of minimum stream flows and/or post operational monitoring. The Siting Board directs the Company to provide a copy of the MDEP approval of G.L. c. 21G permit, together with any attached conditions and a detailed explanation of how all conditions will be met.[144]

Accordingly, the Siting Board finds that, with compliance with the aforementioned condition, the environmental impacts of the proposed facility at the primary site would be minimized with respect to water supply.

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[144] The Siting Board's consideration of the proposed facility assumes implementation of USGEN's effluent/river water use plan. The Siting Board notes that this plan could be modified as a result of conditions imposed by the MDEP in its G.L. c. 21G permit. In Section IV, below, the Siting Board requires USGen to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into that issue. In accordance with this requirement, the Company shall notify the Siting Board if proposed changes in the water supply plan would result in other than minor variations in the environmental impacts, cost or reliability of the proposed facility.

The Company has demonstrated that impacts to all water resources resulting from wastewater and stormwater discharge from the proposed facility would be minimized at the primary site. The Company also has demonstrated that wetlands impacts associated with all interconnections would be minimized at the primary site for the proposed facility as designed. However, the record demonstrates that additional measures may be required to protect the vernal pool containing the marbled salamanders. In order to receive a Conservation Permit from the NHESP, the Company must receive approval of a conservation plan which demonstrates a long-term net benefit to the marbled salamander. The Siting Board directs the Company to provide a copy of the Conservation Permit with attached conditions and a detailed explanation of how all conditions will be met.

In addition, the record demonstrates that construction of the water supply and wastewater return lines will traverse an area of estimated habitat for the wood turtle, a Massachusetts species of special concern. The Company will submit a mitigation plan to the NHESP which is comparable to a recently approved plan for interstate pipeline construction in Massachusetts. The Siting Board directs the Company to provide a copy of the approval of this plan by the NHESP with an explanation of how any attached conditions will be met.

Accordingly, the Siting Board finds that, with compliance with the aforementioned condition, the impacts from water-related discharges and construction-related impacts of the proposed facility at the primary site would be minimized.

Finally, in comparing the primary and alternative sites, the Siting Board finds that impacts of the proposed facility with respect to water supply and related water resources would be comparable at the primary and alternative sites. The Siting Board also finds the impacts from water-related discharges at the primary site would be comparable to those at the alternative site.

With respect to construction impacts to wetlands, the record demonstrates that temporary disturbance of wetlands would be greater at the alternative site while permanent alteration of wetlands would be greater at the primary site with consideration of the construction of the site access road. Approximately 1,000 square feet of wetlands would be permanently altered and 3,500 square feet would be temporarily disturbed at the primary site.

In addition, construction of the site access road would require additional permanent alteration of approximately 2,125 square feet of wetlands. The Siting Board notes that it is appropriate to consider the wetlands impacts of site access road construction as a project impact, since this upgrade to the Town-owned road is required in order for the proposed facilities to be constructed at the primary site. Approximately 10,800 square feet of wetlands would be temporarily disturbed at the alternative site, with the permanent alteration of 800 square feet of wetlands. In addition, although the Company must receive a Conservation Permit which must demonstrates a long-term net benefit to the marbled salamander, no threatened species have been identified on the alternative site. Finally, impacts to wetlands and wood turtle habitat due to construction of the water supply and waste water return lines to the primary and alternative sites would be comparable.

Given the greater permanent alteration of wetlands and the on-site presence of a threatened species at the primary site, the Siting Board finds that the alternative site would be preferable to the primary site with respect to construction impacts to wetlands.

Accordingly, the Siting Board finds that, on balance, the alternative site would be preferable to the primary site with respect to water-related impacts.

c. Visual Impacts

i. Description

The Company submitted a comprehensive evaluation of potential visual impacts of the proposed facility at the primary and alternative sites (Exhs. MPP-0, at 6-152 to 6-166, 7-24 to 7-35; MPP-4, att. 3 at 6-1 to 6-15; EFSB E-54 to EFSB E-62). As part of its evaluation at each site, the Company conducted a viewshed analysis of the surrounding area (Exh. MPP-0, Figs. 6.7-2,.7.7-1). For each viewshed analysis, the Company identified and mapped areas within two miles of the proposed sites from which the 225 foot stack[145] of the facility might be visible (id.). From areas where the stack had the potential to be visible, the

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[145] The Company indicated that it did not consider a stack lower than 225 feet, because such a stack would be lower than GEP height and would result in increased ground level air pollutant concentrations above the EPA-defined SILs (Exh. EFSB E-21).

Company selected a number of visual receptor locations on the basis of land use, proximity to site, and potential of impact; the Company added visual receptor locations at the request of the Staff (id. at 6-154, 7-25 to 7-26, Figs. 6.7-2, 7.7-1, Exhs. EFSB E-55 to EFSB E-59; EFSB E-62).[146] The Company presented views both with and without deciduous foliage based on photographs taken from the identified receptor locations looking toward the proposed facility (Exhs. MPP-0, Figs. 6.7-4, 6.7-5; EFSB E-58). The Company then generated a computer-developed perspective of the facility and stack as they would appear from a given receptor and superimposed the perspective on the associated photograph (Exhs. MPP-0, Figs. 6.7-2 to 6.7-12, 7.7-2 to 7.7-9; EFSB E-55 to EFSB E-59; EFSB E-62).

The Company also conducted a plume analysis to assess the conditions and frequency under which plumes were likely to emanate from the main stack and cooling tower of the proposed facility, and the distance from the proposed facility to which visible plumes would likely extend (Exh. MPP-14, att. 1, at 4-6). Based on its analysis, the Company indicated that, over the course of a year, during daylight hours, plumes from the main stack with lengths of 50 meters or more would be visible approximately 20 percent of daylight hours and plumes of 100 meters or more would be visible approximately six percent of daylight hours (id., Table 6.2-10 (rev. A)). The Company also indicated that plumes from the cooling tower of 50 meters or more would be visible approximately 50 percent of daylight hours and that plumes of 100 meters or more would be visible approximately 20 percent of daylight hours (id.). The Company further indicated that plumes from the main stack and cooling tower would be most visible during the winter season and least visible during the summer season (id.). In addition, the Company stated that its plume analysis showed that fog and/or precipitation would be present 73 percent and 52 percent of the time that main stack and cooling tower plumes of 100 meters or longer were present, reducing the visibility of the plumes (Exh. MPP-14, att. 1, at 4). The Company indicated that, while plumes also

[146] The Company indicated that the visual receptor locations for each site also included locations from which the stack would not be visible in order to verify the computer generated analysis and to present a balanced assessment of the overall visual impact (Exh. MPP-0, at 6-154, 7-24).

would be created during nighttime hours, a plume would generally be far less noticeable at night due to the lack of illumination (Tr. 9, at 90-91). The Company indicated that plume visibility above the stack exit location would be the same for the primary and alternative sites (Exh. EFSB E-26).

ii. Primary Site

The Company asserted that the proposed facility at the primary site would be screened from view in most directions and that, where the facility would be visible, its effect would be generally limited by terrain, vegetation and distance (Exh. MPP-0, at 156). In addition, the Company stated that the view of the proposed facility immediately adjacent to the site would be consistent with the industrial zoning of the site and its surroundings (id.).

The Company indicated that both the facility structures and the stack would be visible from certain areas to the east of the facility, including portions of Harrington Road in Charlton, and the east side of Route 169 at Sherwood Lane (id. at 6-152, 156, Figs. 6.7-7, 6.7-8, 6.7-12). The Company indicated that approximately six residences on Harrington Road likely would have pronounced views of the proposed facility and that it would be difficult to screen views of the proposed facility from this area (Exh. MPP-0, at Fig. 6.7-8; Tr. 9, at 79-80, 93, 99-101).[147] The Company also stated that the facility structures and the stack would not be visible from the west and that in other directions, visibility would be limited to the top of the stack (Exh. MPP-0, at 156). However, the Company indicated that from some vantage points where the facility itself would not be visible, such as the golf course to the northwest of the site, plumes, when present, would be visible (Tr. 9, at 94-98).

The Company provided a copy of the Central Upland section of the most recent Massachusetts Landscape Inventory prepared by the Massachusetts Department of

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[147] USGen stated that on-site plantings would not substantially screen views of the proposed facility from Harrington Road (Tr. 9, at 79-80). The Company also stated that, due to the terrain, it would be difficult to screen views with off-site plantings but that plantings close to the homes or window awnings might screen views to some degree (id. at 99-100).

Environmental Management ("MDEM"), which indicates that three areas designated by the MDEM as "distinctive" or "noteworthy" potentially would have views of the proposed facility (Exh. EFSB E-60(a), att. A, E-60(b)).[148] However, the Company stated that the proposed facility would be visible from only one of the three areas, located nearly two miles northeast of the site, and that visibility would be limited to the distant stack, backed by the existing treeline (Exhs. EFSB E-60(b); EFSB E-55(c); MPP-0, Fig. 6.7-2; Tr. 8, at 89-97). The Company maintained that measures to minimize the visual impact of the facility have been included in facility layout, design, lighting and landscaping (Exh. MPP-0, at 152-153; Tr. 9, at 84-85). The Company stated that the cooling tower would be placed to the west of the HRSG[149] and the main building, thus obstructing the view of the cooling tower from Route 169, and that architectural walls would be placed around the HRSG to enhance its appearance (Exhs. EFSB E-49; EFSB E-51; Tr. 9, at 85). The Company noted that the location of the cooling tower and placement of the architectural wall around the HRSG also would minimize the noise impacts of the proposed facility (Exh. EFSB E-51). The Company also noted that the possible placement of a roof on the HRSG structure, considered as part of an option to achieve higher noise control (see Section III.B.4.a, below) would necessitate increasing the stack height by 50 feet, thus expanding the areas where the proposed facility would be visible (Tr. 8, at 102-106). The Company estimated that within one-half mile of the site, approximately 10 to 50 residences would be affected by an increased stack height (id. at 108).

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148 The Company stated that classification of the area relative to the Massachusetts Landscape Inventory was not specifically taken into account in the site selection process but that overall visual impacts of the proposed facility at primary and alternative sites was a criteria used in the selection of the primary site over the alternative site (Tr. 8, at 100).

149 The Company stated that the location of the cooling tower to the west of the primary generation building would minimize the impact of the cooling tower on views from residences along Harrington Road to the east (Tr. 9, at 85). However, the Company added that a cooling tower plume of 50 feet or greater would be noticeable from these residences (id.).

USGen also stated that all structures would be painted a neutral color to blend the site structures into the natural appearance of the surrounding area to the maximum extent possible, and that the stack and associated catwalks and ladders would be painted a uniform color consistent with the facility color scheme (Exhs. EFSB E-49; EFSB E-50; EFSB E-51). The Company further stated that the site lighting plan had been designed in coordination with the Charlton Planning Board, that there would be no upward-facing lights, and that the amount of lighting would be minimized (Tr. 9, at 84). The Company indicated that at night, facility lights would be visible from certain locations, but would not cast any noticeable light on any residence (id. at 85).[150] In addition, in obtaining Site Plan approval, the Company stated that it agreed with the Town of Charlton Planning Board to provide on-site landscaping (id. at 79; Exhs. MPP-11, at 10; EFSB E-95 (rev. A)). Further, during the hearings, the Company expressed its willingness to provide off-site shrubs, trees, or window awnings to residents within a half mile of the site who have a view of the facility, if requested by residents (Tr. 9, at 98-101).

iii. Alternative Site

The Company asserted that although the visual impacts of the proposed facility at the alternative site would be minimized using the same layout and landscaping design as the primary site, visual impacts would be greater at the alternative site due to its higher elevation and location closer to more densely populated areas surrounding the center of Charlton (Exh. MPP-0, at 7-26; Tr. 9, at 102). The Company maintained that the stack or facility would be visible from most directions around the alternative site, would be visible to a greater number of observers than at the primary site, and that although views would generally be limited to the stack and screened by vegetation, views of the proposed facility would still be more pronounced than at the primary site (Exhs. MPP-0, at 7-26, 7-35, Figures 7.7-2 to 7.7-9; EFSB E-59, atts. A, B, C; Tr. 9. at 10).

150 There will be a steady red beacon at the top of the stack as required by the project's FAA approval (Tr. 9, at 84-85).

With respect to the Massachusetts Landscape Inventory, the Company stated that the upper portion of the stack would be visible within the area designated as "distinctive" and within the two areas designated as "noteworthy" (Exh. EFSB E-60B). The Company indicated that the stack would generally be visible from such areas as a distant view, with its impact reduced by dense vegetation and topography, but also indicated that the nearest landscape area extends to within approximately one-half mile from the facility footprint (Exhs. EFSB E-144; MPP-0, at 7-3; EFSB 60, att. 60A at 144).[151]

iv. Analysis

The record demonstrates that the facility structures at the primary site will be screened from view in most directions but will have pronounced visual impacts along sections of Harrington Road and immediately adjacent to the facility along Route 169. In addition, although weather conditions likely will reduce visibility of cooling tower and stack plumes, visible plumes of 100 meters from the cooling tower and 50 meters from the stack will occur on up to approximately 20 percent of daylight hours, and when visible, plumes will be visible from areas where the facility structures themselves will not be visible. The record also demonstrates that the increased height of the facility stack that would be necessary if a full acoustical enclosure for the HRSG was required for noise mitigation purposes would result in more pronounced visual impacts.

In two recent reviews, the Siting Board has required generating facility proponents to provide selective tree plantings in residential areas up to one mile from the proposed stack location to help mitigate the visibility of the facility and the associated stack. Berkshire

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151 The Company provided photographs along Route 31, east of the alternative site, which indicate the potential for views toward the alternative site that include scenic landscapes due to the open and topographically varied terrain (Exhs. EFSB 144A, MPP-0, Fig. 7.7-7). The nearest vantage point to the site from among the photographs taken from the Route 31 area, is the view southwest from the cemetery at the intersection of Route 31 and Muggett Hill Road, located approximately three quarters of a mile northeast of the alternative site facility footprint (Exhs. EFSB 144A; MPP-0, at 7-3).

Power Decision, 4 DOMSB at 395; Dighton Power Decision, EFSB 96-3, at 47-48. Here, the Company has expressed a willingness to provide shrubs, trees, or window awnings, if so requested by the local residents within a half-mile of the facility, where visibility of the facility is likely to be highest. Consistent with Siting Board precedent to ensure that visual impacts are minimized, the Siting Board directs the Company to provide reasonable off-site shrub and tree plantings or window awnings to help screen the proposed facility from properties on Harrington Road and from roadways and other locations within one mile of the proposed facility, as may be requested by property owners or appropriate municipal officials. Given the identified difficulty in providing effective off-site screening of the facility from residences on Harrington Road due to the topography of the area, the Siting Board notes that evergreen plantings of maximum height may be warranted. Therefore, the Siting Board directs the Company to make available to affected Harrington Road residents the option of at least one strategically placed planting of 20 feet or more as may be practical and appropriate to the setting, in lieu of a row of several smaller plantings.

In implementing its overall plan for off-site shrub and tree planting or window awning installation, the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner and along public ways only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to appropriate officials in Charlton and to all affected property owners prior to commencement of construction; (3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement of plantings as necessary to ensure that healthy plantings become established. In addition, the Siting Board encourages the Company to work with affected local residents, entities and institutions to develop other reasonable forms of cost-effective visual mitigation.

Accordingly, the Siting Board finds that, with the implementation of the aforementioned conditions, and with a 225 foot stack, the environmental impacts of the proposed facility at the primary site would be minimized with respect to visual impacts. The Siting Board notes that visual impacts of a 275 foot stack, which would be necessary for full acoustical enclosure of the HRSG structure, would be greater than those of a 225 foot stack. The Siting Board will review the balance between the visual impacts of 275 foot stack and the noise impacts of the facility as planned with a 225 foot stack in Section III.B.4.a, below.

The record demonstrates that the proposed facility at the alternative site would be visible in most directions around the site, would be visible within a more densely populated area than at the primary site, and would be visible from more closely situated scenic landscape areas than at the primary site. However, the record also demonstrates that views of the alternative site would be limited to the stack and would be screened by vegetation from many vantage points. The record also demonstrates that residences to the east of the primary site would have pronounced views of the facility, and that plumes from the proposed facility would be visible in areas where the facility itself would not be visible, thus increasing the visual impacts of the proposed facility at the primary site to a wider area. Accordingly, the Siting Board finds that the primary site and alternative site would be comparable with respect to visual impacts.

d. Noise

The Company asserted that the projected noise impacts of the proposed facility at the primary site would not adversely affect neighboring residences or properties and would be minimized in accordance with Siting Board standards of balancing environmental impacts consistent with minimizing cost (Exhs. MPP-0, at 6-175; MPP-4, att. 3, at 8-12; Company Brief at 11). The Company further asserted that noise increases from operation of the proposed facility would not be significant since they would be within the applicable MDEP ten-dBA limit at residential receptors, and would cause no adverse effects at the nearest property lines based on the extent of buffer or existing non-residential land uses and zoning (Exh. MPP-0, at 6-167).[152]

The Company stated that an increase of three decibels is the minimum increase in average sound level that is perceptible to the human ear (Tr. 6, at 100-101). The Company stated that there are various measures of noise, and indicated that the MDEP guideline which limits allowable noise increases to ten dBA is based on a relatively quiet measure of noise that essentially is the background sound level that is observed in the absence of louder, transient sounds (Exh. MPP-4, att. 3, at 8-4; Tr. 6, at 104). The Company stated that for the purposes of noise analysis in this case, the background level is defined as that level of noise that is exceeded 90 percent of the time ("L_{90}") (Exh. MPP-4, att. 3, at 8-4; Tr. 6, at 102-103, 110).

In support of its position that the proposed facility would adequately minimize noise impacts, the Company provided analyses of existing noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. MPP-0, at 6-167; MPP-4, att. 3, at 8-1). To establish existing background noise levels, the Company conducted surveys at six noise sensitive locations at various distances and directions from the primary site. The Company stated that the results of this survey were used to conduct the acoustical design and impact analysis for the proposed facility (Exh MPP-4, att. 6, at 6-15).

The Company stated that it selected the six monitoring locations in order to project noise increases at the nearest affected residences and property lines (Exh. MPP-4, att. 3, at 8-1 to 8-4. The Company indicated that it performed measurements at three points along Route 169: one directly east of the site at the nearest residences, the Cady Brook Apartments and an adjacent residence, hereinafter referred to as the "Cady Brook

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152 Based on its initial noise modelling, the Company recognized that noise from the proposed facility would exceed the MDEP ten-decibel standard along the west and southwest property lines of its primary site (Exhs. MPP-0, at 6-170; EFSB E-7, att.). The Company subsequently stated that it intends to purchase abutting lands affected by facility noise in order to comply with the applicable property line standard (Tr. 7, at 17-18).

Apartments," ("receptor 1"),[153,154] one located a half mile north of the site ("receptor 5"), and one located a half mile south of the site at the Southbridge town line ("receptor 4") (Exh. MPP-0 at 6-169). Additional residential locations to the east of the site were represented by the closest residences along Harrington Road ("receptor 2") (id.). Measurements at residences to the west of the site were conducted at H. Foote Road ("receptor 6") (id.). Finally, noise was measured at the southeast property line on Sherwood Lane, adjacent to commercial and industrial uses ("receptor 3") (id.). The Company indicated that an existing residence also located at receptor 3 would be purchased by the Company prior to construction (Exh. MPP-4, att.6, at 6-2; Tr. 4, at 127-128).

At receptors 1 and 2, the Company provided continuous measurements of the existing noise environment over a 37 hour period (Exh. MPP-4. att. 3, at 8-8 to 8-9). At the remaining four receptors, the Company provided spot measurements that were taken during two to three hour intervals that the Company indicated would be representative of the daytime, evening and nighttime periods (Exh. MPP-4, att. 6, at 6-8 to 6-12). The Company stated that significant sources of ambient noise in the vicinity of the proposed site include mechanical equipment at nearby commercial and industrial facilities, vehicle traffic on nearby roadways, including Route 169, and distant transportation noise from the Massachusetts Turnpike (Exh. MPP-0, at 6-168).

With respect to construction noise, the Company provided estimates of maximum levels of construction noise and equivalent levels of such noise at the locations that would

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153 The Company stated that measurements presented for receptor 1 were taken at two different positions, A and B (Exh. MPP-0, at 6-169). The Company indicated that it determined that background measurements at position 1A were being masked by diesel trucks idling at a nearby industrial facility (id.). The Company stated that it moved its monitoring equipment south along Route 169 to position 1B in order to more accurately measure background levels in this vicinity (id.). Henceforth, references to receptor 1 shall refer to position 1B.

154 The Company stated that a single residence is located adjacent to the Cady Brook Apartments and is the same distance from the primary site as the Cady Brook Apartments (Tr. 4, at 127-128).

experience the largest noise increases, H. Foote Road and Harrington Road (Exh. MPP-0, at 6-174). The Company stated that the maximum noise impact due to construction would be 51 dBA at receptor 6 (Exh. MPP-0, at 6-174). The Company estimated that increases in ambient noise (L_{90}), would range from zero to eight dBA during the excavation and steel erection phases of construction, with lesser increases ranging from zero to four dBA during the remainder of the construction period (Exhs. MPP-0, at 6-174; MPP 4, att. 3 at 8-10, att. 6, at 6-15; EFSB E-2; EFSB E-14; Tr. 6, at 88-92). The Company asserted that construction noise impacts at other locations would be negligible because relatively high daytime background levels, caused by noise from Route 169, would tend to mask construction noise at these locations (Exh. MPP-0, at 6-174).

The Company stated that construction noise impacts would be mitigated by (1) limiting most construction activity to weekday, daytime periods,[155] and (2) routine inspection and mandatory installation of adequate diesel exhaust mufflers on equipment working at the site (Exh. MPP-4, att. 6, at 6-15).

The Company also stated that cleaning and testing of the facility's pressurized systems would necessitate steam or air releases in the closing stages of project construction (id.). The Company noted that these events would be loud but of relatively short duration,[156] and indicated that noise impacts of these events would be mitigated by either or both of the following: pre-notification of area residents; and the use of portable mufflers to control noise emissions (id.; Exhs. EFSB E-15; Tr. 6, at 92-98).

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155 The Company stated that the daily work schedule likely would be Monday to Thursday or Friday, with work commencing between the hours of 7 a.m. and 8 a.m. and with major construction activity ceasing between the hours of 3 p.m. and 6 p.m. The Company indicated that construction activity could take place outside of these parameters, and that weekend activity might occur in order to maintain the overall project schedule (Exhs. E-127(a); EFSB E-163; Tr. 6, at 89-90).

156 The Company stated that individual steam or air release events typically would last for less than one minute, but that several consecutive releases could occur during a period of hours or days (Exh. EFSB E-15; Tr. 6, at 94-95).

To analyze the noise impacts from operation of the proposed facility, the Company provided estimates of facility noise and combined facility and background noise, by receptor, for daytime and nighttime periods (Exh. MPP-4, att. 3, at 8-12). The Company's model projected that noise contributions from the proposed facility would be 48.3 dBA at receptor 1, 46.7 dBA at receptor 3, and 43.1 at receptor 6, with lesser amounts at the remaining receptors (id.). The Company's analysis indicated that with facility operation, daytime L_{90} levels would increase by zero to six dBA at the six receptors, including an increase of 1 dBA to a combined facility and background level of 48 dBA at receptor 1, an increase of 2 dBA to a new level of 46 dBA at receptor 3, and an increase of 6 dBA to a combined level of 42 dBA at receptor 6 (Exh. MPP-4, att. 6, at 6-10, 6-17). The analysis further indicated that with facility operation, nighttime L_{90} levels would increase by one to ten dBA at the six receptors, including an increase of 10 dBA to a combined level of 48 dBA at receptor 1, an increase of 6 dBA to a combined level of 43 dBA at receptor 2, and an increase of 10 dBA to a combined level of 42 dBA at receptor 6 (id.).

To further analyze the impact of noise from the proposed facility at the residential locations represented by receptors 1 and 2, the Company provided and analyzed facility noise in terms of the L_{50} metric, or that level of noise that is exceeded 50 percent of the time (Exhs. MPP-4, att. 3, at 8-8, 8-9; EFSB E-135; Tr. 6, at 104; Tr. 7, at 13). The Company projected that at receptor 2 during a typical daytime period, noise from the proposed facility would result in an L_{50} increase of 3.4 dBA from 41.5 dBA to 44.9 dBA; given that this increase is above the 3 dBA threshold of perceptibility, the Company added that as a result, noise from the plant would be perceptible 50 percent of the time to an observer at this location (Exh. EFSB E-135; Tr. 7, at 14-15). The Company also stated that during the quietest nighttime hour, L_{50} at receptor 1 would increase by 7.6 dBA, from 41.5 dBA to 49.1 dBA, indicating that noise from the proposed facility would be perceptible at least 50 percent of the time at this location (Exh. EFSB E-135b (rev. A)).

The Company also provided day-night sound levels ("L_{dn}")[157] for receptors one and two (Exh. EFSB E-10b).[158] The Company indicated that the L_{dn} noise from the proposed facility would be 54.7 dBA at the most affected location, receptor 1 (id.). The Company further indicated that based on data from its noise survey, the existing ambient L_{dn} at receptor 1 is 67.5 dBA, and that future L_{dn} of the proposed facility plus background would be 67.8 dBA (id.). The Company indicated that the L_{dn} already present at receptor 1 is well above the 55 dBA guideline, and is therefore indicative of high existing background noise levels in the area (Tr. 6, at 118; Company Brief at 7). The Company stated that at receptor 2, L_{dn} sound level from the proposed facility would be 48.6 dBA, and added that the facility noise would increase the ambient L_{dn} level at Harrington Road residences from 54.7 dBA to 55.6 dBA (Exh. EFSB E-10b). The Company argued that L_{dn} increases at both receptor 1 and receptor 2 would be small, and thus inconsequential (Tr. 6, at 118, 128-129).

The Company asserted that its proposed facility is being designed with careful consideration of measures to mitigate noise impacts in the surrounding community (Exhs. MPP-0, at 6-167; MPP-4, att. 6, at 6-1; Tr. 6, at 86-87). The Company's noise modelling and analysis assumed the incorporation of a series of noise abatement technologies which constituted its "baseline" noise mitigation package for the proposed facility (Exhs. MPP-0, at 6-168; EFSB RR-19; Tr. 7, at 25). Specifically, to mitigate facility noise, the Company stated that the proposed facility would incorporate: (1) a sound absorbing turbine building including 18 gauge siding, four inches of insulation, acoustical louvers and ventilation fan

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157 In response to an information request, the Company provided USEPA Document 550/9-74-004, entitled "Information on the Levels of Environmental Noise Requisite to Protect Public Health and Welfare With an Adequate Margin of Safety" ("Levels Document") (Exh. EFSB E-10a (att.)). In the Levels Document, L_{dn} is defined as the 24 hour A-weighted equivalent sound level, with a 10 decibel penalty applied to nighttime levels (id. at Abb. 2)

158 In the Levels Document, the USEPA recommends an outdoor L_{dn} level of 55 dBA or less for residential areas, and states that this level typically would prevent adverse effects on public health and welfare due to interference with speech and other outdoor activity (Exh. EFSB E-10a at 22).

silencers; (2) silencing of air inlets to the combustion turbine; (3) silencing baffles in the HRSG stack to attenuate exhaust noise; (4) use of slow speed or aerodynamically designed low noise fans in the cooling tower; and (5) acoustical barrier walls around the HRSG structure composed of siding and insulation (id.). The Company stated that the total cost of its proposed baseline noise mitigation package (including an operating efficiency penalty of $473,200) would be $2,898,200 (Exh. EFSB RR-19).

The Company stated that its baseline noise mitigation package was designed to bring the proposed facility into compliance with applicable state noise standards, and argued that an L_{90} increase equal to MDEP's ten-dBA limit would represent an appropriate balance between mitigation of environmental impacts and costs for the proposed facility at the primary site. The Company further explained that the acoustic design of the facility was largely driven by the noise environment at the closest residential receptor, the Cady Brook Apartments (Exhs. MPP-4, att. 3, at 8-1; EFSB E-11c; EFSB E-134; Tr. 6, at 117-118).

Further, the Company stated that the actual noise increases from the proposed facility likely would be less than those identified in its noise model due to: (1) conservatism inherent in the noise modelling process; and (2) conservatism built in to the noise attenuation guarantees provided by the facility's various equipment suppliers (Exhs. EFSB E-136; Tr. 6, at 155-159; Tr. 7, at 18-21).

With respect to the conservatism inherent in the noise modelling process, Mr. Hessler stated that the noise model employed in the analysis of the proposed facility was a Hemispherical Free Field ("HFF") model in which the noise source is assumed to be sitting on flat, sound-reflective terrain (Exhs. EFSB E-4; EFSB E-136; Tr. 6, at 155). The Company explained that, in general, an HFF type model assumes no benefit from ground absorption, foliage, or terrain effects such as elevation changes (id.). Mr. Hessler also stated that neutral meteorological conditions are assumed by the model, and noted that this assumption likely would add to the conservatism of the model under the majority of weather conditions (Tr. 6, at 156). The Company indicated that, here, the model likely would be conservative by one to two dBA at receptor 1, and would be conservative by three dBA to as much as five to eight dBA at receptor 6 (Exh. EFSB E-136; Tr. 7, at 19).

With respect to the conservatism of the noise attenuation guarantees provided by the facility's various equipment suppliers, the Company stated that, in performing the noise analysis for the proposed facility, it assumed that each vendor's warranties with respect to noise would just be met (Tr. 7, at 20). Mr. Hessler stated that, based on his experience, vendor guarantees would be conservative on the order of three dBA, and added that Westinghouse in particular is noted for the conservative nature of its noise guarantees (id. at 21).[159]

In sum, the Company stated that combining the conservatism of the HFF model with that incorporated in the vendor noise guarantees would result in L_{90} increases that would be overstated in the Company's filing by an amount of three dBA or more (id. at 20-21). The Company stated that it would expect the actual L_{90} increase at receptor 1 to be three dBA less than that modelled, and that with respect to receptor 6, the increase likely would be overstated by between five and eight dBA (Exh. EFSB E-136; Tr. 6, at 157; Tr. 7, at 19).

In response to requests from the Siting Board staff, the Company identified a number of options to further mitigate the noise impacts of the proposed facility (Exh. EFSB E-11). The Company stated that it developed an option designed to reduce facility noise by an additional three dBA in all directions ("Option 1")[160] (id.). The Company indicated that Option 1 would limit the L_{90} increase to 7.5 dBA at receptor 1, and would reduce facility noise at other residential locations by two to three dBA below the baseline (id.). In addition, the Company indicated that, at Harrington Road, Option 1 would limit the L_{90} increase to 4.4 dBA and additionally would hold L_{50} increases during typical nighttime periods to less than

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159 The Company stated that Westinghouse would be the supplier of the combustion turbine, as well as the turbine inlets and the stack exit, and indicated that Westinghouse would be the source of the noise guarantees for each of these components of the proposed facility (Tr. 6, at 136-137).

160 The Siting Board notes that under Option 1, the actual decrease in facility noise at the various receptors shows some variation around the nominal three dBA reduction proposed under this option. Combined facility and background noise (L_{90}) at receptor 6 would be decreased by 3.3 dBA while noise at receptors 1 and 2 would be decreased by 2.3 dBA and 1.9 dBA respectively.

two dBA, whereas under the baseline mitigation, the increase would be 3.1 dBA (Exhs. EFSB E-11; EFSB E-135b; EFSB E-135b (rev. A)).

The Company stated that Option 1 would include the following mitigation measures: (1) additional silencing to the combustion turbine inlet; (2) additional silencing in the HRSG stack where flue gas is discharged; (3) inlet silencing to reduce noise from the cooling tower; and (4) increased insulation in the barrier walls surrounding the HRSG (Exh. EFSB E-137). The Company stated that the total cost of noise mitigation under Option 1 would be $3,790,500, or $892,300 more than the Company's proposed baseline mitigation package, and indicated that Option 1 would impose an operating efficiency penalty of $591,500, or $118,300 more than under the baseline mitigation (Exh. EFSB RR-19).

The Company stated that it developed a second option designed to result in a reduction of facility noise by six dBA below baseline in all directions ("Option 2").[161] The Company indicated that Option 2 would limit the L_{90} increase from the proposed facility to 5.5 dBA at receptor 1 (Exh. EFSB E-11). The Company stated that Option 2 would include the following mitigation measures: (1) lengthening of silencers in the combustion turbine inlet; (2) lengthening of baffles in the HRSG stack exit; (3) inlet and outlet silencing to reduce cooling tower noise emissions; and (4) full enclosure of the HRSG (Exhs. EFSB E-11; EFSB E-137; Tr. 7, at 61-67). The Company stated that the total cost of noise mitigation under Option 2 would be $5,509,000,[162] or $2,610,800 more than the baseline

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161 The Siting Board notes that under Option 2, the actual decrease in facility noise at the various receptors would be somewhat less than the nominal six dBA reduction proposed under this option. Combined facility and background noise impacts (L_{90}) at receptor 6 would be decreased by 4.3 dBA while noise impacts at receptors 1 and 2 would be decreased by 4.3 dBA and 3.0 dBA respectively.

162 The Company stated that this cost figure assumed no increase in stack height (Exh. EFSB RR-19). The Company asserted that in order to fully enclose the HRSG structure, any such roof would need to be constructed 20 feet higher than the current height of the HRSG barrier walls (90 feet) (Exh. EFSB E-137). The Company noted that this, in turn, would necessitate a 50 foot increase in stack height to 275 feet in order to satisfy GEP requirements (id.; Exh. EFSB RR-19) see also Exh. MPP-4, att. 6 at 5-7.

cost, and indicated that Option 2 would impose an efficiency penalty of $903,000, or $429,800 more than under the baseline mitigation package (Exh. EFSB RR-19).

The Company stated that it was not proposing to incorporate any of the measures from Options 1 or 2 into the pre-construction design of the facility, and argued that additional mitigation beyond that proposed in the baseline package would not produce significant benefits at affected locations, and further that the additional cost of implementing either option would not be justified given the existing noise environment in the affected areas (Company Brief at 12).

The Company recognized that the noise increases from operation of the proposed facility would be larger than those previously accepted by the Siting Board (Company Brief at 12). However, the Company argued that additional expenditure on noise mitigation would not be justifiable because it would provide no significant benefits at the most affected locations (id.). The Company argued that noise levels expected at the nearest residences, the Cady Brook Apartments, would not be significantly improved by additional mitigation because the noise environment at this location is dominated by existing sources such as vehicle traffic on Route 169 (id.). The Company asserted that, because of the distinctive noise environment at the Cady Brook Apartments, mitigation of facility noise would yield less benefit than at locations where background levels are more constant (id. at 13). With respect to noise levels at receptor 6, H. Foote Road, the Company asserted that combining the conservatisms discussed above would result in significantly less facility noise at this location than that projected by the Company's model (Exh. EFSB E-136). As a result, the Company argued that additional expenditures on noise mitigation to control increases at receptor 6 would be unnecessary because, in practice, L_{90} increases at that location are expected to be significantly less than ten dBA (Company Brief at 14).

The Company also argued against the imposition of a prescriptive solution to noise mitigation, under which the Siting Board would mandate the specific mitigation measures to be included in the design of the proposed facility (id. at 15). Rather, the Company argued in favor of a performance-based noise standard, under which the Siting Board would identify only the acceptable increment of noise from the proposed facility (id.). The Company advocated this approach for two reasons: (1) it would permit the Company to exercise flexibility in the design of its final noise mitigation package and therefore would allow the Company to take advantage of improvements to, or innovations in, noise mitigation equipment that might be realized prior to completion of the proposed facility; and (2) that such flexibility would avoid the imposition of design constraints that might inadvertently compromise the cost-competitiveness or reliability of the proposed project (id.). In sum, the Company asserted that a performance-based approach would allow the Company to meet the Siting Board's performance standard by using the most cost-effective means available to it (id.).

i. Alternative Site

The Company stated that the proposed facility at the alternative site would require noise mitigation measures beyond those that would be required at the primary site (Exh. MPP-0, at 7-42). The Company indicated that the proposed facility at the alternative site would be designed to mitigate noise impacts and would be consistent with the MDEP ten dBA L_{90} standard (id. at 7-35). The Company therefore asserted that the proposed facility would have no significant noise impact on the local community (id. at 7-33).

The Company provided analyses of ambient background noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. MPP-0, at 7-35 to 7-42; MPP-4, att. 3, at 8-1). To establish existing background noise levels, the Company surveyed ambient sound levels at two locations representing noise sensitive receptors. The Company stated that residences located along Burlingame Road ("location 1"), would be the closest receptors to the west of the site, and that residences along Flint Road ("location 2"), would be the closest receptors to the east of the site (Exh. MPP-0, at 7-36). The Company provided continuous noise measurements over a 42 hour period for both locations (id. at 7-39 and 7-40). The Company stated that the minimum L_{90} levels occurred at night and were 32 dBA at location 1, and 29 dBA at location 2 (id. at 7-41). The Company estimated that the proposed facility would result in a ten dBA increase above the nighttime L_{90} levels at both locations (id.).

With respect to construction noise, the Company asserted that it would apply the same mitigation techniques that it identified for the primary site, but stated that noise impacts at the alternative site would be more pronounced than at the primary site because of the small buffer distance between the site and the nearest residences, and the low ambient noise levels present in the area (id. at 7-38).

With respect to operational noise, the Company stated that, to meet the MDEP standard at the closest residences, the proposed facility at the alternative site would require the following mitigation measures in addition to the baseline mitigation package proposed for the primary site: (1) longer silencing baffles for the combustion turbine inlets; (2) a silencer assembly in the HRSG vertical stack; (3) slower speed fans for the cooling tower; (4) use of splash mats in the cooling tower to reduce noise from falling water; and (5) either construction of a barrier wall along the east side of the cooling tower, or the addition of inlet silencing to the cooling tower (id. at 7-41 to 7-42).

The Company stated that to achieve a level of noise mitigation that would be comparable to that proposed for the primary site, the total cost of noise mitigation at the alternative site would be $6,400,000, or $3,501,800 more than for the primary site (Exhs. EFSB RR-19; EFSB RR-38). The Company also noted that it likely would not be able to meet the MDEP standard at the nearest property line, due primarily to the lack of buffer space between the facility footprint and the property line (Exh. EFSB MPP-0, at 7-11; Tr. 7, at 24).

ii. Analysis

In past decisions, the Siting Board has reviewed estimated noise impacts of proposed facilities for general consistency with applicable governmental regulations, including the MDEP's ten-dBA standard. Berkshire Power Decision, 4 DOMSB at 403; Cabot Decision, 2 DOMSB at 406-407; Altresco-Pittsfield Decision, 17 DOMSC at 401. In addition, the Siting Board has considered the significance of expected noise increases which, although lower than ten dBA, may adversely affect existing residences or other sensitive receptors.

Berkshire Power Decision, 4 DOMSB at 404; 1993 BECo Decision, 1 DOMSB at 104-106; Enron Decision, 23 DOMSC at 210-211; NEA Decision, 16 DOMSC at 402-403.

In a past review in which a proponent calculated that nighttime L_{90} would increase by seven dBA to a level of 48 dBA, the Siting Council raised concerns about the calculated maximum noise increase of seven dBA, citing the possibility of abutter complaints.[163] NEA Decision, 16 DOMSC at 401-403. Here, the Company's noise analysis at the primary site indicates that at two residential receptors, the Cady Brook Apartments to the east and H. Foote Road to the west, facility operation would result in nighttime L_{90} increases of ten dBA, which would be the largest such noise increase ever accepted by the Siting Board.

In previous reviews, the Siting Board has included the level of existing background noise as a factor in assessing whether expected noise increases from a proposed generating facility would be acceptable. Berkshire Power Decision, 4 DOMSB at 404-405; Enron Decision, 23 DOMSC at 210. In a recent review, in which the proponent calculated that nighttime L_{90} would increase by eight dBA to a level of 41 dBA, the Siting Board approved that increase citing an analysis which demonstrated that L_{dn} noise at all residential receptors would be well below the USEPA's 55-dBA guideline.[164] Berkshire Power Decision, 4 DOMSB at 398, 404. However, in an earlier case where existing background noise levels were high, and the proponent calculated impacts at residences that would be in excess of the USEPA L_{dn} guideline, the Siting Board cited high existing noise levels in limiting further

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163 The Siting Council accepted the proposed seven-dBA increase because the proponent had asserted that actual noise increases would be less, owing to conservative assumptions embodied in the noise modelling process. Regardless, the Siting Council ordered the proponent to monitor facility noise at the nearest residence for two years following facility start-up, and to report to the Siting Council any noise complaints and the proposed resolution of such complaints. NEA Decision, 16 DOMSC at 402, 403, 408.

164 The Siting Board, in accepting the eight-dBA increase, also cited overall noise impacts that were considerably lower than corresponding worst-case impacts for four earlier gas-fired generating facilities approved by the Siting Board. Berkshire Power Decision, 4 DOMSB at 399-400.

increases in nighttime L_{90} noise from facility operation to five dBA.[165] 1993 BECo Decision, 1 DOMSB at 108-109, 114.

Here, given the Company's noise analysis for receptor 1 along Route 169, the primary site is most akin to that in the 1993 BECo case in which existing background levels were high. In fact, the calculated L_{dn} of 67.8 dBA for receptor 1 with operation of the proposed facility is significantly above the maximum L_{dn} of 59 dBA that was at issue in the 1993 BECo case.

As indicated by the Company, the principal source of high background noise at receptor 1 is time varying, reflecting vehicle traffic along Route 169. In contrast, previous Siting Board reviews which considered high background noise levels, including the 1993 BECo Decision and the Enron Decision, involved settings having significant levels of industrial source noise. The Siting Board recognizes that the difference in background noise source -- time varying traffic noise versus industrial noise which typically is more constant -- may reduce the significance of L_{90} noise increases in the instant case, as compared to the cited previous cases where high background noise levels were present.[166]

While the primary site noise analysis is distinct from those in previous cases with high background noise, the Siting Board cannot agree that the Company's proposed L_{90} increases at residential receptors are insignificant. The record indicates that nighttime facility noise impacts at the most affected receptors would approach the MDEP ten-dBA limit during quieter portions of the noise pattern, and would be perceptible half of the time or more

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165 The Siting Board stated that controlling noise increases may be particularly important in cases where ambient conditions at or near a proposed site already exceed the USEPA's 55-dBA guideline for outdoor day-night noise. 1993 BECo Decision, 1 DOMSB at 114. The Siting Board notes that in BECo, the projected L_{dn} for combined ambient and facility noise was 59 dBA, a level which clearly exceeds the USEPA guideline.

166 A time varying pattern of background noise may result in calculation of a higher L_{90} noise increase, as this measure reflects the quietest ten percent of the pattern. Also, importantly, a time varying noise environment results in higher masking of facility noise impacts during the noisier portion of the pattern.

during nighttime hours.[167] Further, the Siting Board is concerned that at the Cady Brook Apartments, the existing noise environment, as reflected by an L_{dn} of 67.5 dBA, may already be a source of annoyance to residents. The Siting Board also notes that at the Cady Brook Apartments, the projected L_{dn} of the proposed facility would be 54.7 dBA, a level which, by itself, would just meet the USEPA guideline.

The record indicates that the Company has considered options that would further mitigate noise impacts from operation of the proposed facility. The additional mitigation proposed under Option 1 and Option 2 would reduce expected noise increases that: (1) would be well above the three-dBA threshold for noticeable noise; (2) would approach the ten-dBA limit at residential receptors and property lines; and (3) would be larger than increases previously accepted by the Siting Board. The record demonstrates that the Company has identified a noise mitigation option that would hold L_{90} increases at the most affected residences to 7.5 dBA. The record further demonstrates that the noise reductions that could be achieved at receptor 1 and receptor 2 (residential receptors) to the east of the proposed facility would be significant, and would result in effective noise reduction benefits to these residential areas. However, the Company has not proposed to implement either option to further mitigate noise impacts from the proposed facility, citing cost and limited effectiveness.

Thus, based on the identification of options for additional noise mitigation in the record for this proceeding, there are noise issues which require the Siting Board to evaluate trade-offs between environmental impacts and cost. To complete its review, the Siting Board must address this issue to determine whether noise impacts would be minimized consistent with minimizing cost and other environmental impacts.

The record indicates that the Company's baseline noise mitigation package would result in calculated L_{90} increases of ten dBA at residential locations. Option 1 would hold

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167 The Siting Board notes that the noise analysis indicates that under the baseline case, residents along Harrington Road likely would be able to observe noise increases from the proposed facility for 50 percent of the time not only during typical nighttime and minimum hour periods, but also during typical daytime periods as well.

calculated L_{90} increases to 7.5 dBA, an increase that would be within the range of the seven to eight dBA increases accepted by the Siting Board as reasonable limits in past cases where the Siting Board had sought to minimize noise impacts consistent with minimizing cost.

The Siting Board notes that the incremental cost of Option 1, nearly $900,000, plus an efficiency penalty of a little over $100,000 would exceed the cost of incremental mitigation required in past reviews, which has ranged from $175,000 to $500,000. As an offsetting consideration, the Siting Board also notes that the proposed facility would be somewhat larger than other generating facilities reviewed previously that were held to L_{90} increases of seven to eight dBA. Even allowing for its larger size, on balance, Option 1 would involve higher costs to attain L_{90} limits that would be comparable to those in past cases. At the same time, the Siting Board notes that the maximum L_{90} increase under Option 1, 7.5 dBA, exceeds the maximum L_{90} increase of 5 dBA accepted in previous cases with high background noise.[168] As a mitigating factor, we have recognized above that the significance of L_{90} increases may be less if background conditions reflect time varying traffic sources rather than steady-state sources. On balance, however, Option 1 would involve accepting L_{90} increases that are at best comparable to those in past cases, and that are potentially less preferable when considered together with substantial exceedances of the USEPA L_{dn} noise guideline that exist in the area.

Considering cost and environmental impacts together, Option 1 would involve somewhat higher noise mitigation costs than past cases, but also accepts the potential for somewhat more significant noise impacts than in past cases based upon evidence of both L_{90} increases and exceedance of the USEPA residential guideline. Thus, the noise increases provided for under Option 1 represent an appropriate balance between minimizing environmental impacts consistent with minimizing cost.

The Company has argued that, due to the conservatism of noise guarantees provided by the facility's various equipment providers, and to the conservatism of its noise model,

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168 The record demonstrates that limiting facility noise to a calculated L_{90} increase of 5 dBA would require the implementation of Option 2, with an incremental cost of approximately $2,600,000, plus efficiency costs of approximately $430,000.

noise increases that were calculated for the proposed facility would be overstated by three dBA to as much as five to eight dBA, depending on distance and direction from the proposed site.

The Siting Board accepts the Company's argument that its calculated noise impacts are likely to be conservatively overstated based on their incorporation of vendor noise guarantees. Further, the Siting Board accepts the Company's estimate that vendor guarantees result in conservative overstatement of noise impacts by one to as much as three dBA, but notes that the Company's assertions as to the appropriate extent of adjustment appear to be more judgmental than the original calculations of predicted noise. See Dighton Power Decision, at 55; Silver City Decision, 3 DOMSB at 336; NEA Decision, 16 DOMSC at 403.

The Siting Board also recognizes that the Company's calculated noise impacts are likely to be conservatively overstated based on omission of environmental factors that potentially reduce noise. However, given that such factors are time-varying and are therefore not consistently present, we note that their omission may be appropriate for purposes of assessing worst-case noise impacts.

With respect to the Company's position that the Siting Board should adopt a performance based standard with respect to noise mitigation, the Siting Board agrees with the Company's arguments pertaining to (1) the benefits of flexibility in terms of the final design of the noise mitigation package for the proposed facility, and (2) avoiding the imposition of design constraints that could compromise the cost competitiveness of the project, and notes that such a standard would be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Therefore, in order to capture for affected abutters the benefits of conservatism in calculated noise increases, as well as to limit noise increases from the proposed facility to levels that are consistent with Siting Board precedent, the Siting Board directs the Company to meet either of the following conditions: (1) the Company shall incorporate noise mitigation measures into its pre-construction facility design such that calculated L_{90} noise increases would not exceed 7.5 dBA at residential receptors; or (2) the Company shall incorporate noise mitigation measures in its proposed facility such that measured L_{90} noise increases at residential receptors would not exceed six dBA.[169] The Siting Board notes that for either approach, the Company must, for all receptors, prevent L_{90} noise levels from increasing beyond the levels provided for under its baseline mitigation package.

Further, prior to commencing construction, the Company shall inform the Siting Board as to which of the two compliance approaches it will follow. Should the Company elect to meet the 7.5 dBA calculated limit, it shall submit to the Siting Board confirmation that it plans to proceed with Option 1 or, if an alternative noise mitigation package is preferred by the Company, provide information concerning its final noise mitigation package, including (1) a description of each mitigation measure to be incorporated in the proposed facility, (2) results of noise modelling showing that calculated L_{90} increases at residential receptors would not exceed 7.5 dBA, and (3) detailed cost information including the cost of each identified noise mitigation measure, including allowance for any efficiency penalties, and the total cost of noise mitigation for the proposed facility.

Should the Company elect to meet the six-dBA measured limit, it shall develop a noise testing protocol, to be implemented during the first twelve months of commercial operation, to determine that noise from operation of the proposed facility does not result in actual L_{90} noise increases of greater than six dBA at any of the residential receptors. Such testing protocol should be consistent with others that have been developed for testing compliance with the MDEP standard, and should be conducted at, or as close as is practicable to, the receptor locations identified in the Company's filing.

The Siting Board notes that noise mitigation measures required in this case are based upon the evidentiary record as presented. In setting forth its directive with respect to noise mitigation, it is not the intention of the Siting Board to suggest that greater latitude would be afforded at quieter sites with respect to allowable noise increases. Rather, it is the intent of

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169 The distinction between the pre-construction noise level required under the calculated limit, and the lower level required under the measured limit, takes into account the conservatism inherent in the noise modelling process and presents two options for which the de facto outcome would be comparable.

the Siting Board to continue to evaluate each site in the context of the facility being proposed to ensure that environmental impacts are minimized consistent with minimizing cost.

Accordingly, the Siting Board finds that, with the implementation of the above condition, the noise impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost. The Siting Board further finds that the primary site would be preferable to the alternative site with respect to noise impacts.

e. Traffic

i. Primary Site

The Company asserted that construction and operation of the proposed facility at the preferred site would have negligible impacts on local traffic conditions (Exh. MPP-0, at 6-176). In support of its assertion, the Company presented projections of trip generation and related traffic impacts with and without the proposed facility, including separate estimates of construction-related traffic and facility operation traffic (id. at 6-184 to 6-185, 6-192 to 6-195). The Company presented separate estimates of delivery vehicle volumes during construction and operation of the proposed facilities (id.).

The Company indicated that the majority of construction[170] activity would occur between 7:30 a.m. and 4:00 p.m., Monday through Friday (Exh. MPP-0, at 6-184).[171] The Company estimated that the maximum number of construction workers employed at any one time at the site would be 208 (id.). The Company presented a comparison of expected peak-hour levels of service ("LOS")[172] with and without the proposed project for each of the

170 For purposes of this decision, construction shall mean site clearing or other physical construction on the site or water routes.

171 The Company stated that after-hour or weekend construction would be necessary in limited circumstances (Exh. MPP-0, at 6-184). However, the Company indicated that only a small number of workers would be on the site during such periods, and that after-hour traffic would therefore have no appreciable impact (id.).

172 Regarding its peak-hour traffic comparison, the Company indicated that the efficiency of traffic operations at a location is measured in terms of LOS (Exh. MPP-0, (continued...)

three primary gateway intersections, Route 20 and Route 169, Worcester Street and Route 169, and Route 169 and Sherwood Lane (id. at 6-190; Exh. EFSB E-128, att. A). The Company stated that the existing peak commuting periods in the area of the primary site are 7:15 a.m. to 8:15 a.m., and 4:30 p.m. to 5:30 p.m. (Exh. MPP-0, at 6-186). The Company stated that in estimating the number of trips created by the proposed project, it assumed 1.1 workers per car, that 100 percent of the workers would arrive during the morning peak period, and that 50 percent of the workers would depart during the evening peak (id. at 6-184).[173] In addition to employee work trips, the Company indicated that there would be 20 delivery vehicle round trips per day during peak construction (id. at 6-186). The Company stated that it assumed deliveries would be distributed evenly over a 10-hour delivery day (id.). The Company further stated that the delivery of very large equipment would be scheduled for off-peak times and that the Company would coordinate such deliveries with local officials (id.). Based on its analyses, the Company stated there would be no change in LOS due to construction-related traffic (id. at 6-190).[174]

The Company further stated that once the facility is fully operational, 14 employees would be on site during the day shift, and three employees would be required for the evening shift (id. at 6-192). The Company concluded that its traffic analysis demonstrates negligible

[172](...continued) at 6-178). The Company further indicated that LOS is measured in terms of traffic flow along roadways and intersections and is described in terms of Levels A through F, where A represents the best possible conditions and F represents forced-flow or failing conditions (id. at 6-178, 6-180).

[173] The Company explained that its assumption that only 50 percent of workers would depart either site during the evening peak hour of travel is conservative because the work shift ends at 4:00 p.m., 30 minutes prior to the commencement of the evening travel peak (Exh. EFSB E-123).

[174] The Company indicated that changes of less than one second of overall intersection delay would be expected at the intersection of Routes 20 and 169, with similarly negligible changes in delay at the Worcester Street/Route 169 intersection (Exhs. MPP-0, at 6-190 to 6-191; EFSB E-128, att. A). The Company also projected acceptable traffic conditions at the unsignalized Sherwood Lane intersection with Route 169 (id.).

impacts to intersection conditions during peak hours when the facility is operational, and that no changes in LOS are anticipated (id. at 6-195; Exh. EFSB E-128, att. B).

The Company explained that the likely route of vehicles delivering fuel oil, chemicals, and supplies to the Millennium project, would originate from Route 90 (Massachusetts Turnpike) to Route 20 -- either in Sturbridge or in Auburn (Exh. EFSB E-121).[175] The Company's witness, Mr. Sellars, testified that the addition of forty oil trucks per day during a period of oil burning without on-site storage reserve would not appreciably change Company calculations of Route 20 traffic impacts due to the facility's operation (Tr. 5, at 9-12).[176]

In response to a Siting Board Staff request, the Company provided MHD accident statistics for a segment of Route 20 between Sturbridge and Auburn, a likely route of access for construction and operation of the proposed facility (Exhs. EFSB E-121; EFSB E-164; EFSB E-181).[177] The Company indicated that 22 accidents resulting in 25 fatalities have occurred since 1978 along the total 7.7-mile length of Route 20 in Charlton (Exh. EFSB E-164, atts. A and B).

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175 The Company indicated that the segment of Route 20 between Sturbridge and Auburn would be used for such facility-related supplies at either the primary or alternative site (Exh. EFSB E-121).

176 With respect to potential Route 20 traffic impacts of the proposed project at either site, the Company stated that facility construction-related traffic would represent less than two percent of total daily traffic, while operational traffic would represent less than 0.2 percent of total daily traffic (Exh. EFSB E-164).

177 The Company summarized and provided Massachusetts Highway Department ("MHD") data for Route 20 that included the years 1984 to 1986 and 1990 to 1995 (Exh. EFSB E-181, supp. B, att. A). Based on the overall MHD data provided, there were gaps in the annual statistics requested by Siting Board staff due to the unavailability of data for some years (id.). Further, the Company noted a large number of accidents contained in the data that were ambiguous as to whether they occurred along coincident sections of Routes 20, 12, and Southbridge Street in Auburn (id.). The Company also indicated that it was necessary to summarize the original data obtained from the MHD as it contained the aggregate of reported accidents on all roads throughout the four towns, not exclusively those which took place on Route 20 (id., supp. A).

The Company indicated that a roadway improvement project, including widening, median installation and installation of separate turning lanes at major intersections, is proposed by the MHD for a 3.83-mile section of Route 20 in Charlton between Route 169 and Richardson's Corner to the east (id.).[178] The Company provided information indicating that the roadway improvement project is proposed for construction from 1998 to 2000, and will include a 2.5-mile segment of Route 20 between Route 169 and Route 31 that accounts for a disproportionately high share of reported accidents and fatalities (id., att. A). Specifically, the Company stated that the 2.5-mile segment represents 33 percent of the length of Route 20 in Charlton, but has accounted for 64 percent of reported accidents and 60 percent of reported fatalities since 1978 along Route 20 in Charlton (id.).

ii. Alternative Site

The Company asserted that construction and operation of the proposed facility at the alternative site also would have minimal impacts on local traffic conditions (Exh. MPP-0, at 7-42). In support of its assertion, the Company developed projections of trip generation and related traffic impacts, with and without the proposed facility at the alternative site, including separate estimates of construction-related traffic and facility operation traffic (id. at 7-49 to 7-50, 7-52, 7-60). The Company based these projections on the same assumptions used for the primary site, except that morning peak hours are estimated to be 7:30 to 8:30 a.m. (id.). The Company presented a comparison of expected peak-hour LOS for five primary intersections: Route 31 and Flint Road, Route 31 and Burlingame Road, Route 31 and Old Worcester Road, Flint Road and Burlingame Road, and the site drive and Burlingame Road (id. at 7-57, 7-62). The Company indicated that LOS would be degraded

178 Based on confirmation with the MHD District 3 Office in Worcester, Massachusetts, the Siting Board notes that another improvement along Route 20 in Auburn, at the intersection of Prospect Street, is near completion and entailed road widening and the installation of a dedicated turning lane onto Prospect Street. The Siting Board further notes that this improvement is situated on a short span of Route 20 between Route 90 and the Route 290/20 interchange in Auburn.

in only one area, from LOS C to LOS D, solely for turns from Burlingame Road onto Route 31 during construction (id. at 7-57).[179]

The Company concluded that its analysis demonstrated that traffic impacts from construction and operation of the proposed facility at the alternative site would be negligible (id. at 7-64). However, the Company argued that the alternative site is inferior to the primary site because it would require the use of local roadways near residential areas, whereas the preferred site would use the more heavily travelled Route 169 for facility access (id.).

iii. Analysis

The record indicates that there would be no significant change in LOS at the primary site as a result of either the construction or the operation of the proposed project. The record further indicates that, at either site, the impact of the proposed project's construction on Route 20 traffic between Sturbridge and Auburn would be statistically small relative to the average daily traffic volume, while normal facility operational traffic impacts to Route 20 would be even smaller, less than two percent and 0.2 percent, respectively.

The record also indicates, however, a significant number of reported accidents and fatalities since 1978 along Route 20 in Charlton, with a disproportionately high incidence of such accidents and fatalities in the 2.5-mile segment of Route 20 extending east from Route 169. The MHD proposes a 3.83-mile roadway improvement project which would encompass the 2.5-mile segment, with completion scheduled for 2000.

The Siting Board notes that the Company's LOS analysis and the additional record information with respect traffic and accident statistics for Route 20 between Sturbridge and Auburn address different aspects of the existing traffic situation in the area surrounding the

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179 The Company stated that even at this intersection, overall intersection delay at the study area intersection is maintained at LOS A, operating well within acceptable parameters (Exh. MPP-0, at 7-55). Further, the Company indicated that the temporary change in LOS during construction would result in only short delays averaging 21 seconds instead of average delays of 11 seconds expected without the addition of construction traffic (id.).

proposed facility sites. The LOS analysis focuses on traffic delays at intersections, and indicates no notable problems either at present or with construction and operation of the proposed facility. The additional Route 20 traffic and accident statistics focus on safety issues not necessarily related to traffic delay, and indicate some cause for concern based on apparent high incidence of accidents and fatalities along Route 20, notably between Route 169 and Route 31.

As mentioned, the proposed facility would have a small impact on Route 20 traffic volumes, and a roadway improvement project is proposed for the segment of Route 20 near both sites that accounts for the higher incidence of accidents and fatalities noted by the Company. However, the roadway improvement project is proposed for a future date, and project-related effects on Route 20 traffic, although statistically small, may warrant consultation with safety officials in communities along portions of Route 20 that will provide access to the facility site during construction and operation of the project.

The Company has stated that it would schedule the delivery of very large equipment for off-peak hours and coordinate said deliveries with local officials. However, the Siting Board notes that the delivery of materials and equipment in general during facility construction could affect area traffic on access routes, including Route 20. Once in operation, the Siting Board further notes that adverse impacts also could occur in the event the Company were to burn oil for an extended period of time, assuming delivery of oil by truck and the frequency of deliveries necessary to run the Millennium plant.

Therefore, the Siting Board requires USGen to develop and implement a traffic mitigation plan which includes the scheduling of the delivery of fuel oil, materials, and equipment to avoid peak daily travel periods or route modifications or other appropriate measures, excluding capital improvements, to minimize traffic-related impacts along likely access routes to the site including Route 20 and Route 169. The Company shall consult with the towns of Auburn, Oxford, Sturbridge, and Charlton.

Accordingly, the Siting Board finds that, with implementation of the aforementioned condition, the environmental impacts of the proposed facility at the primary site would be minimized with respect to traffic impacts.

In comparing the primary and alternative sites, the record indicates that use of the alternative site would result in a greater potential for residential traffic impacts. Accordingly, the Siting Board finds that the primary site would be preferable to the alternative site with respect to traffic impacts.

f. Safety

With respect to safety issues associated with the construction and operation of the proposed facility, the Company committed to ensuring that construction and operation activities would conform to applicable public safety and Occupational Safety and Health Administration ("OSHA") standards (Exhs. EFSB E-115; MPP-4, att. 3, at 3-23).[180] The Company also stated that specific provisions requiring adherence to applicable safety and health laws and regulations would be incorporated into all contracts between the Company and its contractors (Exhs. EFSB E-116; MPP-4, att. 3, at 3-23). In addition, to ensure reliance on appropriate safety measures at all times, the Company has committed to developing an emergency response plan in coordination with local emergency services and town officials prior to the opening of the facility at either the primary or the alternative site (Exhs. MPP-0, at 6-149; EFSB E-118a; EFSB E-118b; Tr. 5, at 25).

180 The Company specified that, at a minimum, safety and emergency systems incorporated into the design of the proposed facility would include the following features: properly designed containment basins or dikes for all storage areas; automatic shutdown systems with backup power supply for the turbines, fuel supply and chemical systems; and a number of fire prevention and control measures (Exh. MPP-4, att. 3, at 3-23 to 3-24). The Company indicated that continuous monitoring of operations at the proposed facility and a program of regular maintenance would provide additional guarantees that the proposed facility would operate safely (id. at 3-25 to 3-26). The Company also detailed a number of security measures it would take, including posting a guard throughout the construction period and permanently enclosing the proposed facility with a fence, to prevent unauthorized access to the facility site and/or footprint during construction and operation of the proposed facility (id. at 3-24; Exh. EFSB E-119).

i. Materials Handling and Storage

The Company indicated that oil, aqueous ammonia and hydrogen, and all other chemicals to be stored on site at the proposed facility would be managed in accordance with applicable OSHA and public safety and health standards (Exhs. EFSB E-115; EFSB E-116; MPP-4, att. 3, at 3-20 to 3-24; EFSB RR-13). The Company further indicated that it anticipated no special safety hazards associated with trucks entering, exiting or travelling along access roads to deliver fuel oil or chemicals at either the primary or the alternative site (Exhs. EFSB E-120; EFSB E-121; Tr. 5, at 6 to 8, 14 to 15).[181]

The Company described the steps it would take to control potential safety and health risks associated with aqueous ammonia, including construction of an internal floating roof to minimize ammonia vapor emissions and conducting all transfers of ammonia within a fully diked and contained area (Exh. MPP-0, at 6-25). The Company stated that aqueous ammonia would be stored in one 20,000 gallon, above-ground storage tank surrounded by a catch basin equipped with floating-ball baffles to reduce the ammonia vaporization rate in the event of an accidental spill (id.).

The Company provided TSCREEN modeling which demonstrated that ammonia concentrations from a spill at the proposed facility at either the primary or the alternative site would be under the Immediately Dangerous to Life or Health ("IDLH") threshold of 500 parts per million ("ppm") at the nearest fenceline, property line, or public road (Exh. EFSB E-122 (rev.); Tr. 5, at 42 to 47). The Company stated that worst-case ammonia concentrations would fall below the IDLH threshold at the identified receptors even given a catastrophic spill of a full tank of aqueous ammonia under unfavorable meteorological conditions (Exh. EFSB E-122 (rev.)). Specifically, the Company's modeling predicted that worst-case ammonia concentrations from the proposed facility at the primary site would be 486 ppm at the nearest fence line, 124 ppm at the nearest property line, and 71 ppm at the nearest public road (Exh. EFSB E-122). At the alternative site, the Company anticipated

181 The Company stated that, with respect to both the primary and alternative sites, it would confirm the preferability of its chosen routing for fuel oil and chemical deliveries with local officials (Exh. EFSB E-121).

ammonia concentrations from the proposed facility of 466 ppm at the nearest fence line, 466 ppm at the nearest property line and 49 ppm at the nearest public road (id.).

The Company asserted that, because of the conservatism of the TSCREEN model, actual concentrations of ammonia in the event of a catastrophic spill would be lower than predicted (Tr. 5, at 43 to 44). The Company identified two factors in particular as responsible for the conservatism of TSCREEN modeling, the use of (1) worst-case meteorological assumptions and (2) very conservative dispersion algorithms (id. at 44). The Company explained that dispersion algorithms used in TSCREEN modeling do not take into account such phenomena as building- or terrain-induced turbulence that might cause the plume to dissipate more rapidly (id.).[182] The Company also stated that personnel unloading aqueous ammonia would be required by the Company's safety procedures to wear respiratory equipment that would protect them from exposure to ammonia concentrations above the IDLH threshold should a catastrophic spill occur (id. at 46 to 47).

The Company indicated that aqueous ammonia would be transported, handled, stored and used in the same manner at the alternative as at the primary site (Exh. EFSB E-122 (rev.)).

ii. Fogging and Icing

The Company stated that it used five years of meteorological data and the Seasonal/Annual Cooling Tower Plume Impact ("SACTI") model[183] to determine the likely

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182 The Company indicated that ammonia concentrations at the nearest fenceline, property line, or public road could be reduced using a smaller storage tank or an underground storage tank (Exh. EFSB E-122 (rev.)). The Company argued, however, that a smaller tank would need to be filled more often and would therefore increase traffic impacts (id.). The Company also argued that, given the low frequency of ammonia releases, cost increases associated with constructing an underground storage tank would exceed the resulting benefits to public safety (id.).

183 The SACTI model is an outgrowth of work sponsored by the Electric Power Research Institute ("EPRI") (Exh. MPP-0, at 6-27). The Company characterized the SACTI model as "conservative", i.e., as tending to overpredict the incidence of fogging and icing (id.; Exhs. E-24a; E-24c; Tr. 5, at 28 to 30).

frequency and location of fogging and/or icing due to evaporative cooling for the proposed facility at both the primary and alternative sites (Exh. MPP-0, at 6-27, 7-6; MPP-14, att. 1, at 7; Tr. 5, at 31). The Company stated that, with respect to either site, its modeling of facility plume over a five-year period predicted that ground-level fogging and icing would be confined to the immediate vicinity of the cooling towers themselves (Exh. MPP-0, at 6-27, 7-7; MPP-14, att. 1, at 7).

However, the Company also indicated that fogging and icing could occur along Route 169 and Sherwood Lane at the primary site, or along Flint Road and Burlingame Road at the alternative site (Exh. MPP-14, att. 1, at 7). Based on its modeling, the Company stated that, at Route 169, ground level fogging would likely occur approximately 17 hours per year and icing would likely occur approximately 12 hours per year (id.; Exh. MPP-4, att. 6 (rev.) at 5-6). The Company stated that potential fogging and icing episodes at Sherwood Lane likely would occur 4 and 3 hours per year, respectively (Exh. MPP-14, att. 1, at 7; Exh. MPP-4, att. 6 (rev.) at 5-6). With respect to the alternative site, the Company determined that fogging and icing likely would occur 14 and 10 hours per year, respectively, at Flint Road (Exh. MPP-14, att. 1, at 7). The Company anticipated approximately one hour of ground level fogging per year at Burlingame Road and less than one hour per year of icing (id.).

The Company further stated that natural fog, rain or snow was likely to occur coincident with fogging or icing from the cooling tower, and that the location of the towers would minimize the potential for fogging and icing (Exhs. MPP-0, at 6-27; EFSB E-24c; Tr. 5, at 30 to 31). Finally, the Company indicated that it will monitor actual fogging and icing conditions throughout the first operating year to determine the potential need for mitigation (Exh. MPP-0, at 6-27). The Company also indicated its commitment to working with the Town and the MHD to ensure that any potential safety concerns, including concerns related to fogging and icing, are adequately addressed (id.; Exhs. EFSB E-24b (rev.); MPP-4, att. 6 (rev.) at 5-7; Tr. 5, at 34 to 37).

iii. Analysis

The record demonstrates that aqueous ammonia, and all other non-fuel chemicals to be stored on site at the proposed facility, will be managed in accordance with all applicable public and occupational safety and health standards. In particular, the Siting Board notes that ammonia concentrations for the proposed facility, even in the event of a worst-case spill of aqueous ammonia, would not exceed the IDLH standard at sensitive receptors at either the primary or alternative site. The Siting Board further notes, however, that the alternative site facility fence line would be at the property line, resulting in worst-case ammonia concentrations of 466 ppm at the alternative site property line -- 342 ppm higher than at the primary site.[184] The Siting Board therefore concludes that the primary site would be slightly preferable to the alternative site with respect to potential impacts of a worst-case aqueous ammonia spill at the proposed facility.

With respect to chemical storage and handling, the record demonstrates that the Company has designed facilities for the proposed project to avert spills of hazardous materials at either site and to contain any such accidental spills. The Siting Board also notes that the Company intends to develop emergency procedures and response plans similar to those found acceptable in previous Siting Board decisions. See Dighton Power Decision, EFSB 96-3, at 62; Berkshire Power Decision, 4 DOMSB at 416, Cabot Decision, 2 DOMSB at 417.

The record demonstrates that fogging and icing associated with the evaporative cooling tower for the proposed facility at both the primary and alternative sites would be limited to the immediate vicinity of the facility at both the primary and alternative sites, and that the towers have been sited to minimize fogging and icing. However, the Siting Board also notes that the conservative SACTI model predicts the potential for limited fogging and icing on public roadways. To minimize the potential impacts of fogging and icing on public

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184 The Siting Board also notes that the potential mitigating effects of using a smaller or an underground storage tank at either the primary or alternative site would be countered by associated increases in traffic impacts in the case of the smaller tank and cost increases in the case of underground tank construction.

roadways, the Siting Board directs the Company to work with the Town and the MHD to monitor fogging and icing in the vicinity of the proposed facility and, as necessary, to establish a plan with the identified local and state officials to ensure that any safety concerns are addressed.

Accordingly, the Siting Board finds that, with the implementation of the above condition, the environmental impacts of the proposed facility at the primary site would be minimized with respect to safety. In addition, the Siting Board finds that the primary site would be slightly preferable to the alternative site with respect to safety.

g. Electric and Magnetic Fields[185]

i. Primary Site

The Company indicated that operation of the proposed facility would produce magnetic fields associated with (1) the new 115 kV interconnect lines extending from the switchyard at the proposed site to transmission lines owned by New England Power Service Company ("NEPSCo") and designated as the W-123 line, and (2) increased power flows on certain existing transmission lines (Exh. MPP-16, at 4; Tr. 6, at 29-31).[186] The Company stated that project interconnection would require reconductoring the NEPSCo W-123 line to accommodate the full 360 MW plant output (id.).

The Company also pursued, but ultimately rejected, a two-line interconnection plan, which would have involved interconnection with a second NEPSCo transmission on the same

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185 Electric fields produced by the presence of voltage, and magnetic fields produced by the flow of electric current, are collectively known as electromagnetic fields ("EMF").

186 The Siting Board notes that NEPSCo's and other utilities' existing transmission lines are not ancillary facilities as defined in G.L. c. 164, § 69G. However, in order to allow comprehensive analysis of environmental impacts associated with the construction and operation of the proposed generating facility at both sites, the Siting Board may identify and evaluate any potentially significant effects of the facility on magnetic field levels along existing transmission lines. See Berkshire Decision, 4 DOMSB at 417; Altresco Lynn Decision, 2 DOMSB at 213; 1993 BECo Decision, 1 DOMSB at 148, 192.

ROW, the U-173 line, at a later date ("two-line plan"). The Company added that under the two-line plan, it would have pursued the reconductoring of the U-173 line to assist in delivering the plant's output to the area transmission system by sharing approximately half the plant's output with the W-123 line (id.).[187]

The Company indicated that EMF levels from the proposed interconnect line would be negligible off the proposed site and along the existing NEPSCo ROW, known as the Southwestern corridor, occupied by the W-123 and U-173 lines (Exh. EFSB E-111a). The Company added that the interconnect line would be located entirely on the proposed site and would be approximately 100 feet long (Exhs. MPP-4, att. 3, at 9-10; EFSB E-112).

With respect to increased power flows on the transmission system along the Southwestern corridor as a result of the proposed project's operation, the Company indicated that magnetic field levels at the ROW edges would be well below the 85 milligauss ("mG") threshold which the Siting Board has previously recognized, regardless of whether the Millennium Power facility is connected to one or both of the transmission lines along the Southwestern corridor (Exh. MPP-37, at 2-4). The Company also indicated that, under the two-line plan, the U-173 line along the Southwestern corridor would be changed to a davit arm configuration, thereby reducing the magnetic field levels at the ROW edge as compared to its present design (Exhs. MPP-16, att. 1; EFSB RR-14; Tr. 6, at 39, 45).[188] In response to a staff record request, the Company stated that as the final design for upgraded transmission along the Southwestern corridor proceeds, it would request that NEPSCo

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187 In the hearing, the Company's witness, Mr. Lambert, stated that, given the permitting and construction requirements for upgrading the U-173 line, the upgrade would have been pursued as a second phase that could occur after the project was on line (Exh. MPP-37, at 1-2; Tr. 6, at 29-30). He explained that with use of a bundled conductor, the W-123 line could be reconductored to ensure that the facility would meet the identified need and provide a reliable interconnection for an indefinite period, in the event a second interconnection line was not permitted and/or otherwise not completed (Exh. MPP-18, at 2-4).

188 The Company indicated that, compared to a horizontal arrangement of conductors, a davit arm design would result in greater clearances from the edge of the ROW, as well as a phase arrangement that reduces magnetic fields (Exh. EFSB RR-14).

consider the potential benefit, cost, feasibility, safety, and environmental impact implications of different conductor phasing arrangements in jointly selecting the final design for the reconductoring of one or both lines (Exh. EFSB RR-14).

The Company provided calculations of magnetic field levels along the Southwest corridor ROW both with and without operation of the proposed facility (Exhs. MPP-16, atts. 2-5; MPP-37, atts. 1-2). With operation of the interconnection as proposed, the Company indicated that the greatest magnetic field levels would be approximately 70 mG and 42 mG on the eastern and western edges, respectively, of the Southwest corridor ROW (id.). With operation of the interconnection under the two-line plan, the Company stated that the greatest magnetic field levels would be approximately 41 mG and 47 mG on the eastern and western edges, respectively (id.).

The Company identified two residences that would be located within 200 feet of the centerline of the Southwest corridor ROW (Exh. EFSB E-110, supp. A; Tr. 6, at 56-57).[189] The Company's witness, Dr. Bailey, testified that the closest residence to the ROW west side ("Residence A") would be approximately 100 feet from the centerline of the W-123 line, and the closest residence to the ROW east side ("Residence B") would be approximately 200 feet from the centerline (Tr. 6, at 56-57, 68). The Company provided estimates of magnetic field levels at both residences under the proposed interconnection and under the two-line plan (Exhs. EFSB E-110, supp. A; MPP-16, att. 3). The estimates indicate that the magnetic field level at Residence A would be 31 mG under either the proposed interconnection or the two-line plan, while magnetic field levels at Residence B would be 19 mG under the proposed interconnection and 12 mG under the two-line plan (id.). The Company further indicated that magnetic field levels are presently at or below 5 mG at Residence A and approximately 1 mG at Residence B (Exh. MPP-16, att. 3). The Company added that other

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189 The Company stated that the ROW between the proposed point of interconnect and the Carpenter Hill substation is characterized by low vegetation bordered by scrub forest (Exh. EFSB E-110). The Company identified the locations of four residences in the vicinity of the transmission lines, the closest two being within 200 feet of the lines (id.).

area residences are further away and would realize correspondingly lower magnetic field impacts (Tr. 6, at 72).

The Company indicated that it ultimately concluded that the proposed interconnection to the W-123 line would be preferable to the two-line plan because: (1) based on operation records recently obtained from NEPSCo, the W-123 line shows low outage rates, including a forced outage rate of 1.5 minutes in five years and a scheduled outage rate of eight hours per year; and (2) interconnection to the U-173 line would require replacement of transmission structures, resulting in significant additional impacts to wetlands (Exh. EFSB RR-40 (Supp. A)). The Company did not provide information as to the extent of wetland impacts under the two-line plan, nor their importance relative to EMF advantages of the two-line plan. Further, the Company did not estimate the additional costs for the two-line plan.

The Company's witness, Mr. Lambert, confirmed that the W-123 and U-173 115 kV transmission lines extend to the Carpenter Hill substation where they interconnect both with a 115 kV circuit designated as the V-174 line, and, following voltage transformation, with 345 kV circuits designated as the 302 line to the east and the 301 line to the west (id. at 60).

The Company indicated that the operation of the proposed facility would decrease magnetic field levels on the south side of the 302/V-174 ROW known as the Eastern corridor and increase magnetic fields on the north side (id. at 64-66; Exh. MPP-16, atts. 4,5).[190] The Company further indicated that under a wide variety of operating conditions, magnetic field levels would not exceed 50 mG at the edge of ROW along the Eastern corridor (Exh. MPP-16, atts. 4,5).[191] The Company stated that NEPSCo would reconductor the V-174

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190 For the Western corridor containing the 301 and W-175 circuits, the Company indicated that expected magnetic field levels, with operation of the proposed facility, would not exceed approximately 35 mG at the northern ROW edge, or approximately 8 mG at the southern ROW edge (Exh. MPP-16, att. 4).

191 The Company provided magnetic field levels along the northern and southern ROW edges on the Eastern corridor under (1) Millennium (peak system load), (2) Millennium (45 percent system load), (3) Existing (peak system load), (continued...)

transmission line, and added that it would ask NEPSCo to investigate the potential for reductions in EMF levels and the associated costs (Exh. EFSB RR-16).

ii. Alternative Site

The Company indicated that operation of the proposed facility at the alternative site would produce both electric and magnetic fields associated with the new 345 kV interconnect line extending from the switchyard at the alternative site to the NEPSCo 302 transmission line (Exhs. MPP-0, at 7-67; EFSB E-111a). The Company stated that EMF levels from the interconnect line would be confined mostly to the alternative site, or to the ROW of the 302 line (id.). The Company also stated that EMF levels due to the interconnect line would affect only one residence located on the alternative site itself, and that the Company would purchase that residence in the event the proposed project was to be located there (id.).[192] The Company indicated that most of the interconnect line would be located within the alternative site boundary and would be approximately 1,900 feet long (Exh. MPP-0, at 1-16).

The Company stated that it did not perform load flow simulations to determine the impact of plant operation at the alternative site (Exh. EFSB E-108). However, the Company further stated that interconnecting at the alternative site could decrease power flows presently incurred along the segment of 302 line extending easterly to a NEPSCo substation in the Town of Millbury from the plant's point of interconnection (Exh. EFSB E-160b). The Company indicated that power flowing westerly along the 302 line between the proposed

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[191](...continued)
and (4) Existing (45 percent system load) conditions (Exh. MPP-16, att. 5). The Company's projections of magnetic fields showed reductions along the southern ROW edge from approximately 8 mG at present to 2 mG or less with the proposed project under either system load scenario, and increases along the northern ROW edge, from approximately 10 mG at present to 42 mG with the proposed project under peak system load (id.).

[192] With regard to existing land uses along the Eastern corridor ROW from the Carpenter Hill substation to substation facilities in the Town of Millbury, the Company indicated that there were few, if any, abutters (Exh. EFSB RR-17).

facility's point of interconnect and the Carpenter Hill substation would not likely be reduced as a result of operation of the proposed facilities at the alternative site (id.). The Company presented magnetic field calculations along the Eastern corridor indicating that, under several scenarios, magnetic field levels at the ROW edges would be well under 50 mG (Exh. MPP-0, at 7-68 to 7-69).[193]

iii. Analysis

In a previous review of proposed transmission line facilities, the Siting Board accepted edge-of-ROW levels of 1.8 kV/meter for the electric field and 85 mG for the magnetic field. 1985 MECo/NEPCo Decision, 13 DOMSC at 228-242. Here, off-site electric and magnetic field levels would remain below the levels found acceptable in the 1985 MECo/NEPCo Decision.

Although consistent with edge-of-ROW levels previously accepted by the Siting Board, the estimated maximum magnetic fields along the Southwestern corridor with operation of the proposed facility -- 70 mG at ROW edge and 31 mG at the nearest residence -- are among the highest ever reviewed by the Siting Board. Further, although the transmission upgrade involves an existing line on an existing ROW, the estimated magnetic field level at the nearest residence represent a very substantial increase above the existing level of 5 mG or less.

The Company indicated that the 115 kV transmission lines on the Southwestern corridor and the Eastern corridor would be reconductored by NEPSCo as part of the interconnection strategy. The need for such reconductoring presents the Company and

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193 The Company stated that no reconductoring or other changes to existing facilities along the Eastern corridor are required as a result of operation of the proposed facilities at the alternative site (Exh. EFSB E-113). As such, the Company stated that there would be no opportunity to lower magnetic fields at little additional cost (id.). However, the Company added that by interconnecting at 345 kV, the current flow on the interconnect line and on the 302 circuit is lower than for a 115 kV interconnection, and therefore no further design options have been considered (id.).

NEPSCo with the opportunity to select physical designs capable of minimizing magnetic field impacts.

The Siting Board expects that, in pursuing interconnection plans that require upgrades to the regional transmission system, generating facility applicants will seek inclusion of practical and cost-effective transmission designs to minimize magnetic field levels at the edge of the ROW. Berkshire Decision, 4 DOMSB at 421; Silver City Decision, 3 DOMSB at 353-354. The Siting Board notes that the Company has committed to request that NEPSCo consider potential magnetic field reductions and costs as well as the feasibility, environmental impact, and safety implications of different electrical phasing arrangements in jointly selecting the final design for reconductoring the W-123 and V-174 circuits.

The record indicates that, although maximum magnetic fields along the east side of the Southwestern corridor would be held to lower levels with implementation of the two-line plan, the Company rejected that plan based on evidence that it would provide little reliability advantage. The Company also cited wetland impacts as a disadvantage of the two-line plan, but offered little evidence to substantiate those wetlands concerns, or to identify the incremental cost of the two-line plan. With respect to balancing any such wetland and cost disadvantages with the identified magnetic field advantages of the two-line plan, the record also shows that residential magnetic field concerns associated with interconnecting the project are limited to only a segment of the Southwestern corridor. The Siting Board notes, therefore, that reconductoring a second line along the overall corridor may not be a cost-effective way to minimize residential magnetic fields in a limited segment of the corridor.

Given the Company's rejection of the two-line plan, the Siting Board encourages the Company and NEPSCo to further consider transmission design options, and related implications for magnetic field impacts, based on the proposed reconductoring of the W-123 line alone. In particular, to minimize the projected increase in magnetic fields at the most affected residences along the Southwestern corridor, the Siting Board encourages the Company and NEPSCo to consider different configurations for the segment of the W-123 line near those residences. Such configurations could potentially limit any increases in the magnetic fields in that segment by maximizing cancellation of such fields, or maximizing the line's separation from residences, subject to considerations of operating safety and good engineering practice.

Accordingly, the Siting Board finds that, with the Company's pursuit of designs for reconductoring the W-123 and V-174 lines that the Company and NEPSCo determine would best limit magnetic field increases at affected residences, and also be practical and cost-effective, the environmental impacts of the proposed facility at the primary site would be minimized with respect to EMF impacts.

The record indicates that operation of the proposed facility at the alternative site would result in lower overall magnetic field levels on the existing transmission system than operation at the primary site, based on incrementally higher magnetic field levels at the edge of the Southwestern corridor from the primary site to the Carpenter Hill substation, and on the Eastern corridor. These incrementally higher levels may be due, in part or in whole, to initial interconnection and transmission of power from the proposed facility at 115 kV transmission voltage at the primary site versus 345 kV at the alternative site.

Therefore, the Siting Board finds that the alternative site would be preferable to the primary site with respect to EMF impacts.

h. Land Use

i. Primary Site

The Company stated that the development of the Millennium Power project at the preferred site will be compatible with current land use characteristics and zoning for the site and will be consistent with relevant town and regional development objectives (Exh. MPP-0, at 6-143, 6-147). The Company further stated that the proposed Millennium project would be compatible with surrounding uses and would be an economic benefit to the region (id. at 6-147 to 6-148).

The Company indicated that the facility is proposed to be constructed in an Industrial-General zone located along Route 169 (id. at 6-143 to 6-144). The Company stated that the 120 acre site is currently vacant and mostly wooded, although a portion of the site has been previously cleared (id. at 6-144). The Company stated that the proposed facility layout would occupy approximately 15 acres of the 120 acre site, of which approximately seven acres consists of currently cleared upland area (id., Exh. E-98; Tr. 4 at 114).

The Company stated that the preferred site is located in a mixed industrial, commercial and residential area with a number of industrial facilities abutting the site (Exh. MPP-0, at 6-143, 6-145). The Company described the contiguous land uses as utility easements and vacant land to the north and west,[194] commercial and industrial land to the southeast, and residential and vacant land to the east and northeast (Tr. 4, at 120). The Company indicated that the heights of surrounding commercial/industrial structures are not as tall as several of the components of the proposed facility (Tr. 9, at 81-82). Based on the Massachusetts Geographic Information System ("GIS") and Charlton zoning map information, the Company estimated that 80 percent of the area within a one-mile radius of the proposed facility site is open land, 15 percent is devoted to residential uses, and 5 percent is used for commercial/industrial purposes (Exh. EFSB E-93). Within a half-mile radius, the Company noted that the Town of Charlton planner estimated that 70 percent of the land was agricultural, which encompasses the development of agricultural and low density residential use, and 30 percent of the land was industrial, which also includes commercial uses (id.; Exhs. EFSB E-156; MPP-0, at 6-145).

The Company stated that most of the residential and vacant land in the vicinity of the site is located along roadways outside of the immediate Route 169 corridor (Exhs. MPP-0, at 1-9; MPP-4, att. C). The Company stated that presently the closest residence is located 800 feet southeast of the proposed facility on Sherwood Lane; however, the Company explained that this residence is located on property to be acquired by the Company as part of the site (Exh. EFSB E-92). Therefore, post construction, the nearest occupied residences would be

194 The Siting Board notes that H. Foote Road, west of the electric utility easement, is located approximately 300 feet from the northwestern site boundary and 1,500 feet from the footprint of the proposed site and is a residential area (Exhs. MPP-0, at 6-146; Tr. 4, at 132, 133, 137).

the Cady Brook Apartments, a 24 unit complex approximately 1,000 feet east of the facility footprint and a single family residence located next to the apartment complex (Exhs. EFSB E-99, EFSB E-154, EFSB E-175b; EFSB RR-9). Further, the Company stated that the nearest residences to the site property line are located less than 300 feet to the east of the site (Exhs. EFSB E-92; EFSB E-175). The Company indicated that approximately 100-150 residences are located within one-half mile of the preferred site (Exhs. EFSB E-92; MPP-18 at 6-7).

The Company reported that the majority of the site is located within the Town's Industrial-General zone, in which an electrical generation facility is a permitted use (Exhs. MPP-0, at 6-147; EFSB E-90).[195] The Company maintained that a portion of the site north of the facility footprint is currently located in Charlton's Agricultural zone,[196] but is not actively cultivated, further, the Company explained that only a limited amount of construction, related to installation of the gas and oil pipeline interconnections, would occur in this area (Exh. MPP-0, at 6-147).

The Company asserted that it has met all Charlton zoning criteria[197] and therefore it would not be requesting any additional permits from the planning board or zoning board of appeals (Tr. 4, at 148). The Company added that the site plan submitted to the Charlton Planning Board had been unanimously approved in April of this year, although that approval is under appeal by a group of residents (Exhs. EFSB E-95; E-96 (Supp. B, Supp. C, and Supp. D).

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195 The Company stated that the identified site area was re-zoned from agricultural use to industrial-general use in the 1980's (Exh. EFSB E-103).

196 The purpose of the Charlton Agricultural zoning district is to provide for agricultural and lowest density residential sites while encouraging open space (Exh. EFSB E-90, at 14).

197 The Company indicated that the Charlton Zoning By-laws set a maximum building height in the Industrial-General District of 36 feet, however, structures not devoted to human occupancy, and normally built above the roof, do not fall under the maximum height limitation (Exh. EFSB E-90 at 26; Tr. 4, at 147-148).

The Company also presented evidence to the Siting Board regarding its "Property Value Guarantee" program for Charlton residents living within a half-mile of the proposed site (Exh. MPP-18, at 6-7). The Company explained that the program has been offered to approximately 100 homeowners and landowners to guarantee the current value of their homes (id.). The Company further explained that the program is specifically targeted only for those homeowners who had expressed a concern about the loss of property values (Tr. 3, at 4-5).

The Company asserted that the proposed facility would not have an adverse impact on historical or archaeological properties (Exh. MPP-0, at 6-156; Tr. 4 at 36). The Company stated that staff of the Public Archaeological Laboratory, Inc. ("PAL") surveyed the preferred site and identified three historic period structures of potential interest on the site, and that therefore the Company would follow the recommendations set forth in the PAL avoidance plan necessary to preserve the identified historic structures (Exhs. MPP-0, at 6-151 to 6-152; EFSB RR-41; Tr. 4, at 137) . The Company stressed that none of these structures will be disturbed by the proposed project or the related utility interconnections (Exhs. MPP-0, at 6-151 to 6-152; EFSB E-158, rev. A).

ii. Alternative Site

The Company stated that the proposed site is preferable to the alternative site for industrial development (Company Brief at 186 to 187). However, the Company stated that the alternative site would be suitable for development as an electric generating facility, and noted that it has entered into an option to purchase agreement with the current owners (Tr. 4, at 122-123, 125). The Company indicated that the 50 acre alternative site is currently used for residential purposes, with two occupied residences on site, one at the location of the proposed facility footprint and one to the north of the gas pipeline easement (Exh. MPP-0, at 1-14). The Company described the majority of the property as consisting of open grassed areas and wooded land, and noted that the site is traversed both by separate electric and gas utility corridors (Exh. MPP-0, at 7-19 to 7-20).

The Company characterized the area as rural-residential, with a majority of residential and non-industrial uses (Exh. MPP-0, at 7-20; Tr. 4, at 124). The Company described the surrounding land use as residential to the west along Burlingame Road, a former landfill to the south and east along Flint Road, scattered residences also along Flint Road to the east, residential along Burlingame Road, and otherwise vacant land and utility easements to the north (Exhs. EFSB E-92; MPP-0, at 7-20). Further, the Company noted that the town Department of Public Works ("DPW") garage is located just southeast of the alternative site, and commercial uses, such as nurseries,[198] are found at State Route 31, which runs a quarter mile east of the alternative site (Exh. MPP-0, at 7-20). Based on GIS and Charlton zoning map information, the Company estimated that 70 percent of the area within a one-mile radius of the proposed alternative site is forest and open land use, 10 percent is industrial use, 10 percent is urban open use, and 10 percent is residential (Exh. EFSB E-93). The Company indicated that, according to the Charlton planner, 90 percent of the land within a half-mile of the site is agricultural, and 10 percent is residential (id.).

The Company stated that the closest residence, with the exception of the residences located on-site, is approximately 600 feet from the nearest facility structure and 80 feet from the facility boundary (Exh. EFSB E-92). The Company indicated that approximately 150 residences are located within one-half mile of the alternative site (id.). The Company stated that the presence of the abandoned landfill, and the proximity to the DPW garage, as well as multiple utility easements, renders the site suitable for industrial development (Exh. MPP-0, at 7-20; Tr. 4, at 122-124).

The Company stated that the alternative site is located in the Charlton Agricultural zone, in which an electrical generation facility is not a permitted use (Exh. MPP-0, at 7-20). Therefore, the Company stated that the alternative site would require a change in zoning designation in order for the Millennium project to be built (id.). The Company explained that any rezoning petition that would be filed in the event the Company was to develop the alternative site, would involve a number of parcels in the area, such as the abandoned landfill and not just the proposed alternative site (Tr. 4, at 161 to 162). The Company asserted that

198 The Company indicated that in addition to a nursery, the specific commercial uses consisted of one retail store/commercial warehouse, an engineering office, and an in-home business (Exh. EFSB E-105, att. A).

in its experience, such a rezoning is feasible (Exh. EFSB S-15, rev. A). The Company asserted that even though the site is zoned agricultural, there is little or no active farming in the immediate vicinity (Exh. MPP-0, at 7.)

Finally, based on the reconnaissance survey conducted by PAL, the Company stated that the alternative site likely contained cultural resources such as stone walls that would require further archaeological investigation (Exh. MPP-0, at 7-23).

iii. Analysis

As part of its review of land use impacts, the Siting Board considers whether a proposed facility would be consistent with state and local requirements, policies, or plans relating to land use and terrestrial resources.[199] Here, the record indicates that the primary site and surrounding areas are zoned for both industrial and agricultural/residential use, that the abutting uses are a mixture of light industrial/commercial, residential, and vacant land. The record further indicates that the area within a half mile radius of the primary site is predominantly open land, and approximately a third is being used in an industrial and commercial capacity. The proposed facility is an allowed use under the Zoning By-laws of the Town of Charlton. The Siting Board notes that the proposed stack is considerably taller than existing structures in the area, but that according to the Charlton zoning by-laws, stack height in excess of the 36-foot height limitation is allowed. The Company has received site plan approval from the Charlton Planning Board, although the approval is under appeal by abutting residents.

The Siting Board has considered the adequacy of site buffering and proposed mitigation to limit the visual and noise impacts of the proposed facility in Sections III.B.2.c. and III.B.2.d, above. Further, the Siting Board has imposed conditions to limit visual and noise impacts of the proposed facility in Sections III.B.2.c. and III.B.2.d, above.

199 See Section III.B.2.b.i.(c), Water Resources, for a discussion regarding the aquatic and terrestrial habitat of the marbled salamander.

In regard to the Property Guarantee Program, the Siting Board notes that to the extent that there are property value impacts not addressed by the visual impact and noise mitigation, the program could contribute to the mitigation of such impacts. The Siting Board notes that in past reviews of generation facilities, it generally has not required such programs, and that the program proposed here is an entirely voluntary action on the part of the Company.[200]

Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the primary site would be minimized with respect to land use.

The Siting Board notes that: (1) the alternative site is located in a rural-residential area with the nearest off-site residence located 600 feet from the facility footprint, and other residences located along the abutting roads, Burlingame Road and Flint Road; (2) there is no industrial land use within a half mile of the alternative site footprint, and commercial uses within a mile are minimal, consisting of a nursery, a retail store and two offices; (3) scenic landscapes including an area designated as distinctive in the DEM Landscaping Inventory are proximate to the alternative site (see Section III.B.2.c, above); and (4) the alternative site is zoned for agricultural/residential use and would require a change in zoning. The Company has asserted that the presence of an abandoned landfill and utility easements, along with the DPW garage, are indicators of comparable industrial use. The Siting Board notes that utility easements can exist in any district and are not in and of themselves indicative of an industrial area. Further, an abandoned landfill would be categorized as vacant land and in its present decommissioned state is not readily associated with industrial use, especially in terms of building scale and related impacts. The Siting Board is aware that it may be appropriate to locate a generating facility in an agricultural district with large amounts of undeveloped land. However, in this case, the specific site is: (1) located in a district whose overall characteristic is large lot residential use and vacant land; (2) the facility would be less than one eighth of a mile from the nearest residence; (3) the facility would be proximate to scenic

---

200 In the Silver City Decision, the Siting Board did find that an abutter property guarantee program was warranted to establish that land use impacts would be adequately minimized. Id. 3 DOMSB at 365.

landscapes; and (4) the site would have to be rezoned.[201] These factors combine to create an inferior site on which to locate a generating facility.

Accordingly, the Siting Board finds that the primary site would be preferable to the alternative site with respect to land use.

3. Cost

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine if an appropriate balance has been achieved between environmental impacts and costs. The Siting Board then compares the estimated costs of constructing and operating the proposed facilities at the primary and alternative sites.

The Company stated that the total cost of the proposed facilities at the primary site would be $204,725,000 in 2000 dollars (Tr. 10, at 23).[202] The Company stated that this cost estimate includes an estimate of the site specific and current information regarding: (1) construction costs; (2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance; (4) site acquisition costs; (5) other costs, including NO_x offset costs; and (6) financing and related costs, including development costs (id.; Exh. MPP-11, att. 2). The Company further stated that the total cost of the proposed facilities at the alternative site would be $209,500,000, approximately $4.775 million greater than at the primary site (Tr. 10, at 23). The Company stated that the increased costs at the alternative site would be due primarily to increased land acquisition costs and wastewater discharge/water supply pipeline costs (id.). The Company noted that the operation and maintenance costs of the facility at the primary and alternative sites would be essentially identical (id. at 26). The

[201] Consistent with Siting Board precedent, the fact that rezoning would be required does not in and of itself make the site unsuitable for development. NEA Decision, 16 DOMSC at 392.

[202] The Company estimated that new design modifications to the electrical interconnect will reduce costs by $8 million to $10 million at the primary site (Exh. EFSB RR-40 (supp. A)).

Company asserted that the cost estimate was realistic for a facility of this size and design based on the price of the equipment and the Company's experience in similar projects (id. at 30; Exh. MPP-0, at 6-207).

The Company also identified the costs of several options to further minimize the environmental impacts associated with the proposed facility including use of dry cooling, additional noise mitigation technology and using gas as the exclusive fuel (Exhs. EFSB E-63; EFSB RR-19; EFSB RR-36; MPP-7, at 7-8). The Company estimated that the capital cost of a dry cooling tower or a wet/dry cooling system would exceed the capital cost of the proposed evaporative cooling tower by \$8.4 million to \$14.4 million and that output and efficiency also would decrease with a dry or wet/dry cooling system (Exh. EFSB E-63). As noted above in Section II.B.2.d, the Company indicated that noise mitigation technology to further reduce the noise impacts at the most affected residential noise receptors would cost: (1) an additional \$900,000 to limit the noise increase over the L_{90} to 7-8 dBA, and (2) an additional \$2,600,000 to limit the noise increase over the L_{90} to 5-6 dBA at the most affected residential receptors (Exh. EFSB RR-19). The Company also indicated that the cost of a firm 365 day gas contract with dedicated firm gas transportation service to use gas as the exclusive fuel would increase fuel costs by \$60 to \$200 million over the ten year term of the proposed fuel supply contract (Exh. MPP-7, at 7-8). However, the Company noted that the cost of NOx offsets and SO_2 allowances would decrease by approximately \$178,635 if gas were used exclusively (Exh. EFSB RR-36).

The record contains estimates of the overall costs of the proposed facility at the primary and alternative sites, as well as cost information for measures to further minimize environmental impacts at both sites. The Company has noted specific cost advantages of siting the proposed facility at the primary site.

Accordingly, the Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine which site is preferable with respect to cost and whether an appropriate balance would be achieved among environmental impacts and cost.

With respect to comparison of the primary and alternative sites overall, the Company's analysis shows a total capital cost advantage of approximately $4.775 million for the primary site over the alternative site. The record demonstrates that the cost of operating the proposed facility at the primary site would be comparable to the alternative site. Consequently, the Siting Board finds that the primary site is preferable to the alternative site with respect to cost.

4. Conclusions

In this section, the Siting Board reviews the consistency of the proposed facility with its overall review standard, which requires that the appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as between these environmental impacts and costs.

a.. Conclusion on the Proposed Facility at the Primary Site

The Siting Board has found that, with the implementation of the conditions specified in Section III.B.2 above, the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality, water supply, water-related discharges, construction related impacts to wetlands, visual impacts, traffic, safety, EMF, and land use. Further, in Section III.B.3, the Siting Board has found that USGen has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and cost.

As discussed in Sections III.B.2, above, the Company has identified and considered the cost-effectiveness of further measures for mitigation of the estimated noise impacts of the proposed facility. In addition, as part of its consideration of noise mitigation that would require increasing the height of the main building and stack, the Company considered the relative trade-off between noise and increased visual impact.

The Siting Board finds that, with the implementation of proposed mitigation and conditions, the noise impacts of the proposed facility would be minimized, consistent with minimizing cost. Therefore, the Siting Board finds that, with the implementation of the above conditions and with the conditions set forth in Sections III.B.2 above, the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost.

b. Comparison of the Primary and Alternative Sites

In Section III.B.2 above, the Siting Board has found that:

- the primary site would be comparable to the alternative site with respect to air quality;
- the primary site would be comparable to the alternative site with respect to water supply;
- the primary site would be comparable to the alternative site with respect to water-related discharges;
- the alternative site would be preferable to the primary site with respect to construction-related impacts to wetlands;
- the primary site would be comparable to the alternative site with respect to visual impacts;
- the primary site would be preferable to the alternative site with respect to noise;
- the primary site would be preferable to the alternative site with respect to traffic impacts;
- the primary site would be slightly preferable to the alternative site with respect to safety;
- the alternative site would be preferable to the primary site with respect to EMF impacts; and
- the primary site would be preferable to the alternative site with respect to land use.

Accordingly, on balance, the Siting Board finds that the environmental impacts of the proposed facility at the primary site are superior to those at the alternative site.

The Siting Board also has found, in Section III.B.3, above, that the primary site would be preferable to the alternative site with respect to cost. Accordingly, the Siting Board finds that the primary site is preferable to the alternative site with respect to minimizing environmental impacts consistent with minimizing cost.

IV. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. In addition, the statute requires the Siting Board to determine whether plans for expansion or construction of energy facilities are consistent with the current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

In Section II.A, above, the Siting Board has found that the Company has established need for the proposed project. Further, in Sections II.B and II.C, above, the Siting Board has found that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost, and that upon compliance with the listed conditions, USGen has established that its proposed project is reasonably likely to be a viable source of energy. In Sections III.A and III.B, above, the Siting Board has found that USGen has considered a reasonable range of practical facility siting alternatives, and that with implementation of the listed conditions relative to air quality, water supply, water-related discharges, construction-related impacts to wetlands, visual impacts, noise, traffic, and safety, the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost. Finally, in Section III.B, above, the Siting Board has found that the construction and operation of the proposed facility at the primary site is preferable to construction and operation of the proposed facility at the alternative site.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.C, and III.B, above, and listed below, the construction and operation of the proposed facility will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Sections III.A and III.B, above, the Siting Board has reviewed various environmental impacts of the proposed facility in light of related regulatory or other programs of the Commonwealth, including programs relating to air quality, water supply, water-related discharges, wetlands protection, noise, rare and endangered species, agricultural land preservation, and historical preservation. As evidenced by the above discussions and analyses, the proposed facility will be generally consistent with identified requirements under all such programs. In addition, prior to construction the Company shall file with the Siting Board a signed copy of its certificate on its FEIR.

Accordingly, the Siting Board APPROVES the petition of U.S. Generating Company to construct a 360 MW bulk generating facility and ancillary facilities in Charlton, Massachusetts subject to the following conditions during construction and operation of the proposed facility:

(A) In order to ensure that the project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives, the Siting Board directs USGen to provide: (1) a copy of a signed EPC contract between USGen and BPC or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, and (2) a copy of a signed interconnection agreement between the Company and NEPSCo providing the proposed project with access to the regional transmission system.

(B) In order to ensure that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, the Siting Board requires USGen to provide a signed O&M contract between USGen and USOSC or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer.

(C) In order to allow the Siting Board to monitor developments affecting gas capacity into New England, which relates to USGen's expectations as to the reliability of its fuel supply strategy, the Siting Board requires USGen to provide periodic updates on the status of gas supply projects to increase gas capacity into New England.

(D) In order to mitigate CO_2 emissions, the Siting Board requires USGen to provide CO_2 offsets through a donation of $370,000, to be paid in five annual installments of $74,000 during the first five years of facility operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff. If the Company chooses to provide the entire donation within the first year of facility operation, the CO_2 offset requirement would be a donation in the amount of $305,000 to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff.

(E) In order to minimize impacts to water resources, the Siting Board directs USGen to provide a copy of the MDEP approval of G.L. c. 21G permit, together with any attached conditions and a detailed explanation of how all conditions will be met.

(F) In order to minimize wetland impacts, the Siting Board directs USGen to provide a copy of the Conservation Permit from the NHESP with attached conditions and a detailed explanation of how all conditions will be met.

(G) In order to minimize visual impacts, the Siting Board directs the Company, consistent with the directives in Section III.B.2.c, to develop and implement an off-site shrub and tree plantings or window awnings plan. In this regard, the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner, and along public ways, only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to public officials in Charlton and to all affected property owners prior to the commencement of construction; (3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement plantings as necessary to ensure that health plantings become established. In addition, the Siting Board directs USGen to make available to affected Harrington Road residents the option of at least one strategically placed planting of 20 feet or more as may be practical and appropriate to the setting, in lieu of a row of several smaller plantings.

(H) In order to minimize noise impacts consistent with minimizing cost, the Siting Board requires the Company to meet either of the following conditions consistent with the directives in Section II.B.2.d, above: (1) the Company shall incorporate noise mitigation measures into its pre-construction facility design such that calculated L_{90} noise increases would not exceed 7.5 dBA at residential receptors; or (2) the Company shall incorporate noise mitigation measures in its proposed facility such that measured L_{90} noise increases at residential receptors would not exceed 6.0 dBA.

(I) In order to minimize traffic related impacts, the Siting Board requires USGen, in consultation with the Towns of Auburn, Oxford, Sturbridge, and Charlton, to develop and implement a traffic mitigation plan which includes scheduling of the delivery of fuel oil, materials, and equipment to avoid peak daily travel periods or route modifications or other appropriate measures to minimize traffic-related impacts along likely access routes to the site including Route 20 and Route 169.

(J) In order to minimize the potential impacts of fogging and icing on public roadways, the Siting Board directs USGen to work with the Town of Charlton and the MHD to monitor fogging and icing in the vicinity of the proposed facility and, as necessary, to establish a plan with the identified local and state officials to ensure that any safety concerns are addressed.

Because issues addressed in this decision relative to this facility are subject to change over time, construction of the proposed generating facility and ancillary facilities must be commenced within three years of the date of this decision.

In addition, the Siting Board notes that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

Jolette Westbrook
Jolette A. Westbrook
Hearing Officer

Dated this 3rd day of November, 1997

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of November 3, 1997 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Janet Gail Besser, (Commissioner, Acting Chair EFSB/DPU); John D. Patrone (Commissioner, DPU); Sonia Hamel (for Trudy Coxe, Secretary, Executive Office of Environmental Affairs); Francis Cummings (for David A. Tibbetts, Director, Department of Economic Development); Nancy Brockway (Public Member); and Joseph Faherty (Public Member).

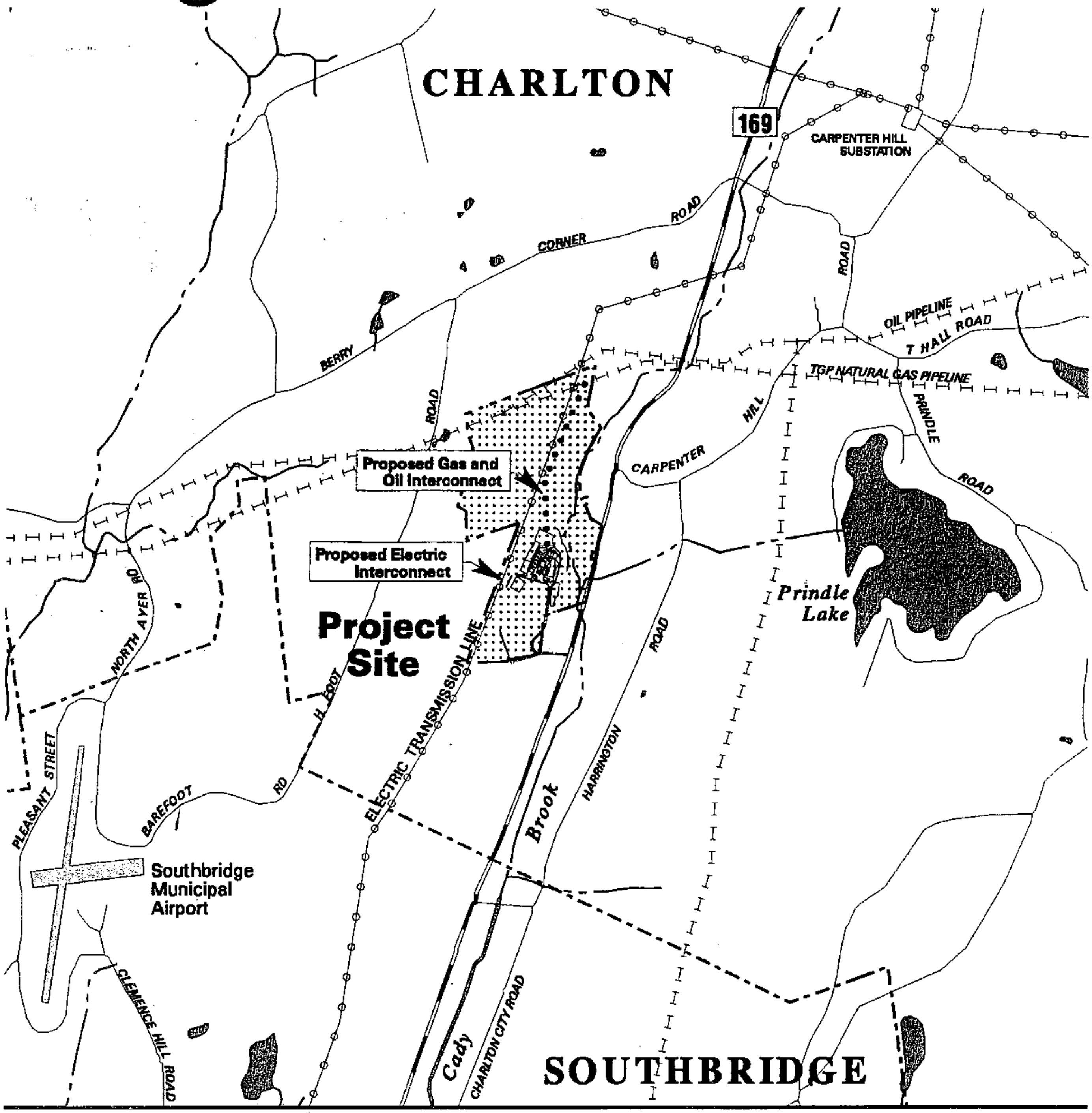
Janet Gail Besser

Janet Gail Besser
Acting Chair

Dated this 4th day of November, 1997

Appeal as to matters of law from any final decision, order or ruling of the Siting Board may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Board be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).



Legend:

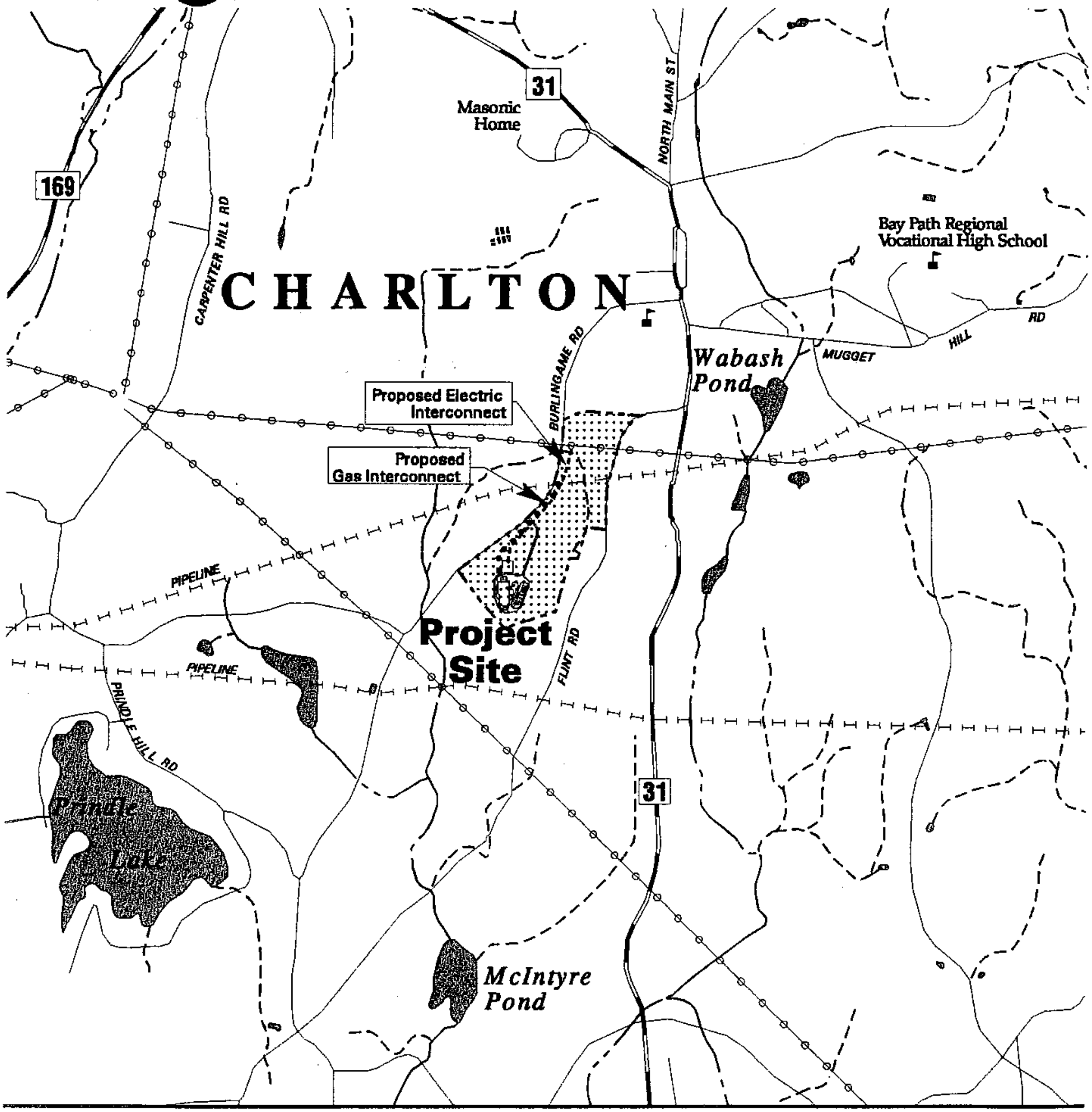
- Stream
- Town Line
- Electric Transmission Line
- Pipeline

Millennium Power Project
Proposed Site

FIGURE 1

Scale 1:24000
0 2000 4000
Feet

Data supplied by Massachusetts EOEA, MassGIS.



Legend:

- Stream
- Town Line
- Electric Transmission Line
- Pipeline

Millennium Power Project

Alternate Site

FIGURE 2

Scale 1:24000

0 2000 4000

Feet

Data supplied by Massachusetts EOEA, MassGIS.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Boston Edison Company for Approval of its Occasional Supplement and Plan to Construct a New 115/14kV Substation and Transmission Line in Milford and Hopkinton, Massachusetts The Petition of Boston Edison Company for Exemption of Proposed Transmission Lines, Transmission Station, Substation and Distribution Facilities from the Zoning By-Laws of the Towns of Milford and Hopkinton, Massachusetts and for a Determination that Proposed Transmission Lines, Transmission Station, Substation and Distribution Facilities are Necessary and Will Serve the Public Convenience and be Consistent With the Public Interest	)	EFSB 96-1

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
December 22, 1997

On the Decision:
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William S. Febiger
Phyllis Brawarsky
Barbara Shapiro

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V

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FIGURES:

FIGURE 1: PRIMARY AND ALTERNATIVE ROUTES

FIGURE 2: NOTICED ROUTE SEGMENTS

The Energy Facilities Siting Board hereby APPROVES the petition of Boston Edison Company to construct two 1.3-mile long, 115-kilovolt underground electric transmission lines; a transmission station; a 115/14-kilovolt substation; and distribution facilities in the towns of Hopkinton and Milford, Massachusetts using the Company's preferred sites and routes.

I. INTRODUCTION

A. Summary of the Proposed Project

Boston Edison Company ("BECo" or "Company") is an investor-owned electric utility corporation engaged in the generation, transmission, distribution, purchase, and bulk and retail sale of electricity in forty communities in the Commonwealth of Massachusetts, including the Town of Hopkinton (Exh. BE-1, at 1-1).

BECo has proposed to construct two 1.3-mile long, 115-kilovolt ("kV") underground electric transmission lines which would be located beneath Purchase Street in Milford and South Street in Hopkinton (id. at 1-5). These two new transmission lines would connect the Company's proposed substation on South Street in Hopkinton ("South Street substation" or "Station #126") with a proposed transmission station, to be located off Purchase Street in Milford (id.). The proposed transmission station would provide an interconnection point with two existing, overhead 115-kV New England Electric System ("NEES") transmission lines, which run from Medway to Milbury and pass through Milford to the south of Hopkinton (id.).

For its preferred route, BECo has proposed two overhead taps to connect the two existing NEES transmission lines with the Company's proposed transmission station (id. at 1-5, fig. 1-1). The proposed Company transmission lines would then exit underground, from within the enclosed area of the transmission station, and proceed to Purchase Street and run north under Purchase Street into Hopkinton (id. at 1-5; 1-7). The transmission lines would then continue north under South Street in Hopkinton to the proposed site of the South Street substation (id.) (see Figure 1).

BECo also identified a comparable set of facilities using alternative sites and routes (id. at 1-7, fig. 1-2). The alternative facilities would tap the same NEES transmission lines at a point approximately two miles to the west of the preferred route tap site and connect with an alternative transmission station, which would be located off East Street in the Town of Upton (id. at 1-7). The two new transmission lines would then exit underground, from within the enclosed area of the alternative transmission station, and proceed to East Street and run north under East Street and School Street approximately 1.1 miles to an alternative substation which would be located near the intersection of School Street and West Main Street in Hopkinton (id.) (see Figure 2).

BECo indicated that the transmission station at either site would be located on an approximately 140-foot square area surrounded by a seven-foot high barbed-wire fence, and would consist of four manually operated disconnect switches, two single pressure sulfur hexafloride circuit breakers, two sets of measuring transformers, surge protection equipment and cable terminators (Exh. BE-AJ-1, at 4). A 25-foot square control house would house the control equipment and a storage battery for control power, and two 40-foot tall shielding masts[1] would be located within the enclosed area (id.; Exhs. BE-AJ-4; Hopkinton-RR-1). In addition, to effect the tap of the NEES transmission lines. BECo would locate two sets of three steel poles on the NEES right-of-way ("ROW") and three short sections of wire would connect the existing transmission lines to an incoming bridge structure, within the transmission station, by way of the new set of three steel poles (Exhs. BE-1(att. A); HO-E-14). The existing NEES steel structures which support the existing transmission lines will either be raised by approximately ten feet or replaced (id.).

The proposed substation at either site would consist of two 24/32/40 mega-volt ampere ("MVA"), 115/14-kV low-noise transformers and two sections of 14-kV switchgear equipped with a total of 12, 14-kV feeder positions (Exh. BE-1, at 1-5). The transformers would be enclosed on three sides by sound barriers to attenuate noise, and the entire substation would be enclosed by a seven-foot high barbed-wire fence (id.).

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1 BECo originally indicated that the shielding mast would be "a maximum height of 75 feet" (Exh. BE-1 at 1-5).

In addition to the proposed new transmission lines, transmission station and substation, BECo would install new distribution circuits and equipment connecting the proposed substation at either site to the existing distribution system, using routes which vary depending on the substation site chosen (id. at 1-7, 1-9).

B. Procedural History

BECo filed its "Occasional Supplement to the Long Range Forecast" ("petition") with the Energy Facilities Siting Board ("Siting Board") on March 11, 1996. In its petition, the Company sought approval of its plans to construct the South Street substation, two new 115-kV transmission lines, and the associated transmission station and distribution facilities. The Siting Board docketed the petition as EFSB 96-1. The Company requested a postponement of the public hearings on its petition and memorialized the Siting Board's approval of the postponement in a May 10, 1996 letter. On November 1, 1996, BECo filed an Addendum to its Occasional Supplement ("Addendum") and requested the Siting Board to proceed with the adjudication in this docket. On December 4 and 5, 1996, the Siting Board conducted public hearings on the petition and addendum in the Town of Milford and the Town of Hopkinton, respectively. In accordance with the direction of the Hearing Officer, BECo provided notice of the public hearings and adjudication.

Timely petitions to intervene were submitted by: the Town of Upton Board of Selectmen ("Town of Upton"); the Town of Milford; the Town of Hopkinton Board of Selectmen ("Town of Hopkinton"); State Senator Richard T. Moore; State Senator David P. Magnani; State Representative Barbara Gardner; State Representative Marie J. Parente; the Office of the Attorney General for the Commonwealth ("Attorney General"); Andrej Thomas Starkis, Esq.; Mr. Douglas Vrooman; Ms. Mary M. Plummer; and Brendan J. Perry and Joseph F. Oliveri d/b/a/ Interface Realty Partnership ("IRP"), Sovereign Development, Ltd. ("Sovereign") and Interface Electronics Corp. ("IEC"). In addition, timely petitions to participate as an interested person were received from Richard A. Amato and Ms. Stephanie Atanian. BECo also submitted a letter indicating that it had no objection to the granting of interested person status to Mrs. Eleanor Broderick, who made an oral request for such status following the conclusion of the public hearing in Hopkinton. On December 19, 1996, the Conservation Law Foundation, Inc. ("CLF") filed a late-filed petition to intervene on a limited basis.

The Hearing Officer allowed the petitions to intervene of: the Towns of Upton, Milford[2] and Hopkinton; Senators Moore and Magnani; Representatives Gardner and Parente; the Attorney General; Attorney Starkis; Mr. Vrooman; Ms. Plummer; and IEC.[3] See Hearing Officer Procedural Order, January 17, 1997, at 6-7. The Hearing Officer also allowed the petitions to participate as an interested person of: Mr. Amato; Ms. Atanian; Mrs. Broderick; and CLF. Id. at 7.

The Siting Board conducted seven days of evidentiary hearings commencing June 11, 1997 and ending June 26, 1997. BECo presented four witnesses: Amin R. Jessa, a senior supervisor engineer for the Company, who testified regarding the need for the project, the project approach comparison, the site/route selection process, and costs and reliability of the proposed and alternative facilities; Pamela M. Chan, senior program director in the Air Quality Consulting and Engineering Group for Earth Tech, an environmental engineering and consulting firm, who testified regarding alternative approaches including alternative sites and routes; Daniel J. Stuart, senior environmental scientist for Earth Tech, who testified regarding environmental issues and permitting; and Dr. Peter A. Valberg, principal at Gradient Corporation and adjunct associate professor of environmental health at the Harvard School of Public Health, who testified regarding electric and magnetic fields ("EMF") and their potential health effects.

The Town of Hopkinton presented three witnesses: William Teuber, vice president and chief financial officer for EMC Corporation ("EMC^2"), who testified regarding the financial impact of power outages experienced at EMC^2; Daniel Fitzgerald, director of corporate facilities for EMC^2, who testified regarding the future energy requirements for EMC^2; and Maureen Dwinnell, the treasurer-tax collector for the Town of Hopkinton, who

2 The Town of Milford withdrew as an intervenor on June 20, 1997.

3 IEC withdrew as an intervenor on March 24, 1997.

testified regarding the need for reliable electric service in the Town of Hopkinton.

The Town of Upton presented written testimony of one witness, Richard A. Amato, the owner of the Amato Farm which is located near the site of the alternative substation site and abuts the route of the alternative transmission lines, who testified regarding the impacts of construction of the alternative facilities on his home and business.

Senator Magnani, the State Senator for the Town of Hopkinton, provided testimony regarding the need for increased electrical reliability and capacity for the industrial parks in the Town of Hopkinton.

The Hearing Officer entered 119 exhibits into the record, consisting largely of responses to information and record requests. The Company entered 32 exhibits into the record. The Attorney General entered 45 exhibits into the record. Representative Parente entered 38 exhibits into the record. Senator Magnani entered 3 exhibits into the record. The Town of Milford entered 65 exhibits into the record. The Town of Upton entered 95 exhibits into the record. The Town of Hopkinton entered 18 exhibits into the record. Attorney Starkis entered 53 exhibits into the record. Mr. Vrooman entered 116 exhibits into the record.

Initial briefs were filed by BECo ("BECo Initial Brief"), the AG ("AG Brief"), the Town of Hopkinton ("Hopkinton Brief"), Attorney Starkis ("Starkis Initial Brief"), and CLF ("CLF Brief") on August 4, 1997. Reply Briefs were filed by BECo ("BECo Reply Brief") and Attorney Starkis ("Starkis Reply Brief") on August 11, 1997.

C. Jurisdiction

The Company's petition is filed in accordance with G.L. c. 164, § 69H, which requires the Siting Board "to implement the energy policies . . . to provide a necessary 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 electric companies to obtain Siting Board approval for construction of proposed facilities at a proposed site before a construction permit may be issued by another state agency.[4]

The Company's proposal to construct two 1.3-mile long, 115-kV electric transmission lines falls squarely within the second definition of "facility" set forth in G.L. c. 164, § 69G. That section states, in part, that a facility is:

> (2) any new electric transmission line having a design rating of sixty-nine kilovolts or more and which is one mile or more in length except reconductoring or rebuilding of existing transmission lines at the same voltage.

The Company also proposes to construct a new transmission station and new substation in Milford and Hopkinton, respectively. The third definition of facility set forth in G.L. c. 164, § 69G is pertinent in determining whether the transmission station and substation are jurisdictional facilities. In that third definition a facility is defined as:

> (3) any ancillary structure including fuel storage facilities which is an integrated part of the operation of any electric generating unit or transmission line which is a facility.

The Siting Board has interpreted the term "ancillary structure" in its prior decisions, and has stated that such a structure is a "facility" within the meaning of G.L. c. 164, § 69G if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility. See Commonwealth Electric Company, EFSB 96-6, at 4 (1997) ("1997 ComElec Decision"); New England Power Company, EFSB 95-2, at 5 (1996) ("1996 NEPCO Decision"); Commonwealth Electric Company, 17 DOMSC 249, 263 (1988) ("1988 ComElec Decision").

The Company has stated, and the Siting Board agrees, that the proposed transmission station, substation and associated distribution facilities will be supplemental to the jurisdictional transmission facilities and would provide no benefit in the absence of the jurisdictional transmission lines (See Company Initial Brief at 4). Accordingly, the Siting

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4 The Siting Board notes that St. 1997, c. 164, which was enacted on November 24, 1997, does not alter the Siting Board's jurisdiction or standards of review as it relates to the Company's proposed project.

Board finds that the proposed transmission station, substation and associated distribution facilities are facilities within the meaning of the third definition of facility in G.L. c. 164, § 69G.

BECo also filed with the Department of Public Utilities ("Department") petitions pursuant to G.L. c. 164, § 72 and G.L. c. 40A, § 3 that relate to the need for, construction of, and siting of the proposed facilities. These petitions were docketed by the Department as D.P.U. 96-35 and D.P.U. 96-36, respectively. Although the Department has initial jurisdiction over such petitions, G.L. c. 164, § 69H(2) provides that the Siting Board may accept such matters for review and approval or rejection that are referred by the Chairman of the Department pursuant to G.L. c. 25, § 4, provided that it shall apply Department and Siting Board standards in a consistent manner. The Chairman referred these two petitions to the Siting Board on April 25, 1996 in an Order in which these matters were consolidated with the Siting Board docket in EFSB 96-1. The Siting Board hereby accepts for review these two petitions.

D. Scope of Review

In accordance with G.L. c. 164, § 69H, before approving an application to construct facilities, the Siting Board requires applicants to justify transmission line facility proposals 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 that its project is superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the previously identified need (see Section II.B, below). Finally, the Siting Board requires the applicant to show that its site selection process has not overlooked or eliminated clearly superior sites, 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, below).[5] Additionally, in the

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[5] When a transmission line facility proposal is submitted to the Siting Board, the petitioner is required to present: (1) its preferred facility site and/or route; and (2) at (continued...)

case of an electric company which is required by G.L. c. 164, § 69I to file a long-range forecast with the Department, the applicant must show that the facility is consistent with the electric company's most recently approved long-range forecast. G.L. c. 164, § 69J. BECo is an electric company required to make such a filing and to make such a showing.[6]

[5](...continued)
least one alternative facility site and/or route. These sites and routes often are described as the "noticed" alternatives because these are the only sites and routes described in the notice of adjudication published at the commencement of the Siting Board's review. In reaching a decision in such a facility case, the Siting Board can approve a petitioner's preferred site or route, approve an alternative site or route, or reject all sites and routes. The Siting Board, however, may not approve any site, route, or portion of a route which was not included in the notice of adjudication published for purposes of the proceeding.

6 The Department's most recent review of a long-range forecast for BECo was in D.P.U. 94-49, in which, consistent with 220 C.M.R. §§ 10.00 et seq., the Department accepted the Company's forecast. Boston Edison Company, D.P.U. 94-49 (1995).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, § 69H, the Siting Board is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Board evaluates whether there is a need for additional energy resources[7] to meet reliability, economic efficiency, or environmental objectives. The Siting Board must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

2. Description of the Existing System

The Company indicated that the Town of Hopkinton is supplied by seven 14-kV distribution lines, three of which are tapped off BECo Distribution System Supply ("DSS") lines, and four of which are supplied directly from 115/14-kV Company-owned distribution substations (Exh. BE-1, at 2-2). The Company explained that two 14-kV distribution lines, 65-1325H3 and 65-1325H4, are tapped off DSS line 65-1325H, which extends from BECo Substation 65 in Medway to BECo Substation 274 in Sherborn, and that line 519-75H1 is tapped off DSS line 519-75H, which supplies BECo Substation 519 in Framingham from BECo Substation 274 in Sherborn (Exhs. BE-1, at 2-4; DV 1.1(att.)). Of the remaining four lines, the Company indicated that the 65-H2 and 65-H6 lines originate at Substation 65 in

7 In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions, including, but not limited to, electric generating facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management ("C&LM").

Medway and extend into Hopkinton from Holliston,[8] while the 274-H2 line is supplied from Substation 274 in Sherborn, and the 455-H3 line is supplied from Substation 455 in West Framingham (Exh. BE-1, at 2-2). The Company stated that the 14-kV distribution circuits supplying Hopkinton extend nine to eighteen miles from their 14-kV supply source, averaging 10.7 miles in exposed length (id.; Exh. BE-AJ-1, at 6).[9] The Company also stated that the present distribution system serving Hopkinton has a firm capacity of approximately 41 MW (Exhs. BE-3; BE-AJ-1, at 6; Tr. 2, at 73).

The Company indicated that the NEES 115-kV transmission line facilities that pass through Upton and Milford near Hopkinton's southern border, do not supply power directly to Hopkinton (Exh. BE-1, at 4-6).[10]

3. Reliability of Supply

BECo asserted that the proposed project is needed both to improve the reliability of electric service to its customers in Hopkinton and to serve forecasted load growth (id. at 1-1). BECo stated that Hopkinton historically has experienced poor reliability of electric

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8 BECo stated that distribution circuits 65-H2 and 65-H6 (65-H6 has been redesignated as DSS line 587-1365H) were brought into Hopkinton during the Fall of 1995 to relieve loading on DSS line 65-1325H and distribution line 455-H3 (Exhs. BE-1, at 2-2; BE-AJ-1, at 6). Line 587-1365H now serves as a dedicated supply to the EMC^2 facility on South Street in Hopkinton (Exhs. BE-1, at 2-2; BE-AJ-1, at 6).

9 The Company stated that the distribution circuits which presently supply Hopkinton leave the three substations (#65, #274, & #455) in underground ductbanks (Exh. BE-3, at 4). These distribution circuits proceed to where they rise up and then are supported by wooden poles along road sides and ROW's (id.). The Company added that an exception is 4,200 feet of circuit 65-1325H4 which lies underground along South Street in Hopkinton between Hayward Street and EMC^2's customer Substation No. 587 (id.; Tr. 2, at 109-110).

10 BECo and NEES both own portions of the 115-kV transmission facilities extending from Millbury to Medway (Exhs. BE-1, Figure 4-2; HO-N-15). BECo indicated that its portion is designated 274-509 and extends southerly from Sherborn into Medway, then northwesterly to the Milford town line where it enters NEES service territory and becomes the property of NEES (Exhs. HO-N-10; HO-N-15).

service due to its rapid growth, location on the western edge of BECo's service territory, and lack of a local source of electric supply (id. at 1-3 to 1-4, 2-6 to 2-8).[11] BECo identified two problems with the existing 14-kV distribution supply configuration that result in reduced system reliability (id.). First, the Company stated that Hopkinton is supplied by long overhead distribution supply lines from sources located in Framingham, Medway, and Sherborn (id.). The length of these lines renders them susceptible to a high frequency of service interruptions (id.). Second, the Company stated that Hopkinton has experienced voltage stability problems as a result of excessive voltage drops and associated failures on the system (id.). The Company asserted that the large number of voltage regulators which have been added in the Hopkinton area to help control these problems will, over time, increase reliability problems, since voltage regulators are mechanical devices subject to external stresses and eventual internal degradation (Tr. 2, at 21). BECo also stated that peak summer load on this system is projected to increase during 1997 and 1998, and noted that this projected load growth would potentially increase service interruptions and voltage stability problems (Exh. BE-AJ-1, at 8).[12]

BECo stated that it previously installed two major rounds of distribution system reinforcements to address the reliability and capacity problems first experienced in Hopkinton during the 1980's (Exhs. HO-N-1b; BE-1, at 1-3, 2-4). BECo indicated that the first round of reinforcements was completed in 1988 and included the installation of 14-kV spacer cable, power transfers from nearby circuits, establishment of new distribution circuits, conversion of 4-kV service areas to 14-kV, and the installation of radio controlled devices and reclosing

11 The Company indicated that the Town of Hopkinton's first written request for BECo to address electric service problems which would be addressed by the proposed project, was issued by the Town of Hopkinton Board of Selectmen on February 8, 1986 (Exh. HO-N-14(att.)).

12 The Company's witness, Mr. Jessa, testified that there is a linear relationship concerning line length, electrical impedance, and voltage drop; the longer the line, the higher the electrical impedance and the larger the voltage drop along the line (Tr. 4, at 7-8). Mr. Jessa added that any increase in load along such a line only adds to the voltage drop (power loss) thereon (id.).

equipment to provide quick load transfer capability to reduce outage durations (Exh. BE-1, at 1-3, 2-4). BECo stated that the second round of reinforcements, which were installed beginning in the summer of 1995, included an expanded preventative maintenance program, replacement of existing 175-kilovolt-ampere ("kVA") voltage regulators with 250-kVA models, installation of new technology fuses to prevent voltage sags under certain fault conditions, load transfer from unregulated to regulated circuits, one distribution circuit extension, and the establishment of two new distribution circuits (id.). BECo asserted that these reinforcements, while providing the best reliability under the existing supply configuration and expected short-term loads, do not solve the fundamental problems in Hopkinton associated with circuit length (id. at 2-5). Beyond the two distribution system reinforcements described above, the Company added there would be one additional reinforcement option available if conditions warrant (Exhs. HO-N-3b; ATS-8).[13]

The Company stated that, at present, in the event of the failure of any of the distribution feeders supplying Hopkinton load, it would transfer loads from unaffected parts of the circuits to adjacent circuit(s) while attempting to keep circuit loads within their respective ratings and maintain proper voltage levels (Exh. HO-N-3c).

In this Section, 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, appropriate and reliable methods for assessing system reliability based on load flow analyses; (2) whether existing and projected loads, either normally or under certain contingencies, exceed the Company's reliability criteria, thereby requiring additional energy resources; and (3) whether acceleration of C&LM programs could eliminate the need for such additional energy resources.

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13 The Company stated that this third and final reinforcement option would involve the extension of distribution circuit 65-1325H3 to South Street, providing relief to two existing circuits: 455-H3 and 587-1365H (Exh. HO-N-3b(att. 2)). The Company further stated that circuit 274-H2 could also be relieved via circuit 65-H5 if necessary, but added that no reasonable options would exist beyond these measures to reinforce the existing Hopkinton circuits (id.).

a. Reliability Criteria

i. Positions of the Parties

The Company cited four distribution system reliability criteria which are applicable to the reliability problems experienced in the Hopkinton Supply Area ("HSA").[14] These four criteria are: (1) to maintain single contingency firm service on an emergency basis until a fault is repaired or defective equipment is replaced; (2) to maintain equipment loadings within their respective emergency capacity ratings during a single contingency, and within their normal capacity ratings during normal operating conditions; (3) to maintain acceptable voltage levels at each customer;[15] and (4) to maintain on a qualitative basis acceptable levels of reliability with respect to distribution system performance in supply areas, including frequency of interruptions and voltage level deviation (Exh. BE-1, at 2-5, 2-6). The Company's witness, Mr. Jessa, testified that BECo does not use strict reliability criteria for indicators such as voltage deviation and frequency of interruptions, but qualitatively compares performance in supply areas such as the HSA with norms for overall system operation (Tr. 3, at 121-122).

The Company stated that the distribution circuits that supply electric power to Hopkinton range in length from nine to 18 miles, and are over twice the typical length for overhead distribution circuits system-wide (Exh. BE-1, at 2-7). The Company also stated that the frequency of interruptions experienced by Hopkinton customers is approximately 1.5 times greater than the average for the entire BECo overhead distribution system (Exh. Milford 1-5; Tr. 3, at 123). The Company explained that this high frequency of interruptions is due primarily to the high average length of the distribution circuits supplying Hopkinton (Exh. BE-1, at 2-7). BECo presented records of specific interruptions on the distribution circuits that supply Hopkinton (id.).

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14 Company diagrams indicate that the HSA consists of six towns: Framingham, Sherborn, Medway, Holliston, Hopkinton, and Ashland. See, e.g., Exh. HO-N-3(att. 1).

15 The Company stated that line voltage levels of 114 Volts ("V") to 126 V under normal conditions, and between 110 V to 127 V under short-term emergency conditions, are considered acceptable (Exh. BE-1, at 2-6, n.4).

On the issue of voltage, Mr. Jessa testified that the HSA has more distribution voltage regulators than in other cities and towns throughout BECo's service territory -- 18 sets[16] of voltage regulators overall and up to four sets on individual circuits (Exh. BE-3, at 3; Tr. 2, at 20-21). Mr. Jessa added that the HSA is the only area within BECo's service territory that uses any 250-kVA voltage regulators, or that has more than two sets of 175-kVA voltage regulators on a single circuit (Tr. 2, at 21; Tr. 3, at 105). The Company indicated that voltage regulators, like other mechanical equipment, can fail, and that the high number of voltage regulators in the HSA increases the exposure of the HSA to reliability problems associated with equipment failures (Tr. 3, at 118). The Company further indicated that subjecting voltage regulators to loads above their rating increases their failure rate (id. at 88). The Company's outage records indicate that voltage regulator failures have accounted for 20 percent of interruptions on one of its distribution circuits, and less than ten percent of interruptions on each of the other distribution circuits (Exh. DV 1.4; Tr. 3, at 162).

ii. Analysis

The Siting Board consistently has found that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain system reliability. Norwood Municipal Light Department, EFSB 96-2, at 11-12 (1997) ("Norwood Decision"); 1996 NEPCo Decision, EFSB 95-2, at 10; New England Power Company, 21 DOMSC 325, 339 (1991) ("1991 NEPCo Decision").

With respect to BECo's reliability criteria relative to the maintenance of firm service, equipment loadings and, voltage levels, the Siting Board agrees that operation of BECo's distribution system within the parameters BECo has identified, helps avoid overloads, voltage instability, and outages, and is therefore essential for providing a reliable, least-cost energy supply.

16 Mr. Jessa indicated that each set contains three regulators, one for each electrical phase (Tr. 3, at 32-33).

Accordingly, the Siting Board finds that BECo's reliability criteria relative to the maintenance of firm service, equipment loadings, and voltage levels are reasonable for purposes of this review.

With respect to BECo's qualitative comparison of the HSA with system-wide operational statistics concerning frequency of interruptions and voltage level regulation, the Siting Board agrees that both indicators identified by the Company are potentially important measures of a distribution area's performance. The Siting Board notes, however, that it has not previously reviewed the need for a new transmission line based on qualitative comparisons for the performance indicators that BECo identifies.

In some past reviews, the Siting Board has considered on a case-by-case basis reliability criteria which were based on indicators that were new or of special relevance in those cases. See, Norwood Decision, EFSB 96-2, at 9-12; 1991 NEPCo Decision, 21 DOMSC at 325. In those cases, applicants sought to justify new or case-specific reliability criteria based on comparisons to industry practices and experience within the applicant's own system, rather than on comparison to the applicant's system alone. Id.

In the Norwood Decision, EFSB 96-2, at 12, the Siting Board reviewed criteria premised on the expectation that voltage concerns and line losses arise from use of long feeder lines. In that decision, the Siting Board noted that direct indicators of voltage concerns such as high average feeder line length, coupled with outage and complaint records showing reduced reliability, might well be an appropriate reliability-based system design criterion. Id. Here, BECo has cited the HSA's longer-than-average distribution supply lines as an underlying factor accounting for both the high incidence of outages and abnormal voltage deviations on the system.

While the Company has related feeder line length to performance indicators, i.e., outage frequency and voltage regulation problems, the Siting Board notes that the record does not indicate how the Company selects and justifies thresholds for identifying the presence of unacceptable performance. The Siting Board notes that BECo's comparison approach might have been more appropriate for use in establishing need if it relied on a fixed standard or comparison to industry practice, rather than relying solely on a comparison to

BECo's own system-wide norm.[17] However, the Siting Board recognizes that a comparison approach may reasonably demonstrate need if, for example, such comparisons demonstrate a very significant deviation from a company's system-wide norm. Therefore, the Siting Board finds reasonable the approach of identifying particular performance indicators, e.g., incidence of outage or voltage regulation problems, to serve as a basis for the determination of an unacceptable level of reliability.

The Siting Board concludes that, consistent with our requirement as set forth in the Norwood Decision, BECo has presented evidence of high average feeder line length in conjunction with a high frequency of outages or other service interruptions in Hopkinton. Further, to support its position that such indicators demonstrate a need for additional energy resources, BECo has presented evidence as to the extent of deviation of such indicators from the Company's system-wide norms.[18] Therefore, BECo has established that outage frequency comparisons constitute a potentially reasonable basis for establishing need as part of the Siting Board's system configuration analysis in this review (see Section II.A.3.c, below).

Accordingly, the Siting Board finds that BECo's reliability criteria relative to the maintenance on a qualitative basis of acceptable levels of reliability with respect to distribution system performance in supply areas, including frequency of interruptions and voltage level deviation, are reasonable for purposes of this review.[19]

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[17] In future cases, the Siting Board may require that a reliability criterion reflect comparison to the reliability levels of other utilities serving areas of similar density.

[18] The Siting Board notes that its standard requires a showing of "high average feeder line length" in conjunction with "outage and complaint records." Here, the Company has provided detailed documentation of outages between the years 1993 and 1995 and explained why outage records beyond 1995 were not yet available, and why outage records from prior to 1993 could not be compiled.

[19] In making this finding, the Siting Board notes that evidence in the record concerning voltage regulation indicates that a small portion of outages are attributed to voltage regulator failures. Evidence which merely identifies significant variations in the number or size of voltage regulators, either alone or in comparison with system-wide norms, does not establish that voltage regulation concerns constitute a reasonable basis for establishing need.

The Siting Board notes that the Company's qualitative comparison-based criteria may also be appropriate for use in conjunction with other need analyses that are based on fixed reliability limits or thresholds, rather than for use as stand-alone indicators of need.[20] The Siting Board further notes that for purposes other than establishing need, e.g., for comparing alternative project approaches or facility-level alternatives, a comparison to system-wide norms may also be appropriate.

b. Load Forecasts

The Siting Board statute requires that forecasts be based on substantially accurate historical information and reasonable statistical projection methods. See G.L. c. 164, §§ 69J and 69I. To ensure that this standard has been met, the Siting Board and the Department have consistently required forecasts to be reviewable, appropriate and reliable. Norwood Decision, EFSB 96-2, at 14-15; Colonial Gas Company, D.P.U. 96-18, at 5 (1996); Northeast Utilities, 17 DOMSC 1, 6 (1988). 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 utility 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, 24 DOMSC 125, 146 (1992); Commonwealth Electric Company/Cambridge Electric Company; 22 DOMSC 116, 124-125 (1991); Commonwealth Electric Company/Cambridge Electric Company; 12 DOMSC 39, 42 (1985).

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[20] For example, if it were established that a company's existing energy resources and facilities would be inadequate to meet that company's service requirements in a future year, based on a fixed standard of reliability, it would be established that there is a need for additional energy resources or facilities beginning no later than that future year. To the extent that there is an unresolved question as to when the additional energy resources or facilities should be added, as opposed to whether they should be added, the comparison approach might be used to demonstrate that there is a reasonable need for the additional energy resources or facilities in an earlier year.

i. Positions of the Parties

The Company argued that Hopkinton has experienced significant load growth over the past five years and is one of the fastest growing portions of BECo's service territory (Company Initial Brief at 12).[21] In support of its argument, the Company provided historical and projected loads for Hopkinton and the HSA, and also provided projected loads from its system-wide forecast for the portion of its system, identified as Region 12, which encompasses Hopkinton and the HSA (Exhs. HO-N-7b; HO-N-1(att.); HO-RR-5(att.); ATS-1; Tr. 4, at 11).[22]

With respect to its Hopkinton forecast, the Company indicated that it develops town-specific forecasts based on projections of growth in existing load and additions of new load, developed for both residential and commercial/industrial components of load (Exh. HO-N-7a).[23] The Company indicated that Hopkinton peak load was 25 MW in 1995, and projected peak load will increase to 40 MW in 1998 and 44 MW in 2000

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[21] Maureen Dwinnell, who testified on behalf of the Town of Hopkinton, indicated that Hopkinton has experienced a greater than 16 percent increase in population between 1990 and 1996; an almost 12 percent increase in residential housing units between 1993 and 1996; and an approximately 42 percent increase in business growth between 1986 and 1995 with a corresponding increase of approximately 70 percent in persons employed by those businesses (Exh. MLD-1, at 2-3). Further, Hopkinton's population is projected to increase an additional 35 percent over the next twenty years and the number of businesses is projected to increase an additional 11 percent over the next four years and an additional 61 percent over the next 20 years (id. at 7-8). Ms. Dwinnell attributes this growth to the location of Hopkinton near the confluence of Interstate Routes 495 and 90, ready access by auto or rail to many points in New England within a short period of time, and Hopkinton's ability to retain a "characteristic small town, rural ambience, while attracting many new residents who seek a rural life-style within easy access of the major commercial areas" (id. at 3).

[22] Mr. Jessa, testified that he and a distribution engineer prepared the Hopkinton forecast, and that he also coordinated with BECo personnel responsible for preparing the system-wide forecast (Tr. 4, at 130).

[23] The Company stated that projections of new load for the residential sector were based on housing development expectations in Hopkinton, and that projections of new load for the commercial/industrial sector were based on evaluation of new projects within that sector (Exh. HO-N-7a).

(Exh. ATS-1b). The Company indicated that the forecasted peak load of 44 MW in the year 2000 represents a nearly three-fold increase from 1990 levels (Exh. ATS-1; Tr. 4, at 11). The Company attributed approximately 83 percent of the projected 1995-1998 increase in peak load to the planned operation of five new or expanded facilities at EMC^2 on South Street in Hopkinton (Exh. BE-1, at 1-3 to 1-4).[24]

With respect to its forecast for Region 12, the Company indicated that it uses system-wide forecast methods for residential, commercial and industrial components of load (Exh. HO-N-7).[25] Mr. Jessa stated that the system-wide model then forecasts loads for each region of BECo's service territory by analyzing the performance of substations located within each region (Tr. 4, at 131). In addition, BECo also relied on information provided by the Massachusetts Department of Communities and Development ("MDCD") and local planning boards in developing its Region 12 forecast (Exh. HO-RR-5). The Region 12 forecast shows a peak load of 265 MW in 1995, and a projected peak load of 300 MW in 1999 (Exh. HO-RR-5).

Mr. Jessa stated that, based on consultation with the preparer of the system-wide forecast, he concluded that there was a high degree of consistency in the approaches used and the results of the Region 12 forecast and the Hopkinton forecast (id.; Exh. HO-N-7a). Prior to finalizing the forecast data for the Town of Hopkinton, Mr. Jessa stated that he and the preparer of the system-wide forecast met to ensure that their respective forecasts, as they applied to Hopkinton, were consistent (Tr. 4, at 131). Mr. Jessa confirmed that he treated

24 BECo indicated that the expected growth of peak summer load in Hopkinton above the 1995 level would be 10.5 MW by 1997, 15.5 MW by 1998 and 19.5 MW by 2000, of which EMC^2's expanded facilities on South Street would account for 9 MW by 1997, 13 MW by 1998 and 17 MW by 2000 (Exhs. BE-1, at 1-3 to 1-4; ATS-1b; HO-N-9b; AG 1-1(att.) at table 2). BECo further indicated that, of the projected 9 MW increase in EMC^2 peak load between 1995 and 1997, 2 MW in added load had materialized as of 1996 (Exhs. HO-N-9b; AG 1-8).

25 The Company indicated that the residential forecast is based on appliance-specific end-use analysis, the commercial forecast is based on end-use analysis by building type, and the industrial forecast is based on projections for 19 standard industrial classifications (Exh. HO-N-7a).

the system-wide forecast as a given, and added that any corrections to inconsistencies were made to the Hopkinton forecast, but that any differences that the Company believed reflected more accurate information for the Hopkinton forecast were retained (id. at 136-138).

Mr. Starkis argued that BECo's forecast of load growth in Hopkinton is almost entirely dependent on growing demand from EMC^2, and that EMC^2 has stated that it now has sufficient power to meet its projected needs (Exhs. BE-1, at 1-3 to 1-4; DJF-1, at 3; Starkis Initial Brief at 7; Starkis Reply Brief at 2).[26] Further, Mr. Starkis argued that during testimony, in contravention to the Town of Hopkinton's assertion of growth at EMC^2's Hopkinton facilities, Daniel Fitzgerald and William Teuber, both of EMC^2, discussed only a company-wide revenue-growth projection of 25 percent which they did not specifically relate to growth at the Hopkinton facilities (Starkis Reply Brief at 3, citing, Tr. 7, at 89-92).

ii. Analysis

The record indicates that BECo has submitted load growth projections based on expected loads in Hopkinton's residential and commercial/industrial sectors. In addition, BECo analyzed its Hopkinton forecast to establish its consistency with the system-wide forecast for BECo's Region 12, the larger service area in which the Town of Hopkinton is situated.

In previous transmission line reviews, the Siting Board has stated that, in facility reviews where a company projects load growth for a portion of its service territory, the Siting Board will require the company to use quantitative techniques where sufficient data is available, or other systematic techniques, and to document all pertinent assumptions to support the allocation of system-wide growth to service areas and to individual substations within the service areas. 1997 ComElec Decision, EFSB 96-6, at 14; 1991 NEPCo

26 The Siting Board notes that Mr. Fitzgerald's testimony states "[e]xisting generation is sufficient to meet our projected needs. Existing distribution and transmission, however, are woefully and critically insufficient" (Exh. DJF-1, at 2-3). The Siting Board further notes that BECo's proposed project is one of distribution and transmission, not generation.

Decision, 21 DOMSC at 344.

Here, BECo has indicated that it uses end-use models and other quantitative techniques to develop a system-wide forecast. With respect to the allocation of system-wide growth to Region 12, however, BECo indicated only that it developed projected loads based on the performance of substations within regions, and also used information from MDCD and local planning boards. As for BECo's Hopkinton forecast, the record indicates that it is based on projections of growth in existing load and additions of new load.

The Siting Board notes that the Company did assess the consistency of its Hopkinton forecast with its Region 12 forecast. Mr. Jessa testified that the Company made some adjustments to its Hopkinton forecast to address inconsistencies with the Region 12 forecast, but also retained differences where the Company believed that the Hopkinton forecast reflected more accurate information. The record indicates that, with these adjustments for consistency, the Hopkinton forecast still incorporates growth rates that are well in excess of those reflected in the Region 12 forecast. The Siting Board further notes that, consistent with previous Siting Board reviews, the Company has relied on a combination of quantitative and judgmental factors to assess consistency between the two forecasts. See, 1996 NEPCo Decision, EFSB 95-2 at 12-13; 1995 NEPCo Decision, 4 DOMSB at 126-127.

Here, the Company has used a step-down approach to develop its region-level forecast, and compared that forecast's consistency with the Hopkinton forecast. However, the record does not indicate whether, and if so how, BECo used quantitative or other systematic techniques to allocate system-wide growth to service areas, e.g., Region 12, or individual substations within the service area, as required by the Siting Board's standard of review.

Further, the record does not include sufficient documentation of the Company's methods for the Siting Board to conclude that the Hopkinton forecast is reviewable or appropriate as those terms are defined above. Thus, BECo has not demonstrated that the Hopkinton forecast, considered on a stand-alone basis, meets our statutory requirement.

With regard to the Hopkinton forecast, the record indicates that EMC^2 accounts for approximately 83 percent of the short-term growth in the Hopkinton forecast. Thus, in this case, the reliability of BECo's forecast depends to a significant degree on the accuracy of projected requirements for EMC^2.

Mr. Starkis argued that BECo has failed to establish need because the record does not contain EMC^2's commitment to expand at its Hopkinton facilities as opposed to elsewhere. However, although EMC^2 accounts for approximately 83 percent of the Company's short-term peak load growth in Hopkinton, BECo has pursued the proposed project to meet overall needs in the community, not specifically to provide a dedicated supply to EMC^2. Further, we note that simply because EMC^2 accounts for a large share of projected growth, it does not follow that little or none of the growth attributable to EMC^2 would materialize in the absence of EMC^2's continued or expanded operations in Hopkinton. Rather, the record supports an expectation that the projected growth may well reflect a variety of demographic and economic opportunity factors present in Hopkinton -- notably the accessibility from Route 495 -- that transcend the decision of any one industrial customer to expand or not expand in the community.

The Siting Board is concerned that BECo has failed to adequately demonstrate either (1) that it used quantitative or other systematic techniques to derive its Region 12 forecast and/or its Hopkinton forecast from its system-wide forecast, or in the alternative (2) that it used reviewable and appropriate methods to develop its Hopkinton forecast.[27] The Siting Board also notes that the large share of growth attributable to EMC^2, although unusual, does not justify a lack of attention to documentation of forecast allocation methods in the review. In the present case, the Siting Board has recognized that some of the 83 percent of forecasted short-term growth attributed to EMC^2 likely also reflects demographic and economic

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27 In previous Siting Board reviews of transmission lines, investor-owned utilities generally have used a top-down forecast approach to support their need analyses, based on allocation of system-wide growth to system subareas and/or substations. 1997 ComElec Decision, EFSB 96-6, at 12-13; 1996 NEPCo Decision, EFSB 95-2, at 10-12. In a recent review of a new transmission line proposed by a municipal light plant, the Siting Board accepted as reviewable and appropriate a stand-alone forecast for the affected community based on econometric and other regression analysis. Norwood Decision, EFSB 96-2, at 13-15.

opportunity factors attributable to the service area, as distinct from reflecting only EMC^2's presence as a customer. Generally, a company's forecast provides the means to document any such factors that affect load growth. In addition, the record indicates that an approximately 17 percent share of BECo's forecasted short-term growth is not attributable to EMC^2.

The Siting Board notes that when a single customer accounts for a large share of projected growth in a service area for which facility improvements are proposed, it is prudent to closely monitor that customer's planned growth as it relates to its future energy and load requirements. Specifically, the Siting Board expects that, as part of a continuing monitoring of the load growth in a community in which a facility has been approved, a company should obtain at frequent intervals prior to the commencement of construction of such approved facilities, updates from all major customers concerning their expectations with respect to future energy and load requirements and alter their construction activities appropriately.

The Siting Board finds that a general step-down forecast approach is a reasonable and acceptable method for forecasting subareas within a company's service territory provided it (1) fully identifies the geographic and any other components of that company's forecast framework at the regional forecast level, and the relationship of such components to the system-wide forecast, and (2) fully describes the methods for deriving region level forecasts from the system-wide forecast, and the application of those methods to derive the specific forecast for the region in which the proposed project is located. However, here the Siting Board finds that, although the extent of growth forecasted for Hopkinton is substantial, BECo has not established that its forecast is reviewable, appropriate, or reliable.

c. <u>Equipment Loading and Configuration Analysis</u>

In this Section, the Siting Board considers whether there is a need for additional energy resources based on BECo's reliability and design criteria.

i. Positions of the Parties

BECo asserted that electrical facilities serving Hopkinton would be operating near or in excess of their maximum capacity ratings in the 1998-2000 time-frame (Exh. BE-1, at 2-10; Tr. 3, at 96). In addition, the Company indicated that its existing exposure to outages and voltage instabilities on the long HSA distribution feeders was inconsistent with its system reliability planning and design criteria (Exh. BE-1, at 2-5, 2-6).

BECo indicated that the maintenance of firm service under a single contingency, without overloading equipment, was its primary reliability criteria (id.) (see Section II.A.3.a, above). The Company stated that implementation of the third set of distribution reinforcements, potentially necessary during 1997-1998, would be the last reasonable short-term alternative to the proposed project (Exh. HO-N-3b; Tr. 3, at 96). The Company indicated that these reinforcements, and the two sets of reinforcements that preceded them, were never intended as long-term solutions to Hopkinton's reliability problems (Tr. 3, at 43).

The Company provided system diagrams and tables showing equipment loadings on the distribution system serving the HSA under normal operations and worst-case contingencies for 1997 and 1999 (Exhs. HO-N-3(att. 2); BE-AJ-10; BE-3, at 1 and revised tables N-3a-3, N-3a-4). The Company indicated that it developed projected loadings for 1997 based on the existing system and projected loadings for 1999 assuming implementation of the third stage of distribution reinforcements (Exhs. HO-N-3(att. 2); BE-AJ-10; Tr. 3, at 96-97). The Company also provided estimates of voltage drop and compensation requirements for selected circuits, based on results of its loading calculations and information on circuit length and size (Exh. AG-1(att.), table 1; Exh. DV-1.1; Tr. 4, at 139-158).[28]

BECo stated that for the Summer of 1997, it analyzed the worst-case contingency on the existing HSA system of a 14-kV bus section failure at Substation 65 in Medway, which resulted in the unscheduled loss of both the 587-1365H DSS line and the 65-H2 distribution

28 The Company acknowledged that it used manual calculations rather than load flow models to analyze the Hopkinton area distribution system (Tr. 3, at 143). The Company explained that it only recently acquired a user-friendly load-flow model program for distribution circuits, and that it was easier to use manual calculations (id.).

circuit (Exhs. BE-3, at 1, 3; AG 1-9). BECo indicated that, under this contingency, the emergency rating of the 455-H3 distribution circuit would be exceeded (Exhs. BE-3, at 1; HO-N-3, table N-3a-2). BECo further indicated that, under the same contingency, unstable voltage conditions would occur on portions of the 65-1365H4 line for a "good amount of time," in contravention of its reliability standards, until switching operations were performed (Tr. 3, at 146-153).

BECo stated that for the Summer of 1999, it analyzed the same worst-case contingency on the existing HSA system which resulted in the unscheduled loss of the same distribution circuit and DSS line as under the Summer 1997 scenario (Exhs. BE-3, at 2, 3, Table N-3a-3; HO-RR-1, table N-3a-3). BECo indicated that, under such contingency, the emergency rating of the 65-H5 distribution circuit would be substantially exceeded (Exh. HO-RR-1, table N-3a-3). BECo further indicated that under Summer 1999 normal load without any contingency, the normal rating of the 65-H2 distribution circuit would be exceeded (id.).

The Company also provided comparative data as to the length of supply circuits on the 14-kV distribution system, and associated reliability concerns, including a high incidence of outages and problems with voltage regulation (Exhs. BE-1, at 2-7; HO-N-6). The Company stated that Hopkinton's supply circuits range in length from nine to 18 miles, and are over twice the typical length for overhead distribution circuits system-wide (Exh. BE-1, at 2-7).

With respect to outages, BECo presented records of specific interruptions on the distribution circuits supplying Hopkinton (Exh. DV-1.4A; HO-N-6).[29] Senator Magnani

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[29] The Company's 1993-1995 outage records show total outages as well as classes of outages such as (1) outages attributable to particular types of conductor faults including fallen tree/limb, struck pole and similar incidents, and (2) outages attributable to failures of other types of equipment, including transformers, line taps, regulators, and capacitors (Exh. DV-1.4A; HO-N-6). Over the three-year period, the 11.4-mile long 455-H2 circuit from Framingham showed the highest incidence of both total outages and outages attributable to conductor faults relating to fallen tree/limb, struck poles, and similar incidents (Exhs. DV-1.4A; HO-N-6; HO-N-3). The remaining circuits, ranging from (continued...)

provided a survey and other information concerning commercial/industrial and residential electrical failures and complaints in Hopkinton (Exhs. HO-N-14(att.); DPM-1(atts.); ATS-DPM-1; ATS-DPM-1(supp.); ATS-TOH-4; ATS-TOH-4(supp.)). The Company stated that the frequency of interruptions experienced by Hopkinton customers is approximately 1.5 times greater than the average for the entire BECo overhead distribution system (Exh. Milford 1-5; Tr. 3, at 123). The Company explained that the high frequency of interruptions experienced is due primarily to the high average length of the distribution circuits supplying Hopkinton (Exh. BE-1, at 2-7). With respect to voltage, the Company stated that Hopkinton's residential and business customers frequently experience unacceptable voltage level deviations (id. at 2-8).

Andrej T. Starkis argued that the Company has failed to demonstrate either the need under G.L. c. 164, §§ 69I and 69J, or the reasonable necessity under G.L. c. 40A, § 3, for the proposed project. Mr. Starkis argued that the proponents of the proposed project have, in aggregate, produced no credible evidence to support the alleged electrical reliability problems associated with the existing distribution supply system in Hopkinton (Starkis Initial Brief at 7-8; Starkis Reply Brief at 4). Further, Mr. Starkis noted that in contravention of the Company's position regarding the mere presence of voltage regulators on a circuit, and a corresponding potential increase in both exposure and internal regulator failure, record evidence indicated that only about 10 percent of aggregate interruptions appeared to be attributable to voltage regulator presence (exposure) or failure (Tr. 4, 106-107; Starkis Reply Brief at 5).

With regard to Senator David P. Magnani's testimony, Mr. Starkis noted that it was

[29](...continued)
9.9 to 12.8 miles in length and originating in Sherborn and Medway, show incidences of total outages of approximately one third to two thirds that shown for the 455-H2 line, and also show similarly lower incidences of outages attributable to conductor faults related to fallen tree/limb, struck poles and similar incidents (Exh. DV-1.4A; HO-N-6). The Company also indicated that the 455-H2 line is primarily an on-street distribution line, but that the circuits originating in Sherborn and Medway are routed along separate ROWs for portions of their length (Exhs. BE-1, figures 2-1, 4-2, 4-3; BE-3, at 4).

accompanied by a compilation of business survey results prepared by EMC[2]'s Corporate Community Involvement Manager, and later supplemented (Exhs. DPM-1; ATS-DPM-1 (supp.); Starkis Initial Brief at 7). Mr. Starkis stated that of those businesses, less than half reported any problems (Starkis Initial Brief at 7). Of those businesses that did report problems, Mr. Starkis added that few provided sufficient specifics to evaluate the relevancy of those problems to the Company's petition (id.). Mr. Starkis noted that some of the problems cited were problems dating back to the late 1980s, while other problems that were cited corresponded to massive weather-related outages throughout eastern Massachusetts (id.). Mr. Starkis argued that yet other problems cited reflected significant exaggeration of the scope of the problems encountered (id.).

Mr. Starkis also claimed that the Town of Hopkinton's records submitted as evidence were sparse and similarly ambiguous (Exh. MLD-1(exhs. a, b, c); Tr. 7, at 153; Starkis Initial Brief at 7-8; Starkis Reply Brief at 4). Further, he noted that in response to an intervenor information request, the Town of Hopkinton supplied only two July, 1987 letters from EMC[2]'s General Counsel, indicating the "veritable plague of outages" it was experiencing at that time (Exh. ATS-TOH-4(supp.)(atts. 2, 3); Starkis Initial Brief at 8).

Mr. Starkis also argued that the record does not support the Company's argument that BECo's circuits will experience overloading absent the proposed project, particularly in light of BECo's anticipated system reinforcements (Starkis Reply Brief at 2). Mr. Starkis argued that the Company's analysis projects overloads only in Medway near Substation 65, and that the assumptions of load growth and system operation associated with that overload are only as accurate as Mr. Jessa's projections (Starkis Reply Brief at 2).

The Town of Hopkinton noted that even with BECo's short-term distribution improvements in place, EMC[2] still experienced two outages in April, 1997 and two outages and one low-voltage condition in June, 1997 (Exh. DJF-1, at 4; Tr. 7, at 40, 72-84). The Town of Hopkinton argued that this provides evidence that reliability problems in the Town persist and "invariably will increase" (Hopkinton Brief at 7).

The Town of Hopkinton also noted that the record indicates that power-reliability problems have been a concern since as early as 1989 (id., citing, Exhs. ATS-TOH-4(sup.)

(att. 2); MLD-1, at 5-6). The Town of Hopkinton stated that the Company has attempted to resolve its reliability problems within the confines of the present configuration of BECo's facilities serving Hopkinton (Hopkinton Brief at 10). The Town of Hopkinton argued that the Siting Board should not penalize a company for instituting short-term remedies by requiring the company to then wait for additional data as to the effectiveness of those short-term remedies before instituting more long-range solutions as to do so would be a disincentive to companies to attempt to address problems in the short-term (id.).

ii. Analysis

The Company has developed analyses of equipment loadings and voltage levels on the distribution system serving the HSA under normal operations and worst-case contingencies for 1997 and 1999. The Company described its methods for calculating load flow by system component and identifying equipment loading excedances, and provided full HSA results on a set of system load flow diagrams. With respect to voltage levels, the Company described its calculation methods and provided analyses that showed exceedances of its voltage criteria.[30]

The Company also provided detailed documentation of outages in the HSA for the years 1993 through 1995. The Company then presented comparative statistics for the HSA and the overall BECo service area with respect to (1) the incidence of outages, and (2) system characteristics that potentially relate to outage rates and other performance indicators, including average distribution line length and extent of reliance on voltage regulation.

The Siting Board finds that the Company used reviewable and appropriate methods

30 Although the record indicates that the Company used manual calculations, in other Siting Board reviews where distribution system issues were significant, applicants have provided relevant analyses of distribution circuits based on load flow models. 1991 NEPCo Decision, 21 DOMSC at 345-358; 1988 ComElec Decision, 17 DOMSC at 271-273, 276-278. For purposes of future petitions, the Siting Board notes that load flow models are preferable to manual calculations, as such models allow results to be more fully developed and provide greater flexibility in analyzing a range of load scenarios and operating contingencies.

for assessing the reliability of its supply based on appropriate system reliability planning and design criteria.

The Company and other parties have provided outage and complaint records, cited above, that indicate that the extended feeder lines that serve Hopkinton, ranging from 9 to 18 miles and averaging 10.7 miles in length, result in a frequency of interruptions that is 1.5 times the system average. The record demonstrates that extended feeder lines also result in higher impedance and voltage drops along these lines.

In addition, the Company has projected that equipment loadings would exceed capacity ratings under peak load as early as 1997. As indicated in Section II.A.3.b, above, the Siting Board was unable to find that the Company's forecast met the Siting Board's standard of review. However, the record indicates EMC^2's load increased 2 MW between 1995 and 1996, and that BECo expected EMC^2's ongoing expansion in Hopkinton to result in 7 MW of additional load between 1996 and 1997 and further increments of additional load beyond 1997. Although the Company's overall forecast of as much as 44.5 MW of load in Hopkinton by 2000 cannot be accepted as reliable, the Company's 1997 contingency analysis is based on a Hopkinton load of 35.0 MW -- 9.5 MW less than the projected level for 2000.

Based on recent load levels in Hopkinton and the expectations for expansion and associated load requirements at EMC^2 through 1997, the Siting Board concludes that the peak load in Hopkinton is likely to reach the level underlying the Company's 1997 contingency analysis within the 1997-2000 time frame. Thus, based on the record, the Siting Board finds that the 1997 contingency analysis provides a reasonable basis for establishing need in this review.

The Siting Board finds that the Company's analysis demonstrates that (1) under the worst-case single contingency with the present configuration, emergency ratings on one or more existing distribution lines would be exceeded beginning in 1997, and (2) under the worst-case single contingency with the present configuration, the voltage level on an existing distribution line would be inconsistent with system reliability criteria beginning in 1997. In addition, the Siting Board finds that the frequency of interruptions in the HSA is higher than system norms, and considered together with other existing and expected violations of system reliability criteria (noted in (1) and (2), above) in the HSA, such frequency of interruptions is inconsistent with the operation of a reliable system.

The Siting Board is not persuaded that it is appropriate to analyze the record in a manner that ignores the fact that short-term solutions are not equivalent to long-term solutions, as urged by Mr. Starkis.[31] Rather, we agree with the arguments of the Town of Hopkinton that penalizing a company for instituting short-term remedies by requiring the companies to then wait for additional data as to the effectiveness of those short-term remedies would be a disincentive to companies to attempt to address problems in the short-term.

The record demonstrates that, even with the first two sets of short-term remedies in place, as recently as June, 1997, outage and voltage deviation conditions are still occurring in Hopkinton. The fact that BECo may be able to rectify such conditions were it to complete the third set of short-term distribution system reinforcements does not negate the evidence as to unacceptable reliability with the existing configuration.[32] Nor does the availability of a short-term solution detract from an analysis suggesting that only a long-term solution would meet all identified needs (see also Section II.B, below).

As noted above, the Siting Board has previously held that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain system reliability. Accordingly, consistent with this precedent, the Siting Board here finds that BECo has established that there presently is a need for additional energy resources in Hopkinton based on the Company's reliability criteria.

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[31] Further, the Siting Board notes that the fact that not all entities who were surveyed relative to electrical outage or voltage problems they mat have experienced had reason to complain does not negate the existence of the complaints from those that did complain.

[32] Further, the fact that BECo's projected overload in 1999 is in Medway does not affect the conclusion that the HSA, which includes Hopkinton, will experience an unacceptable electric condition at that time.

d. Accelerated Conservation and Load Management

G.L. c. 164, § 69J requires a petitioner to include a description of actions planned to be taken to meet future needs and requirements, including the possibility of reducing requirements through load management.

i. Positions of the Parties

The Company argued that although C&LM programs may marginally reduce loads at certain points on the HSA system, the acceleration of such programs would not rectify the underlying problems in the HSA associated with distribution supply circuit length and exposure, or the consequent equipment failures, frequency of service interruptions, and unacceptable customer voltage levels (BECo Initial Brief at 13).

BECo asserted that, given the nature of the electrical supply problems in the HSA, accelerated C&LM efforts would not address the identified reliability need (Exhs. BE-1, at 2-10, 2-11; AG 1-14; HO-N-8b). BECo further asserted that the reliability problems faced in Hopkinton require a comprehensive solution that will result in a dramatic reduction in the length of overhead distribution circuits, and indicated that measures such as C&LM and distributed generation were, therefore, accordingly weighted (Exh. AG 1-16).[33]

BECo stated that it offers a full range of C&LM programs to its residential and commercial/industrial customers throughout its service territory (Exhs. BE-1, at 2-10 to 2-11; MJP 1-13; HO-N-8a). BECo indicated that penetration of these programs in Hopkinton is consistent with the rate of penetration of C&LM programs throughout BECo's service territory (Exh. BE-1, at 2-10 to 2-11). BECo provided documents detailing its C&LM and

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33 In response to an Attorney General information request concerning potential opportunities for the implementation of targeted C&LM in the Hopkinton area -- in light of the Company's anticipated 14-month delay of the proposed project's in-service date to December of 1998 -- BECo stated that said delay has no effect on the ability of C&LM to defer or eliminate some or all of the identified need (Exh. AG 1-15).

energy conservation measure programs at EMC[2] (Exh. AG 1-17(supp.)(atts.)).[34] BECo provided annual potential load reductions in Hopkinton as a result of C&LM efforts (Exh. HO-N-8a). BECo projects that C&LM will provide annual load reductions of 1.82 MW to 2.02 MW from 1997 through 1999 (id.). BECo indicated that the commercial/industrial component of those savings would exceed 1 MW annually in the same timeframe (id.; Exh. MJP 1-13).

The Attorney General argued that the Company failed to consider Demand Side Management ("DSM")[35] and distributed generation technologies as need options in their analysis and recommendations in this proceeding[36] (Attorney General Brief at 1, citing, Exhs. AG 1-16; AG 2-5; BE-1; BE-2). The Attorney General stated that two separate reports, conducted on behalf of BECo during 1995, identified Hopkinton as an area with high potential savings from targeted DSM and distributed generation technologies, which could help BECo avoid higher-than-average transmission and distribution ("T&D") costs[37] for the Hopkinton area (Exhs. AG-3, at 8; AG-4A).[38] The Attorney General argued that, based on these reports alone, the Company should have at least included a detailed analysis of

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34 Mr. Fitzgerald of EMC[2] testified that his company has implemented C&LM programs, both in conjunction with BECo and on its own initiative (Exh. DJF-1, at 1; Tr. 7, at 59).

35 The Siting Board notes that the terms C&LM and DSM, although not actually synonymous, were used that way by the parties in this proceeding.

36 The Siting Board reviews distributed generation in its analysis of alternatives. See Section II.B, below.

37 The Attorney General indicated that one of the reports concluded that the total avoided T&D cost for Hopkinton is 1.5 times BECo's system-wide average (Exh. AG-3, at 8; Attorney General Brief at 2).

38 The Attorney General indicated that the reports were titled (1) "Application of the Distributed Utility Concept to the Boston Edison Company Creating Additional Value for the Customer" by David Schoengold of MSB Energy Associates, and (2) "Renewing Our Neighborhoods - DSM Renewables in the Boston Edison Service Area" jointly prepared by the Union of Concerned Scientists and MSB Energy Associates (Exhs. AG-3; AG-4).

investments in such alternatives located proximate to the load, instead of the more costly T&D investments in the Hopkinton area (Attorney General Brief at 2). Finally, the Attorney General encouraged the Siting Board to direct the petitioner to investigate the impact that DSM and distributed generation technologies, collectively referred to by the Attorney General as distributed utility planning, would have in the Hopkinton area, and to commence a pilot project to introduce said technologies into this area during 1998 (id.).

CLF noted that the two reports, cited above and provided by the Attorney General, were prepared for the BECo DSM Settlement Board in 1995 (CLF Brief at 3). CLF stated that both reports specifically identify the Hopkinton area as prime for the use of distributed generation and C&LM as alternatives to conventional T&D system investments (id.). CLF stated that in responding to Exhibit AG 2-12, BECo stated that Hopkinton area reliability problems and the ability to maintain customer choice created the need for a more comprehensive solution (id. at 4). CLF asserted that, by not conducting a rigorous analysis, BECo has not demonstrated that Hopkinton's electrical problems could not be addressed by a sophisticated distributed generation and C&LM solution (id.). Finally, CLF requested that the Siting Board require BECo to conduct an extensive analysis of the feasibility and cost-effectiveness of an alternative utilizing distributed generation and C&LM (id. at 5).

ii. Analysis

The record demonstrates that while C&LM efforts, either accelerated or at expected annual incremental levels, could theoretically alleviate some of the equipment overloads, thereby increasing the reliability of some portions of the HSA, it would not appreciably eliminate the aggregate length and corresponding exposure of the Hopkinton distribution supply system, or provide a long-term solution to the potential load growth on that system in the Hopkinton area during the next several years. The record demonstrates that a reasonable acceleration of planned DSM programs would not be sufficient to meet the identified need. Therefore, an extensive analysis of the feasibility and cost-effectiveness of a C&LM alternative is not warranted. See, 1996 NEPCo Decision, EFSB 95-2, at n.2, 17. Here, the Siting Board has acknowledged that the present configuration of the HSA distribution supply system is unique enough, in terms of its high average length and corresponding exposure, that system improvements beyond C&LM are needed. In addition, although the Siting Board has not found BECo's load forecast to be reliable, the Siting Board agrees with the Company that, if Hopkinton load does increase by the projected 19.5 MW over the 1995-2000 period, it is unlikely that even accelerated C&LM efforts in Hopkinton would provide any significant long-term relief from the identified reliability problems.[39,40]

Therefore, based on the above, the Siting Board sees no need to direct the Company to further investigate accelerated C&LM as an alternative to the proposed project.[41]

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39 The Siting Board also notes that, even if accelerated C&LM could avoid identified needs, such an approach would require maintenance and likely reinforcement of an existing system of lengthy overhead feeder lines, each extending up to ten miles or more in length. In contrast, the proposed project involves the construction and operation of underground T&D facilities along a combined route of less than two miles -- a minimal distance compared to the extended supply network the proposed project would replace (see Sections III.A & C, below).

40 The alternative of distributed generation is discussed in Sections II.B, below.

41 In response to the arguments raised by the Attorney General and CLF, the Siting Board notes that the record in this proceeding contains no foundation on which the Siting Board can base its acceptance of the conclusions contained in the two reports provided by the Attorney General. Although the Attorney General states that these two reports were "conducted on behalf of BECo," the "Acknowledgment" on page 2 of Exhibit AG-4b states that

> The Union of Concerned [Scientists] ("UCS") has prepared this research on behalf of the Boston Edison DSM Settlement Board ("Settlement Board"). The Settlement Board consists of Boston Edison Company, the Massachusetts Office of the Attorney General, the Massachusetts Division of Energy Resources, and MASSPIRG. <u>The views expressed in this report are those of UCS and do not necessarily reflect those of the Settlement Board or its members</u>. (emphasis added)

In addition, in a Memorandum attached to Exhibit AG-3, David Schoengold, the author of the report states that the report was prepared by him "for the Distributed Utility Planning Workshop." To the extent that the authors of these two reports made assertions (continued...)

However, the Siting Board expects that BECo will encourage the implementation of C&LM measures whenever and wherever possible throughout its service territory. Further, in future proceedings where the identified need relates primarily to the need for additional capacity in a targeted area, the Siting Board may require a more extensive analysis of the feasibility and cost-effectiveness of a C&LM alternative.

Accordingly, the Siting Board finds that acceleration of C&LM programs could not eliminate the identified need for additional energy resources based on BECo's reliability criteria.

e. Conclusions on Reliability of Supply

The Siting Board has found that BECo's reliability criteria relative to the maintenance of firm service, equipment loadings, and voltage levels are reasonable for purposes of this review. The Siting Board also has found reasonable the approach of identifying particular performance indicators, e.g., incidence of outage or voltage regulation problems, to serve as a basis for the determination of an unacceptable level of reliability, and has found that BECo's reliability criteria relative to the maintenance on a qualitative basis of acceptable levels of reliability with respect to distribution system performance in supply areas, including frequency of interruptions and voltage level deviation, are reasonable for purposes of this review.

The Siting Board has further found that BECo has not demonstrated that the Hopkinton forecast, considered on a stand-alone basis, represents a forecast that meets our statutory requirement. In addition, the Sting Board has found that, although the extent of growth forecasted for Hopkinton is substantial, BECo has not established that its forecast is reviewable, appropriate, or reliable.

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[41](...continued)
relative to T&D costs which were not subject to cross-examination by the Siting Board or parties to this proceeding, the Siting Board can find no basis to accept these assertions as uncontroverted. This is especially so in light of evidence in the record as to actual costs that was provided by the Company and that was subject to discovery and cross-examination which appears to contradict the assertions of the two authors.

The Siting Board has also found that the Company used reviewable and appropriate methods for assessing the reliability of its supply based on appropriate system reliability planning and design criteria, and that the Company's analysis demonstrates that (1) under the worst-case single contingency with the present configuration, emergency ratings on one or more existing distribution lines would be exceeded beginning in 1997, and (2) under the worst-case single contingency with the present configuration, the voltage level on an existing distribution line would be inconsistent with system reliability criteria beginning in 1997. In addition, the Siting Board has found that the frequency of interruptions in the HSA is higher than system norms, and considered together with other existing and expected violations of system reliability criteria (noted in (1) and (2), above) in the HSA, such frequency of interruptions is inconsistent with the operation of a reliable system. The Siting Board has therefore found that BECo has established that there presently is a need for additional energy resources in Hopkinton based on the Company's reliability criteria.

Finally, the Siting Board has found that acceleration of C&LM programs could not eliminate the identified need for additional energy resources based on BECo's reliability criteria.

Accordingly, the Siting Board finds that additional energy resources currently are needed for reliability purposes in Hopkinton.

In making this finding, the Siting Board notes that it has not relied on the future forecasted load projected by BECo beyond 1997 and reviewed in Section II.A.3.b, above. As set forth in that section, the Siting Board rejected that forecast, based on the failure of BECo to fully explain the methods it used in its step-down forecast approach. Nevertheless, the Siting Board notes that if BECo's projections of load growth beyond 1997 do in fact occur, reliability problems in the Hopkinton area likely will be either more pronounced than indicated by the analysis above, or will occur sooner than expected.

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 necessary 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; (b) other sources of electrical power or natural gas; and (c) no additional electric power or natural gas.[42]

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the identified need. 1997 ComElec Decision, EFSB 96-6, at 22; Norwood Decision, EFSB 96-2, at 20; Boston Edison Company, 13 DOMSC at 63, 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 ComElec Decision, EFSB 96-6, at 23, Norwood Decision, EFSB 96-2, at 21; Massachusetts Electric Company, 18 DOMSC at 383, 404-405 (1989).

2. Development of Project Approaches

The Company presented four alternative approaches for meeting the identified need in the Hopkinton area: (1) the proposed project;[43] (2) the installation of a new single-transformer 115/14-kV substation in Hopkinton, similar to the proposed project in location and layout, supplied by a single 1.3-mile long underground transmission line ("one transformer alternative"); (3) a low voltage alternative to supply Hopkinton center via approximately eight miles of new underground 14-kV distribution circuits in ductbanks from

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42 G.L. c. 164, § 69J also requires a petitioner to provide a description of "other site locations." The Siting Board reviews the petitioner's proposed site, as well as other site locations, in Section III.B, below.

43 The Company stated that, after the proposed project was in operation, the existing distribution lines supplying Hopkinton would be electrically switched to serve as distribution supply circuits for Ashland, Framingham, and Holliston loads, as well as to provide backup to distribution circuits for the proposed BECo Substation on South Street (Exhs. HO-N-11; BE-AJ-1(att. 8)).

an existing BECo substation in Sherborn to Hopkinton center ("low voltage alternative"); and (4) local generation to provide 30 MW of firm capacity at a single site or at multiple locations in Hopkinton ("local generation alternative") which included an analysis of both a combustion turbine option and a fuel cell option (Exh. BE-1, at 1-5, 3-1 to 3-3).[44,45]

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44 BECo stated that it also considered as the "no build alternative" continued implementation of short-term supply reinforcements (Exh. BE-1, at 3-1). BECo indicated that this alternative would have no relative environmental impacts, and would cost considerably less than the other alternatives (id. at 3-3 to 3-6). However, BECo stated that this alternative would provide no margin for additional load growth beyond that expected through 1997 (id.).

General Laws c. 169, § 69J requires the Company to consider the alternative of "no additional electrical power." However, the Siting Board has found that additional energy resources currently are needed for reliability purposes in Hopkinton (see Section II.A.3.e, above). Consequently, the Siting Board finds that the alternative of "no additional electric power" would be unable to meet the identified need. A more detailed analysis of this alternative is therefore unnecessary.

45 In addition to the above approaches, the Company presented information to the Siting Board regarding a potential new substation to be shared by BECo and NEES ("shared substation alternative") (Exh. BE-2, at 3-1 to 3-5). The Company analyzed two Milford locations for the shared substation: East Main Street, which would require approximately seven miles of new underground duct work to supply Hopkinton; and Cedar Street, which would require approximately five miles of new underground ductwork to supply Hopkinton (id. at 3-2 to 3-3). Neither site would require the construction of a transmission station (id.). The Company stated that implementation of the shared substation alternative at the East Main Street site would not significantly reduce the overall length of the distribution circuits, contributing to costly annual line losses (id. at 3-3). Further, the Company concluded that there was no environmental advantage to the East Main Street shared site over the proposed project (id.).

The Company stated that it had similar concerns with the shared substation alternative at the Cedar Street site, although based on the shorter underground ductbank, the cost would be approximately $3 million less than if the East Main Street site were used. BECo indicated that it discussed the possibility of sharing a substation at the Cedar Street site with NEES, but NEES informed BECo that it did not foresee any benefits to pursuing a shared substation at the Cedar Street location and would not consider the proposal (id. at 3-3, 3-5).

(continued...)

The Company stated that the proposed project would have the capability to add 80 MW of capacity to the HSA, with a firm capacity of 40 MW (Exh. BE-2, at 3-3; Tr. 4, at 71, 92). The Company indicated that the configuration of the HSA distribution system would be changed such that the proposed project would serve 80 percent of the Hopkinton load and that the remaining areas, located close to the Hopkinton-Holliston or Hopkinton-Ashland border, would be served by circuits from substations located in Framingham, Medway and Sherborn (Tr. 3, at 29).[46] BECo noted that there were several possible routing options for the proposed project (Exh. BE-1, at 4-13 to 4-24). For purposes of comparing the different alternatives, the Company assumed that the proposed project would tap the existing NEES 115-kV transmission line via a new BECo transmission station, and that the 115-kV transmission lines would extend underground from the transmission station northerly under Purchase Street across the Hopkinton town line to the site of the proposed South Street substation (id.).

The Company stated that the one transformer alternative would follow the same route and have essentially the same environmental impacts as the proposed project, but would provide only 40 MW of capacity to the HSA (Exh. BE-1, at 3-4; Tr. 4, at 92). The Company stated that the one transformer alternative would cost approximately $3 million less than the proposed project (id. at 3-6; Tr. 4, at 76).

The Company stated that the low voltage alternative would consist of the construction of an eight-mile underground ductbank with four new distribution circuits located entirely in local streets and Route 135, with no overland portions (Exh. BE-1, at 3-2; Tr. 4, at 126). The low voltage alternative would begin at Station 274 in Sherborn, travel on local streets to Route 135 in Framingham, continue through downtown Framingham, through Ashland and

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[45](...continued)

The Siting Board notes that a shared substation would be a significant distance from BECo's Hopkinton load center, and the shared substation approach could not be resolved to meet each company's needs. Therefore, the Siting Board does not further analyze the shared substation alternative.

[46] The Company stated that the load on the proposed substation would be approximately 30 MW (Tr. 4, at 22, 71).

end at the center of Hopkinton, in the vicinity of town hall (Tr. 4, at 125). The Company stated that the cost of the low voltage alternative would be approximately $13.27 million (Tr. 4, at 81; Exh. DV-1:29, att. 2).

The Company initially analyzed a local generation alternative consisting of three 15 MW gas-fired combustion turbines ("CTG alternative") at a single location near the South Street industrial area, providing 30 MW of firm capacity (Exh. BE-1, at 3-2). As in the case of the proposed project, the configuration of the HSA distribution system would be changed such that the generation alternative would serve approximately 80 percent of Hopkinton load (Tr. 2, at 14; Tr. 3, at 29).

In response to questions concerning the use of a distributed generation alternative using renewable energy sources rather than combustion turbines, the Company asserted that fuel cells were the only distributed resource technology that could possibly provide capacity to meet the 30 MW need (Exh. AG-2-12; Tr. 4, at 44).[47] Further, the Company asserted that any type of distributed generation would have to be located in the South Street area, proximate to the load, in order to meet the identified need (Exh. AG-2-12). For purposes of addressing the questions raised about the option of distributed generation, the Company outlined a fuel cell scenario consisting of an unspecified number of units assumed to occupy a space of 2.5 square feet per kW, or 75,000 square feet for 30 MW ("fuel cell alternative") (id.).

However, the Company argued that local generation of any kind within Hopkinton would not fully remove the reliance on extended feeder lines, and therefore could only partially correct the fundamental problems associated with the present supply configuration (Exh. HO-A-2). The Company stated that because either local or distributed generation could only partially address the reliability problems in Hopkinton, could involve significantly greater environmental impacts, and would result in greater costs than the proposed approach, generation of any kind within the Town of Hopkinton was not further considered as a project

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[47] The Company noted that fuel cells would convert natural gas or other fuel to hydrogen and then use a chemical process to combust the hydrogen with oxygen to create electricity (Exh. AG-4b at 35).

approach (id.) (See Section II.B.5, below).

Both CLF and the AG expressed concerns regarding BECo's early dismissal of distributed generation as a project approach. CLF asserted that the opportunity to explore distributed generation and C&LM in Hopkinton was identified and presented to BECo at least two years ago through two reports prepared for the Boston Edison DSM Settlement Board (id. at 3, citing, Exh. AG-3; AG-4A). CLF asserted that BECo did not thoroughly investigate distributed generation and C&LM alternatives before proposing the project (id. at 4). CLF argued that, to ensure that BECo is providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board should require BECo to conduct an analysis of the feasibility and cost-effectiveness of using clean distributed generation and C&LM (id. at 5).

The Attorney General, while not questioning the need for the proposed project or BECo's cost analysis, asserted that BECo improperly overlooked distributed utility planning when developing the proposed project (AG Brief at 1). The Attorney General argued that, given that two separate reports which identified the potential for high savings from distributed generation versus traditional high-cost T&D projects, BECo should have prepared a detailed analysis comparing distributed generation and targeted DSM as alternatives to the proposed project (id. at 2). The Attorney General urged the Siting Board to require the Company to investigate the impacts that distributed utility planning would have in the Hopkinton area, and to implement a pilot project in the area in the next year in conjunction with the construction of the proposed facilities (id.).

3. Ability to Meet the Identified Need

In Section II.A.3.c, above, the Siting Board found that there is a need for additional energy resources based on the Company's reliability criteria relative to (1) the maintenance of firm service, equipment loadings, and voltage levels under worst case contingencies, and (2) frequency of outages. In this section the Siting Board evaluates whether each approach would provide a reliable supply to the HSA consistent with the Company's reliability criteria for equipment loadings and voltage levels.

a. Proposed Project

The Company asserted that the proposed project would meet the identified need by providing for sufficient firm capacity at the Hopkinton load center to meet future load growth, maintain acceptable voltage levels, and improve reliability (Exh. BE-1, at 3-3). The Company indicated that the proposed project would: provide approximately 80 MW of firm system capacity to meet expected load growth; reduce the average length of overhead circuits from 10.7 miles to 4 to 5 miles, thereby reducing the frequency of outage and voltage problems;[48] and reduce the number of voltage regulators from 18 sets to two operating sets and two backup sets, thereby reducing the number of incidences of voltage regulator failure (id. at 2-4; Tr. 3, at 32; Tr. 4, at 71). The Company presented a load flow diagram indicating that with the implementation of the proposed project, as of the summer of 1999, all circuits would function within normal ratings under normal load and within emergency ratings under a single contingency (Exh. BE-AJ-8).

The record demonstrates that the proposed project would meet projected load under a single contingency without exceeding equipment capabilities; and remove the current dependence on extended feeder lines that has resulted in a high frequency of outages, exceedence of BECO's voltage criteria, and problems with voltage and regulation. Accordingly, the Siting Board finds that the proposed project would meet the identified need.

b. One Transformer Alternative

The Company stated that the one transformer alternative would provide increases in near-term capacity, reduction in lengthy exposed circuits, and a reduction in voltage regulators similar to those provided by the proposed project (Exh. BE-1, 3-3). However, the Company stated that the use of a single transformer substation would leave the HSA

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48 The Company estimated that the proposed project would reduce the number of outages of less than five minutes to one-fourth that expected under the existing system with short-term reinforcements, and would reduce the number of "voltage sag" incidents to one-fifth that expected under the existing system (Exh. AG-1-1(att.), chart 1).

vulnerable to a station transformer fault or transmission cable fault (id.). The Company therefore asserted that its reliability standard of firm service under any single contingency event would not be met (Exh. HO-A-3). The Company explained that the only back-up supply under the one transformer alternative would be the existing distribution system, which cannot reliably serve the entire Hopkinton load (id.; Exh. Milford-1-9). Further, the Company noted that the single transformer would provide approximately 40 MW of capacity at the Hopkinton load center, as opposed to the 80 MW of capacity provided by the proposed project (Tr. 4, at 93).

The record demonstrates that the one transformer alternative would not maintain firm service in the contingency of a station transformer fault or transmission cable fault and therefore would not meet the Company's reliability criteria to provide a firm supply for the HSA. Accordingly, the Siting Board finds that the one transformer alternative would not meet the identified need.

c. Low Voltage Alternative

The Company stated that the low voltage alternative would provide 30 MW of firm capacity to the HSA via new underground circuits, and would reduce the length of some of the exposed overhead circuits (BECo Initial Brief at 18; Exh. BE-1, at 3-4). However, the Company asserted that not all of the circuits supplying Hopkinton would be connected to new underground lines and that the system, therefore, would still be exposed to reliability problems posed by lengthy overhead circuits (Exhs. BE-1, at 3-4; HO-A-3).

The Company also stated that the low voltage alternative would not significantly reduce the system's need for voltage compensation, due to the size of the load and the distance from the load to the supply source (Exhs. BE-1, at 3-4; HO-A-5). The Company referred to its need analysis of the existing system, showing unacceptable voltage levels on one circuit beginning in 1997 under a worst case contingency, and indicated a similar contingency likely would cause unacceptable voltage levels under the low voltage alternative

(Tr. 4, at 104-105, 107-109).[49]

In addition, the Company stated that although the low voltage alternative would consist of a nine conduit ductbank, only four new circuits of 10 MW[50] each would be installed at this time (Tr. 4, at 23-24, 70). The Company stated that if in the future it was necessary to add capacity over 40 MW, it would be costly to upgrade the low voltage alternative, while the proposed project would be able to provide 80 MW of capacity without later upgrades (id. at 109-110). The Company indicated that the construction cost for running the circuits is $50 a linear foot, and each circuit would need to run underground for a distance of approximately eight miles (id. at 25-26, 109).

The record indicates that the low voltage alternative would provide additional distribution line capacity to serve Hopkinton, enabling the Company to meet a worst-case single contingency without equipment overloads. In addition, the low voltage alternative would relieve portions of the extended overhead distribution system via the new underground feeder lines, thereby shortening overhead circuit length and reducing associated exposure to frequent outages. However, because the combined underground-overhead length of circuits supplying Hopkinton would remain lengthy, the low voltage alternative would not significantly reduce the existing need for voltage compensation. Mr. Jessa's testimony indicated that, under a worst case contingency with the low voltage alternative, the Company's basic voltage criteria likely would be violated on one or more circuits.[51,52]

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49 The Company noted that, while the worst case contingency under the existing system is a bus section failure at Station 65 in Medway, the worst case contingency under the low voltage alternative would be a bus section failure at Station 274 in Sherborn, which is the starting point of the low voltage alternative (Tr. 4, at 108-109).

50 The Company explained that the capacity of a single circuit is approximately 10 MW, therefore the capacity of the four circuits would be 40 MW, but the firm capacity would be 30 MW which is the emergency capacity if one circuit fails (Tr. 4, at 89).

51 The record indicates that the Company has not fully demonstrated that a large number of voltage regulators contribute to a significant number of outages.

Accordingly, the Siting Board finds that the low voltage alternative would not meet the identified need.

d. Local Generation Alternative

The Company stated that adding generation within the Town of Hopkinton would alleviate the heavy load flows over existing long distribution lines (Exh. HO-A-2). However, the Company asserted that, to maintain stability under the local generation alternative, the Company would need to maintain an interconnection to the regional grid (id.; Exh. HO-A-9, Tr. 3, at 25-26). Specifically, the Company stated that local generation, sited either in the South Street industrial area or throughout Hopkinton, would have to be operated in parallel with the overall BECo system to minimize the frequency deviations and voltage fluctuations associated with load changes (Exh. HO-A-9). The Company therefore determined that the long existing overhead circuits have to be retained as part of the overall area supply system under the local generation alternative (Exh. HO-A-2). The Company therefore argued that the addition of local generation would not reduce system exposure to short circuits and the interruptions or voltage level drops that occur during those short circuits (id.). The Company concluded that the local generation alternative could eliminate that portion of outages attributable to regulator failures, which could be up to 20 percent on respective circuits (Tr. 4, at 14).

The Company acknowledged that the fuel cell alternative would not need to be connected to the regional grid in order to maintain stability (Tr. 1, at 188). BECo explained that the small-scale nature of fuel cells would most likely avoid potential stability problems, but noted the likelihood of a problem would be dependent on the size and the associated

[52](...continued)

[52] The Siting Board also notes that the low voltage alternative would require installation of underground lines with the same type of impacts as the proposed project, and would be approximately eight miles in length as compared to less than two miles for the combined length of underground transmission and distribution lines for the proposed project. Further, it provides no cost advantage over the proposed project.

generating capacity of each fuel cell (id.; Tr. 2, at 134).[53]

The record indicates that the CTG alternative would provide 45 MW of new capacity, including 15 MW of backup generation capacity, to ensure a firm supply of 30 MW. This level of capacity at the Hopkinton load center should be sufficient to ensure that equipment loadings would be maintained within appropriate levels under normal and single-contingency conditions. However, BECo argues that for stability purposes, it would be necessary to connect the CTG alternative to the existing grid by retaining the existing distribution system links, and that those links would continue to subject the HSA to the existing high incidence of outages. The record is not clear as to whether it would be necessary to retain the entire existing system of multiple circuits, as opposed to one circuit or a small number of circuits, in order to maintain steady state stability. Further, the record indicates that the existing distribution circuits differ as to exposure characteristics and the actual extent and mix of outages. Therefore, it is not clear that the maintenance of a distribution link to provide stability for the CTG alternative would create an unacceptable level of exposure such as exists under the present system.

The record indicates that the fuel cell alternative theoretically could provide sufficient new capacity to the Hopkinton load center to ensure that equipment loadings would be maintained within appropriate levels under normal and single-contingency conditions. It also indicates that, depending on the configuration of the fuel cell array, it may be unnecessary to connect the fuel cells to the regional grid. In addition, as with the CTG alternative, it is not clear that maintenance of a distribution link for the fuel cell alternative would create an unacceptable level of exposure.

Accordingly, for purposes of this review, the Siting Board finds that the local generation alternatives potentially could meet the identified need. The Siting Board considers BECo's argument concerning possible continued exposure to distribution lines outages at greater length as part of its comparison of reliability.

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[53] The Company indicated that in the event that the fuel cells were to be used for back-up purposes, the fuel cells would need to be connected to the BECo system (Tr. 1, at 188).

e. Conclusion on the Ability to Meet the Identified Need

The Siting Board has found that BECo has demonstrated that the proposed project would meet the identified need, and that the local generation alternatives potentially could meet the identified need, but that the one transformer alternative and the low voltage alternative would not meet the identified need.

Accordingly, the Siting Board next evaluates the reliability, environmental impacts, and the cost of the proposed project and the local generation alternatives.

4. Reliability

In this section, the Siting Board compares the proposed project with local generation relative to providing a reliable supply of electricity to the HSA (see Section II.A.3.a, above).

The Company asserted that local generation would not address the reliability problems caused by exposure to lengthy overhead circuits which would be addressed by the proposed project (BECo Initial Brief at 19). BECo stated that in order for local generation to maintain steady state stability and to respond quickly to changes in load, the source of local generation must be connected to the existing distribution circuits; therefore the existing overhead circuit would need to be kept in place (Exhs. HO-A-2; HO-A-9; Tr. 4, at 14). The Company noted that construction of the proposed project may make future installation of distributed generation for capacity purposes a more viable alternative, since the system would be more stable than it is at present and could operate in a reliable manner (Tr. 4, at 18-19).

The record demonstrates that Hopkinton experiences a high incidence of service interruptions, voltage deviations, and other reliability problems that are associated with the existing long distribution lines. The record indicates that the CTG alternative would require a closed 14-kV link to the regional transmission system for stability purposes, but appears to indicate that such a link would not be required for the fuel cell alternative. Either alternative would require delivery of natural gas or other fuel to support operations in Hopkinton.

With respect to the CTG alternative, the record does not clearly establish the extent of the 14-kV interconnection that would be required. Moreover, the record shows that the existing distribution lines differ as to their exposure characteristics, and the extent and the mix of past outages. However, retention of any closed 14-kV link based on one or more overhead lines of nearly 10 miles or more in length would expose the Hopkinton supply to a greater likelihood of outages than the proposed project, which would provide firm transmission supply near the Hopkinton load center without the need for any closed 14-kV links.[54] In addition, if natural gas provides the sole fuel supply to operate the CTG alternative, such supply would be subject to potential interruption.

With respect to the fuel cell alternative, the record does not indicate the extent or likely means for providing gas or other fuel to support such operations in Hopkinton. Assuming use of natural gas, the Siting Board notes that, as in the case of the CTG alternative, such fuel supply would be subject to potential interruption. In addition, the Siting Board notes that the record does not address industry experience with reliance on fuel cell generating technology to meet a load of the size and characteristics present in Hopkinton, including the concentration of load in the South Street area.

Accordingly, the Siting Board finds that the proposed project would be preferable to the CTG alternative and slightly preferable to the fuel cell alternative with respect to reliability.

5. Environmental Impacts

In this Section, the Siting Board compares the proposed project to the local generation alternatives including both the CTG alternative and the fuel cell alternative, with respect to environmental impacts resulting from: (1) facility construction; (2) permanent land use; and (3) magnetic field levels.

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54 The Siting Board notes that under different circumstances, when a system meets stability requirements and need focuses on capacity additions rather than the combination of capacity additions and removing long overhead distribution lines, local generation, whether located at a single site or multiple sites, could very well be a reliable project approach.

a. Facility Construction Impacts

BECo asserted that environmental impacts of the proposed project would be limited to the temporary impacts associated with the construction of the underground transmission and distribution lines in and along roadways (Exh. BE-1, at 3-4). The Company indicated that temporary traffic interruptions would occur during construction along Purchase Street, a fully developed residential roadway (id.). BECo stated that construction activities along Purchase Street would be confined to one side of the street in order to maintain one lane of traffic (id. at 5-13). Although the underground transmission line would traverse a wetland between the proposed transmission station and Purchase Street, the Company indicated that directional drilling would be used to minimize impacts to the surface wetlands (Exh. BE-DS-1, at 2; Tr. 6, at 30-36). In addition, BECo stated that construction noise would be temporary and would be confined to the daytime (Exh. BE-1, at 5-13).

With respect to the CTG alternative, the Company indicated that, if the CTG site were not proximate to an existing gas pipeline, construction of a natural gas pipeline to serve the CTG alternative would have impacts at least comparable to the construction impacts associated with the proposed underground transmission facilities (id. at 3-5). The Company noted that the Tenneco pipeline that travels through Hopkinton is located approximately two miles from the South Street industrial area (Tr. 4, at 84).

The Siting Board notes that the proposed project consists of the construction of a transmission station and a substation at two separate sites, and construction in roadways for the underground transmission and distribution lines. The impacts from the construction of the transmission line along Purchase Street, while temporary, would be more disruptive than the construction impacts of the transmission station and substation. With regard to construction of the CTG alternative at one location in an industrial area, construction of a 45-MW facility would likely involve more extensive construction and take a longer time than the proposed project. Further, since the CTG alternative is gas-fired, there is the potential for disruption of roadways or other parcels of land in order to construct an interconnect to an existing gas pipeline. Accordingly, the Siting Board finds that the proposed project would be preferable to the CTG alternative with respect to facility construction impacts.

With respect to the fuel cell alternative, the record does not indicate that installation of fuel cells would require greater or lesser construction impacts than those associated with the construction of the substation and transmission station. While the proposed project would involve additional construction impacts associated with the proposed transmission line, the Siting Board also notes that the fuel cell alternative would require delivery of fuel which could involve construction impacts. Given the concentration of load in the South Street area, we further note that most but not necessarily all of the fuel cells likely would be located at the proposed substation site or at industrial facilities nearby. Therefore, assuming use of natural gas as fuel, the Siting Board notes that the fuel cell alternative, like the CTG alternative, would potentially require disruption of roadways or other parcels of land in order to construct new or expanded facilities to deliver gas. Accordingly, the Siting Board finds that the fuel cell alternative would be comparable to the proposed project with respect to facility construction impacts.

b. Permanent Land Use and Community Impacts

BECo asserted that the permanent land use impacts of the proposed facilities would be limited to the proposed transmission station and substation, and would be minimal (Exh. BE-1, at 3-4). With respect to tree clearing, the Company stated that approximately two acres of trees would be cleared for the proposed project (Exh. HO-RR-11(att.)). With respect to community impacts, the Company stated that the sites of the proposed transmission station and the proposed substation would be located approximately 800 feet, and 700 feet, respectively, from the nearest sensitive receptor (Exh. BE-1, at 5-9; Tr. 2, at 43-49). The Company further indicated that the proposed transmission station would have a minimal visual impact based on its size, an approximately 200 square feet area, its location on a 25.6-acre site in a forested area that is lower in elevation than the nearby residences, and the additional landscaping that will be installed by BECo (Exh. BE-1, at 1-5, 5-9). Further, BECo stated that the proposed substation would have minimal visual impacts based on its location in commercial/industrial area, surrounded by commercial uses on three sides of the parcel (id.). The Company indicated that the substation site is 65,000 square feet, and the fenced-in area that would contain the proposed substation facilities would be 25,000 square feet (Tr. 4, at 23, 84).

BECo asserted that when operational, the CTG alternative would have significantly greater noise and visual impacts than the proposed project, would produce air emissions, and would require significant amounts of water (Exh. BE-1, at 3-5).[55] Specifically, the Company asserted that noise impacts from the CTG alternative would be six to nine decibels greater than the operational noise levels of the proposed project (id.). The Company asserted that the CTG alternative would require approximately 80-105 gallons per hour of water for NOx control, which would create a strain on the Hopkinton water supply (Exh. Milford 1-10, (att. TM 1-10)). The Company indicated that the fuel cell alternative would produce water, heat and carbon dioxide as by-products (Exh. AG-2-12).

The Company stated that either the CTG alternative or the fuel cell alternative would require significant amounts of land, and estimated that 75,000 square feet would be necessary for installing fuel cells based on 2.5 square feet per kW (Exh. AG-2-12; Tr. 4, at 87).[56] By comparison, BECo indicated that the proposed project would require 44,200 square feet of land at two sites for the proposed transmission station and substation (Exh. AG-2-12). The Company indicated that its property on South Street -- the substation site under the proposed project -- is too small for either the CTG alternative or the fuel cell alternative (Tr. 4, at 85).

The record indicates that the permanent land use impacts of the proposed project would be minimal due to the location of the transmission station in a wooded area away from residents, and the location of the substation in a commercial/industrial area. In addition, as discussed above, the transmission line will be located underground. However, the record indicates that the transmission station, substation and transmission line would require the clearing of approximately two acres of trees.

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55 BECo indicated that the CTG alternative would produce more air emissions than the proposed project in the Hopkinton area. The Siting Board notes that while the CTG alternative would result in air emissions in Hopkinton, it would displace generation elsewhere, potentially resulting in offsetting reductions in emissions.

56 The Company did not indicate the space requirement for the CTG alternative.

In comparison, the CTG alternative would have greater noise and visual impacts, and greater local air emissions, and would have water requirements that could strain the local water supply. In addition, the record indicates the Company's substation site likely would not accommodate the CTG alternative. Thus, the record indicates that overall the CTG alternative would have greater permanent land use impacts than the proposed project.

In order to accommodate 30 MW of firm capacity, the fuel cell alternative would require more space that the proposed project, and a larger site than is available at the Company's substation site in the South Street industrial area. The South Street site likely could accommodate approximately two-thirds of the fuel cells required, with the remaining one-third located at another smaller site or at existing industrial facilities in the area. The proposed project would also require use of two sites and the clearing of two acres of trees. Thus, on balance, the permanent land use impacts of the fuel cell alternative and the proposed project are comparable.

Accordingly, the Siting Board finds that the proposed project would be preferable to the CTG alternative, and comparable to the fuel cell alternative, with respect to permanent land use and community impacts.

c. Magnetic Field Levels

The Company stated that the proposed project would minimize exposure to electric and magnetic fields (Exh. BE-PV-1, at 3). The Company explained that the underground, steel-pipe-encased 115-kV transmission lines would produce minimal magnetic fields and that the ancillary distribution line would traverse a commercial/industrial area (id.). The Company stated that the current power supply in Hopkinton is supplied by lengthy overhead 14-kV distribution lines, including significant lengths of on-street line, and that with the proposed project, power would be provided in close proximity to most major users, reducing overall exposure in the Town of Hopkinton to magnetic fields (Tr. 6, at 131).

The record indicates that the proposed 115-kV transmission line will generate minimal magnetic fields. Although the ancillary distribution line would have significantly higher field levels, it is of limited length and would extend through a commercial/industrial area along an alignment located 20 to 25 feet from property frontages (see Section III.C.3.v, below). Both local generation alternatives, if sited at the Hopkinton load center, would not require transmission lines, but would involve distribution lines in essentially the same configuration as the distribution lines for the proposed project.

Accordingly, the Siting Board finds that the proposed project is comparable to both local generation alternatives with respect to magnetic fields.

d. Conclusions on Environmental Impacts

In Sections II.B.5.a, b, and c, above, the Siting Board has found that: (1) the proposed project would be preferable to the CTG alternative, and comparable to the fuel cell alternative, with respect to facility construction impacts; (2) the proposed project would be preferable to the CTG alternative, and comparable to the fuel cell alternative, with respect to permanent land use and community impacts; and (3) the proposed project would be comparable to both local generation alternatives with respect to magnetic field impacts.

Based on the above analyses, the proposed project is preferable to the CTG alternative and comparable to the fuel cell alternative with respect to environmental impacts. However, the record indicates that the assumed firm capacity of both the CTG alternative and the fuel cell alternative would be 30 MW -- sufficient to meet projected load requirements in the 1997-to-2000 time frame -- while the firm capacity of the proposed project would be 40 MW. The Siting Board notes that the space requirements and possibly other identified impacts of the CTG alternative and the fuel cell alternative would be greater, if based on an initial firm capacity of 40 MW, or if impacts of possible future capacity additions to meet longer term load growth are considered.

The record also does not include documented analysis of the relative impacts of alternative project approaches on air quality, including consideration of displacement of emissions at existing generating plants elsewhere in the region. With respect to the fuel cell alternative, the Siting Board notes that displacement of air emissions from plants using combustion technologies is a potential benefit of fuel cell and other distributed generation technologies. The record indicates that the fuel cell alternative would result in emissions of carbon dioxide but not other air pollutants.

The Siting Board concludes that the record demonstrates a clear environmental advantage for the proposed project, relative to the CTG alternative, but does not indicate a clear environmental advantage, on balance, between the proposed project and the fuel cell alternative.

Accordingly, the Siting Board finds that the proposed project would be preferable to the CTG alternative, and comparable to the fuel cell alternative with respect to environmental impacts.

6. Cost

The Company asserted that the proposed project would be preferable to both local generation alternatives with respect to cost (Exh. BE-1, at 3-6). The Company stated that the capital costs of installing the CTG alternative would be approximately twice those of the proposed project (id.; Exh. HO-RR-7). BECo stated that it estimated that construction costs for the proposed project would be $12.547 million, and that total costs, including construction, engineering, consultant fees, study fees and permitting costs would be $13.42 million (Exhs. DV-1.1-3; DV-1.2-9(att. 2); Tr. 4, at 72-74). The Company stated that the installed cost of the CTG alternative would be approximately $26 million, not including the cost of the gas pipeline, and estimated the cost for fuel cells to be $600 per kW, or $18 million for 30 MW (Exh. Milford 1-10; AG-2-12).

The Company asserted that wheeling charges, transmission line losses, distribution losses, and fuel costs would be comparable for the proposed project and the CTG alternative (Exh. HO-RR-7). The Company explained that fuel costs would be comparable, even though the proposed facilities do not use fuel, because the CTG would displace existing generation facilities (id.). BECo calculated that the annual O&M costs of the CTG alternative would be $4.19 million, including costs for staffing the station and maintaining the turbines and fuel system, while the projected first year O&M costs for the proposed project would be $32,300 to $35,600, including costs of substation and transmission station operation and transformer losses (id.; Exh. HO-RR-6(att. 2)).[57]

The record demonstrates that, based on the Company's estimates of capital costs and operating and maintenance costs, the overall cost of either the CTG alternative or the fuel cell alternative would be significantly higher than the cost of the proposed project.[58] Accordingly, the Siting Board finds that the proposed project would be preferable to the CTG alternative and the fuel cell alternative with respect to cost.

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

In comparing the proposed project to the one transformer alternative, the low voltage alternative, and the local generation alternatives, the Siting Board has found that the proposed project would meet the identified need, that the local generation alternatives potentially would meet the identified need, and that the one transformer alternative and the low voltage alternative would not meet the identified need.

With respect to the reliability, environmental impacts, and costs of the proposed project and the local generation alternatives, the Siting Board has found that: (1) the proposed project would be preferable to the CTG alternative and slightly preferable to the fuel cell alternative with respect to reliability; (2) the proposed project would be preferable to the CTG alternative and comparable to the fuel cell alternative with respect to environmental impacts; and (3) the proposed project would be preferable to both local generation alternatives with respect to cost. Accordingly, the Siting Board finds that the proposed project is preferable to the local generation alternatives.

The Siting Board notes that the capital costs for the fuel cell alternative are 50 percent

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57 The Company did not provide O&M cost estimates for the fuel cell alternative.

58 The record indicates that the assumed firm capacity of both the CTG alternative and the fuel cell alternative would be 30 MW, while the firm capacity of the proposed project would be 40 MW. The Siting Board notes that the estimated cost of the CTG alternative and the fuel cell alternative would be greater, if based on an initial firm capacity of 40 MW, or if future costs to meet possible longer term load growth are considered.

higher than the cost of the proposed project, and that the fuel cell alternative apparently provides no compensating reliability or environmental advantages. For this reason, in addition to the reasons set forth in Section II.A.3.d, above, the Siting Board can find no basis, in this case, on which to require the Company to investigate the impacts that distributed utility planning would have in the Hopkinton area, or to implement a pilot project in the area in the next year in conjunction with the construction of the proposed facilities as urged by the Attorney General. We note that such a pilot program in Hopkinton would clearly raise the costs of the proposed project to BECo ratepayers, without providing any documented benefits. Similarly, we find no basis for requiring BECo to conduct an analysis of the feasibility and cost-effectiveness of using clean distributed generation in the Hopkinton area, as CLF has requested. Such a requirement, except in the context of another facility proposal, is beyond our authority. However, we put BECo and other utilities on notice that we will continue to require all project proponents to evaluate all reasonable project alternatives, including distributed generation, where appropriate, as part of our project review. As the Siting Board noted in the 1996 NEPCo Decision, EFSB 95-2 at 19, "in future transmission line cases, the Siting Board expects applicants to provide a more complete analysis of the ability of distributed generation to meet the identified need, or to provide an explanation of why distributed generation is not appropriate."

III. ANALYSIS OF THE PROPOSED AND ALTERNATIVE FACILITIES

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H and J. Further, G.L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In its review of other site locations, the Siting Board requires a petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. 1997 ComElec Decision, EFSB 96-6, at 47; Norwood Decision, EFSB 96-2, at 33; 1991 NEPCo Decision, 21 DOMSC at 376.

A. Description of the Proposed and Alternative Facilities

1. Proposed Facilities

BECo proposes to construct two new, 1.3-mile long, underground 115-kV transmission lines in Milford and Hopkinton that will connect the proposed South Street substation with a proposed transmission station in Milford (Exh. BE-1, at 1-5, fig. 1-1). The new transmission station would be located adjacent to the existing NEES 115-kV Medway to Millbury overhead transmission lines, at a point to the west of Purchase Street in Milford, and would be connected to these lines by two new overhead tap lines (id.). The new transmission lines would exit underground from within the enclosed area of the transmission station, proceed along a new ROW to Purchase Street, run north under Purchase Street into Hopkinton and continue north under South Street in Hopkinton to the site of the proposed South Street substation (id. at 1-5, 1-7, Fig. 1-1).

BECo indicated that the transmission station would be located on an approximately 140-foot square area; structures would include a 25-foot square control house and two 40-foot tall shielding masts (Exhs. BE-AJ-1, at 4; Hopkinton-RR-1). In addition, two sets of three steel poles would be located on the NEES ROW and three short sections of wire would connect the existing transmission lines to an incoming bridge structure, within the transmission station, by way of the new sets of three steel poles (Exhs. BE-1(app. A); HO-E-14). The proposed South Street substation would consist of two 24/32/40 MVA, 115/14-kV transformers and related equipment (Exh. BE-1, at 1-5). In addition, new distribution facilities would be installed to connect the new substation to the existing distribution system (id. at 1-7). Distribution facilities would include (1) three new distribution circuit feeders that would run underground from 300 to 7,000 feet and rise up to connect with existing overhead circuits in South Street, and (2) two DSS line feeders that would run underground to supply and backup a proposed new customer-built substation on South Street (id.).

2. Alternative Facilities

BECo also identified a comparable set of facilities using alternative transmission line routes and alternative substation and transmission station sites (id. at 1-7, fig. 1-2). For the alternative route, two overhead taps would connect the NEES Medway-to-Millbury lines, at a point approximately two miles to the west of the primary route tap site, to a transmission station which would be located off East Street in the Town of Upton (id. at 1-7). The two new transmission lines would then exit the alternative transmission station underground, proceed to East Street and run north under East Street and School Street approximately 1.1 miles to an substation which would be located near the intersection of School Street and West Main Street in Hopkinton (id. at 1-7, Fig. 1-2). The new distribution facilities would include four distribution circuits and two DSS lines (id. at 1-9). Three of the distribution circuits would connect with overhead lines on School Street and the fourth distribution circuit and two DSS lines would travel underground for approximately two miles along West Main Street and South Street to Hayward Street where the distribution circuit would connect with overhead lines (id.). The DSS lines would continue underground to a proposed new customer-built substation on South Street (id.).

B. Site Selection Process

1. Standard of Review

In order to determine whether a facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. 1997 ComElec Decision, EFSB 96-6, at 50; Norwood Decision, EFSB 96-2, at 36; Northeast Energy Associates, 16 DOMSC 335, 381, 409 (1987) ("NEA Decision"). In order to determine that a facility proponent has considered a reasonable range of practical siting alternatives, the Siting Board requires the proponent to meet a two-pronged test. First, the facility proponent must establish that it developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. 1997 ComElec Decision, EFSB 96-6, at 50; Norwood Decision, EFSB 96-2, at 38; Berkshire Gas Company (Phase II), 20 DOMSC 109, 148-149, 151-156 (1990). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity. ComElec Decision, EFSB 96-6, at 50; Norwood Decision, EFSB 96-2, at 36; NEA Decision, 16 DOMSC at 381- 409.

In the sections below, the Siting Board reviews BECo's site selection process, including BECo's development and application of its siting criteria as part of that process.

2. Development and Application of Siting Criteria

a. Description

The Company indicated that it conducted a two-stage site selection process (Exh. BE-1, at 4-2). The Company stated that in the first stage it developed a set of threshold criteria to narrow the geographic area under consideration and to identify all viable facility configurations within the defined geographic area (id.). BECo stated that in the second stage it developed a set of detailed screening criteria to rank the identified options (id.).

BECo asserted that its threshold criteria were consistent with satisfying reliability considerations at the least cost with minimum environmental impact (id.). The Company indicated that distinct threshold criteria were developed for the siting of each component of the new facilities -- the substation, the transmission line and the transmission station (id.

at 1-2, 4-2 to 4-3).[59] Specifically, the Company stated that: (1) the substation had to be located within the Town of Hopkinton, within a five-mile radius of the extreme edge of the Company's service territory;[60] (2) the maximum length of the transmission line from a 115-kV supply source with adequate power and capacity was two miles for an underground route and nine miles for an overhead route; (3) an underground transmission line had to be located beneath existing roadways; (4) an overhead transmission line had to be located on an existing overland ROW with sufficient width for construction and maintenance of the lines; and (5) both the substation and transmission station required buildable, upland sites with direct access to a public street (id.). In addition, the Company stated that the substation had to abut the transmission line route and provide access to the existing distribution system, while the transmission station had to abut the supply source and the transmission line route (id. at 4-3). The Company explained that the two mile and nine mile maximum for underground and overhead transmission line construction, respectively, were cost-based (Exh. Milford 1-18). The Company stated that, in order to reasonably limit overall project costs, it determined that the cost of the transmission line component of the project should be comparable to the cost of the substation component (id.).

The Company identified potential overhead and underground transmission line corridors connecting potential supply sources to the identified substation siting area (Exh. BE-1, at 4-3). The Company then identified potential transmission station sites at the intersections of the potential transmission corridors and supply sources and potential substation sites along the transmission corridors within the substation siting area (id.). The Company stated that when one of the threshold criteria was not met, the facility configuration was eliminated from consideration (BECo Initial Brief at 28). The Company stated that one identified underground transmission line route as well as three identified overhead

[59] The Company assumed that distribution circuits could be developed as needed anywhere in the identified geographic area and therefore did not consider the distribution component of the project at the threshold level (Exh. BE-1, at 4-3).

[60] The Company explained that in meeting the substation location criterion, the substation would be located proximate to the load (Tr. 5, at 33).

transmission line routes, including the Interstate 495 corridor, were eliminated from further consideration due to inadequate width and significant construction difficulties (Exh. BE-1, at 4-7 to 4-8).

Based on the application of the threshold criteria, the Company identified seven transmission line routes with related facilities ("facility alternatives") (Exh. BE-1, at 4-13 to 4-24). The Company stated that four of the facility alternatives would tap the existing NEES Medway to Millbury 115-kV transmission lines and include underground transmission lines -- the proposed and alternative facilities along South Street and School Street, respectively, and the West Main Street and Hayden Rowe alternatives (id. at 4-13 to 4-24). The Company further stated that three of the facility alternatives would tap BECo's existing Substation 365 and associated 115-kV transmission line in Medway and include overhead transmission lines -- the Ash Street, Chestnut Street, and South Mill Street alternatives (id.).

The Company stated that the Interstate 495 corridor intersects the existing NEES Medway to Millbury 115-kV transmission line in Milford and travels north to the substation siting area (id.). The Company explained that overhead construction within the Interstate 495 highway median was initially considered but was determined to be infeasible due to the terrain and problems of access for construction (Exh. BE-2, at 4-1; Tr. 5, at 27-28, 30). However, in response to concerns of the Town of Milford, the Company later reassessed the Interstate 495 highway median as a potential overhead transmission line route and developed preliminary design plans for constructing the transmission line within the highway median, and identified two potential tap sites and two potential substation sites using this route (Exh. BE-2, at 4-2).[61] The Company stated that the length of the transmission line along this route would range from 2.3 miles to three miles and that construction would entail clearing the majority of the vegetation within the highway median, blasting, disturbance of wetland areas, crossing of streams that are tributary to the Town of Milford water supply, and

61 The Company indicated that it identified both the highway median and eastern side of the Interstate 495 corridor as potential overhead routing options but did not assess routing along the eastern side due to Town of Milford concerns about potential residential impact (Exh. HO-S-1).

spanning the southbound highway lane to connect to a substation site (id.; Tr. 6, at 13-15).

The Company stated that the preliminary design plans were presented to the Massachusetts Highway Department ("MHD") and that the MHD determined that the above ground placement of transmission lines in the median area was not an acceptable alternative (Exh. BE-2, at 4-4).[62] The Company stated that in light of the response from the MHD, it rejected further consideration of the Interstate 495 corridor transmission line route (id.). The Company added that it did not discuss an underground route along the Interstate 495 corridor with the MHD because such a route did not meet its criteria that an underground transmission line be located beneath existing developed roadway corridors (Exh. AG-2-1). The Company asserted that underground construction outside of the developed Interstate 495 roadway would not be reasonable or feasible due to significant construction difficulties and access constraints (Tr. 5, at 42-45, 54, 79).[63]

The Company stated that it developed screening criteria for the categories of environmental impacts, reliability and cost and a rating system of raw scores and weighting factors to evaluate each of the seven facility alternatives (Exh. BE-1, at 4-25). BECo stated that its environmental screening criteria included thirteen criteria that could be affected by

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62 The Company noted that the MHD "Policy on the Accommodation of Utilities Longitudinally, along Controlled-Access Highways" provides that: (1) permits shall not be granted where there are alternative locations for the utility facilities which would provide safe, efficient utility services at a reasonable cost; (2) no part of a utility facility, other than location markers, shall be visible above ground unless unusual terrain or other environmental conditions warrant a portion of the utility facilities to be placed above ground; and (3) rock cuts, wetlands or other difficult but common construction conditions would not necessarily be considered unusual terrain (Exh. BE-2, at 4-4). The Company asserted that the MHD policy encompasses the highway roadbed, highway median and side areas (Tr. 5, at 41-42).

63 The Company explained that due to limited flexibility of underground transmission line facilities, underground construction cannot entail sharp bends or changes in elevation (Tr. 5, at 158-160). Therefore, BECo stated that, due to varying topography and bedrock within the Interstate 495 corridor, underground transmission line construction would require construction of a new level roadbed as far from the highway as possible (id. at 44-45). The Company stated that such a route would thus require blasting, wetland filling, and numerous stream crossings (id. at 44-45, 158-160; Tr. 6, at 15).

the proposed project within three general groupings -- water resources, land resources and community resources (id. at 4-27). The Company indicated that: (1) water resources included wetlands and floodplains, surface waters, ground waters, and protected waters; (2) land resources included significant habitat, tree clearing, protected lands, geology, and soil; and (3) community resources included cultural resources, traffic, noise and visual impacts (id. at 4-27 to 4-37).

BECo next calculated raw scores and weights for each facility alternative for each environmental screening criterion (id. at 4-27 to 4-37, App. B). To calculate the raw score for each of the thirteen criteria, the Company assigned a ranking of low, medium or high based on specified indicators that classified the severity of impact for each criterion, with low designating the most severe impacts (id.). The Company assigned raw numerical scores of one for a low ranking, two for a medium ranking and three for a high ranking (id.).

To calculate weighting factors, the Company assigned a level of importance -- very important, moderate importance, or minor importance -- to each of the thirteen criteria based on the overall importance of each criterion and the ability to minimize or mitigate impacts (id. at 4-17 to 4-38; Tr. 5 at 20).[64] The Company then assigned values of one, two and three to the levels of minor importance, moderate importance and very important, respectively and multiplied the value for each criterion by the number of environmental criteria assigned that level of importance (i.e., three criteria of minor importance, five criteria of moderate importance, five criteria that were very important) (Exh. BE-1, at 4-38). The results of this multiplication were then added together. The total, 28, was divided into 100 to determine a percentage equivalent for each unit of value (id.). The result, 3.6 percent, was then multiplied by the assigned value of one, two or three for the levels of importance -- minor, moderate and very important (id.). Therefore, the resultant weighting factors were:

64 The Company indicated that: (1) criteria of minor importance were surface waters, soils and noise; (2) criteria of moderate importance were groundwater, tree clearing, geology, cultural resources, and traffic; and (3) very important criteria were wetlands/floodplain, protected waters, significant habitat, protected land, and visual impacts (Exh. BE-1, at 4-27 to 4-38).

(1) minor importance criteria, 3.6 percent; (2) moderate importance criteria, 7.2 percent; and (3) very important criteria, 10.8 percent (Exh. BE-1, at 4-38).

The Company then multiplied the raw score by the weighting factor to determine the weighted environmental score for each environmental criterion for each facility alternative (Exh. BE-1, at App. B).[65] BECo then summed the weighted scores for each facility alternative to determine its overall environmental score (id. at App. B). The Company indicated that the resultant environmental scores for the facility alternatives ranged from 1.21 to 2.15 (Exh. DV 1.1-8)

The Company stated that it developed a reliability criterion to compare alternatives with respect to (1) improvement of power quality, i.e., maintenance of required voltage, and (2) reduction in the frequency of interruptions (Exh. BE-1, at 4-25).[66] The Company explained that power quality would be improved and the frequency of interruptions reduced by reducing the exposure of the distribution circuits in Hopkinton (id.).[67] For each facility alternative, the Company calculated a reliability index which was based on the expected

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65 For example, the protected lands criterion was ranked as (1) high for the proposed facilities along South Street because they would not be located proximate to protected lands, and (2) low for the alternative facilities along School Street because they would be located within 500 feet of state and privately owned open space (Exhs. DV 1.1-2, 1.1-3). Accordingly, the raw scores for protected lands were three for the proposed facilities and one for the alternative facilities (id.). Since this criterion was very important, it was multiplied by 10.8 percent, resulting in a weighted score of 0.32 for the proposed facilities and 0.11 for the alternative facilities (id.).

66 The Company stated that an increase in capacity was not used as a screening criteria because all the possible alternatives would meet the projected capacity requirements (Exh. BE-1, at 4-25).

67 The Company stated that overhead distribution lines have greater exposure to damage and therefore are subject to a greater degree of service interruptions (Exh. BE-1, at 4-25). The Company further stated that overhead distribution lines have a higher impedance which, when exacerbated by long lines and heavy load, requires the use of voltage regulators to maintain the needed voltage and that the use of voltage regulators adds exposure to the circuit, increasing the likelihood of outages (id.).

number of interruption incidents each year (Exh. BE-1, at 4-25).[68] The Company stated that the reliability score for each facility alternative was a comparison of that facility alternative's reliability index to the reliability index of the facility alternative with the highest reliability, converted to a scale of one to three, with a score of one assigned to the least reliable facility configuration (id.).[69] The Company stated that the category of reliability was considered to be very important (id. at 4-37). The Company indicated that the resultant reliability scores for all of the facility alternatives ranged from one to three (Exh. DV 1.1-8).

To determine the cost of each facility alternative, the Company summed the separate costs of distribution, stations, transmission and land acquisition (Exh. BE-1, App. B). The Company further stated that, like the reliability score, the cost score was based on a comparison of the total cost of each facility alternative to the total cost of the least-cost facility alternative, converted to a scale of one to three, with a score of one designating the highest cost (id., at 4-26, App. B).[70] BECo stated that the category of cost also was considered to be very important (id. at 4-37). The Company indicated that the resultant cost scores for all of the facility alternatives ranged from one to three (Exh. DV 1.1-8).

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68 The Company stated that the expected number of interruption incidents each year was derived by adding the number of overhead distribution line miles times the overhead incidents per mile to the number of underground miles times the underground incidents per mile (Exh. BE-1, at 4-25, App. B). The Company explained that the overhead incidents per mile was based on the average for the Town of Hopkinton and that the underground incidents per mile was based on the average for the BECo territory (id. at 4-26).

69 The Company stated that to calculate a reliability score, the minimum reliability index of all facility alternatives was subtracted from a facility alternative's reliability index and then divided by one-half of the difference between the maximum and minimum reliability index values for all facility alternatives (Exh. BE-1, at 4-26). The result was then subtracted from three to determine a score on a scale of one to three (id.).

70 The Company stated that to calculate a cost score, the lowest cost of all facility alternatives was subtracted from a facility alternative's cost and then divided by one-half of the difference in the maximum and minimum costs of all facility alternatives (Exh. BE-1, at 4-26). The result was subtracted from three to determine a score on a scale of one to three (id.).

BECo assigned the same weight of .333 to each of the categories of environmental impact, cost and reliability (Exh. BE-1, at 4-40). For each facility alternative, BECo multiplied each of its total environmental, cost and reliability scores by a factor of .333 to calculate weighted scores and then summed the three weighted scores to determine an overall score (id. at 4-38 to 4-40). BECo asserted that the three categories of environment, cost and reliability were equally important, but acknowledged that environmental impacts had a smaller influence on the total score than did the cost and reliability because its scoring system resulted in a narrower range for environmental scores (1.21 to 2.15) compared to the range of cost and reliability scores (1 to 3) (id. at 4-38; Tr. 5, at 130). However, the Company stated that the range of environmental scores adequately reflected the range of impact and that it would not have been appropriate to expand the environmental scores to a one to three range because the differences in environmental impacts would have been further emphasized (Tr. 5, at 124, 130).

BECo then compared the seven identified facility alternatives (Exh. BE-1, at 4-38 to 4-40). The Company indicated that the facility alternatives that included underground transmission lines had the highest environmental scores while the facility alternatives that included overhead transmission lines had the lowest scores (Exh. DV 1.1-8). The Company stated that, overall, the South Street alternative (the proposed facilities) had the best environmental score of 2.15 with the fewest criteria rated as having high impacts (Tr. 5, at 24). The Company explained that the proposed facilities received low scores for three environmental criteria -- wetlands and floodplain, protected waters and traffic (id. at 23). BECo stated that the low scores resulted from: (1) the need to fill wetlands in order to construct the access road to the transmission station; (2) the classification of wetlands within the access road area as an outstanding resource-water-related wetlands system; and (3) the need to construct beneath heavily travelled streets (id. at 23-24).[71]

[71] The Siting Board notes that in accordance with the terms of the Settlement Agreement with the Milford Parties, the BECo changed the location of the transmission station access road so that the access road would be constructed along the existing NEPCo ROW (Exh. HO-11(supp.)).

The Company indicated that the School Street alternative received the next best environmental score of 1.90 (Exh. DV 1.1-8). The Company indicated that the School Street alternative received low scores for the criteria of surface waters, protected lands, cultural and traffic and overall, received fewer high scores than the proposed facilities (Exh. DV 1.1-2). The Company stated that the environmental scores for the two remaining facility alternatives with underground transmission lines were 1.87 and 1.72, while the environmental scores for the facility alternatives with overhead transmission lines were lower, ranging from 1.54 to 1.21 (Exh. DV 1.1-8).

The Company stated that the reliability scores ranged from 3.00 for greatest reliability to 1.00 for least reliability (id.). BECo stated that the proposed facilities received the highest score of 3.00 because they had the least number of expected interruptions -- 5.21 incidents per circuit per year (id.). The Company stated that the School Street and West Main Street alternatives had reliability scores of 2.10 based on 6.15 expected incidents per circuit per year (id.). The Company added that the reliability scores for the other facility alternative with underground transmission, the Hayden Rowe alternative, was 1.00, the lowest of all alternatives, based on expected interruptions of 7.28 incidents per circuit per year (id.). The Company further stated that the reliability scores for facility alternatives with overhead transmission lines ranged from 2.56 to 1.53 based on expected interruptions ranging from 5.67 to 6.74 incidents per circuit per year (id.).

The Company stated that the cost scores ranged from 3.00 for the least cost alternative to 1.00 for the highest cost alternative (id.). BECo stated that the proposed facilities received the highest score of 3.00 because they were least cost with a total cost of $12.547 million (id.). The Company indicated that the lower cost of the proposed facilities was due, in large part, to its comparatively lower distribution component cost (Exhs. DV 1.1-1 to 1.1-7). The Company stated that the School Street alternative had the next lowest cost, $13.894 million, with a score of 2.55 (Exh. DV 1.1-8) The Company also stated that the Hayden Rowe alternative had the highest cost at $18.564 million, with a score of 1.00, and that the remaining facility alternatives had costs ranging from $14.388 million to $15.232 million, with corresponding scores ranging from 2.39 to 2.11 (id.).

In summing the environmental, reliability and cost scores for each of the seven routes, the Company indicated that summed scores ranged from 2.72 to 1.24 (id.). The proposed facilities received the highest score of 2.72 and the School Street facilities received the next highest score of 2.18 (id.).

b. Arguments of the Intervenors

Mr. Starkis argued that the Company's site selection process was inadequate in that the Company did not evaluate an Interstate 495 underground transmission line route (Starkis Brief at 10). He stated that the Company should have balanced the potential additional costs of an Interstate 495 route against the benefit of avoiding residential areas (id. at 11). In addition, Mr. Starkis criticized the Company's weighting and scoring system (id.). He argued that the Company should have employed standard reliability criteria rather than criteria unique to the electrical supply system in Hopkinton (id.). In addition, he argued that the environmental impacts scoring system does not realistically balance competing environmental concerns and that the overall scoring system does not adequately balance environmental concerns in the aggregate with concerns of reliability and cost (id.). He noted that because reliability and cost are scored from one to three and environmental impacts are scored within a one-point range, environmental impacts have less of an influence on the final outcome than cost and reliability (id.).

c. Analysis

BECo has developed a set of criteria for identifying and evaluating alternative facilities that includes natural resource factors, land use factors, human environmental factors, cost and reliability -- types of criteria that the Siting Board has found to be appropriate for the siting of transmission lines and related facilities. See 1997 ComElec Decision, EFSB 96-6, at 53; Norwood Decision, EFSB 96-2, at 38; New England Power Company, 4 DOMSB 109, 167 (1995) ("1995 NEPCo Decision"). The Company first developed a set of threshold criteria to identify the geographic boundaries of the proposed substation location, transmission line length and ROW requirements, and location of the transmission station and substation in relation to the other facilities. The Company used these threshold criteria to identify seven potential facility configurations. In order to evaluate the identified routes, BECo prepared a comprehensive list of environmental criteria that could be affected by the construction and operation of the proposed facilities, assigned scores to each of the criteria which considered the severity of impacts, and assigned weights to each of the criteria which considered the level of importance of the criterion and the ability to minimize or mitigate impacts. BECo also assigned scores to the cost and reliability categories based on specific factors in each category. In addition, the Company determined category weights to conduct a balancing of the environmental, reliability and cost categories and to calculate an overall score for each of the identified alternatives.

Thus, the Company has provided a comprehensive, quantitative method to compare identified alternatives on the basis of environmental impacts, cost and reliability. However, the Company's criteria and scoring system leads, in two respects, to potential under-emphasis on environmental factors compared to cost and reliability factors. First, the Company's threshold criteria requiring that underground and overhead transmission lines be no longer than two and nine miles in length, respectively, were based exclusively on cost, specifically the cost of the substation. The Siting Board recognizes that it is reasonable to consider the clear cost advantages of overhead lines when determining maximum reasonable line lengths; however, by the same logic, these maximum line lengths should also reflect the environmental advantages of typical underground lines.

Second, the Company's scoring methodology, while theoretically giving equal weight to the three categories of environmental impacts, reliability and cost, in practice places greater weight on cost and reliability. Specifically, because the range of reliability and cost scores is greater than the range of summed environmental scores, reliability and cost actually have a greater influence on the total score than does environmental impacts. The Company defended its scoring system indicating that it adequately reflected the range of environmental impacts but acknowledged that it had the effect of narrowing the potential magnitude of impact of the environmental score on the overall score. The Siting Board is concerned that the structure of the Company's scoring system is unequal in important aspects among the three overall categories, leading to an inherent potential to underweight environmental impacts relative to cost and reliability.

First, scores for both cost and reliability range from one to three, without regard for the significance of the actual range of costs and reliability indicators. In contrast, the score for each environmental criterion ranges from one to three only if the worst and best alternatives actually show the characteristics for high and low environmental impact.

Second, unless the same alternatives are scored one and three for every environmental criterion, the summing of scores for respective criteria to derive total environmental scores incorporates a netting offset that reduces the range of the summed scores to a multiple of less than one to three. The scoring for cost and reliability indicators is done on a total score basis, and incorporates no netting effects among component categories.

The Company has both defended its methods and concluded that the outcome of its site selection scoring appropriately reflected environmental, cost and reliability considerations. However, the record shows that structural elements of the Company's scoring system led to a smaller range of environmental scores, relative to cost and reliability scores. This discrepancy, which results from the relative lack of sophistication in scoring cost and reliability criteria, is essentially inherent to the scoring approach. The Company did not provide convincing reasons, separate from its scoring, as to why overall environmental differences among its alternatives were less significant than the cost and reliability differences.[72]

Nevertheless the Company's site selection process enabled it to identify a number of potential underground and overhead transmission line routes. Although the underground route along Interstate 495 exceeded two miles, it was not eliminated from further consideration based on the two-mile criteria. Instead, it was not identified as a viable route because it could not be implemented in the roadway and was therefore inconsistent with the

72 The Siting Board notes that there is no reason to assume that cost, reliability, and environmental impacts should be equally weighted. What is most important is that a proponent must have a clear and convincing explanation for the weights that is has chosen.

Company's criterion limiting underground line location to an existing roadbed.

In addition, the Company used a method for comparing the identified routes which included a quantitative balancing of environmental impacts, reliability and cost impacts. Further, although the categories of environmental impacts, reliability and cost may not have been appropriately balanced, the proposed facilities received the highest scores in all three categories.

Based on the foregoing, the Siting Board finds that the Company has developed a reasonable set of criteria for identifying and evaluating facility alternatives. The Siting Board also finds that the Company has applied its site selection criteria consistently and appropriately, and in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to the proposed project.

Accordingly, the Siting Board finds that the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternatives to the proposed project in a manner which ensures that is has not overlooked or eliminated any siting options which are clearly superior to the proposed project.

3. Geographic Diversity

BECo presented two different underground routes for the proposed transmission line -- one route that travels within streets within the Towns of Milford and Hopkinton and one route that travels within roadways within the Towns of Upton and Hopkinton. They each start at a different point along the existing NEES Medway to Millbury 115-kV transmission line ROW where a transmission station will be constructed and each terminate at the site of a new substation. The Siting Board finds that the Company has identified a practical range of transmission line routes and facility sites with some measure of geographic diversity.

4. Conclusions on the Site Selection Process

The Siting Board has found that the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternatives to the proposed project in a manner which ensures that is has not overlooked or eliminated any siting options which are clearly superior to the proposed project. In addition, the Siting Board has found that BECo has identified a practical range of transmission line routes and facility sites with some measure of geographic diversity.

Accordingly, the Siting Board finds that the Company has considered a reasonable range of practical siting alternatives.

C. Environmental Impacts, Cost and Reliability of the Proposed and Alternative Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring a reliable energy supply. To determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed project site for the facility is superior to the noticed alternatives on the basis of balancing cost, environmental impact, and reliability of supply. 1997 ComElec Decision, EFSB 96-6, at 60; Norwood Decision, EFSB 96-2, at 43; Berkshire Gas Company, 23 DOMSC 294, 324 (1991).

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost, and reliability. 1997 ComElec Decision, EFSB 96-6, at 60; Norwood Decision, EFSB 96-2, at 43; Eastern Energy Corporation, 22 DOMSC at 188, 334, 336 (1991) ("EEC Decision"). A facility which achieves that appropriate balance thereby meets the Siting Board's statutory requirement to minimize environmental impacts at the lowest possible cost. 1997 ComElec Decision, EFSB 96-6, at 60; Norwood Decision, EFSB 96-2, at 43; EEC Decision, 22 DOMSC at 334, 336.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. 1997 ComElec Decision, EFSB 96-6, at 60; Norwood Decision, EFSB 96-2, at 43-44; EEC Decision, 22 DOMSC at 334, 336. The Siting Board previously has found that compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Id. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in respective facility proposals. 1997 ComElec Decision, EFSB 96-6, at 60-61; Norwood Decision, EFSB 96-2, at 44; EEC Decision, 22 DOMSC at 334-335.

The Siting Board recognizes that an evaluation of the environmental, cost and reliability trade-offs associated with a particular review must be clearly described and consistently applied from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts and among environmental impacts, cost, and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination. 1997 ComElec Decision, EFSB 96-6, at 61; Norwood Decision, EFSB 96-2, at 44; Boston Edison Company (Phase II), 1 DOMSB 1, 39-40 (1993). The Siting Board can then determine whether environmental impacts would be minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability would be achieved. 1997 ComElec Decision, EFSB 96-6, at 61; Norwood Decision, EFSB 96-2, at 44; Boston Edison Company (Phase II), 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental impacts, cost and reliability of the proposed facilities along BECo's primary and alternative routes to determine: (1) whether the environmental impacts of the proposed facilities would be minimized; and (2) whether the proposed facilities would achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability. In this examination, the Siting Board conducts a comparison of the primary and alternative routes to determine which is preferable with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

2. Analysis of the Proposed Facilities Under the Primary Configuration

a. Environmental Impacts of the Proposed Facilities Under the Primary Configuration

In this section, the Siting Board evaluates the environmental impacts of the proposed facilities along the primary route and the proposed mitigation for such impacts, and any options for additional mitigation. As part of its evaluation, the Siting Board first addresses whether the petitioner has provided sufficient information for the Siting Board to determine: (1) whether environmental impacts of the proposed facilities would be minimized; and (2) whether the proposed facilities achieve the appropriate balance among environmental impacts and among environmental impacts, cost and reliability. The Siting Board then addresses whether the environmental impacts of the proposed facilities along the primary route would be minimized.

i. Water Resources

(a) Wetlands and Surface Water

BECo stated that the proposed facilities under the Primary Configuration would traverse a wetland and other areas in proximity to water resources (Exhs. BE-DS-1, at 2; BE-DS-3; BE-AJ-1, at 5). However, the Company indicated that no wetland would be altered by construction of the proposed facilities or access road (Exh. BE-DS-4(att. D) at D-1; HO-RR-11(sup.)).

The Company stated that approximately 300 feet of transmission line conduit would be installed beneath wetlands by directional drilling[73] between Purchase Street and the transmission station, in order to avoid alteration of the surface wetlands (Exh. BE-DS-1, at 2; Tr. 6, at 17). The Company's witness, Daniel Stuart, testified that directional drilling would leave the wetland's surface undisturbed and minimize the potential of sediment flow into the wetland area during facility construction (Tr. 6, at 17).[74]

With respect to indirect impacts to water resources, the Company stated that approximately 1,850 square feet of buffer zone would be disturbed due to grading in the northeastern corner of the transmission station (Exh. BE-DS-4(att. D) at D-4). In addition, BECo stated that the transmission line route for the proposed facilities would pass within 100 feet of wetlands at one location near the town line of Milford and Hopkinton, along Purchase and South Streets (id. at D-5; Exh. BE-1, at 5-2). The Company stated that approximately 4,000 square feet of buffer zone would be impacted by construction work in the roadway (Exh. BE-DS-4(att. D) at D-5). The Company stated that construction of the substation would occur in proximity to a small, 240 square foot wetland area, but added that it would be unaffected by the construction activity (id. at D-6; Exh. BE-1, at 5-4). The Company indicated that construction at the substation site would disturb approximately 9,400 square feet of buffer zone (Exh. BE-DS-4(att. D) at D-6).

The Company stated that new concrete-encased duct bank containing new distribution lines would be constructed underground and extend from the substation to South Street,

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73 The Company stated that the process of directional drilling would require the construction of two pits, four to five feet in depth, on both sides of the wetland, and the boring of four holes at the bottom of one pit to the other to accommodate the two transmission lines and other transmission station utilities (Exh. BE-DS-4(att. D) at D-5).

74 Based on consultation with the DEP, the Company stated that the Water Quality Certificate for the proposed project will address required actions in the event problems develop during the drilling process, such as migration of clay to the wetland's surface (Exh. BE-DS-4(att. D) at D-5). The Company added that upon completion of the drilling operation, any clay that has entered the wetland would be removed and the surface restored in accordance with the permit conditions (id.).

travelling north beneath the paved surface for approximately 2,000 feet to where it would interconnect with the existing distribution system in Hopkinton (id.; Exh. BE-1, at 1-7). The Company indicated that these underground facilities would be placed within 100 feet of nine forested wetlands that border the east and west sides of South Street in Hopkinton, but added that construction would not directly impact these wetlands (Exhs. BE-1, at 5-4; BE-DS-4(att. D) at D-6 to D-7). The Company stated that approximately 9,100 square feet of buffer zone would be impacted in this area (Exh. BE-DS-4(att. D) at D-7).

The Company further stated that it would use standard erosion control measures at all proposed facilities in or within 100 feet of wetlands in order to minimize potential impacts to wetland resources areas (Exh. BE-1, at 5-4). The Company indicated that where work would occur in close proximity to a wetland, silt fencing and staked haybales would be installed between the wetland edge and the work area to minimize silt migration into wetland areas down gradient of construction activity (id.). The Company added that where excavation is necessary in close proximity to wetland boundaries, any water that flows into a trench would be pumped out into either a closed corral of staked haybales or a wetland filter bag (id.).

BECo stated that surface waters are located near the proposed facilities in the vicinity of the Milford/Hopkinton town line (id. at 5-5). The Company indicated that the underground transmission lines would pass beneath two culverts in this area, one of which conveys an unnamed intermittent stream (id.). The Company stated that while no direct impact is anticipated, groundwater could be encountered during construction that would require the dewatering of the trench in order to facilitate installation of the two transmission line pipes (id.). The Company added that the distribution line facilities would cross at least four culverts in this area (id.).[75]

The Company stated that outstanding resource waters ("ORW"s) have been identified on the transmission station site, and in the vicinity of the underground transmission and

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[75] The Company indicated that four culverts pass beneath South Street in this area that hydrologically connect some of the wetlands located on opposite sides of the road (Exh. BE-DS-4(att. D) at D-7).

distribution routes for the proposed facilities under the Primary Configuration (id. at 5-6; Exh. MJP 1-9). The Company stated that construction of the proposed facilities under the Primary Configuration could introduce sediments into ORWs, but added that it would use construction measures which avoid or minimize such impacts (Exhs. BE-DS-4, at 5, 5A; BE-1, at 5-4 to 5-6).

The Company stated that the ORW on the transmission station site is a wetland that borders a tributary to Louisa Lake, a public water supply located approximately 1.5 miles southeast of the proposed transmission station site in Milford (Exh. BE-1, at 5-6).[76] The Company stated that ORWs also occur on either side of Purchase and South Streets in Milford and Hopkinton, respectively, along the underground transmission and distribution line routes (id.). The Company stated that these ORWs include wetlands associated with Craddock Crewes Pond, and the headwaters of Huckleberry Brook, a tributary to Louisa Lake (id.). The Company indicated that while no direct impact is anticipated to these ORWs, groundwater could be encountered during construction of the underground lines (id.). The Company added that any trench dewatering necessary to eliminate unwanted groundwater encountered during construction would be done in a way to minimize the potential impact to the ORW (id.).

The record demonstrates that construction of the proposed facilities under the Primary Configuration would require construction both within and in proximity to wetlands. Specifically, the record indicates that the most sensitive areas along the Primary Configuration would be at the transmission station site and immediately beyond it where the Company plans to use directional drilling to avoid impacts to the surface of a wetland, and near the Milford/Hopkinton Town line where culverts interconnect wetlands separated by a roadway. However, the Company has proposed the use of appropriate mitigation techniques during construction to avoid or minimize adverse water-related impacts. Accordingly, the Siting Board finds that, with implementation of the proposed mitigation measures, the

76 The Company explained that Louisa Lake and all of its tributaries, and wetlands bordering on them, are classified as Class A waters and ORWs (Exh. BE-1, at 5-6).

environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to wetlands and surface water.

(b) Groundwater and Wells

The Company asserted that construction of the proposed facilities under the Primary Configuration likely would not affect groundwater resources (Exh. BE-1, at 5-5 to 5-6). Specifically, the Company noted that the Primary Configuration is not located over protected water supply resources or in close proximity to public supply wells for the Towns of Hopkinton or Milford (id. at 5-5). The Company stated that an area delineated as Zone II, approved by the Department of Environmental Protection for public groundwater supplies in Milford, is located approximately one-half mile southwest of the proposed transmission station site (id.). The Company further stated that appropriate mitigation measures would be used to minimize any indirect impacts to groundwater associated with construction (id. at 5-6).

The record demonstrates that construction of the proposed transmission and distribution facilities, which would primarily be within existing paved roadways, would avoid direct, or minimize indirect, impacts to groundwater along the primary route.

Accordingly, the Siting Board finds that, with implementation of proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to groundwater and wells.

(c) Conclusions

The Siting Board has found that with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to wetlands and surface water. In addition, the Siting Board has found that with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to groundwater and wells. Therefore, the Siting Board finds that with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to water resources.

ii. Land Resources

In this Section, the Siting Board reviews the impact of the proposed facilities under the Primary Configuration with respect to tree clearing and upland vegetation, potential soil erosion and wildlife habitat.

BECo indicated that construction of the facilities under the Primary Configuration would require the clearing of approximately two acres of trees in aggregate (Exh. BE-1, at 5-7).[77] BECo stated that a maximum of one-half acre of tree clearing would be required at the substation site, a portion of which was previously cleared, and that a maximum of 1.5 acres of clearing would be required at the transmission station site (id.). The Company stated that the transmission station and substation sites are relatively level and well vegetated, and exhibit no significant potential for erosion during construction or operation of the proposed facilities (id.). The Company further stated that both sites would be covered with crushed stone to maintain soil stability following construction (id.).

The Company stated that construction impacts to soil resources will be further minimized through the location of underground T&D lines within existing roadways, thereby avoiding additional impacts to developed or open spaces (id. at 5-7, 5-9). The Company stated that it would enable the repavement of the full width of all affected road surfaces via payments to the Towns of Milford and Hopkinton upon completion of construction of the underground T&D facilities, but added that both town's Public Works Departments would be responsible for scheduling the repaving projects (id. at 5-9; Exh. HO-E-9).

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77 The Siting Board notes that the record on tree clearing is contradictory. In response to a Siting Board information request, BECo stated that the preferred facilities would require the clearing of nearly three acres of trees, while its petition indicated an aggregate clearing of approximately two acres (Exhs. HO-E-16; BE-1, at 5-7). The Siting Board accepts the two-acre estimate based on additional record information indicating that a new access road originally planned for the transmission station will not be constructed (Exh. HO-RR-11(att.)).

BECo stated that, based on its review of the 1995-1996 Edition of the Massachusetts Natural Heritage Atlas,[78] neither protected species nor unique ecological habitats are known to occur either on, or in close proximity to, the site of the proposed facilities (Exh. BE-1, at 5-7).[79]

The record demonstrates that a significant portion of the proposed facilities would be located in areas which are already paved, and that BECo plans to implement measures to limit erosion impacts, to stabilize areas disturbed by construction, and to return such areas as much as possible to their original condition. Such measures include laying crushed stone at the transmission station and substation sites, and enabling the repavement of the full widths of roadways affected by the installation of the proposed transmission and distribution facilities.

In addition, the record demonstrates that there are no known rare or endangered species in the vicinity of the proposed facilities that would be adversely affected by the proposed construction.

Accordingly, the Siting Board finds that, with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to land resources.

iii. Land Use

In this Section, the Siting Board reviews the impact of the construction and maintenance of the proposed facilities under the Primary Configuration with respect to land use, zoning, traffic, safety and noise.

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78 BECo indicated that this publication is provided by the Massachusetts Division of Fisheries and Wildlife (Exh. BE-1, at 5-7).

79 BECo explained that in making this determination, it consulted the Milford Quadrangle for both "Estimated Habitats of Rare Wetlands Wildlife and Certified Vernal Pools" and "High Priority Sites of Rare Species Habitats and Exemplary Natural Communities" (Exh. BE-1, at 5-7).

BECo stated that the proposed facilities in Milford would be located in a residentially zoned district (Exh. BE-1, at 5-10). The Company stated that the transmission station would be located on an undeveloped forested parcel adjacent to the existing NEES ROW, and approximately 1,000 feet from Purchase Street, a fully developed residential street (id.). The Company noted that construction of the proposed transmission station is a permitted use under Milford zoning by special permit, and that placement of the transmission lines underground from the station out to Purchase Street is a permitted use (id.). The Company added that the transmission station would be fenced to inhibit unauthorized access (id.).

The Company stated that all proposed facilities within the Town of Hopkinton would be located in an industrially zoned district (id.). The Company added that the project area in Hopkinton is developed with commercial uses along the entire length of South Street (id.). The Company stated that the proposed substation would be sited on an industrial parcel with an abutting commercial use to the rear of the site and an abandoned gravel pit to the north (id.). In order to inhibit unauthorized access, the Company indicated that the substation would be fenced around its perimeter (Exh. HO-E-7(att. 1), at 3). The Company noted that Hopkinton's zoning by-law does not specifically address public utility facilities (Exh. BE-1, at 5-10).

With respect to impacts on historical or archaeological resources, BECo stated that it reviewed files at the Massachusetts Historical Commission ("MHC") including base map files, State Register of Historical Places and archeological site maps (Exh. BE-1, at 5-14). BECo stated that the only resources identified in the project area include historic properties along the proposed transmission line route in Milford (id.). The Company further stated that construction activity could potentially affect these resources if rock removal is required for trench excavation (id.). The Company added that rock removal is not expected based on its review of soil maps of the area which indicate no surface bedrock (id.).

BECo stated that if bedrock is encountered in these areas, it would be removed with backhoes or jack hammers if possible (Exh. BE-1, at 5-14). BECo further stated that if a significant amount of blasting is required near historic properties, it would contact the MHC and property owners to determine if there is a potential for any adverse impact to the structures (id.). BECo added that any required blasting would be conducted in accordance with applicable state and federal regulations to ensure the safety of construction personnel and properties in the immediate vicinity (id.).

With respect to traffic impacts, the Company stated that temporary traffic disruptions due to construction of the underground facilities would occur along Purchase and South Streets in Milford and Hopkinton, respectively, between the transmission station and the substation (id. at 5-10). The Company stated that trench excavation would be limited to one side of the street in order to maintain one lane of traffic (id. at 5-13 to 5-14). The Company stated that it would implement several measures to mitigate potential construction impacts on local traffic, in coordination with Milford's and Hopkinton's Departments of Public Works and other permitting authorities having jurisdiction (id.). The Company indicated that such measures would include construction restrictions during morning and afternoon hours of peak travel, use of steel plates to ensure access to driveways and intersections, identification of construction worker parking areas, police details to direct traffic during construction, periodic street sweeping to minimize the migration of sediments off-site, and an on-site community liaison to address local concerns (id.). The Company added that operation of the proposed facilities would not noticeably affect traffic in Milford or Hopkinton (id. at 5-10). However, the Company acknowledged that on average, typical maintenance of a transmission line includes approximately twice a year inspection of the transmission line and manholes, a process that takes about twenty minutes (Tr. 5, at 93-94, 105).

With respect to noise impacts of the proposed project, BECo asserted that sound levels emanating from the proposed substation on South Street would be inaudible at the nearest residence (id., Appendix E at 3, n.2). The Company explained that noise from operation of the proposed substation would be attenuated through the selection of low-noise transformers, and the installation of a sound barrier on three of each transformer's four sides (id., at 5-11 to 5-12; Tr. 6, at 79-80). The Company provided the results of a noise analysis conducted to determine the potential impact of the two new transformers at the substation, the only permanent noise sources from the project (Exh. BE-1, at 5-11 to 5-12). The Company stated that it measured the nighttime ambient sound levels at the proposed substation site, and indicated that the lowest nighttime[80] ambient L_{90} noise level was 40 dBA (id., Appendix E, Table 2; Tr. 6, at 77-78). The Company indicated that operation of the two low-noise transformers at the substation would generate 39 dBA of noise, and that the combined effect of the ambient noise level and the facility noise level at the nearest residence would be 43 dBA, an increase of 3 dBA in the nighttime ambient noise levels (id., Appendix E at 2, 3; Exh. HO-RR-8; Tr. 6, at 78). In order to mitigate the noise impacts of construction, the Company stated that it would use standard construction equipment sound muffling devices, cease construction activity during the nighttime hours, and adhere to federal truck-noise regulations (Exh. BE-1, at 5-13).

Finally, BECo noted that under the terms of a settlement agreement between BECo and several intervenors[81] in the instant proceeding dated June 19, 1997 ("Terms of Settlement" or "Settlement Agreement"), the Company would be required to consult with the Town of Milford and restrict the construction hours for the project in order to avoid adverse impacts on rush hour traffic and provide funds for re-paving of the full width of Purchase Street where disturbed by the construction and installation of the proposed facilities (Exh. HO-RR-11(att.)). The Company also indicated that the Terms of Settlement require that it restrict noise levels to levels no higher than those listed in Appendix E of Exhibit BE-1 concerning the proposed project under the Primary Configuration (id.).

The record demonstrates that traffic, safety, and noise impacts associated with construction of the proposed facilities under the Primary Configuration would be temporary and acceptable, with implementation of mitigation measures proposed by the Company. Specifically, according to the record, BECo would contribute funding to re-pave streets disturbed by construction, take steps during construction to minimize impacts to traffic as well as to local residences and businesses, and maintain a community liaison during

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80 The Company stated that, for purposes of ambient sound level measurement, the nighttime is considered to be between 10:00 PM and 6:00 AM (Exh. BE-1, at 5-12).

81 State Senator Richard T. Moore, State Representative Marie J. Parente, Douglas Vrooman, the Town of Milford, and the Company were parties to the Settlement Agreement (Exh. HO-RR-11(att.)).

construction to address concerns of the public. The record also indicates that although bedrock formations are unexpected, there is a small possibility that historic properties in Milford could be adversely impacted if blasting is required to remove bedrock formations encountered along that portion of the route. BECo has committed to consult both with the MHC and affected property owners, and to follow applicable state and federal regulations to ensure safe conditions for all affected persons and properties in the vicinity.

With regard to traffic, safety, and noise impacts associated with the operation of the proposed facilities under the Primary Configuration the record indicates that there would be no discernable traffic impacts during typical daily operation of the proposed facilities, although some minor traffic impacts may be encountered on those days that semi-annual inspections of the transmission line and manholes occur. In addition, the record demonstrates that both the transmission station and substation would be fenced to restrict access to Company personnel thereby minimizing any safety impacts associated with the operation of the proposed facilities. Further, the record demonstrates that operational noise from the proposed substation's low-noise transformers would be further reduced by the placement of a sound barrier around three sides of each transformer.

Accordingly, the Siting Board finds that with implementation of all proposed mitigation, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to land use. Zoning issues will be further addressed in Section IV, below.

iv. Visual Impacts

BECo stated that the potential for visual impacts to nearby residences and businesses would be limited to aboveground facilities -- the transmission station and the substation (Exh. BE-1, at 5-9). BECo explained that because the T&D lines would be located underground, related visual impacts would occur only during construction (id.).

The Company stated that the transmission station would be located on a residentially-zoned, 25.6-acre undeveloped parcel with access to Purchase Street (id.; Exhs. BE-4e, 4g, 4h, 4j). The Company asserted that the size of the parcel would provide sufficient separation of the transmission station from residences (Exh. BE-1, at 5-9). The Company stated that the transmission station would be placed adjacent to the north side of the NEES ROW in an area chosen to maximize the distance between the station and nearby residences (id.). The Company indicated that the closest home, located on Rose Road in Milford, would be situated 720 feet from the transmission station site while other homes on Purchase and Camp Streets would be at least 800 feet from the site (id.; Exh. HO-E-10a, Table E-10a-1). The Company stated that most of the area surrounding the transmission station would remain forested, and added that landscaping would be used to screen any openings providing views of the transmission station site from residences (Exh. BE-1, at 5-9).[82]

The Company stated that the proposed substation site is located in an industrial area (id.). The Company indicated that businesses abut the north, south, and west sides of the parcel, and that the east side faces South Street (id.; Exhs. BE-4a, 4b, 4c). The Company indicated that the nearest residence to the substation site on South Street in Hopkinton would be located on Purchase Street in Milford, almost 1,100 feet away (Exh. HO-E-10a, Table E-10a-1). The Company further indicated that all other non-residential sensitive receptors[83] would be located no closer than 700 feet from the substation site, thus minimizing potential adverse visual effects from the substation facilities (Exh. BE-1, at 5-9).

The Company presented four architectural designs compatible with surrounding facilities and has committed to design the substation facade of brick to be similar in type with

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82 BECo stated that the elevation at the proposed transmission station site is approximately 20 to 25 feet below the elevation of homes along Purchase and Camp Streets, and thus would contribute to a minimal visual impact at the homes (Exh. BE-1, at 5-9). BECo further stated that the tallest structures at the station would be two lightning-shield masts at a maximum height of 75 feet, and added that this height would be below the height of the existing transmission line facilities on the NEES ROW immediately behind the site (Exhs. BE-AJ-1, at 4; BE-AJ-4; Hopkinton-RR-1).

83 BECo indicated that it defines sensitive receptors as any homes, businesses, churches, and schools, etc., from where the proposed aboveground facilities can be viewed (Exh. Upton 6).

other buildings in the surrounding area (Exh. BE-1, at 5-9; Tr. 2, at 86; Tr. 6, at 23). In addition, under the Terms of Settlement, the Company is required to plant shrubs and trees of a sufficient height and density to screen the proposed substation facilities in Hopkinton from view from South Street and residential properties in Milford (id.).

The record demonstrates that, with the implementation of the proposed landscaping at the transmission station, the construction of the substation with a brick facade to resemble nearby buildings, and the screening requirements contained in the Terms of Settlement, the visual impacts of the proposed facilities under the Primary Configuration would be negligible. Accordingly, the Siting Board finds that, with the proposed mitigation relative to the design and screening of the proposed facilities, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to visual impacts.

v. Magnetic Field Levels[84]

The Company asserted that the proposed facilities have been designed to minimize exposure to magnetic fields (BECo Initial Brief at 45). The Company indicated that, presently, the magnetic field levels along Purchase Street in Milford, which are due to the distribution lines and circuit drops along the street, vary from three to five milligauss ("mG"), according to location on the east or west side of the street (Exh. BE-DS-1(att. E)). BECo indicated that there are two residences, 327 and 339 Purchase Street, which are located 20 feet from the proposed transmission line and that these residences will be the closest residences to the proposed transmission line (Exh. HO-10, Table 10a-1). The Company indicated that existing magnetic field levels at the edge of the roadway closest to

84 The Siting Board focuses on magnetic field levels rather than electric field levels because perceived heath impact generally relate to magnetic field levels. See 1997 ComElec Decision, EFSB 96-6, at 41, n.23; 1996 NEPCo Decision, EFSB 95-2, n.22; 1995 NEPCo Decision, 4 DOMSB at 32, n.51.

the residences are approximately 1.4 mG at 327 Purchase Street and 0.5 mG at 339 Purchase Street (Exh. HO-E-11).[85]

The Company stated that peak magnetic fields directly over the centerline of the proposed transmission line would be: (1) 1.0 mG under anticipated turn-on conditions where power transmission would equal 30 MVA; (2) 1.3 mG under anticipated near-term peak load conditions where power transmission would equal 40 MVA; and (3) 2.0 mG under anticipated long-term (i.e., 20-year) peak load conditions where power transmission would increase to 60 MVA (Exh. HO-RR-12).[86] BECo further stated that the magnetic field levels would decrease with increasing distance from the centerline of the proposed transmission line, decreasing to one-half of the maximum values at a lateral distance of eight feet from the centerline and would continue to decrease rapidly with distance away from the centerline (Exh. BE-DS-1(att. E)). The Company indicated that there are 23 residences within 100 feet of the proposed transmission line route (Exh. HO-E-10, Table 10b-1).

The Company stated that the underground construction and design of the transmission line would minimize the magnetic field impacts of the proposed facilities (id.).[87,88] The Company stated that each of the two transmission lines connecting the transmission station to

85 The Company indicated that the residence located closest to the transmission station is located 720 feet from the transmission station site and that existing maximum magnetic field levels are approximately 0.6 mG at the residence (Exhs. HO-E-10, Table E-10a-1; HO-E-11). The Company also indicted that the residence located closest to the substation and distribution line is located 1,080 feet from both and that existing maximum magnetic field levels are less than 0.2 mG at that residence (id.).

86 BECo stated that under maximum full load conditions of power transmission of 80 MVA, the peak magnetic filed over the center line of the transmission line would be 2.6 mG (Exh. HO-RR-12).

87 BECo indicated that an overhead line carrying the same near-term peak load current would produce magnetic fields of approximately 30 mG and also would produce electric fields (Exh. BE-DS-1(att. E)).

88 The Company stated that underground conductors would produce no electric field impacts because the soil itself entirely shields the electric field (Exh. BE-DS-1(att. E); Tr. 6, at 125).

the substation will consist of three underground cables contained within a six-inch steel pipe (Exh. BE-1, at 5-11). The Company stated that use of one steel pipe for each transmission line would minimize the peak magnetic fields and the distance over which magnetic fields are elevated (Exh. BE-DS-1(att. E); Tr. 6, at 123-125). Dr. Valberg explained that the one-pipe design would bring the cables as close together as possible, and therefore the magnetic fields of the adjacent cables would be cancelled to the greatest extent possible (Tr. 6, at 123-124). Dr. Valberg further explained that steel is a conductive material and would therefore deflect the amount of magnetic fields reaching the environment by a factor of approximately ten (id.).

The Company stated that the distribution lines would be constructed primarily underground and that the highest magnetic field levels associated with the proposed project would occur at a point directly above the new distribution lines as they leave the substation (Exh. BE-1, at 1-7, 5-11). The Company indicated that magnetic field levels would begin to decrease within 300 feet of the substation as the loading on the lines begins to decrease (id.). The Company also stated that the distribution lines would produce higher magnetic fields than the transmission line because (1) their voltage is lower, and (2) they would not be constructed within a steel pipe (Tr. 6, at 127-129). Assuming the distribution lines are dedicated lines that carry the same load as the transmission line as they exit the substation, the Company estimated that, directly above the distribution lines, the magnetic field strength would be approximately 100 times the field strength of the transmission line (id. at 130). Based on this assertion, the Siting Board calculates the magnetic field strength directly over the distribution lines to range from approximately 100 mG to 200 mG under differing peak load conditions. Further, based on the Company's assertion that magnetic field levels would decrease with increasing distance from the centerline of the proposed transmission line, decreasing to one-half of the maximum values at a lateral distance of eight feet from the centerline, the Siting Board calculates that the magnetic field levels would decease to approximately 50 mG to 100 mG at a distance of eight feet from the centerline of the distribution line.

However, the Company stated that the distribution line route would traverse a commercial/industrial area where current in the lines would continue to be reduced as it is drawn off by industrial users and that there are no residences, schools or other sensitive receptors located within 100 feet of the distribution line route (id. at 126; Exh. HO-E-10, Table E-10b-2).[89] The Company indicated that the commercial and industrial property frontages along South Street are located approximately 20 to 25 feet from the proposed distribution line (Exh. HO-E-3(att. 6), Distribution Duct Banks, sheets 1-5).[90] In addition, the Company asserted that because power presently is supplied to Hopkinton via distribution lines, installation of the proposed project which would provide power in close proximity to major users, would reduce the loading on the distribution lines servicing Hopkinton and would therefore result in an overall decrease in existing magnetic field levels in Hopkinton (Exh. BE-1, at 5-11; Tr. 6, at 131).

As a condition of the Settlement Agreement, BECo has agreed to: (1) conduct a baseline survey of EMF levels along Purchase Street, and at the transmission tap station and substation sites prior to installation of the proposed project; (2) conduct follow-up surveys of EMF levels after project installation on an annual basis for the first three years of facility operation and then on a bi-annual basis for the next six years; and (3) report results of all of the aforementioned EMF surveys to the parties to the Settlement Agreement (Exh. HO-RR-11). In addition, if EMF levels from the proposed project are determined to exceed applicable health or safety standards in place as of the date of the Settlement Agreement, BECo agreed to take reasonable corrective action as required by law to reduce such levels (id.).

In a previous review of proposed transmission line facilities, the Siting Board accepted edge-of-ROW levels of 85 MG for the magnetic field. Massachusetts Electric

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89 The Company indicated that the same residence is the closest to both the distribution lines and substation site, and that it is located 1,080 feet from both (Exh. HO-E-10).

90 The Company indicated that there are wetlands located along the commercial and industrial property frontages along the distribution line route (Exh. HO-E-3(att. 6), Distribution Duct Banks, sheets 1-5).

Company/New England Power Company, 13 DOMSC 119, 228-242 (1985) ("1985 MECo/NEPCo Decision"). The Siting Board has also applied these edge-of-ROW levels in subsequent reviews of facilities which included 115-kV transmission lines. See, 1997 ComElec Decision, EFSB 96-6 at 73; Norwood Decision, EFSB 96-2, at 33; MASSPOWER, Inc, 20 DOMSC 301, 401-403 (1990). Here, the magnetic field levels along the transmission line route would remain far below the levels found acceptable in the 1985 MECo/NEPCo Decision, with operation of the proposed transmission line. The record demonstrates that the Company has incorporated features into the design of the proposed transmission line that would minimize its magnetic fields. In addition, in accordance with its Settlement Agreement with the Milford Parties, the Company will monitor magnetic field levels along the transmission line route and will take corrective action if so required.

However, the maximum magnetic field levels near the underground distribution line in South Street likely would exceed the edge-of-the-ROW levels found acceptable in the 1985 MECo/NEPCo Decision. The record demonstrates that magnetic field levels will be highest as the distribution lines leave the substation and then decrease as current is drawn off by industrial users along the route. The record also demonstrates that, depending on peak load conditions, magnetic field levels would range from approximately 100 mG to 200 mG directly over the lines, decreasing to approximately 50 mG to 100 mG at a distance of eight feet from the lines and further decreasing with increasing distance from the lines.

The record further demonstrates that there are no residences within 100 feet of the proposed distribution lines, and that the property frontages of the commercial and industrial properties along South Street are located approximately 20 to 25 feet from the proposed distribution line. Thus, magnetic field levels due to the operation of the proposed distribution line would not exceed 85 mG at the property frontages of the commercial and industrial properties along South Street. In addition, the record demonstrates that magnetic field levels of other distribution lines in Hopkinton would decrease as a result of the operation of the proposed facilities.

Accordingly, the Siting Board finds that, with implementation of the proposed facility design configuration, and the monitoring and mitigation plan set forth in the

Settlement Agreement, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to magnetic field impacts.

vi. Conclusions on Environmental Impacts

In Section III.C.2.a, above, the Siting Board has reviewed the information in the record regarding environmental impacts of the proposed facilities under the Primary Configuration and the potential mitigation measures. The Siting Board finds that the Company has provided sufficient information regarding environmental impacts of the proposed facilities under the Primary Configuration and potential mitigation measures for the Siting Board to determine whether environmental impacts would be minimized and whether the appropriate balance among environmental impacts would be achieved.

In Section III.C.2.a, above, the Siting Board has found that: (1) with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to water resources; (2) with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to land resources; (3) with the implementation of all proposed mitigation, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to land use; (4) with the proposed mitigation relative to the design and screening of the proposed facilities, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to visual impacts; and (5) with implementation of the proposed facility design configuration, and the monitoring and mitigation plan set forth in the Settlement Agreement, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized with respect to magnetic field impacts.

Accordingly, the Siting Board finds that, with the implementation of proposed mitigation and compliance with all applicable local, state, and federal requirements, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized. In Section III.C.3.c, below, the Siting Board addresses whether an appropriate balance among environmental impacts and among cost, reliability, and environmental impacts would be achieved.

b. Cost of the Proposed Facilities Under the Primary Configuration

The Company submitted estimates of both the installation costs and the annual costs for the proposed facilities, and estimates of the installation costs of the alternative facilities (Exhs. DV 1.1-2; DV 1.1-3; HO-RR-6(atts. 1 & 2)). BECo stated that it estimated the installation costs of the proposed project at $12,547,000, and the first year O&M costs, including costs of substation and transmission station operation and transformer losses, at $35,600 (Exhs. DV 1.1-3; HO-RR-6(atts. 1& 2)). The Company indicated that annual distribution line losses in the area supplied by the proposed facilities would be $85,000, as compared with approximately $1,000,000 in losses to serve that area under the existing system (Exh. HO-RR-6).[91]

The Siting Board finds that BECo has provided sufficient cost information for the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and cost.

c. Conclusions

The Siting Board has found that BECo has provided sufficient information regarding the environmental impacts of the proposed facilities under the Primary Configuration and potential mitigation measures for the Siting Board to determine whether environmental impacts would be minimized and whether the appropriate balance among environmental impacts and between costs and environmental impacts would be achieved. The Siting Board has also found that BECo has provided sufficient cost information for the Siting Board to determine whether the appropriate balance would be achieved between environmental impacts and cost.

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91 BECo stated that it did not estimate wheeling charges and transmission losses in calculating O&M costs, as the proposed project would not significantly change such costs (Exh. HO-RR-6).

In Section III.C.2.a., above, the Siting Board reviewed the environmental impacts of the proposed facilities and proposed mitigation under the Primary Configuration with respect to water resources, land resources, land use, visual impacts, and magnetic field levels. For each category of environmental impacts, BECo demonstrated that, with the mitigation discussed above, the impacts would be minimized.

Accordingly, the Siting Board finds that the proposed facilities under the Primary Configuration would achieve an appropriate balance among conflicting environmental concerns as well as between environmental impacts and cost.

3. Analysis of the Proposed Facilities along the Alternative Route and Comparison

a. Environmental Impacts of the Proposed Facilities along the Alternative Route and Comparison

In this Section, the Siting Board evaluates the environmental impacts of the proposed facilities under the alternative route. First, as part of its evaluation, the Siting Board addresses whether the petitioner has provided sufficient information regarding the alternative route for the Siting Board to determine whether the environmental impacts of the proposed facilities would be minimized, and whether the proposed facilities would achieve the appropriate balance among environmental impacts and between cost and environmental impacts. If necessary for its review, the Siting Board separately addresses whether the environmental impacts of the proposed facilities along the alternative route would be minimized, with potential mitigation. Finally, in order to determine a best route, the Siting Board compares the environmental impacts of the Primary Configuration to the environmental impacts of the alternative route.

i. Water Resources

BECo stated that wetlands occur on and in the vicinity of the alternative route for the proposed facilities (Exh. BE-1, at 5-15). The Company indicated that the underground T&D line routes would be located within existing roadways, thus avoiding direct disturbance of wetland resources adjacent to the roadway layout (id. at 5-16 to 5-18). The Company stated that the T&D facilities along the alternative route would cross a total of three culverts, one which enables a hydrological link between wetlands on both sides of East Street in Upton, and two others which convey water flow between the north and south portions of North Pond along a 1,500 foot section of West Main Street in Hopkinton (id.).[92] The Company stated that the West Main Street causeway is elevated in the vicinity of North Pond, but added that groundwater could be encountered during excavation (id.; Exh. Upton 4). BECo stated that because there are no uplands in the immediate vicinity of where dewatering the trench might be necessary, the proper discharge of trench water would be difficult and likely require the use of a settling tank or a wetland filter bag to ensure effective sediment removal prior to discharge into North Pond (Exhs. BE-1, at 5-16 to 5-18; Upton 5). The Company stated that the proposed facilities along the alternative route would not cross or otherwise impact the 100-year floodplain (Exh. BE-1, at 5-18).

BECo stated that a habitat of rare wetlands wildlife is estimated to occur in two areas along the alternative route, but added that construction activities would not directly impact these areas (id. at 5-20; Exh. Upton 2; Tr. 6, at 81-83).[93]

The Company stated that the alternative transmission station and substation sites are located in upland areas, and would not require dewatering activities (Exh. BE-1, at 5-19). The Company further stated that the proposed facilities along the alternative route would not traverse, or be placed in proximity to any water resource designated as an ORW (id.). The Company stated that the public water supply system in Hopkinton extends along the portion

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92 BECo stated that the underground pipes carrying the two transmission lines would be placed beneath an existing shallow culvert (Exh. BE-1, at 5-18). With regard to the placement of the underground distribution lines, BECo indicated that surface waters would be encountered in the vicinity where the two additional culverts would be crossed (id.).

93 The Company indicated that the rare species in the wetland area off East Street is a Spotted Turtle (*Clemmys guttata*) (Exh. Upton 2). BECo's witness, Mr. Stuart, testified that the rare species in the wetland area near North Pond was not identified in a letter from the Massachusetts Division of Fisheries and Wildlife (Exh. Upton 2, (att.); Tr. 6, at 81-82).

of the alternative route on West Main Street (Exh. HO-RR-9). The Company noted that the Hopkinton water supply ends on School Street at the Pine Crest Village Condominiums, and that there is no known town water supply in Upton along the alternative route (id.; Exh. Upton 42). The Company indicated that residences/businesses along East Street in Upton obtain water from private wells (Exh. Upton 42). The Company added that it did not conduct detailed engineering to determine the exact locations of private wells on East Street that could be affected by construction of the alternative facilities (id.).[94]

The record demonstrates that impacts to existing and future water resources from the construction of the proposed facilities could be minimized along the alternative route. The record indicates that the Primary Configuration would involve construction proximate to ORWs, while the alternative route would not. However, the record also demonstrates that the alternative route's construction would be proximate to an estimated habitat of rare wetlands wildlife, and could potentially affect private wells along East Street. On balance, the alternative route could have greater impacts to water resources than the Primary Configuration. Accordingly, the Siting Board finds that the Primary Configuration would be slightly preferable to the alternative route with respect to water resources.

ii. Land Resources

The Company asserted that the land resource impacts from construction of the proposed facilities along the alternative route would be greater than those under the Primary Configuration due to the location of the alternative route substation near protected open space on School Street in Hopkinton (Tr. 6, at 85-86). Specifically, the Company indicated that a portion of the transmission line route and the substation site would abut the protected land (Exh. BE-1, Appendix C).

BECo indicated that approximately 2.5 acres in aggregate would need to be cleared of trees for the alternative facilities, including 1.5 acres for the transmission station and access

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94 BECo stated that if any blasting is required within 100 feet of a private well, it would address any impacts from construction of the project through pre- and post-construction well surveys (Exhs. Upton 42; Upton 2-12).

road, and one acre for the substation and its access road (id. at 5-20; Exh. HO-E-16). The Company indicated that, as with the Primary Configuration, the construction of the alternative route transmission and distribution lines would occur chiefly in existing roadways, thereby minimizing tree clearing impacts (Exh. BE-1, at 5-20). The Company stated that the transmission station and substation sites for the alternative route would be level and well vegetated, thus minimizing the potential for erosion (id.). The Company further stated that bedrock is likely to be encountered only at the existing NEES ROW, where poles would need to be set to tap into the existing transmission lines (id.).

The record demonstrates that impacts of the construction of the proposed facilities along the alternative route with respect to tree clearing, upland vegetation and potential soil erosion would be minimized. However, the record also demonstrates that overall tree clearing impacts for construction of the transmission station, substation, and associated access roads using the alternative route would be 2.5 acres, as compared to 2.0 acres for the Primary Configuration.

Accordingly, the Siting Board finds that the Primary Configuration would be slightly preferable to the alternative route with respect to land resource impacts.

iii. Land Use

BECo asserted that land use impacts from construction of the proposed facilities along the alternative route would be greater than those under the Primary Configuration due to the longer length of underground distribution lines in Hopkinton (Exh. BE-1, at 5-28). The Company stated that the length of the new distribution circuits would be over two miles using the alternative route, compared to approximately 2,000 feet under the Primary Configuration (id. at 5-23).

The Company stated that the proposed facilities along the portion of the alternative route in Upton would be located within an Agricultural-Residential zoning district (id. at 5-22). The Company further stated that, in Hopkinton, the remaining portion of the transmission line route and the substation site would be located in an Agricultural zoning district, while the distribution line route would be located within Agricultural, Residential, and Industrial zoning districts (id. at 5-23). The Company indicated that the same structures, buildings, and equipment as proposed under the Primary Configuration would be used at the alternative transmission station and substation sites (Exhs. Upton 12; Upton 23).

The Company indicated that approximately 18 residences along East and School Streets would be affected by construction of the underground transmission line, compared to approximately 19 residences under the Primary Configuration's transmission route (Exhs. HO-E-10b, Table E-10b-3; Upton 33).[95] The Company indicated that approximately 68 residences would be affected by construction of the underground distribution lines, compared to no residences or other sensitive receptors under the Primary Configuration's distribution line route (Exh. HO-E-10b, Table E-10b-4). The Company further indicated that the distance from the nearest residence to the substation would be 300 feet, and the distance from the nearest residence to the distribution line route would be eight feet (Exh. HO-E-10a).

With respect to traffic impacts, the Company stated that police details and plastic barrels would be used during construction along East Street to maintain one lane of traffic, and added that steel plates would be used to maintain traffic at intersections and driveways (Exhs. Upton 51; Upton 2-13; Upton 2-15).[96] With respect to the longer underground distribution facilities necessary along the alternative route, the Company stated that underground distribution construction proceeds more slowly than that required for underground transmission (Exh. BE-1, at 5-23). The Company further stated that the portion of distribution line route along West Main and South Streets is heavily travelled (id. at 5-24). The Company added that upon completion of construction it would provide funds for re-paving the full width of those roadways affected by excavation and placement of the proposed facilities (Exhs. Upton 58; Upton 59; HO-E-9).

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95 The Company stated that only two businesses are located along the alternative route between the transmission station site in Upton and the intersection of West Main and School Streets in Hopkinton (Exh. Upton 34).

96 The Company confirmed that East Street would be opened for two-way traffic during non-construction hours, and that steel plates would be used to cover any open trenches (Exh. Upton 52).

The Company stated that it did not perform an analysis of the potential noise impacts of the alternative facilities (Exhs. BE-1, at 5-23; Upton 45). However, the Company indicated that the proposed low-noise transformers, large parcel size for the alternative substation site, and use of a three-sided sound barrier, if necessary, would ensure facility operation within the Massachusetts Department of Environmental Policy and local noise regulation guidelines (Exhs. BE-1, at 5-23; Upton 45; Upton 46).

Regarding potential cultural resource impacts, the Company stated that it reviewed files at the MHC to determine if any historical or archaeological resources were present in the vicinity of the alternative route (Exh. BE-1, at 5-24). The Company determined that one building along East Street in Upton was identified in the historic inventory (Exhs. Upton 39; HO-E-22, (att.)).[97] The Company stated that the MHC has determined that the proposed project along the alternative route would not have any adverse impact on historic resources (Exh. Upton 2-11).[98]

With respect to potential archeological impacts, the Company stated that two archeological sites were identified along the route for the alternative distribution facilities (Exh. HO-RR-10). The Company stated that one site includes the shoreline and areas of North Pond, including portions of West Main Street, while the other site includes a 1,000 foot length of West Main Street in the vicinity of the causeway at North Pond, extending to the north and south sides of the roadway (id.).

Richard A. Amato, representing the Amato Farm Partnership ("AFP"), stated that his colonial-era home is located six feet[99] from the edge of East Street, thus increasing the

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97 The Company indicated that the historic property is located on the west side of East Street, approximately 1,000 feet from the proposed location of the transmission station (Exh. HO-E-22, (att)).

98 BECo stated that although no areas of shallow bedrock are expected along the alternative route, it would follow all applicable federal, state, and local guidelines if any blasting activities are necessary (Exhs. BE-1, at 5-24; Upton 41).

99 BECo also identified Mr. Amato's home at 11 East Street as the closest residence, at six feet, to the alternative transmission line route (Exh. HO-E-10a, Table E-10a-2).

likelihood of adverse construction impacts to the home's fieldstone foundation (Exh. RAA-1, at 1, 4).[100] Mr. Amato stated that construction of the underground transmission line along both East and School Streets would adversely impact adjacent properties in Upton and Hopkinton, respectively, owned and operated by the AFP (Exh. RAA-1). Mr. Amato further stated that during the spring and summer, the public is invited to harvest strawberries on the premises, and that convenience and country atmosphere are the principle attractions for AFP's customers (id. at 3).

The record demonstrates that the proposed transmission facilities along the alternative route would traverse agricultural/residential and agricultural zoning districts while the associated substation and distribution facilities would traverse agricultural, residential, and industrial zoning districts. The record also demonstrates that construction of the alternative facilities would occur in more residentially populated areas than would the Primary Configuration. Construction would also affect active agricultural property, open to the public, along the transmission line route.

In addition, the record indicates that although the alternative transmission lines are marginally shorter than those under the Primary Configuration, the new underground distribution facilities would be considerable longer. These longer distribution facilities would require a significantly longer construction period, thus greatly increasing the potential for local traffic impacts and related impacts to residences and businesses along that portion of the alternative route. With respect to potential noise impacts, the record demonstrates that the nearest residence to the substation site is closer at the alternative site than under the Primary Configuration. Potential impacts to archeological resources would be greater along the alternative route, although potential impacts to historic properties would be greater under the Primary Configuration.

100 Mr. Amato explained that a dormant electrical conduit that extends from his home's foundation and passes under East Street could be severed during excavation, causing damage to the foundation (Exh. RAA-1, at 4).

Accordingly, on balance, the Siting Board finds that the Primary Configuration would be preferable to the proposed facilities along the alternative route with respect to land use impacts.

iv. Visual Impacts

BECo indicated that, as with the Primary Configuration, visual impacts of the proposed facilities along the alternative route would be limited to views of the aboveground facilities, including the transmission station and the substation (Exh. BE-1, at 5-20).

The Company stated that the alternative transmission station site in Upton is a 31.6-acre undeveloped parcel in an agricultural/residential zone with access to East Street in Upton and to the NEES ROW (id. at 5-22). The Company stated that the access road to the transmission station would be located between an existing private driveway on East Street and the existing NEES ROW (Exh. Upton 18). The Company stated that the transmission station would be located adjacent to the north side of the NEES ROW, as far as possible from the nearest residence (Exh. BE-1, at 5-22). The Company indicated that the nearest residence, located on East Street in Upton, would be situated 565 feet from the transmission station site (Exh. HO-E-10a, Table E-10a-2). The Company's witness, Mr. Stuart, testified that there are approximately three to four residences within 1,000 feet of the alternative transmission station site (Tr. 6, at 72-73). Mr. Stuart also testified that the proposed transmission station would have greater visual impacts at the alternative site than at the primary site, due chiefly to a rise in topography from East Street, where the existing NEES 115-kV transmission lines cross (id. at 73-74). The Company stated that most of the area surrounding the transmission station would remain forested, and that landscaping would be used to screen any openings providing views of the transmission station site from residences (Exhs. BE-1, at 5-22; Upton 16).

The Company stated that the alternative substation site in Hopkinton is an 18.3-acre undeveloped wooded parcel in an Agricultural zone, the east side of which is adjacent to School Street (Exhs. BE-1, at 5-22 to 5-23; Upton 21). The Company stated that the access road into the substation would be from School Street (Exhs. Upton 29; Upton 30). The

Company also stated that sensitive receptors are located beyond the north and northwest sides of the substation site adjacent to West Main Street (Exh. BE-1, at 5-22). The Company indicated that an undeveloped wooded area is located to the west of the substation site, and a farm field is to the south (id.; Exh. Upton 22). The Company also indicated that the nearest residence to the alternative substation site would be located on School Street in Hopkinton, 300 feet away (Exh. HO-E-10a, Table E-10a-2). The Company further stated that the surrounding woodland will provide significant natural screening of the substation facilities, and added that it would landscape the site to screen any openings providing views of the facilities to nearby residences (Exh. BE-1, at 5-22).

The record demonstrates that the visual impacts of the proposed facilities along the alternative route would be greater than those under the Primary Configuration due to the higher elevation of the alternative transmission station site. Accordingly, the Siting Board finds that the Primary Configuration would be preferable to the proposed facilities along the alternative route with respect to visual impacts.

v. Magnetic Field Levels

The Company indicated that the design of the alternative facilities would be identical to that of the proposed facilities, and that the alternative facilities would operate at the same power level as the proposed facilities (Exh. BE-1, at 5-23). Therefore, the Company stated that magnetic field increases along the new transmission line would be the same for the proposed and alternative facilities (id.). The Company indicated that there are 18 residences within 100 feet of the alternative transmission line route (Exh. HO-E-10, Table E-10b-3).

However, the Company stated that although the distribution lines would be constructed underground along South Street for a portion of the route, the overall route of the underground distribution facilities would traverse a mixed land use area (Exh. BE-1, at 5-23; Tr. 6, at 127, 130). The Company indicated that there are approximately 68 residences located within 100 feet of the alternative distribution line route (Exh. HO-E-10, Table E-10b-4).

The record indicates that the magnetic field impacts of the proposed facilities along the alternative route would be greater than under the Primary Configuration. The record demonstrates that the underground transmission lines along the alternative route would emit the same magnetic field levels, with the transmission line segment marginally shorter than under the Primary Configuration. However, the record also demonstrates that the alternative route's underground distribution facilities extending from the substation would traverse more heavily populated residential areas before terminating into the existing distribution network on South Street in Hopkinton. Therefore, the longer underground distribution facilities along the alternative route would result in a greater overall magnetic field impact due to the presence of 68 residences in proximity to the roadways where these distribution facilities would be located, and the presence of distribution-level currents and correspondingly high magnetic fields.

Accordingly, the Siting Board finds that the Primary Configuration would be preferable to the alternative route with respect to magnetic field levels.

vi. Conclusions on Environmental Impacts

In Sections III.C.3.a(i) to (v), above, the Siting Board has found that the Primary Configuration would be slightly preferable to the proposed facilities along the alternative route with respect to water resources and land resource impacts and preferable to the proposed facilities along the alternative route with respect to land use, visual and magnetic field impacts. Accordingly, the Siting Board finds that the Primary Configuration would be preferable to the proposed facilities along the alternative route with respect to environmental impacts.

b. Cost of the Proposed Facility along the Alternative Route and Comparison

BECo indicated that construction of the Primary Configuration is the least-cost alternative based on its analysis of construction, materials and equipment, and land acquisition, as compared to the alternative facilities (Exhs. BE-1, at 5-14 to 5-15, 5-24;

DV 1.1-2; DV 1.1-3; DV 1.1-8). BECo submitted estimates of installation costs for the alternative configuration (Exhs. DV 1.1-2; DV 1.1-8). BECo explained that its estimates of installation costs for the alternative configuration included costs of 115-kV transmission, 14-kV distribution, a new transmission station and 115/14-kV substation, and land acquisition costs (Exh. DV 1.1-2).

BECo stated that it estimated installation costs at $13,893,750 for the alternative facilities, as compared to $12,547,000 for the Primary Configuration (id.; Exh. DV 1.1-3).

	Proposed Facilities	Alternative Facilities
Distribution	$502,000	$ 2,168,750
Transmission Station/Substation	8,250,000	8,325,000
Transmission Line	3,400,000	2,900,000
Land Acquisition	395,000	500,000
Total Cost	$12,547,000	$13,893,750

Source of Table: Summary of Exhs. DV 1.1-2; DV 1.1-3

BECo indicated that costs of the Primary Configuration would be lower than those of the alternative facilities due primarily to significantly lower distribution costs and lower transmission costs (Exhs. DV 1.1-2; DV 1.1-3). BECo further indicated that the significant increase in 14-kV distribution costs associated with the alternative facilities is due to the alternative route's longer distribution facility length compared to that under the Primary Configuration (Exh. BE-1, at 5-23, 5-28).

The record demonstrates that the installation costs of the alternative facilities would be nearly 11 percent higher than corresponding costs for the Primary Configuration. Accordingly, the Siting Board finds that the Primary Configuration would be preferable to the alternative facilities with respect to cost.

c. Conclusions

In comparing the Primary Configuration to the alternative facilities, the Siting Board has found that the proposed facilities under the Primary Configuration would be preferable to the alternative facilities and route with respect to (1) environmental impacts, and (2) costs.

Accordingly, the Siting Board finds that the proposed facilities under the Primary Configuration would be preferable to the alternative facilities and route with respect to providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

IV. ZONING EXEMPTIONS/PUBLIC CONVENIENCE AND INTEREST

As noted in Section I.C, above, the Company filed two petitions with the Department, which are related to the proposed project under consideration by the Siting Board in the present proceeding and which have been consolidated for review in the Company's Siting Board proceeding. In one petition, the Company, pursuant to G.L. c. 164, § 72, sought a determination by the Department that BECo's proposed electric transmission line, transmission station, substation and distribution facilities are necessary and will serve the public convenience and be consistent with the public interest. In its other petition, the Company, pursuant to G.L. c. 40A, § 3, sought exemptions from the zoning by-laws of (1) the Town of Milford for the proposed transmission line and transmission station, and (2) the Town of Hopkinton for the proposed transmission line, substation and distribution facilities. Pursuant to G.L. c. 164, § 69H(2), the Siting Board applies the Department's standards of review for such petitions to the subject matter of the Company's petitions in a manner consistent with the above findings of the Siting Board.[101]

A. Standard of Review

In its petition for a zoning exemption, the Company seeks approval under G.L. c. 40A, § 3, which, in pertinent part, provides:

> Land or structures used, or to be used by a public service corporation may be exempted in particular respects from the operation of a zoning ordinance or by-law if, upon petition of the corporation, the [D]epartment of [P]ublic [U]tilities shall, after notice given pursuant to section eleven and public hearing in the town or city, determine the exemptions required and find that

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101 The Siting Board notes that the Town of Milford was a signatory to a Settlement Agreement with the Company in which the Town of Milford agreed to "withdraw [its] opposition to the preferred project as described in the [Siting Board and Department] proceedings" (Exh. HO-RR-11(att.)). Accordingly, the Town of Milford is not opposed to a determination that the proposed project is necessary and will serve the public convenience or to the granting of a zoning exemption for the proposed project. Further, the Town of Hopkinton specifically supported the approval of the Company's petitions in its Petition to Intervene (Hopkinton Petition at 2).

> the present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public....

Under this section, the Company first must qualify as a public service corporation (see Save the Bay, Inc. v. Department of Public Utilities, 366 Mass. 667 (1975)), and establish that it requires an exemption from the local zoning by-laws. The Company then must demonstrate that the present or proposed use of the land or structure is reasonably necessary for the public convenience or welfare.

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

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

Save the Bay, 366 Mass. at 680.

In determining whether the present or proposed use is reasonably necessary for the public convenience or welfare, the Department must balance the interests of the general public against the local interest. Id. at 685-686; Town of Truro v. Department of Public Utilities, 365 Mass. 407 (1974). Specifically, the Department is empowered and required to undertake "a broad and balanced consideration of all aspects of the general public interest and welfare and not merely [make an] examination of the local and individual interests which might be affected." New York Central Railroad v. Department of Public Utilities, 347 Mass. 586, 592 (1964). When reviewing a petition for a zoning exemption under G.L. c. 40A, § 3, the Department is empowered and required to consider the public effects of the requested exemption in the State as a whole and upon the territory served by the applicant. Save the Bay, supra, at 685; New York Central Railroad, supra, at 592.

With respect to the particular site chosen by a petitioner, G.L. c. 40A, § 3 does not require the petitioner to demonstrate that its preferred site is the best possible alternative, nor does the statute require the Department to consider and reject every possible alternative site presented. Martarano v. Department of Public Utilities, 401 Mass. 257, 265 (1987); New

York Central Railroad, supra, at 591; Wenham v. Department of Public Utilities, 333 Mass. 15, 17 (1955). Rather, the availability of alternative sites, the efforts necessary to secure them, and the relative advantages and disadvantages of those sites are matters of fact bearing solely upon the main issue of whether the preferred site is reasonably necessary for the convenience or welfare of the public. Id.

Therefore, when making a determination as to whether a petitioner's present or proposed use is reasonably necessary for the public convenience or welfare, the Department examines: (1) the present or proposed use and any alternatives or alternative sites identified (see Massachusetts Electric Company, D.P.U. 93-29/30, at 10-14, 22-23 (1995) ("1995 MECo Decision"); New England Power Company, D.P.U. 92-278/279/280, at 19 (1994) ("1994 NEPCo Decision"); Tennessee Gas Pipeline Company, D.P.U. 85-207, at 18-20 (1986)) ("1986 Tennessee Decision"); (2) the need for, or public benefits of, the present or proposed use (see 1995 MECo Decision, supra, at 10-14; 1994 NEPCo Decision, supra, at 19-22; 1986 Tennessee Decision, supra, at 17); and (3) the environmental impacts or any other impacts of the present or proposed use (see 1995 MECo Decision, supra, at 14-21; 1994 NEPCo Decision, supra, at 20-23; 1986 Tennessee Decision, supra, at 20-25). The Department then balances the interests of the general public against the local interest, and determines whether the present or proposed use of the land or structures is reasonably necessary for the convenience or welfare of the public.[102]

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[102] In addition, the Massachusetts Environmental Policy Act ("MEPA") provides that "[a]ny determination made by an agency of the commonwealth shall include a finding describing the environmental impact, if any, of the project and a finding that all feasible measures have been taken to avoid or minimize said impact." G.L. c. 30, § 61. Pursuant to 301 C.M.R. § 11.01(3), these findings are necessary when an Environmental Impact Report ("EIR") is submitted by the company to the Secretary of Environmental Affairs, and should be based on such EIR. Where an EIR is not required, c. 30, § 61 findings are not necessary. 301 C.M.R. § 11.01(3). In the present case, the Secretary of Environmental Affairs issued her determination that no EIR was required for the proposed project (See Certificate of the Secretary of Environmental Affairs on the Environmental Notification Form, EOEA No. 10840, dated August 30, 1996), and, therefore, a finding is not necessary in this case under G.L. c. 30, § 61.

With respect to the Company's petition filed pursuant to G.L. c. 164 § 72, the statute requires, in relevant part, that an electric company seeking approval to construct a transmission line must file with the Department a petition for:

> authority to construct and use . . . a line for the transmission of electricity for distribution in some definite area or for supplying electricity to itself or to another electric company or to a municipal lighting plant for distribution and sale . . . and shall represent that such line will or does serve the public convenience and is consistent with the public interest. . . . The [D]epartment, after notice and a public hearing in one or more of the towns affected, may determine that said line is necessary for the purpose alleged, and will serve the public convenience and is consistent with the public interest.[103]

The Department, in making a determination under G.L. c. 164, § 72, is to consider all aspects of the public interest. Boston Edison Company v. Town of Sudbury, 356 Mass. 406, 419 (1969). Section 72, for example, permits the Department to prescribe reasonable conditions for the protection of the public safety. Id. at 419-420. All factors affecting any phase of the public interest and public convenience must be weighed fairly by the Department in a determination under G.L. c. 164, § 72. Town of Sudbury v. Department of Public Utilities, 343 Mass. 428, 430 (1962).

As the Department has noted in previous cases, the public interest analysis required by G.L. c. 164, §72 is analogous to the Department's analysis of the "reasonably necessary for the convenience or welfare of the public" standard under G.L. c. 40A, § 3. See, New England Power Company, D.P.U. 89-163, at 6 (1993); New England Power Company, D.P.U. 91-117/118, at 4 (1991); Massachusetts Electric Company, D.P.U. 89-135/136/137, at 8 (1990). Accordingly, in evaluating petitions filed under G.L. c. 164, § 72, the Department relies on the standard of review for determining whether the proposed project is reasonably necessary for the convenience or welfare of the public under G.L. c. 40A, § 3. Id.

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103 Pursuant to the statute, the electric company must file with its petition a general description of the transmission line, provide a map or plan showing its general location, and estimate the cost of the facilities in reasonable detail. G.L. c. 164, § 72.

B. Analysis and Findings

BECo is an electric company as defined by G.L. c. 164, § 1, authorized to generate, distribute and sell electricity. Boston Edison Company, D.P.U. 87-74 (1987). Accordingly, BECo is authorized to petition the Department as public service corporations for the determinations sought under G.L. c. 40A, § 3, in this proceeding.

G.L. c. 40A, § 3, authorizes the Department to grant to public service corporations exemptions from local zoning ordinances or by-laws if the Department determines that the exemption is required and finds that the present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public. With respect to the Company's petition filed pursuant to G.L. c. 40A, § 3, the Company seeks exemptions from the operation of: (1) Article 1, § 1.4 (Building Permits), § 1.5 (Certificate of Zoning Compliance), and § 1.15 (Site Plan Review); and Article II, §2.2 (Use Regulation) and § 2.3 (Use Regulation Schedule) of the Town of Milford Zoning By-laws; and (2) Article Two, § F.19 (Uses Permitted by Right), § 23 (Earth Removal), § 25 (Off Street Parking), and Article Three, § 29(3) Administration and Procedure -- Special Permit) of the Town of Hopkinton Zoning By-laws. Based on its review of the zoning by-laws of the Town of Milford and the zoning by-laws of the Town of Hopkinton, the Siting Board concludes that some or all of these sections could impede the construction, operation and maintenance of the Company's proposed transmission line, transmission station, substation and distribution facilities. Therefore, the Siting Board finds that the Company requires exemptions from the operation of the above-listed sections of the Town of Milford Zoning By-laws and the Town of Hopkinton Zoning By-laws for the construction, operation and maintenance of the proposed project.

Pursuant to G.L. c. 40A, § 3, the Siting Board next examines whether the company's proposed use of the land and structures as set forth in its petitions is reasonably necessary for the convenience or welfare of the public. In making its findings, the Siting Board relies on the analyses in Sections II and III, above. In those sections, the Siting Board found that the Company' reliability criteria are reasonable for purposes of this review, and that the Company's 1997 contingency analysis provides a reasonable basis for establishing need in this review (see Sections II.A.3.a. and c, above). The Siting Board also found that the Company's contingency analysis demonstrates that under the worst-case single contingency with the present configuration, (1) emergency ratings on one or more existing distribution lines in Hopkinton would be exceeded beginning in 1997, and (2) the voltage level on an existing distribution line in Hopkinton would be inconsistent with system reliability criteria beginning in 1997 in contravention of the Company's reliability criteria. The Siting Board also concluded that the peak load in Hopkinton is likely to reach the level underlying the Company's 1997 contingency analysis within the 1997-2000 time frame. In addition, the Siting Board also found that the frequency of interruptions in the HSA is higher than system norms, and considered together with the other existing and expected violations of system reliability criteria in the HSA, such frequency of interruptions is inconsistent with the operation of a reliable system. Therefore, the Siting Board found that there is a need for additional energy resources in Hopkinton based on BECo's reliability criteria.

In addition, the Siting Board found that the Company has demonstrated that acceleration of C&LM programs could not eliminate the identified need in Hopkinton for additional energy resources (see Sections II.A.3.d. and e, above). Consequently, the Siting Board found that additional energy resources currently are needed for reliability purposes in Hopkinton, and therefore, are reasonably necessary for the convenience or welfare of the public in the Hopkinton area.

The Siting Board notes that the Company evaluated a reasonable range of alternatives to the proposed project, including three project alternatives and one alternative facility configuration, in developing its strategy to supply Hopkinton with a reliable supply of electrical power. The record further indicates that the Company considered possible environmental impacts of the proposed transmission line, transmission station, substation and distribution facilities that may be of concern to the surrounding community, including water resources, land resources, land use, visual impacts, and magnetic field level impacts. The record indicates that the Company would implement measures to mitigate these impacts.

Thus, with the implementation of the mitigation measures identified by the Company, the Siting Board finds that the general public interest in the construction, operation and maintenance of the proposed transmission line, transmission station, substation and distribution facilities outweighs the minimal impacts of the Company' proposed project on the local community. Accordingly, the Siting Board finds that the proposed transmission line, transmission station, substation and distribution facilities are reasonably necessary for the convenience or welfare of the public and exempts BECo from the operation of the above-listed sections of the Zoning By-laws of the Town of Milford and the Zoning By-laws of the Town of Hopkinton.

With regard to the Company's petition filed pursuant to G.L. c. 164, § 72, the Siting Board notes that the Company has complied with the requirements that it describe the proposed transmission line, provide a map or plan showing its general location, and estimate its cost in reasonable detail. Consistent with Department precedent and the public interest analysis above, the Siting Board here finds that BECo's proposed transmission line is necessary for the purpose alleged, and will serve the public convenience and is consistent with the public interest.

V. DECISION

The Siting Board has found that the Company has established that additional energy resources currently are needed for reliability purposes in Hopkinton.

The Siting Board also has found that both the proposed project and the local generation alternative would meet the identified need but that the proposed project is preferable to the local generation alternative.

The Siting Board further has found that the Company has considered a reasonable range of practical siting alternatives.

The Siting Board further has found that, with the implementation of proposed mitigation and planned compliance with all applicable local, state, and federal requirements, the environmental impacts of the proposed facilities under the Primary Configuration would be minimized.

The Siting Board further has found that the proposed facilities under the Primary Configuration would achieve an appropriate balance among conflicting environmental concerns as well as between environmental impacts and cost.

Finally, the Siting Board has found that the proposed facilities under the Primary Configuration would be preferable to the alternative facilities and route with respect to providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In addition, the Siting Board finds that the proposed project is consistent with the most recently approved long-range forecast of BECo.

Accordingly, the Siting Board APPROVES the Company's petition to construct two 1.3-mile long, 115-kilovolt underground electric transmission lines; a transmission station; a 115/14-kilovolt substation; and distribution facilities in the towns of Hopkinton and Milford, Massachusetts using the Company's preferred sites and routes.

In addition, the Siting Board finds that BECo's proposed transmission line is necessary for the purpose alleged, and will serve the public convenience and is consistent with the public interest; and

The Siting Board GRANTS the Company's petition for an exemption from the operation of: Article 1, § 1.4, § 1.5, and § 1.15; and Article II, § 2.2 and § 2.3 of the Town of Milford Zoning By-laws; and from Article Two, § F.19, § 23, and § 25, and Article Three, § 29(3) of the Town of Hopkinton Zoning By-laws for the purposes of constructing and operating the proposed transmission line, transmission station and substation.

The Siting Board notes that the findings in this decision are based on the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

Robert P. Rasmussen
Hearing Officer

Dated this 22nd day of December, 1997

APPROVED by a majority vote of the Energy Facilities Siting Board at its meeting of December 19, 1997 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Sonia Hamel, Acting Chair (for Trudy Coxe, Secretary, Executive Office of Environmental Affairs); John D. Patrone (Commissioner, DTE); James Connelly (Commissioner, DTE); David L. O'Connor (for David A. Tibbetts, Director, Department of Economic Development); and Joseph Faherty (Public Member). Nancy Brockway (Public Member) abstained from voting.

Sonia W. Hamel

Sonia Hamel
Acting Chair

Dated this 22nd day of December, 1997

Appeal as to matters of law from any final decision, order or ruling of the Siting Board may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Siting Board be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).